



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

April 30, 2012

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

Re: May 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 May 2012.

Pursuant to the Commission’s authorization of the final compliance tariffs in the Company’s 2010 rate proceeding (Docket No. PU-10-657), the new rates will be implemented on May 1, 2012. The new Service Category Ratio listed below will also become effective:

Service Category Ratios	Current	Effective May 1, 2012
Residential	0.9956	1.0026
C & I Non-Demand	1.0548	1.0281
C & I Demand	1.0219	1.0170
C & I Demand Time of Day On-Peak	1.3135	1.2883
C & I Demand Time of Day Off-Peak	0.7726	0.7889
Outdoor Lighting	0.7088	0.7440

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

May 2012	Fuel Cost Charge (\$/kWh)
Residential	0.02534
C & I Non-Demand	0.02662
C & I Demand	0.02593
C & I Demand Time of Day On-Peak	0.03321
C & I Demand Time of Day Off-Peak	0.01973
Outdoor Lighting	0.01823

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 April 6, 2005 Order in Docket No. PU-05-147 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 types¹, 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 May 2012 FCC the net MISO Day 2 costs for March 2012 as recorded in Account 555. The MISO Day 2 cost recovery included in this May FCC is \$16,971,523, 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.

¹ Previously embedded in other FTR charge types.

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 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 May FCC the net MISO ASM costs for March 2012 as recorded in Account 555. The MISO ASM cost recovery included in this May FCC is \$220,051, 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 May 2012 Asset Based Margin amount of \$20,517 has been included in the May 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 May FCC is \$15,506, or 0.009¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

OTHER REPORTING ITEM

Attached is the calculation of the May 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 May-2012

May-2012 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02604	-\$0.00043	-\$0.00021	\$0.02540
Residential	\$0.02597	-\$0.00043	-\$0.00021	\$0.02534
C & I Non-Demand	\$0.02729	-\$0.00045	-\$0.00022	\$0.02662
C & I Demand Non-TOD	\$0.02658	-\$0.00044	-\$0.00021	\$0.02593
C & I Demand TOD On-Peak	\$0.03404	-\$0.00056	-\$0.00027	\$0.03321
C & I Demand TOD Off-Peak	\$0.02023	-\$0.00033	-\$0.00016	\$0.01973
Outdoor Lighting	\$0.01869	-\$0.00031	-\$0.00015	\$0.01823
Residential				
Residential Service	\$ 0.02597	\$ (0.00043)	\$ (0.00021)	\$ 0.02534
Residential TOD	\$ 0.02597	\$ (0.00043)	\$ (0.00021)	\$ 0.02534
Residential - Underground	\$ 0.02597	\$ (0.00043)	\$ (0.00021)	\$ 0.02534
Residential TOD - Underground	\$ 0.02597	\$ (0.00043)	\$ (0.00021)	\$ 0.02534
Energy Control - (Non-Demand)	\$ 0.02597	\$ (0.00043)	\$ (0.00021)	\$ 0.02534
Limit Off Peak	\$ 0.02597	\$ (0.00043)	\$ (0.00021)	\$ 0.02534
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02729	\$ (0.00045)	\$ (0.00022)	\$ 0.02662
Limit Off Peak	\$ 0.02729	\$ (0.00045)	\$ (0.00022)	\$ 0.02662
Small General Service	\$ 0.02729	\$ (0.00045)	\$ (0.00022)	\$ 0.02662
Small General TOD - Metered	\$ 0.02729	\$ (0.00045)	\$ (0.00022)	\$ 0.02662
Small General TOD - Unmetered	\$ 0.02729	\$ (0.00045)	\$ (0.00022)	\$ 0.02662
Fire and Civil Defense Siren	\$ 0.02729	\$ (0.00045)	\$ (0.00022)	\$ 0.02662
Direct Current (Closed)	\$ 0.02729	\$ (0.00045)	\$ (0.00022)	\$ 0.02662
C & I Demand				
General Service	\$ 0.02658	\$ (0.00044)	\$ (0.00021)	\$ 0.02593
General TOD - On Peak	\$ 0.03404	\$ (0.00056)	\$ (0.00027)	\$ 0.03321
General TOD - Off Peak	\$ 0.02023	\$ (0.00033)	\$ (0.00016)	\$ 0.01973
Peak Controlled (Closed)	\$ 0.02658	\$ (0.00044)	\$ (0.00021)	\$ 0.02593
Peak Controlled TOD (Closed) - On Peak	\$ 0.03404	\$ (0.00056)	\$ (0.00027)	\$ 0.03321
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02023	\$ (0.00033)	\$ (0.00016)	\$ 0.01973
Peak Controlled Tiered	\$ 0.02658	\$ (0.00044)	\$ (0.00021)	\$ 0.02593
Peak Controlled Tiered TOD - On Peak	\$ 0.03404	\$ (0.00056)	\$ (0.00027)	\$ 0.03321
Peak Controlled Tiered TOD - Off Peak	\$ 0.02023	\$ (0.00033)	\$ (0.00016)	\$ 0.01973
Energy Controlled (Closed)	\$ 0.02658	\$ (0.00044)	\$ (0.00021)	\$ 0.02593
Tier 1 Energy Controlled Rider	\$ 0.02658	\$ (0.00044)	\$ (0.00021)	\$ 0.02593
Real Time Pricing - Firm - On Peak	\$ 0.03404	\$ (0.00056)	\$ (0.00027)	\$ 0.03321
Real Time Pricing - Firm - Off Peak	\$ 0.02023	\$ (0.00033)	\$ (0.00016)	\$ 0.01973
Real Time Pricing - Controllable - On Peak	\$ 0.03404	\$ (0.00056)	\$ (0.00027)	\$ 0.03321
Real Time Pricing - Controllable - Off Peak	\$ 0.02023	\$ (0.00033)	\$ (0.00016)	\$ 0.01973
Small Municipal Pumping	\$ 0.02658	\$ (0.00044)	\$ (0.00021)	\$ 0.02593
Municipal Pumping	\$ 0.02658	\$ (0.00044)	\$ (0.00021)	\$ 0.02593
Excess Energy - St. Anthony Falls	\$ 0.02658	\$ (0.00044)	\$ (0.00021)	\$ 0.02593
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01869	\$ (0.00031)	\$ (0.00015)	\$ 0.01823
Street Lighting System	\$ 0.01869	\$ (0.00031)	\$ (0.00015)	\$ 0.01823
Street Lighting Energy	\$ 0.01869	\$ (0.00031)	\$ (0.00015)	\$ 0.01823
Street Lighting Energy - Metered	\$ 0.01869	\$ (0.00031)	\$ (0.00015)	\$ 0.01823
Street Lighting Energy (Closed)	\$ 0.01869	\$ (0.00031)	\$ (0.00015)	\$ 0.01823
Street Lighting - City of St. Paul	\$ 0.01869	\$ (0.00031)	\$ (0.00015)	\$ 0.01823

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Dec-11	Jan-12	Feb-12	Mar-12	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$35,655,438	\$35,849,644	\$40,360,850	\$29,391,806	\$141,257,738
Account 518 - Nuclear Fuel	\$10,116,633	\$11,312,463	\$9,507,504	\$7,698,699	\$38,635,298
Account 555 - Purchased Power ¹	\$33,477,192	\$41,565,189	\$33,040,802	\$33,730,196	\$141,813,379
Account 555 - MISO Day 2 Charges	\$16,418,488	\$11,190,335	\$10,098,736	\$17,066,042	\$54,773,600
Account 555 MISO Day 2 - Schedule 24	(\$97,206)	(\$97,091)	(\$95,325)	(\$94,518)	(\$384,141)
Account 555 MISO - ASM Charges	\$1,795,071	\$1,785,816	\$427,337	\$220,051	\$4,228,274
Total MISO Charges	\$18,116,353	\$12,879,060	\$10,430,748	\$17,191,574	\$58,617,734
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$97,365,616	\$101,606,355	\$93,339,903	\$88,012,275	\$380,324,149
Less Fuel Cost of InterSystem Sales	(\$3,793,539)	(\$5,272,759)	(\$5,459,934)	(\$162,610)	(\$14,688,843)
Net System Costs	\$93,572,077	\$96,333,596	\$87,879,969	\$87,849,665	\$365,635,307
System MWh Sales					
Total NSP System Retail	3,404,903	3,719,673	3,348,071	3,386,762	13,859,409
Non-Gen Muni's/Load Pattern	45,419	49,936	51,225	36,800	183,380
Total NSP System MWh Sales	3,450,322	3,769,609	3,399,296	3,423,562	14,042,789
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.712¢	2.556¢	2.585¢	2.566¢	2.604¢
Base Fuel Cost Included in Rates	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢
Class Ratio/TOD Ratio					
(i) Residential	0.9956	0.9956	0.9956	1.0026	0.9974
(ii) C & I Non-Demand	1.0548	1.0548	1.0548	1.0281	1.0481
(iii) C & I Demand Non-TOD	1.0219	1.0219	1.0219	1.0170	1.0207
(iv) C & I Demand TOD On-Peak	1.3135	1.3135	1.3135	1.2883	1.3072
(v) C & I Demand TOD Off-Peak	0.7726	0.7726	0.7726	0.7889	0.7767
(vi) Outdoor Lighting	0.7088	0.7088	0.7088	0.7440	0.7176
North Dakota Fuel Cost Factor (FCF)					
				FCF Ratio	4 Month Average
(i) Residential				0.9974	2.597¢
(ii) C & I Non-Demand				1.0481	2.729¢
(iii) C & I Demand Non-TOD				1.0207	2.658¢
(iv) C & I Demand TOD On-Peak				1.3072	3.404¢
(v) C & I Demand TOD Off-Peak				0.7767	2.023¢
(vi) Outdoor Lighting				0.7176	1.869¢
North Dakota Retail MWh Sales					
(i) Residential	73,282	84,771	77,586	70,777	306,416
(ii) C & I Non-Demand	10,989	12,556	11,587	10,982	46,114
(iii) C & I Demand Non-TOD	61,589	69,869	62,313	64,672	258,443
(iv) C & I Demand TOD On-Peak	17,709	17,204	17,750	18,251	70,914
(v) C & I Demand TOD Off-Peak	29,446	29,986	27,857	29,309	116,598
(vi) Outdoor Lighting	1,989	2,080	1,960	1,686	7,715
(vii) Total	195,004	216,466	199,053	195,677	806,200
May-2012 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Jan-12 Balance of Unrecovered Expenses)					Total
					Jan-12
					(\$205,226)

¹ Excludes demand-related expenses

Prior Expenses Recovered in Mar-2012 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	70,777	(\$12,852)
(ii) C & I Non-Demand	10,982	(\$2,042)
(iii) C & I Demand Non-TOD	64,672	(\$11,988)
(iv) C & I Demand TOD On-Peak	18,251	(\$4,319)
(v) C & I Demand TOD Off-Peak	29,309	(\$3,917)
(vi) Outdoor Lighting	1,686	(\$161)
(vii) Total	195,677	(\$35,279)

Actual Cost Should Have Been Recovered in Mar-12				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.566¢	0.000¢	195,677	\$5,021,072

Cost Recovered in Mar-12 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	70,777	\$1,864,210
(ii) C & I Non-Demand	10,982	\$307,555
(iii) C & I Demand Non-TOD	64,672	\$1,754,868
(iv) C & I Demand TOD On-Peak	18,251	\$636,852
(v) C & I Demand TOD Off-Peak	29,309	\$601,368
(vi) Outdoor Lighting	1,686	\$31,529
(vii) Total	195,677	\$5,196,382

Total Balance of Unrecovered Expenses (May-12 Balance of Unrecovered Expenses)	
May-2012 Recovery Provision	(\$345,257)
4 Month ND Retail Total MWh Sales	806,200
May-2012 Recovery Provision per KWH	-0.043¢

May-2012 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9974	-0.043¢	-0.043¢
(ii) C & I Non-Demand	1.0481	-0.043¢	-0.045¢
(iii) C & I Demand Non-TOD	1.0207	-0.043¢	-0.044¢
(iv) C & I Demand TOD On-Peak	1.3072	-0.043¢	-0.056¢
(v) C & I Demand TOD Off-Peak	0.7767	-0.043¢	-0.033¢
(vi) Outdoor Lighting	0.7176	-0.043¢	-0.031¢

May-2012 Margin Sharing Refunds			
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
Refund/Special Charge Amount	(\$20,517)	(\$15,506)	(\$36,023)
(i) Residential	-0.012¢	-0.009¢	-0.021¢
(ii) C & I Non-Demand	-0.012¢	-0.009¢	-0.022¢
(iii) C & I Demand Non-TOD	-0.012¢	-0.009¢	-0.021¢
(iv) C & I Demand TOD On-Peak	-0.016¢	-0.012¢	-0.027¢
(v) C & I Demand TOD Off-Peak	-0.009¢	-0.007¢	-0.016¢
(vi) Outdoor Lighting	-0.009¢	-0.006¢	-0.015¢

May-2012 Factors	
	Total
(i) Residential	2.534¢
(ii) C & I Non-Demand	2.662¢
(iii) C & I Demand Non-TOD	2.593¢
(iv) C & I Demand TOD On-Peak	3.321¢
(v) C & I Demand TOD Off-Peak	1.973¢
(vi) Outdoor Lighting	1.823¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Apr-12	May-12	Differ- ence	Percent Change	FCA Application Apr-12	May-12	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$141.1	\$141.3	\$0.1	0.1%	36.0%	37.1%	1.1%
2 Nuclear	\$40.5	\$38.6	(\$1.9)	-4.6%	10.3%	10.2%	-0.1%
3 Purchases	\$153.1	\$141.8	(\$11.3)	-7.4%	39.0%	37.3%	-1.7%
MISO related Purchases	\$57.5	\$58.6	\$1.1	2.0%	14.7%	15.4%	0.7%
4 Total System Costs	392.2	380.3	(\$11.9)	-3.0%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$27.2	\$14.7	(\$12.5)	-46.0%	6.9%	3.9%	-3.0%
6 Net System Costs	\$365.0	\$365.6	\$0.6	0.2%	93.1%	96.1%	3.0%
7							
8 ** GWH OUTPUT **							
9 Fossil	4,671	4,215	(456)	-9.8%	25.7%	23.2%	-2.5%
10 Nuclear	4,452	4,232	(220)	-4.9%	24.5%	23.3%	-1.2%
11 Purchases	4,702	4,955	253	5.4%	25.8%	27.3%	1.5%
12 Hydro & Other	1,162	1,607	445	38.3%	6.4%	8.8%	2.4%
13 Net Interchange	3,218	3,170	(48)	-1.5%	17.7%	17.4%	-0.3%
14 Total Output	18,205	18,179	(26)	-0.1%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,036	986	(50)	-4.8%	5.7%	5.4%	-0.3%
16 Native Requirement	17,169	17,193	24	0.1%	94.3%	94.6%	0.3%
17							
18 ** COST per KWH OUTPUT (\$) **							
19 Fossil	3.021	3.351	0.330	10.9%			
20 Nuclear	0.909	0.913	0.004	0.4%			
21 Purchases	3.257	2.862	-0.395	-12.1%			
22 Total System Costs	2.154	2.092	-0.062	-2.9%			
23 Intersystem Sales	2.625	1.490	-1.135	-43.2%			
24 Net System Costs	2.126	2.127	0.001	0.0%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,728	14,043	315	2.3%			
28							
29 COST per KWH SALES (\$)	2.659	2.604	-0.055	-2.1%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.005	-0.043	-0.038				
(i) Residential	-0.005	-0.043	-0.038				
(ii) C & I Non-Demand	-0.005	-0.045	-0.040				
(iii) C & I Demand Non-TOD	-0.005	-0.044	-0.039				
(iv) C & I Demand TOD On-Peak	-0.006	-0.056	-0.050				
(v) C & I Demand TOD Off-Peak	-0.004	-0.033	-0.030				
(vi) Outdoor Lighting	-0.003	-0.031	-0.027				
32 REFUND	-0.041	-0.021	0.020				
(i) Residential	-0.041	-0.021					
(ii) C & I Non-Demand	-0.042	-0.022					
(iii) C & I Demand Non-TOD	-0.042	-0.021					
(iv) C & I Demand TOD On-Peak	-0.053	-0.027					
(v) C & I Demand TOD Off-Peak	-0.032	-0.016					
(vi) Outdoor Lighting	-0.031	-0.015					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.613	2.540	-0.073	-2.8%			
(i) Residential	2.602	2.534	-0.068				
(ii) C & I Non-Demand	2.757	2.662					
(iii) C & I Demand Non-TOD	2.671	2.593					
(iv) C & I Demand TOD On-Peak	3.433	3.321					
(v) C & I Demand TOD Off-Peak	2.019	1.973					
(vi) Outdoor Lighting	1.852	1.823					

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	(\$0.07)
250	(\$0.17)
500	(\$0.34)
750	(\$0.51)
1,000	(\$0.68)

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>	
	Apr-12	May-12
** GWH OUTPUT **		
Thermal	773,549	1,179,304
Disper gen	(69)	(71)
Hydro plus Wind	388,368	427,836
Hydro and Other	1,161,848	1,607,069
Rounded to nearest thousand:	1,162	1,607
Sales		
Non Gen Munic Total	191,327,000	183,380,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,035,947,000	985,988,000
Rounded to nearest million:	1035.947	985.988

		System	Intersystem	Retail
March 2012 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 19,473,498.65	\$ 524,407.59	\$ 19,997,906.24
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 1,373,686.87	\$ -	\$ 1,373,686.87
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (8,136,391.54)	\$ -	\$ (8,136,391.54)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 601,340.41	\$ -	\$ 601,340.41
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)	\$ 865,745.82	\$ 401,961.87	\$ 1,267,707.69
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 12,917.93	\$ -	\$ 12,917.93
14	Real-Time Distribution of Losses Amount	\$ (1,080,303.48)	\$ -	\$ (1,080,303.48)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (73,086.73)	\$ -	\$ (73,086.73)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 25,088.67	\$ -	\$ 25,088.67
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (1,125.75)	\$ -	\$ (1,125.75)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 1,942,720.28	\$ -	\$ 1,942,720.28
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 1,343,009.52	\$ -	\$ 1,343,009.52
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)	\$ (26,411.21)	\$ -	\$ (26,411.21)
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)	\$ (2,899.94)	\$ -	\$ (2,899.94)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (2,495,222.17)	\$ -	\$ (2,495,222.17)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (95,152.20)	\$ -	\$ (95,152.20)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ 8,304.68	\$ -	\$ 8,304.68
37	Financial Transmission Guarantee Uplift Amount	\$ (8,304.68)	\$ -	\$ (8,304.68)
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 1,808,773.84	\$ -	\$ 1,808,773.84
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 122,415.30	\$ -	\$ 122,415.30
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (78,525.36)	\$ 1,763.62	\$ (76,761.74)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 75,938.26	\$ -	\$ 75,938.26
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (116,662.89)	\$ 2,160.96	\$ (114,501.93)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (70,873.39)	\$ 5,070.88	\$ (65,802.51)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 716,875.64	\$ (3,838.21)	\$ 713,037.43
19	Real-Time Market Administration Amount	\$ 49,856.77	\$ (2,494.27)	\$ 47,362.50
29	Financial Transmission Rights Market Administration Amount	\$ 58,827.60	\$ -	\$ 58,827.60
33	Day-Ahead Schedule 24 Allocation Amount	\$ 89,110.72	\$ (477.28)	\$ 88,633.44
34	Real-Time Schedule 24 Allocation Amount	\$ 6,197.51	\$ (312.64)	\$ 5,884.87
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	\$ (0.34)	\$ -	\$ (0.34)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 2,932,166.14	\$ -	\$ 2,932,166.14
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (2,848,330.31)	\$ -	\$ (2,848,330.31)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (533,309.06)	\$ -	\$ (533,309.06)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 197,923.67	\$ -	\$ 197,923.67
TOTAL MISO CHARGES		\$ 16,137,799.23	\$ 928,242.52	\$ 17,066,041.75
SCHEDULE 24 (FOR RETAIL)				\$ 94,518.31
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 16,971,523.44

MISO ANCILLARY SERVICES MARKET'S (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
March 2012 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (133,574.17)	\$ -	\$ (133,574.17)
2	Day-Ahead Spinning Reserve Amount	\$ (97,595.83)	\$ -	\$ (97,595.83)
3	Day-Ahead Supplemental Reserve	\$ (88,598.70)	\$ -	\$ (88,598.70)
4	Real-Time Regulation Amount	\$ (21,073.82)	\$ 37,228.66	\$ 16,154.84
5	Real-Time Spinning Reserve Amount	\$ (10,132.99)	\$ 38,436.75	\$ 28,303.76
6	Real-Time Supplemental Reserve Amount	\$ 1,565.81	\$ 19,761.73	\$ 21,327.54
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ 1,192.50	\$ -	\$ 1,192.50
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 55,766.84	\$ -	\$ 55,766.84
8b	Real Time Non Excessive Energy Congestion	\$ (3,573.79)	\$ -	\$ (3,573.79)
8c	Real Time Non Excessive Energy Loss	\$ 86,575.69	\$ -	\$ 86,575.69
9	Real Time Net Regulation Adjustment Amount	\$ 5,755.56	\$ (557.78)	\$ 5,197.78
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 168,631.05	\$ -	\$ 168,631.05
11	Real Time Spinning Reserve Cost Distribution	\$ 92,349.27	\$ -	\$ 92,349.27
12	Real Time Supplemental Reserve Cost Distribution	\$ 61,229.29	\$ -	\$ 61,229.29
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 7,487.95	\$ (823.16)	\$ 6,664.79
14	Real Time Contingency Reserve Deployment Failure	\$ -	\$ -	\$ -
TOTAL MISO ASM CHARGES		\$ 126,004.66	\$ 94,046.20	\$ 220,050.86

