



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

December 30, 2011

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

Re: January 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 January 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 January 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 November 2011 calendar month.

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

January 2012	Fuel Cost Charge (\$/kWh)
Residential	0.02499
C & I Non-Demand	0.02648
C & I Demand	0.02565
C & I Demand Time of Day On-Peak	0.03297
C & I Demand Time of Day Off-Peak	0.01939
Outdoor Lighting	0.01779

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 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 January 2012 FCC, the net MISO Day 2 costs for November 2012 as recorded in Account 555. The MISO Day 2 cost recovery included in this January FCC is \$14,385,116, 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

¹ 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 January FCC, the net MISO ASM costs for November 2011 as recorded in Account 555. The MISO ASM cost recovery included in this January FCC is \$1,656,473, 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 2011 Asset Based Margin amount of -\$30,199 has been included in the January 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 2010 Non-Asset Based Margin credit is \$56,225 and this credit amount will be distributed equally each month over the following 12-month period. The refund reflected in the January FCC is \$-7,850, or -0.003¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

OTHER REPORTING ITEM

Attached is the calculation of the January 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 Jan-2012

Jan-2012 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02542	-\$0.00015	-\$0.00016	\$0.02510
Residential	\$0.02531	-\$0.00015	-\$0.00016	\$0.02499
C & I Non-Demand	\$0.02681	-\$0.00016	-\$0.00017	\$0.02648
C & I Demand Non-TOD	\$0.02598	-\$0.00016	-\$0.00017	\$0.02565
C & I Demand TOD On-Peak	\$0.03339	-\$0.00020	-\$0.00022	\$0.03297
C & I Demand TOD Off-Peak	\$0.01964	-\$0.00012	-\$0.00013	\$0.01939
Outdoor Lighting	\$0.01802	-\$0.00011	-\$0.00012	\$0.01779
Residential				
Residential Service	\$ 0.02531	\$ (0.00015)	\$ (0.00016)	\$ 0.02499
Residential TOD	\$ 0.02531	\$ (0.00015)	\$ (0.00016)	\$ 0.02499
Residential - Underground	\$ 0.02531	\$ (0.00015)	\$ (0.00016)	\$ 0.02499
Residential TOD - Underground	\$ 0.02531	\$ (0.00015)	\$ (0.00016)	\$ 0.02499
Energy Control - (Non-Demand)	\$ 0.02531	\$ (0.00015)	\$ (0.00016)	\$ 0.02499
Limit Off Peak	\$ 0.02531	\$ (0.00015)	\$ (0.00016)	\$ 0.02499
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02681	\$ (0.00016)	\$ (0.00017)	\$ 0.02648
Limit Off Peak	\$ 0.02681	\$ (0.00016)	\$ (0.00017)	\$ 0.02648
Small General Service	\$ 0.02681	\$ (0.00016)	\$ (0.00017)	\$ 0.02648
Small General TOD - Metered	\$ 0.02681	\$ (0.00016)	\$ (0.00017)	\$ 0.02648
Small General TOD - Unmetered	\$ 0.02681	\$ (0.00016)	\$ (0.00017)	\$ 0.02648
Fire and Civil Defense Siren	\$ 0.02681	\$ (0.00016)	\$ (0.00017)	\$ 0.02648
Direct Current (Closed)	\$ 0.02681	\$ (0.00016)	\$ (0.00017)	\$ 0.02648
C & I Demand				
General Service	\$ 0.02598	\$ (0.00016)	\$ (0.00017)	\$ 0.02565
General TOD - On Peak	\$ 0.03339	\$ (0.00020)	\$ (0.00022)	\$ 0.03297
General TOD - Off Peak	\$ 0.01964	\$ (0.00012)	\$ (0.00013)	\$ 0.01939
Peak Controlled (Closed)	\$ 0.02598	\$ (0.00016)	\$ (0.00017)	\$ 0.02565
Peak Controlled TOD (Closed) - On Peak	\$ 0.03339	\$ (0.00020)	\$ (0.00022)	\$ 0.03297
Peak Controlled TOD (Closed) - Off Peak	\$ 0.01964	\$ (0.00012)	\$ (0.00013)	\$ 0.01939
Peak Controlled Tiered	\$ 0.02598	\$ (0.00016)	\$ (0.00017)	\$ 0.02565
Peak Controlled Tiered TOD - On Peak	\$ 0.03339	\$ (0.00020)	\$ (0.00022)	\$ 0.03297
Peak Controlled Tiered TOD - Off Peak	\$ 0.01964	\$ (0.00012)	\$ (0.00013)	\$ 0.01939
Energy Controlled (Closed)	\$ 0.02598	\$ (0.00016)	\$ (0.00017)	\$ 0.02565
Tier 1 Energy Controlled Rider	\$ 0.02598	\$ (0.00016)	\$ (0.00017)	\$ 0.02565
Real Time Pricing - Firm - On Peak	\$ 0.03339	\$ (0.00020)	\$ (0.00022)	\$ 0.03297
Real Time Pricing - Firm - Off Peak	\$ 0.01964	\$ (0.00012)	\$ (0.00013)	\$ 0.01939
Real Time Pricing - Controllable - On Peak	\$ 0.03339	\$ (0.00020)	\$ (0.00022)	\$ 0.03297
Real Time Pricing - Controllable - Off Peak	\$ 0.01964	\$ (0.00012)	\$ (0.00013)	\$ 0.01939
Small Municipal Pumping	\$ 0.02598	\$ (0.00016)	\$ (0.00017)	\$ 0.02565
Municipal Pumping	\$ 0.02598	\$ (0.00016)	\$ (0.00017)	\$ 0.02565
Excess Energy - St. Anthony Falls	\$ 0.02598	\$ (0.00016)	\$ (0.00017)	\$ 0.02565
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01802	\$ (0.00011)	\$ (0.00012)	\$ 0.01779
Street Lighting System	\$ 0.01802	\$ (0.00011)	\$ (0.00012)	\$ 0.01779
Street Lighting Energy	\$ 0.01802	\$ (0.00011)	\$ (0.00012)	\$ 0.01779
Street Lighting Energy - Metcred	\$ 0.01802	\$ (0.00011)	\$ (0.00012)	\$ 0.01779
Street Lighting Energy (Closed)	\$ 0.01802	\$ (0.00011)	\$ (0.00012)	\$ 0.01779
Street Lighting - City of St. Paul	\$ 0.01802	\$ (0.00011)	\$ (0.00012)	\$ 0.01779

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 Jan-2012

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Aug-11	Sep-11	Oct-11	Nov-11	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$49,469,418	\$32,381,294	\$31,618,275	\$29,246,148	\$142,715,135
Account 518 - Nuclear Fuel	\$11,630,399	\$11,598,307	\$8,393,084	\$9,550,563	\$41,172,353
Account 555 - Purchased Power ¹	\$41,249,223	\$36,633,495	\$41,852,828	\$45,056,103	\$164,791,650
Account 555 - MISO Day 2 Charges	\$21,897,056	\$14,825,965	\$16,752,659	\$14,479,922	\$67,955,603
Account 555 MISO Day 2 - Schedule 24	(\$101,787)	(\$92,356)	(\$97,215)	(\$94,807)	(\$386,164)
Account 555 MISO - ASM Charges	(\$2,154,021)	\$769,417	\$2,516,975	\$1,656,473	\$2,788,844
Total MISO Charges	\$19,641,248	\$15,503,027	\$19,172,420	\$16,041,588	\$70,358,282
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$121,990,288	\$96,116,123	\$101,036,607	\$99,894,402	\$419,037,420
Less Fuel Cost of InterSystem Sales	(\$13,873,929)	(\$10,853,061)	(\$10,740,247)	(\$12,667,019)	(\$48,134,257)
Net System Costs	\$108,116,359	\$85,263,062	\$90,296,359	\$87,227,383	\$370,903,163
System MWh Sales					
Total NSP System Retail	4,379,112	3,719,112	3,234,963	3,063,600	14,396,787
Non-Gen Muni's/Load Pattern	52,938	51,583	44,858	44,747	194,126
Total NSP System MWh Sales	4,432,050	3,770,695	3,279,821	3,108,347	14,590,913
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.439¢	2.261¢	2.753¢	2.806¢	2.542¢
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	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
North Dakota Fuel Cost Factor (FCF)					
				FCF Ratio	4 Month Average
(i) Residential				0.9956	2.531¢
(ii) C & I Non-Demand				1.0548	2.681¢
(iii) C & I Demand Non-TOD				1.0219	2.598¢
(iv) C & I Demand TOD On-Peak				1.3135	3.339¢
(v) C & I Demand TOD Off-Peak				0.7726	1.964¢
(vi) Outdoor Lighting				0.7088	1.802¢
North Dakota Retail MWh Sales					
(i) Residential	65,506	55,310	46,473	51,430	218,719
(ii) C & I Non-Demand	9,049	8,910	8,004	8,136	34,099
(iii) C & I Demand Non-TOD	70,382	64,666	60,842	54,756	250,646
(iv) C & I Demand TOD On-Peak	20,455	21,042	18,046	17,618	77,161
(v) C & I Demand TOD Off-Peak	31,758	30,284	27,619	28,130	117,791
(vi) Outdoor Lighting	1,181	1,386	1,541	1,761	5,869
(vii) Total	198,331	181,598	162,525	161,831	704,285
Jan-2012 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Sep-11 Balance of Unrecovered Expenses)					Total
					Sep-11
					(\$156,313)

¹ Excludes demand-related expenses

Prior Expenses Recovered in Nov-2011 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	51,430	\$4,315
(ii) C & I Non-Demand	8,136	\$1,269
(iii) C & I Demand Non-TOD	54,756	\$10,534
(iv) C & I Demand TOD On-Peak	17,618	\$3,957
(v) C & I Demand TOD Off-Peak	28,130	\$3,597
(vi) Outdoor Lighting	1,761	\$290
(vii) Total	161,831	\$23,962

Actual Cost Should Have Been Recovered in Nov-11				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.806¢	0.000¢	161,831	\$4,540,978

Cost Recovered in Nov-11 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	51,430	\$1,408,254
(ii) C & I Non-Demand	8,136	\$236,950
(iii) C & I Demand Non-TOD	54,756	\$1,548,261
(iv) C & I Demand TOD On-Peak	17,618	\$640,090
(v) C & I Demand TOD Off-Peak	28,130	\$601,011
(vi) Outdoor Lighting	1,761	\$34,777
(vii) Total	161,831	\$4,469,343

Total Balance of Unrecovered Expenses (Jan-12 Balance of Unrecovered Expenses)	
Jan-2012 Recovery Provision	(\$108,640)
4 Month ND Retail Total MWh Sales	704,285
Jan-2012 Recovery Provision per KWH	-0.015¢

Jan-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	-0.015¢	-0.015¢
(ii) C & I Non-Demand	1.0548	-0.015¢	-0.016¢
(iii) C & I Demand Non-TOD	1.0219	-0.015¢	-0.016¢
(iv) C & I Demand TOD On-Peak	1.3135	-0.015¢	-0.020¢
(v) C & I Demand TOD Off-Peak	0.7726	-0.015¢	-0.012¢
(vi) Outdoor Lighting	0.7088	-0.015¢	-0.011¢

Jan-2012 Margin Sharing Refunds			
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
Refund/Special Charge Amount	(\$30,199)	(\$7,850)	(\$38,049)
(i) Residential	-0.013¢	-0.003¢	-0.016¢
(ii) C & I Non-Demand	-0.014¢	-0.004¢	-0.017¢
(iii) C & I Demand Non-TOD	-0.013¢	-0.003¢	-0.017¢
(iv) C & I Demand TOD On-Peak	-0.017¢	-0.004¢	-0.022¢
(v) C & I Demand TOD Off-Peak	-0.010¢	-0.003¢	-0.013¢
(vi) Outdoor Lighting	-0.009¢	-0.002¢	-0.012¢

Jan-2012 Factors	
	Total
(i) Residential	2.499¢
(ii) C & I Non-Demand	2.648¢
(iii) C & I Demand Non-TOD	2.565¢
(iv) C & I Demand TOD On-Peak	3.297¢
(v) C & I Demand TOD Off-Peak	1.939¢
(vi) Outdoor Lighting	1.779¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Dec-11	Jan-12	Differ- ence	Percent Change	FCA Application Dec-11	Jan-12	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$173.4	\$142.7	(\$30.7)	-17.7%	37.7%	34.1%	-3.6%
2 Nuclear	\$42.8	\$41.2	(\$1.7)	-3.9%	9.3%	9.8%	0.5%
3 Purchases	\$164.1	\$164.8	\$0.7	0.4%	35.7%	39.3%	3.6%
MISO related Purchases	\$79.5	\$70.4	(\$9.1)	-11.5%	17.3%	16.8%	-0.5%
4 Total System Costs	459.8	419.0	(\$40.8)	-8.9%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$48.6	\$48.1	(\$0.4)	-0.9%	10.6%	11.5%	0.9%
6 Net System Costs	\$411.3	\$370.9	(\$40.4)	-9.8%	89.4%	88.5%	-0.9%
7							
8 ** GWH OUTPUT **							
9 Fossil	5,562	5,091	(471)	-8.5%	32.4%	31.8%	-0.6%
10 Nuclear	4,438	4,333	(105)	-2.4%	25.9%	27.1%	1.2%
11 Purchases	5,238	5,032	(206)	-3.9%	30.5%	31.5%	1.0%
12 Hydro & Other	1,358	874	(484)	-35.6%	7.9%	5.5%	-2.4%
13 Net Interchange	551	658	107	19.4%	3.2%	4.1%	0.9%
14 Total Output	17,147	15,988	(1,159)	-6.8%	100.0%	100.0%	0.0%
15 Intersystem Sales	889	894	5	0.6%	5.2%	5.6%	0.4%
16 Native Requirement	16,258	15,094	(1,164)	-7.2%	94.8%	94.4%	-0.4%
17							
18 ** COST per KWH OUTPUT (\$) **							
19 Fossil	3.118	2.803	-0.314	-10.1%			
20 Nuclear	0.965	0.950	-0.015	-1.5%			
21 Purchases	3.133	3.275	0.142	4.5%			
22 Total System Costs	2.682	2.621	-0.061	-2.3%			
23 Intersystem Sales	5.464	5.383	-0.081	-1.5%			
24 Net System Costs	2.530	2.457	-0.072	-2.9%			
25							
26							
27 TOTAL SYSTEM GWH SALES	15,303	14,591	(712)	-4.7%			
28							
29 COST per KWH SALES (\$)	2.688	2.542	-0.146	-5.4%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.023	-0.015	0.008				
(i) Residential	-0.023	-0.015	0.008				
(ii) C & I Non-Demand	-0.024	-0.016	0.008				
(iii) C & I Demand Non-TOD	-0.024	-0.016	0.008				
(iv) C & I Demand TOD On-Peak	-0.030	-0.020	0.010				
(v) C & I Demand TOD Off-Peak	-0.018	-0.012	0.006				
(vi) Outdoor Lighting	-0.016	-0.011	0.005				
32 REFUND	-0.016	0.000	0.016				
(i) Residential	-0.016	-0.016					
(ii) C & I Non-Demand	-0.017	-0.017					
(iii) C & I Demand Non-TOD	-0.016	-0.017					
(iv) C & I Demand TOD On-Peak	-0.021	-0.022					
(v) C & I Demand TOD Off-Peak	-0.012	-0.013					
(vi) Outdoor Lighting	-0.011	-0.012					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.649	2.527	-0.122	-4.6%			
(i) Residential	2.638	2.499	-0.139				
(ii) C & I Non-Demand	2.795	2.648					
(iii) C & I Demand Non-TOD	2.708	2.565					
(iv) C & I Demand TOD On-Peak	3.480	3.297					
(v) C & I Demand TOD Off-Peak	2.047	1.939					
(vi) Outdoor Lighting	1.878	1.779					

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	(\$0.14)
250	(\$0.35)
500	(\$0.69)
750	(\$1.04)
1,000	(\$1.39)

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>	
	Dec-11	Jan-12
** GWH OUTPUT **		
Thermal	962,793	477,245
Disper gen	(89)	(90)
Hydro plus Wind	395,585	397,213
Hydro and Other	1,358,289	874,368
Rounded to nearest thousand:	1,358	874
Sales		
Non Gen Munic Total	195,343,000	194,126,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	888,642,000	894,119,000
Rounded to nearest million:	888.642	894.119

		System	Intersystem	Retail
November 2011 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 17,378,670.19	\$ 846,948.63	\$ 18,225,618.82
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,436,680.89	\$ -	\$ 2,436,680.89
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (9,108,565.10)	\$ -	\$ (9,108,565.10)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 719,275.61	\$ -	\$ 719,275.61
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)	\$ 1,130,581.46	\$ 1,006,564.90	\$ 2,137,146.36
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (31,983.79)	\$ -	\$ (31,983.79)
14	Real-Time Distribution of Losses Amount	\$ (1,457,777.73)	\$ -	\$ (1,457,777.73)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (371,516.59)	\$ -	\$ (371,516.59)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 168,567.51	\$ -	\$ 168,567.51
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (4,200.85)	\$ -	\$ (4,200.85)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 26,949.93	\$ -	\$ 26,949.93
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 403,564.72	\$ -	\$ 403,564.72
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)	\$ 108,155.76	\$ -	\$ 108,155.76
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)	\$ 22,982.13	\$ -	\$ 22,982.13
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (367,540.49)	\$ -	\$ (367,540.49)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (161,960.63)	\$ -	\$ (161,960.63)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ 120,197.10	\$ -	\$ 120,197.10
37	Financial Transmission Guarantee Uplift Amount	\$ (158,153.01)	\$ -	\$ (158,153.01)
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 914,962.22	\$ -	\$ 914,962.22
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 130,384.47	\$ -	\$ 130,384.47
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (15,250.38)	\$ 68.19	\$ (15,182.19)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 237,973.26	\$ -	\$ 237,973.26
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ (39,372.65)	\$ 29,568.06	\$ (9,804.59)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (216,353.55)	\$ 3,404.63	\$ (212,948.92)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 799,611.81	\$ (5,676.29)	\$ 793,935.52
19	Real-Time Market Administration Amount	\$ 58,410.57	\$ (6,235.03)	\$ 52,175.54
29	Financial Transmission Rights Market Administration Amount	\$ 58,307.84	\$ -	\$ 58,307.84
33	Day-Ahead Schedule 24 Allocation Amount	\$ 89,594.20	\$ (617.94)	\$ 88,976.26
34	Real-Time Schedule 24 Allocation Amount	\$ 6,547.89	\$ (717.39)	\$ 5,830.50
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	\$ (8,366.82)	\$ -	\$ (8,366.82)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 2,325,837.84	\$ -	\$ 2,325,837.84
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (2,413,644.80)	\$ -	\$ (2,413,644.80)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (505,025.69)	\$ -	\$ (505,025.69)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 329,071.19	\$ -	\$ 329,071.19
TOTAL MISO CHARGES		\$ 12,606,614.51	\$ 1,873,307.76	\$ 14,479,922.27
SCHEDULE 24 (FOR RETAIL)				\$ 94,806.76
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 14,385,115.51

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
November 2011 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (117,401.56)	\$ -	\$ (117,401.56)
2	Day-Ahead Spinning Reserve Amount	\$ (51,381.83)	\$ -	\$ (51,381.83)
3	Day-Ahead Supplemental Reserve	\$ (74,262.00)	\$ -	\$ (74,262.00)
4	Real-Time Regulation Amount	\$ (17,779.56)	38,071.02	\$ 20,291.46
5	Real-Time Spinning Reserve Amount	\$ (16,478.71)	27,923.66	\$ 11,444.95
6	Real-Time Supplemental Reserve Amount	\$ 174.93	19,863.16	\$ 20,038.09
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (15,324.79)		\$ (15,324.79)
7b	Real Time Excessive Energy Congestion	\$ -		\$ -
7c	Real Time Excessive Energy Loss	\$ -		\$ -
8a	Real Time Non Excessive Energy Amount	\$ 1,228,276.72		\$ 1,228,276.72
8b	Real Time Non Excessive Energy Congestion	\$ 61,952.05		\$ 61,952.05
8c	Real Time Non Excessive Energy Loss	\$ 162,208.42		\$ 162,208.42
9	Real Time Net Regulation Adjustment Amount	\$ 1,441.66	\$ 41.55	\$ 1,483.21
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 239,422.61	\$ -	\$ 239,422.61
11	Real Time Spinning Reserve Cost Distribution	\$ 103,997.33	\$ -	\$ 103,997.33
12	Real Time Supplemental Reserve Cost Distribution	\$ 59,747.31	\$ -	\$ 59,747.31
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 6,092.54	\$ (139.05)	\$ 5,953.49
14	Real Time Contignecy Reserve Deployment Failure	\$ 27.10	\$ -	\$ 27.10
TOTAL MISO ASM CHARGES		\$ 1,570,712.22	\$ 85,760.34	\$ 1,656,472.56

	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12
1 Forecast Month	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11
2 True-up Month	(4,685)	(4,685)	(4,685)	(14,881)	(4,685)	(4,685)	(4,685)	(4,686)	(4,686)	(4,686)	(4,686)	(4,686)
3												
4 Monthly Refund	203,291	203,850	171,035	168,639	174,150	172,841	198,618	180,234	167,256	169,751	201,528	230,843
5												
6 Forecast North Dakota Sales	(0.002)	(0.002)	(0.003)	(0.009)	(0.003)	(0.003)	(0.002)	(0.003)	(0.003)	(0.003)	(0.002)	(0.002)
7												
8 Current Month Refund Factor	(17,897)	(16,914)	(4,666)	7,377	2,316	(8,362)	(6,663)	(10,576)	(3,944)	(6,492)	30	(5,340)
13	(17,916)	(18,780)	(11,666)	858	4,294	(2,471)	(7,404)	(8,770)	(8,660)	(5,838)	(3,385)	(2,176)
14 Expected Refund	19	12,062	7,001	6,519	(1,978)	(5,891)	741	(1,806)	4,716	(654)	3,415	(3,164)
15 Actual Refund												
16 Deviation	0.000	0.006	0.004	0.004	(0.001)	(0.003)	0.000	(0.001)	0.003	(0.000)	0.002	(0.001)
17												
18 True-up Factor	(0.002)	0.004	0.001	(0.005)	(0.004)	(0.006)	(0.002)	(0.004)	0.000	(0.005)	(0.001)	(0.003)
19												
20 Realized Margin	0.9956	1.0548	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219
21												
22 Class Ratios	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135
23 Residential	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726
24 C&I Non-Demand	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088
25 C&I Demand Non-TOD												
26 C&I Demand TOD On-Peak												
27 C&I Demand TOD Off-Peak												
28 Outdoor Lighting												
29												
30 Realized Margin Adj for Class Ratios	(0.002)	0.004	0.001	(0.005)	(0.004)	(0.006)	(0.002)	(0.004)	0.000	(0.005)	(0.001)	(0.003)
31 Residential	0.004	0.004	0.001	(0.005)	(0.004)	(0.006)	(0.002)	(0.004)	0.000	(0.003)	(0.001)	(0.003)
32 C&I Non-Demand	0.004	0.004	0.001	(0.005)	(0.004)	(0.006)	(0.002)	(0.004)	0.000	(0.003)	(0.001)	(0.004)
33 C&I Demand Non-TOD	0.004	0.004	0.001	(0.005)	(0.004)	(0.006)	(0.002)	(0.004)	0.000	(0.003)	(0.001)	(0.003)
34 C&I Demand TOD On-Peak	0.005	0.005	0.002	(0.007)	(0.005)	(0.008)	(0.003)	(0.005)	0.000	(0.004)	(0.001)	(0.004)
35 C&I Demand TOD Off-Peak	0.003	0.003	0.001	(0.004)	(0.003)	(0.005)	(0.002)	(0.003)	0.000	(0.002)	(0.000)	(0.003)
36 Outdoor Lighting	0.003	0.003	0.001	(0.004)	(0.003)	(0.004)	(0.001)	(0.003)	0.000	(0.002)	(0.000)	(0.002)