



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

October 29, 2012

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

Re: November 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 November 2012.

Pursuant to Commission authorization of the final compliance tariffs in the Company's 2010 rate proceeding (Docket No. PU-10-657), the new rates were implemented on May 1, 2012. The new Service Category Ratios listed below also became 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:

November 2012	Fuel Cost Charge (\$/kWh)
Residential	0.02804
C & I Non-Demand	0.02876
C & I Demand	0.02845
C & I Demand Time of Day On-Peak	0.03604
C & I Demand Time of Day Off-Peak	0.02207
Outdoor Lighting	0.02081

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 November 2012 FCC the net MISO Day 2 costs for September 2012 as recorded in Account 555. The MISO Day 2 cost recovery included in this November FCC is \$11,860,697, 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 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 November FCC the net MISO ASM costs for September 2012 as recorded in Account 555. The MISO ASM cost recovery included in this November FCC is \$222,751, 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 November 2012 Asset Based Margin amount of \$58,610 has been included in the November 2012 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 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 the 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 November FCC is \$11,460, or 0.007¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

OTHER REPORTING ITEM

Attached is the calculation of the November 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 /

Paul J Lehman
Manager, Compliance and Filings

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 Nov-2012

Nov-2012 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02798	\$0.00040	-\$0.00041	\$0.02797
Residential	\$0.02805	\$0.00040	-\$0.00041	\$0.02804
C & I Non-Demand	\$0.02877	\$0.00041	-\$0.00042	\$0.02876
C & I Demand Non-TOD	\$0.02846	\$0.00041	-\$0.00042	\$0.02845
C & I Demand TOD On-Peak	\$0.03605	\$0.00052	-\$0.00053	\$0.03604
C & I Demand TOD Off-Peak	\$0.02207	\$0.00032	-\$0.00032	\$0.02207
Outdoor Lighting	\$0.02082	\$0.00030	-\$0.00030	\$0.02081
Residential				
Residential Service	\$ 0.02805	\$ 0.00040	\$ (0.00041)	\$ 0.02804
Residential TOD	\$ 0.02805	\$ 0.00040	\$ (0.00041)	\$ 0.02804
Residential - Underground	\$ 0.02805	\$ 0.00040	\$ (0.00041)	\$ 0.02804
Residential TOD - Underground	\$ 0.02805	\$ 0.00040	\$ (0.00041)	\$ 0.02804
Energy Control - (Non-Demand)	\$ 0.02805	\$ 0.00040	\$ (0.00041)	\$ 0.02804
Limit Off Peak	\$ 0.02805	\$ 0.00040	\$ (0.00041)	\$ 0.02804
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02877	\$ 0.00041	\$ (0.00042)	\$ 0.02876
Limit Off Peak	\$ 0.02877	\$ 0.00041	\$ (0.00042)	\$ 0.02876
Small General Service	\$ 0.02877	\$ 0.00041	\$ (0.00042)	\$ 0.02876
Small General TOD - Metered	\$ 0.02877	\$ 0.00041	\$ (0.00042)	\$ 0.02876
Small General TOD - Unmetered	\$ 0.02877	\$ 0.00041	\$ (0.00042)	\$ 0.02876
Fire and Civil Defense Siren	\$ 0.02877	\$ 0.00041	\$ (0.00042)	\$ 0.02876
Direct Current (Closed)	\$ 0.02877	\$ 0.00041	\$ (0.00042)	\$ 0.02876
C & I Demand				
General Service	\$ 0.02846	\$ 0.00041	\$ (0.00042)	\$ 0.02845
General TOD - On Peak	\$ 0.03605	\$ 0.00052	\$ (0.00053)	\$ 0.03604
General TOD - Off Peak	\$ 0.02207	\$ 0.00032	\$ (0.00032)	\$ 0.02207
Peak Controlled (Closed)	\$ 0.02846	\$ 0.00041	\$ (0.00042)	\$ 0.02845
Peak Controlled TOD (Closed) - On Peak	\$ 0.03605	\$ 0.00052	\$ (0.00053)	\$ 0.03604
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02207	\$ 0.00032	\$ (0.00032)	\$ 0.02207
Peak Controlled Tiered	\$ 0.02846	\$ 0.00041	\$ (0.00042)	\$ 0.02845
Peak Controlled Tiered TOD - On Peak	\$ 0.03605	\$ 0.00052	\$ (0.00053)	\$ 0.03604
Peak Controlled Tiered TOD - Off Peak	\$ 0.02207	\$ 0.00032	\$ (0.00032)	\$ 0.02207
Energy Controlled (Closed)	\$ 0.02846	\$ 0.00041	\$ (0.00042)	\$ 0.02845
Tier 1 Energy Controlled Rider	\$ 0.02846	\$ 0.00041	\$ (0.00042)	\$ 0.02845
Real Time Pricing - Firm - On Peak	\$ 0.03605	\$ 0.00052	\$ (0.00053)	\$ 0.03604
Real Time Pricing - Firm - Off Peak	\$ 0.02207	\$ 0.00032	\$ (0.00032)	\$ 0.02207
Real Time Pricing - Controllable - On Peak	\$ 0.03605	\$ 0.00052	\$ (0.00053)	\$ 0.03604
Real Time Pricing - Controllable - Off Peak	\$ 0.02207	\$ 0.00032	\$ (0.00032)	\$ 0.02207
Small Municipal Pumping	\$ 0.02846	\$ 0.00041	\$ (0.00042)	\$ 0.02845
Municipal Pumping	\$ 0.02846	\$ 0.00041	\$ (0.00042)	\$ 0.02845
Excess Energy - St. Anthony Falls	\$ 0.02846	\$ 0.00041	\$ (0.00042)	\$ 0.02845
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.02082	\$ 0.00030	\$ (0.00030)	\$ 0.02081
Street Lighting System	\$ 0.02082	\$ 0.00030	\$ (0.00030)	\$ 0.02081
Street Lighting Energy	\$ 0.02082	\$ 0.00030	\$ (0.00030)	\$ 0.02081
Street Lighting Energy - Metered	\$ 0.02082	\$ 0.00030	\$ (0.00030)	\$ 0.02081
Street Lighting Energy (Closed)	\$ 0.02082	\$ 0.00030	\$ (0.00030)	\$ 0.02081
Street Lighting - City of St. Paul	\$ 0.02082	\$ 0.00030	\$ (0.00030)	\$ 0.02081

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 Nov-2012

	Column (A) Jun-12	Column (B) Jul-12	Column (C) Aug-12	Column (D) Sep-12	Column (E) 4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$33,749,949	\$58,790,048	\$46,184,773	\$33,831,915	\$172,556,685
Account 518 - Nuclear Fuel	\$10,844,492	\$11,470,923	\$9,668,555	\$10,950,542	\$42,934,512
Account 555 - Purchased Power ¹	\$39,647,383	\$41,035,251	\$38,850,330	\$32,831,145	\$152,364,110
Account 555 - MISO Day 2 Charges	\$24,234,400	\$23,257,210	\$17,553,245	\$11,957,866	\$77,002,721
Account 555 MISO Day 2 - Schedule 24	(\$111,383)	(\$119,841)	(\$93,360)	(\$97,169)	(\$421,754)
Account 555 MISO - ASM Charges	\$907,884	\$1,410,522	\$968,698	\$222,751	\$3,509,855
Total MISO Charges	\$25,030,901	\$24,547,891	\$18,428,582	\$12,083,449	\$80,090,822
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$109,272,725	\$135,844,112	\$113,132,240	\$89,697,051	\$447,946,128
Less Fuel Cost of InterSystem Sales	(\$4,659,393)	(\$4,726,025)	(\$3,716,520)	(\$2,716,704)	(\$15,818,642)
Net System Costs	\$104,613,332	\$131,118,087	\$109,415,720	\$86,980,347	\$432,127,486
System MWh Sales					
Total NSP System Retail	3,449,768	4,163,505	4,241,939	3,435,726	15,290,938
Non-Gen Muni's/Load Pattern	34,482	37,734	42,444	37,855	152,515
Total NSP System MWh Sales	3,484,250	4,201,239	4,284,383	3,473,581	15,443,453
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	3.002¢	3.121¢	2.554¢	2.504¢	2.798¢
Base Fuel Cost Included in Rates	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢
Class Ratio/TOD Ratio					
(i) Residential	1.0026	1.0026	1.0026	1.0026	1.0026
(ii) C & I Non-Demand	1.0281	1.0281	1.0281	1.0281	1.0281
(iii) C & I Demand Non-TOD	1.0170	1.0170	1.0170	1.0170	1.0170
(iv) C & I Demand TOD On-Peak	1.2883	1.2883	1.2883	1.2883	1.2883
(v) C & I Demand TOD Off-Peak	0.7889	0.7889	0.7889	0.7889	0.7889
(vi) Outdoor Lighting	0.7440	0.7440	0.7440	0.7440	0.7440
North Dakota Fuel Cost Factor (FCF)					
				FCF Ratio	4 Month Average
(i) Residential				1.0026	2.805¢
(ii) C & I Non-Demand				1.0281	2.877¢
(iii) C & I Demand Non-TOD				1.0170	2.846¢
(iv) C & I Demand TOD On-Peak				1.2883	3.605¢
(v) C & I Demand TOD Off-Peak				0.7889	2.207¢
(vi) Outdoor Lighting				0.7440	2.082¢
North Dakota Retail MWh Sales					
(i) Residential	50,195	67,595	70,089	50,802	238,681
(ii) C & I Non-Demand	8,199	9,298	9,627	8,088	35,212
(iii) C & I Demand Non-TOD	59,510	66,344	69,444	62,803	258,101
(iv) C & I Demand TOD On-Peak	16,999	19,710	20,606	20,106	77,421
(v) C & I Demand TOD Off-Peak	26,395	32,049	31,310	30,876	120,630
(vi) Outdoor Lighting	1,220	1,125	1,201	1,377	4,923
(vii) Total	162,518	196,121	202,277	174,052	734,968
Nov-2012 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Jul-12 Balance of Unrecovered Expenses)					Total
					Jul-12
					\$1,099,365

¹ Excludes demand-related expenses

Prior Expenses Recovered in Sep-2012 [Billing Record]		ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential		50,802	\$61,968
(ii) C & I Non-Demand		8,088	\$9,758
(iii) C & I Demand Non-TOD		62,803	\$72,393
(iv) C & I Demand TOD On-Peak		20,106	\$29,855
(v) C & I Demand TOD Off-Peak		30,876	\$28,336
(vi) Outdoor Lighting		1,377	\$1,073
(vii) Total		174,052	\$203,383

Actual Cost Should Have Been Recovered in Sep-12				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.504¢	0.000¢	174,052	\$4,358,262

Cost Recovered in Sep-12 [Billing Record]		ND Billed MWh Sales	Actual Recovery
(i) Residential		50,802	\$1,453,335
(ii) C & I Non-Demand		8,088	\$236,535
(iii) C & I Demand Non-TOD		62,803	\$1,812,292
(iv) C & I Demand TOD On-Peak		20,106	\$735,808
(v) C & I Demand TOD Off-Peak		30,876	\$692,479
(vi) Outdoor Lighting		1,377	\$28,889
(vii) Total		174,052	\$4,959,338

Total Balance of Unrecovered Expenses (Nov-12 Balance of Unrecovered Expenses)	
Nov-2012 Recovery Provision	\$294,906
4 Month ND Retail Total MWh Sales	734,968
Nov-2012 Recovery Provision per KWH	0.040¢

Nov-2012 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	1.0026	0.040¢	0.040¢
(ii) C & I Non-Demand	1.0281	0.040¢	0.041¢
(iii) C & I Demand Non-TOD	1.0170	0.040¢	0.041¢
(iv) C & I Demand TOD On-Peak	1.2883	0.040¢	0.052¢
(v) C & I Demand TOD Off-Peak	0.7889	0.040¢	0.032¢
(vi) Outdoor Lighting	0.7440	0.040¢	0.030¢

Nov-2012 Margin Sharing Refunds			
Refund/Special Charge Amount	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
	(\$58,610)	(\$11,460)	(\$70,070)
(i) Residential	-0.034¢	-0.007¢	-0.041¢
(ii) C & I Non-Demand	-0.035¢	-0.007¢	-0.042¢
(iii) C & I Demand Non-TOD	-0.035¢	-0.007¢	-0.042¢
(iv) C & I Demand TOD On-Peak	-0.044¢	-0.009¢	-0.053¢
(v) C & I Demand TOD Off-Peak	-0.027¢	-0.005¢	-0.032¢
(vi) Outdoor Lighting	-0.025¢	-0.005¢	-0.030¢

Nov-2012 Factors		Total
(i) Residential		2.804¢
(ii) C & I Non-Demand		2.876¢
(iii) C & I Demand Non-TOD		2.845¢
(iv) C & I Demand TOD On-Peak		3.604¢
(v) C & I Demand TOD Off-Peak		2.207¢
(vi) Outdoor Lighting		2.081¢

	FCA Application		Comparison		Generation Type by Percent		
	Oct-12	Nov-12	Differ- ence	Percent Change	FCA Application Oct-12	Nov-12	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$169.5	\$172.6	\$3.0	1.8%	37.2%	38.5%	1.3%
2 Nuclear	\$39.6	\$42.9	\$3.3	8.4%	8.7%	9.6%	0.9%
3 Purchases	\$157.7	\$152.4	(\$5.4)	-3.4%	34.6%	34.0%	-0.6%
MISO related Purchases	\$89.1	\$80.1	(\$9.0)	-10.1%	19.5%	17.9%	-1.6%
4 Total System Costs	456.0	447.9	(\$8.1)	-1.8%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$16.0	\$15.8	(\$0.2)	-1.3%	3.5%	3.5%	0.0%
6 Net System Costs	\$440.0	\$432.1	(\$7.8)	-1.8%	96.5%	96.5%	0.0%
7							
** GWH OUTPUT **							
9 Fossil	4,335	4,734	399	9.2%	24.5%	26.8%	2.3%
10 Nuclear	4,131	4,442	311	7.5%	23.4%	25.2%	1.8%
11 Purchases	5,917	5,553	(364)	-6.2%	33.5%	31.5%	-2.0%
12 Hydro & Other	2,610	2,249	(361)	-13.8%	14.8%	12.7%	-2.1%
13 Net Interchange	680	673	(7)	-1.0%	3.8%	3.8%	0.0%
14 Total Output	17,673	17,651	(22)	-0.1%	100.0%	100.0%	0.0%
15 Intersystem Sales	826	856	30	3.6%	4.7%	4.9%	0.2%
16 Native Requirement	16,847	16,795	(52)	-0.3%	95.3%	95.1%	-0.2%
17							
** COST per KWH OUTPUT (\$)							
19 Fossil	3.911	3.645	-0.266	-6.8%			
20 Nuclear	0.959	0.967	0.007	0.8%			
21 Purchases	2.666	2.744	0.078	2.9%			
22 Total System Costs	2.580	2.538	-0.042	-1.6%			
23 Intersystem Sales	1.940	1.848	-0.092	-4.8%			
24 Net System Costs	2.612	2.573	-0.039	-1.5%			
25							
26							
27 TOTAL SYSTEM GWH SALES	15,225	15,443	218	1.4%			
28							
29 COST per KWH SALES (\$)	2.890	2.798	-0.092	-3.2%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	0.020	0.040	0.020				
(i) Residential	0.021	0.040	0.020				
(ii) C & I Non-Demand	0.021	0.041	0.020				
(iii) C & I Demand Non-TOD	0.021	0.041	0.020				
(iv) C & I Demand TOD On-Peak	0.026	0.052	0.025				
(v) C & I Demand TOD Off-Peak	0.016	0.032	0.016				
(vi) Outdoor Lighting	0.015	0.030	0.015				
32 REFUND	-0.021	-0.041	-0.020				
(i) Residential	-0.021	-0.041	-0.020				
(ii) C & I Non-Demand	-0.022	-0.042	-0.020				
(iii) C & I Demand Non-TOD	-0.021	-0.042	-0.020				
(iv) C & I Demand TOD On-Peak	-0.027	-0.053	-0.026				
(v) C & I Demand TOD Off-Peak	-0.017	-0.032	-0.015				
(vi) Outdoor Lighting	-0.016	-0.030	-0.014				
33 SYSTEM FCC IMPACT (\$ / KWH)	2.889	2.797	-0.092	-3.2%			
(i) Residential	2.896	2.804	-0.092				
(ii) C & I Non-Demand	2.970	2.876	-0.094				
(iii) C & I Demand Non-TOD	2.938	2.845	-0.093				
(iv) C & I Demand TOD On-Peak	3.722	3.604	-0.118				
(v) C & I Demand TOD Off-Peak	2.279	2.207	-0.072				
(vi) Outdoor Lighting	2.149	2.081	-0.068				

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	(\$0.09)
250	(\$0.23)
500	(\$0.46)
750	(\$0.69)
1,000	(\$0.92)

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.

	FCA Application	
	Oct-12	Nov-12
** GWH OUTPUT **		
Thermal	2,164,751	1,884,633
Disper gen	(83)	(94)
Hydro plus Wind	445,462	364,290
Hydro and Other	2,610,130	2,248,829
Rounded to nearest thousand:	2,610	2,249
Sales		
Non Gen Munic Total	147,343,000	152,515,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	826,208,000	856,074,000
Rounded to nearest million:	826,208	856,074

Northern States Power Company, A Minnesota Corporation
MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

Attachment 2

Page 1

		System	Intersystem	Retail
September 2012 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 15,796,719.41	\$ 881,979.76	\$ 16,678,699.17
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,107,990.78	\$ -	\$ 2,107,990.78
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (10,543,696.60)	\$ -	\$ (10,543,696.60)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,056,052.47	\$ -	\$ 1,056,052.47
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)	\$ 1,934,227.96	\$ 753,958.73	\$ 2,688,186.69
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 95,379.00	\$ -	\$ 95,379.00
14	Real-Time Distribution of Losses Amount	\$ (1,118,396.29)	\$ -	\$ (1,118,396.29)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (28,092.18)	\$ -	\$ (28,092.18)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ (13,233.58)	\$ -	\$ (13,233.58)
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (3,587.85)	\$ -	\$ (3,587.85)
Congestion-Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 1,228,129.63	\$ -	\$ 1,228,129.63
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 779,417.41	\$ -	\$ 779,417.41
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)	\$ 113,398.03	\$ -	\$ 113,398.03
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)	\$ (13,635.18)	\$ -	\$ (13,635.18)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (1,169,624.32)	\$ -	\$ (1,169,624.32)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (5,244.54)	\$ -	\$ (5,244.54)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (363,307.45)	\$ -	\$ (363,307.45)
37	Financial Transmission Guarantee Uplift Amount	\$ 362,519.52	\$ -	\$ 362,519.52
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 509,914.42	\$ -	\$ 509,914.42
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 90,424.75	\$ -	\$ 90,424.75
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (10,570.08)	\$ (25.70)	\$ (10,595.78)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 197,880.90	\$ -	\$ 197,880.90
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (81,863.31)	\$ 1,716.36	\$ (80,146.95)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (231,849.81)	\$ 3,081.45	\$ (228,768.36)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 563,012.97	\$ (4,353.97)	\$ 558,659.00
19	Real-Time Market Administration Amount	\$ 30,749.51	\$ (4,298.76)	\$ 26,450.75
29	Financial Transmission Rights Market Administration Amount	\$ 33,619.68	\$ -	\$ 33,619.68
33	Day-Ahead Schedule 24 Allocation Amount	\$ 93,495.17	\$ (709.04)	\$ 92,786.13
34	Real-Time Schedule 24 Allocation Amount	\$ 5,092.99	\$ (709.85)	\$ 4,383.14
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	\$ (404,975.13)	\$ -	\$ (404,975.13)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 3,207,268.38	\$ -	\$ 3,207,268.38
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (3,254,929.87)	\$ -	\$ (3,254,929.87)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (800,233.94)	\$ -	\$ (800,233.94)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 165,174.62	\$ -	\$ 165,174.62
TOTAL MISO CHARGES		\$ 10,327,227.47	\$ 1,630,638.98	\$ 11,957,866.45
SCHEDULE 24 (FOR RETAIL)				\$ 97,169.27
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 11,860,697.18

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
September 2012 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (102,411.49)	\$ -	\$ (102,411.49)
2	Day-Ahead Spinning Reserve Amount	\$ (38,746.58)	\$ -	\$ (38,746.58)
3	Day-Ahead Supplemental Reserve	\$ (91,884.15)	\$ -	\$ (91,884.15)
4	Real-Time Regulation Amount	\$ (66,783.23)	\$ 43,002.28	\$ (23,780.95)
5	Real-Time Spinning Reserve Amount	\$ (7,789.49)	\$ 20,241.29	\$ 12,451.80
6	Real-Time Supplemental Reserve Amount	\$ 56,691.48	\$ 28,625.86	\$ 85,317.34
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ 35,332.12	\$ -	\$ 35,332.12
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 59,344.52	\$ -	\$ 59,344.52
8b	Real Time Non Excessive Energy Congestion	\$ (62,869.36)	\$ -	\$ (62,869.36)
8c	Real Time Non Excessive Energy Loss	\$ (17,800.76)	\$ -	\$ (17,800.76)
9	Real Time Net Regulation Adjustment Amount	\$ 16,724.80	\$ (1,044.97)	\$ 15,679.83
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 181,327.05	\$ -	\$ 181,327.05
11	Real Time Spinning Reserve Cost Distribution	\$ 115,282.69	\$ -	\$ 115,282.69
12	Real Time Supplemental Reserve Cost Distribution	\$ 50,809.89	\$ -	\$ 50,809.89
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 4,831.43	\$ (132.04)	\$ 4,699.39
14	Real Time Contingency Reserve Deployment Failure	\$ -	\$ -	\$ -
TOTAL MISO ASM CHARGES		\$ 132,058.92	\$ 90,692.42	\$ 222,751.34

Forecast Month	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13
True-up Month	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12
1	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)
2	209,900	204,486	176,872	172,668	167,827	180,675	198,082	165,774	179,024	171,102	-	-
3	(0,006)	(0,006)	(0,007)	(0,007)	(0,007)	(0,007)	(0,006)	(0,007)	(0,007)	(0,007)	-	-
4	(1,271)	(7,850)	(9,247)	(15,472)	(13,816)	(15,506)	(13,246)	(13,482)	(11,314)	(10,160)	-	-
5	(3,820)	(4,174)	(7,227)	(11,762)	(12,366)	(13,820)	(13,728)	(15,118)	(13,806)	(10,496)	-	-
6	2,549	(3,676)	(2,020)	(3,710)	(1,450)	(1,686)	482	1,636	2,492	356	-	-
7	0.001	(0.002)	(0.001)	(0.002)	(0.001)	(0.001)	0.000	0.001	0.001	0.000	-	-
8	(0.004)	(0.008)	(0.008)	(0.008)	(0.008)	(0.007)	(0.006)	(0.006)	(0.005)	(0.007)	-	-
9	0.9956	1.0548	1.0548	1.0481	1.0415	1.0348	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281
10	1.0219	1.0219	1.0219	1.0207	1.0195	1.0182	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170
11	1.3135	1.3135	1.3135	1.3072	1.3009	1.2946	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883
12	0.7726	0.7726	0.7726	0.7767	0.7808	0.7848	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889
13	0.7088	0.7088	0.7088	0.7176	0.7264	0.7352	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440
14	(0.004)	(0.008)	(0.008)	(0.009)	(0.008)	(0.007)	(0.006)	(0.006)	(0.005)	(0.007)	-	-
15	(0.005)	(0.008)	(0.008)	(0.009)	(0.008)	(0.008)	(0.006)	(0.006)	(0.005)	(0.007)	-	-
16	(0.006)	(0.008)	(0.008)	(0.009)	(0.008)	(0.008)	(0.006)	(0.006)	(0.005)	(0.007)	-	-
17	(0.006)	(0.010)	(0.010)	(0.012)	(0.010)	(0.010)	(0.007)	(0.008)	(0.007)	(0.009)	-	-
18	(0.003)	(0.006)	(0.006)	(0.007)	(0.006)	(0.006)	(0.005)	(0.005)	(0.004)	(0.005)	-	-
19	(0.003)	(0.005)	(0.005)	(0.006)	(0.006)	(0.005)	(0.004)	(0.005)	(0.004)	(0.005)	-	-
20	0.9956	1.0548	1.0548	1.0481	1.0415	1.0348	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281
21	1.0219	1.0219	1.0219	1.0207	1.0195	1.0182	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170
22	1.3135	1.3135	1.3135	1.3072	1.3009	1.2946	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883
23	0.7726	0.7726	0.7726	0.7767	0.7808	0.7848	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889
24	0.7088	0.7088	0.7088	0.7176	0.7264	0.7352	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440
25	(0.004)	(0.008)	(0.008)	(0.009)	(0.008)	(0.007)	(0.006)	(0.006)	(0.005)	(0.007)	-	-
26	(0.005)	(0.008)	(0.008)	(0.009)	(0.008)	(0.008)	(0.006)	(0.006)	(0.005)	(0.007)	-	-
27	(0.006)	(0.008)	(0.008)	(0.009)	(0.008)	(0.008)	(0.006)	(0.006)	(0.005)	(0.007)	-	-
28	(0.006)	(0.010)	(0.010)	(0.012)	(0.010)	(0.010)	(0.007)	(0.008)	(0.007)	(0.009)	-	-
29	(0.003)	(0.006)	(0.006)	(0.007)	(0.006)	(0.006)	(0.005)	(0.005)	(0.004)	(0.005)	-	-
30	(0.003)	(0.005)	(0.005)	(0.006)	(0.006)	(0.005)	(0.004)	(0.005)	(0.004)	(0.005)	-	-