



414 Nicollet Mall  
Minneapolis, Minnesota 55401

—Via Electronic Filing—

November 30, 2012

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

**Re: December 2012 Fuel Cost Charge**

Dear Mr. Nitschke:

Northern States Power Company, doing business as Xcel Energy and operating in North Dakota, hereby submits its electric fuel cost charge (FCC) for December 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:

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

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

<b>December 2012</b>	<b>Fuel Cost Charge (\$/kWh)</b>
<b>Residential</b>	0.02520
<b>C &amp; I Non-Demand</b>	0.02584
<b>C &amp; I Demand</b>	0.02556
<b>C &amp; I Demand Time of Day On-Peak</b>	0.03238
<b>C &amp; I Demand Time of Day Off-Peak</b>	0.01983
<b>Outdoor Lighting</b>	0.01870

## **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 MISO Day 2 charge types: 3 Auction Revenue Rights (ARR) and 3 Financial Transmission Rights (FTR) charge types<sup>1</sup>, to be reflected in the Fuel Cost Rider. Consistent with this Order and the required "net" accounting of Day 2 costs and revenues, we have included in the December 2012 FCC the net MISO Day 2 costs for October 2012 as recorded in Account 555. The MISO Day 2 cost recovery included in this December FCC is \$12,022,080, which is the net of many items. Pursuant to the above mentioned Orders, the Company also provides more detailed records in Attachment 2, page 1 to support the calculation of the MISO Day 2 costs.

### MISO ASM Charges

With the implementation of the MISO Ancillary Services Market (ASM) on January 6, 2009, the net costs or revenues of 14 ASM charge types are included in the Fuel Cost Rider, pursuant to Commission guidance in Docket No. PU-09-016. Consistent with the MISO Order and the required "net" accounting of ASM costs and revenues, we include in the December FCC the net MISO ASM costs for October 2012 as recorded in Account 555. The MISO ASM cost recovery included in this December FCC is \$1,167,811, which is the net of many items. The detailed records are contained in Attachment 2, page 2.

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

## **REFUNDS**

### Asset and Non-Asset Based Margins Sharing Refund

Pursuant to the above referenced Order Adopting Settlement, the December 2012 Asset Based Margin amount of \$20,252 has been included as a credit, or offset, to the December 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 December FCC is \$11,060, or 0.006¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

### Sales of Renewable Energy Credits

Pursuant to the Commission Order dated September 9, 2010 in Docket No. PU-10-19, the Company is authorized to sell excess Renewable Energy Credits (RECs) allocable to our North Dakota jurisdiction and credit 90 percent of the net proceeds back to customers through the Fuel Cost Rider (FCR). The Company executed and settled these REC sales in October 2012. Therefore, the Company has included in the December FCC a total credit of \$280,039 or 0.145 ¢ per kWh. Attachment 3, page 3 contains the derivation of this refund to the class FCCs.

## **OTHER REPORTING ITEM**

Attached is the calculation of the December 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, Regulatory 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 Dec-2012

Dec-2012 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
<b>System</b>	\$0.02729	-\$0.00055	-\$0.00016	\$0.02658
<b>Residential</b>	\$0.02736	-\$0.00055	-\$0.00161	\$0.02520
C & I Non-Demand	\$0.02806	-\$0.00056	-\$0.00165	\$0.02584
C & I Demand Non-TOD	\$0.02775	-\$0.00056	-\$0.00164	\$0.02556
C & I Demand TOD On-Peak	\$0.03516	-\$0.00070	-\$0.00207	\$0.03238
C & I Demand TOD Off-Peak	\$0.02153	-\$0.00043	-\$0.00127	\$0.01983
Outdoor Lighting	\$0.02030	-\$0.00041	-\$0.00120	\$0.01870
<b>Residential</b>				
Residential Service	\$ 0.02736	\$ (0.00055)	\$ (0.00161)	\$ 0.02520
Residential TOD	\$ 0.02736	\$ (0.00055)	\$ (0.00161)	\$ 0.02520
Residential - Underground	\$ 0.02736	\$ (0.00055)	\$ (0.00161)	\$ 0.02520
Residential TOD - Underground	\$ 0.02736	\$ (0.00055)	\$ (0.00161)	\$ 0.02520
Energy Control - (Non-Demand)	\$ 0.02736	\$ (0.00055)	\$ (0.00161)	\$ 0.02520
Limit Off Peak	\$ 0.02736	\$ (0.00055)	\$ (0.00161)	\$ 0.02520
<b>C &amp; I Non-Demand</b>				
Energy Controlled - (Non-Demand)	\$ 0.02806	\$ (0.00056)	\$ (0.00165)	\$ 0.02584
Limit Off Peak	\$ 0.02806	\$ (0.00056)	\$ (0.00165)	\$ 0.02584
Small General Service	\$ 0.02806	\$ (0.00056)	\$ (0.00165)	\$ 0.02584
Small General TOD - Metered	\$ 0.02806	\$ (0.00056)	\$ (0.00165)	\$ 0.02584
Small General TOD - Unmetered	\$ 0.02806	\$ (0.00056)	\$ (0.00165)	\$ 0.02584
Fire and Civil Defense Siren	\$ 0.02806	\$ (0.00056)	\$ (0.00165)	\$ 0.02584
Direct Current (Closed)	\$ 0.02806	\$ (0.00056)	\$ (0.00165)	\$ 0.02584
<b>C &amp; I Demand</b>				
General Service	\$ 0.02775	\$ (0.00056)	\$ (0.00164)	\$ 0.02556
General TOD - On Peak	\$ 0.03516	\$ (0.00070)	\$ (0.00207)	\$ 0.03238
General TOD - Off Peak	\$ 0.02153	\$ (0.00043)	\$ (0.00127)	\$ 0.01983
Peak Controlled (Closed)	\$ 0.02775	\$ (0.00056)	\$ (0.00164)	\$ 0.02556
Peak Controlled TOD (Closed) - On Peak	\$ 0.03516	\$ (0.00070)	\$ (0.00207)	\$ 0.03238
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02153	\$ (0.00043)	\$ (0.00127)	\$ 0.01983
Peak Controlled Tiered	\$ 0.02775	\$ (0.00056)	\$ (0.00164)	\$ 0.02556
Peak Controlled Tiered TOD - On Peak	\$ 0.03516	\$ (0.00070)	\$ (0.00207)	\$ 0.03238
Peak Controlled Tiered TOD - Off Peak	\$ 0.02153	\$ (0.00043)	\$ (0.00127)	\$ 0.01983
Energy Controlled (Closed)	\$ 0.02775	\$ (0.00056)	\$ (0.00164)	\$ 0.02556
Tier 1 Energy Controlled Rider	\$ 0.02775	\$ (0.00056)	\$ (0.00164)	\$ 0.02556
Real Time Pricing - Firm - On Peak	\$ 0.03516	\$ (0.00070)	\$ (0.00207)	\$ 0.03238
Real Time Pricing - Firm - Off Peak	\$ 0.02153	\$ (0.00043)	\$ (0.00127)	\$ 0.01983
Real Time Pricing - Controllable - On Peak	\$ 0.03516	\$ (0.00070)	\$ (0.00207)	\$ 0.03238
Real Time Pricing - Controllable - Off Peak	\$ 0.02153	\$ (0.00043)	\$ (0.00127)	\$ 0.01983
Small Municipal Pumping	\$ 0.02775	\$ (0.00056)	\$ (0.00164)	\$ 0.02556
Municipal Pumping	\$ 0.02775	\$ (0.00056)	\$ (0.00164)	\$ 0.02556
Excess Energy - St. Anthony Falls	\$ 0.02775	\$ (0.00056)	\$ (0.00164)	\$ 0.02556
<b>Outdoor Lighting</b>				
Automatic Protective Lighting	\$ 0.02030	\$ (0.00041)	\$ (0.00120)	\$ 0.01870
Street Lighting System	\$ 0.02030	\$ (0.00041)	\$ (0.00120)	\$ 0.01870
Street Lighting Energy	\$ 0.02030	\$ (0.00041)	\$ (0.00120)	\$ 0.01870
Street Lighting Energy - Metered	\$ 0.02030	\$ (0.00041)	\$ (0.00120)	\$ 0.01870
Street Lighting Energy (Closed)	\$ 0.02030	\$ (0.00041)	\$ (0.00120)	\$ 0.01870
Street Lighting - City of St. Paul	\$ 0.02030	\$ (0.00041)	\$ (0.00120)	\$ 0.01870

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 Dec-2012

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Jul-12	Aug-12	Sep-12	Oct-12	4 Month Total
<b>Fuel and Purchased Power Costs</b>					
Account 151 - Fossil Fuel	\$58,790,048	\$46,184,773	\$33,831,915	\$33,325,277	\$172,132,013
Account 518 - Nuclear Fuel	\$11,470,923	\$9,668,555	\$10,950,542	\$10,412,782	\$42,502,802
Account 555 - Purchased Power <sup>1</sup>	\$41,035,251	\$38,850,330	\$32,831,145	\$37,933,779	\$150,650,506
Account 555 - MISO Day 2 Charges	\$23,257,210	\$17,553,245	\$11,957,866	\$12,123,296	\$64,891,617
Account 555 MISO Day 2 - Schedule 24	(\$119,841)	(\$93,360)	(\$97,169)	(\$101,215)	(\$411,586)
Account 555 MISO - ASM Charges	\$1,410,522	\$968,698	\$222,751	\$1,167,811	\$3,769,781
Total MISO Charges	\$24,547,891	\$18,428,582	\$12,083,449	\$13,189,891	\$68,249,812
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$135,844,112	\$113,132,240	\$89,697,051	\$94,861,729	\$433,535,133
Less Fuel Cost of InterSystem Sales	(\$4,726,025)	(\$3,716,520)	(\$2,716,704)	(\$2,690,921)	(\$13,850,171)
Net System Costs	\$131,118,087	\$109,415,720	\$86,980,347	\$92,170,808	\$419,684,962
<b>System MWh Sales</b>					
Total NSP System Retail	4,163,505	4,241,939	3,435,726	3,387,097	15,228,267
Non-Gen Muni's/Load Pattern	37,734	42,444	37,855	32,604	150,637
Total NSP System MWh Sales	4,201,239	4,284,383	3,473,581	3,419,701	15,378,904
<b>Average Unit Cost of Fuel and Purchased Power</b>					
Fuel Cost per kWh for NSP System	3.121¢	2.554¢	2.504¢	2.695¢	2.729¢
Base Fuel Cost Included in Rates	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢
<b>Class Ratio/TOD Ratio</b>					
(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
<b>North Dakota Fuel Cost Factor (FCF)</b>					
				FCF Ratio	4 Month Average
(i) Residential				1.0026	2.736¢
(ii) C & I Non-Demand				1.0281	2.806¢
(iii) C & I Demand Non-TOD				1.0170	2.775¢
(iv) C & I Demand TOD On-Peak				1.2883	3.516¢
(v) C & I Demand TOD Off-Peak				0.7889	2.153¢
(vi) Outdoor Lighting				0.7440	2.030¢
<b>North Dakota Retail MWh Sales</b>					
(i) Residential	67,595	70,089	50,802	52,225	240,711
(ii) C & I Non-Demand	9,298	9,627	8,088	8,822	35,835
(iii) C & I Demand Non-TOD	66,344	69,444	62,803	65,092	263,683
(iv) C & I Demand TOD On-Peak	19,710	20,606	20,106	18,623	79,045
(v) C & I Demand TOD Off-Peak	32,049	31,310	30,876	28,368	122,603
(vi) Outdoor Lighting	1,125	1,201	1,377	1,599	5,302
(vii) Total	196,121	202,277	174,052	174,729	747,179
<b>Dec-2012 Recovery Provision (True-up Factor) Calculation</b>					
Prior Unrecovered Expenses (Aug-12 Balance of Unrecovered Expenses)					Total
					Aug-12
					\$148,648

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

Prior Expenses Recovered in Oct-2012 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	52,225	\$47,146
(ii) C & I Non-Demand	8,822	\$8,709
(iii) C & I Demand Non-TOD	65,092	\$64,321
(iv) C & I Demand TOD On-Peak	18,623	\$23,996
(v) C & I Demand TOD Off-Peak	28,368	\$22,474
(vi) Outdoor Lighting	1,599	\$1,486
(vii) Total	174,729	\$168,132

Actual Cost Should Have Been Recovered in Oct-12				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.695¢	0.000¢	174,729	\$4,708,947

Cost Recovered in Oct-12 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	52,225	\$1,524,837
(ii) C & I Non-Demand	8,822	\$263,879
(iii) C & I Demand Non-TOD	65,092	\$1,923,837
(iv) C & I Demand TOD On-Peak	18,623	\$698,847
(v) C & I Demand TOD Off-Peak	28,368	\$651,916
(vi) Outdoor Lighting	1,599	\$34,746
(vii) Total	174,729	\$5,098,062

Total Balance of Unrecovered Expenses (Dec-12 Balance of Unrecovered Expenses)	
Dec-2012 Recovery Provision	(\$408,599)
4 Month ND Retail Total MWh Sales	747,179
Dec-2012 Recovery Provision per KWH	-0.055¢

Dec-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	-0.055¢	-0.055¢
(ii) C & I Non-Demand	1.0281	-0.055¢	-0.056¢
(iii) C & I Demand Non-TOD	1.0170	-0.055¢	-0.056¢
(iv) C & I Demand TOD On-Peak	1.2883	-0.055¢	-0.070¢
(v) C & I Demand TOD Off-Peak	0.7889	-0.055¢	-0.043¢
(vi) Outdoor Lighting	0.7440	-0.055¢	-0.041¢

Dec-2012 Refunds/Additional Charges				
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Refund	Total
Refund/Special Charge Amount	(\$20,252)	(\$11,060)	(\$280,039)	(\$300,291)
(i) Residential	-0.010¢	-0.006¢	-0.145¢	-0.161¢
(ii) C & I Non-Demand	-0.011¢	-0.006¢	-0.149¢	-0.165¢
(iii) C & I Demand Non-TOD	-0.011¢	-0.006¢	-0.147¢	-0.164¢
(iv) C & I Demand TOD On-Peak	-0.013¢	-0.007¢	-0.187¢	-0.207¢
(v) C & I Demand TOD Off-Peak	-0.008¢	-0.005¢	-0.114¢	-0.127¢
(vi) Outdoor Lighting	-0.008¢	-0.004¢	-0.108¢	-0.120¢

Dec-2012 Factors	
	Total
(i) Residential	2.520¢
(ii) C & I Non-Demand	2.584¢
(iii) C & I Demand Non-TOD	2.556¢
(iv) C & I Demand TOD On-Peak	3.238¢
(v) C & I Demand TOD Off-Peak	1.983¢
(vi) Outdoor Lighting	1.870¢

FUEL CLAUSE ADJUSTMENT (FCA) COMPARISON -  
Prior Month Compared to Current Month FCA

	FCA Application		Comparison		Generation Type by Percent		
	Nov-12	Dec-12	Difference	Percent Change	FCA Application Nov-12	FCA Application Dec-12	Difference
<b>** COSTS (Millions) **</b>							
1 Fossil	\$172.6	\$172.1	(\$0.4)	-0.2%	38.5%	39.7%	1.2%
2 Nuclear	\$42.9	\$42.5	(\$0.4)	-1.0%	9.6%	9.8%	0.2%
3 Purchases	\$152.4	\$150.7	(\$1.7)	-1.1%	34.0%	34.7%	0.7%
MISO related Purchases	\$80.1	\$68.2	(\$11.8)	-14.8%	17.9%	15.7%	-2.2%
4 Total System Costs	447.9	433.5	(\$14.4)	-3.2%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$15.8	\$13.9	(\$2.0)	-12.4%	3.5%	3.2%	-0.3%
6 Net System Costs	\$432.1	\$419.7	(\$12.4)	-2.9%	96.5%	96.8%	0.3%
7							
<b>** GWH OUTPUT **</b>							
9 Fossil	4,734	5,124	390	8.2%	26.8%	29.7%	2.9%
10 Nuclear	4,442	4,411	(31)	-0.7%	25.2%	25.6%	0.4%
11 Purchases	5,553	5,231	(322)	-5.8%	31.5%	30.3%	-1.2%
12 Hydro & Other	2,249	1,786	(463)	-20.6%	12.7%	10.4%	-2.3%
13 Net Interchange	673	692	19	2.8%	3.8%	4.0%	0.2%
14 Total Output	17,651	17,244	(407)	-2.3%	100.0%	100.0%	0.0%
15 Intersystem Sales	856	997	140	16.4%	4.9%	5.8%	0.9%
16 Native Requirement	16,795	16,247	(547)	-3.3%	95.1%	94.2%	-0.9%
17							
<b>** COST per KWH OUTPUT (\$) **</b>							
19 Fossil	3.645	3.359	-0.286	-7.8%			
20 Nuclear	0.967	0.964	-0.003	-0.3%			
21 Purchases	2.744	2.880	0.136	5.0%			
22 Total System Costs	2.538	2.514	-0.024	-0.9%			
23 Intersystem Sales	1.848	1.390	-0.458	-24.8%			
24 Net System Costs	2.573	2.583	0.010	0.4%			
25							
26							
27 TOTAL SYSTEM GWH SALES	15,443	15,379	(64)	-0.4%			
28							
29 COST per KWH SALES (\$)	2.798	2.729	-0.069	-2.5%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	0.040	-0.055	-0.095				
(i) Residential	0.040	-0.055	-0.095				
(ii) C & I Non-Demand	0.041	-0.056	-0.097				
(iii) C & I Demand Non-TOD	0.041	-0.056	-0.096				
(iv) C & I Demand TOD On-Peak	0.052	-0.070	-0.122				
(v) C & I Demand TOD Off-Peak	0.032	-0.043	-0.075				
(vi) Outdoor Lighting	0.030	-0.041	-0.071				
32 REFUND	-0.041	0.000	0.041				
(i) Residential	-0.041	-0.161	-0.161				
(ii) C & I Non-Demand	-0.042	-0.165	-0.165				
(iii) C & I Demand Non-TOD	-0.042	-0.164	-0.164				
(iv) C & I Demand TOD On-Peak	-0.053	-0.207	-0.207				
(v) C & I Demand TOD Off-Peak	-0.032	-0.127	-0.127				
(vi) Outdoor Lighting	-0.031	-0.120	-0.120				
33 SYSTEM FCC IMPACT (\$ / KWH)	2.797	2.674	-0.123	-4.4%			
(i) Residential	2.804	2.520	-0.284				
(ii) C & I Non-Demand	2.876	2.584					
(iii) C & I Demand Non-TOD	2.845	2.556					
(iv) C & I Demand TOD On-Peak	3.604	3.238					
(v) C & I Demand TOD Off-Peak	2.207	1.983					
(vi) Outdoor Lighting	2.081	1.870					

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	(\$0.28)
250	(\$0.71)
500	(\$1.42)
750	(\$2.13)
1,000	(\$2.84)

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	
	Nov-12	Dec-12
<b>** GWH OUTPUT **</b>		
Thermal	1,884,633	1,449,623
Disper gen	(94)	(99)
Hydro plus Wind	364,290	336,788
Hydro and Other	2,248,829	1,786,312
Rounded to nearest thousand:	2,249	1,786
<b>Sales</b>		
Non Gen Munic Total	152,515,000	150,637,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	856,074,000	996,573,000
Rounded to nearest million:	856.074	996.573

		System	Intersystem	Retail
<b>October 2012 Actual</b>				
<b>Energy and Loss Charges</b>				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 14,670,167.21	\$ 3,567,903.36	\$ 18,238,070.57
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 1,544,989.57	\$ -	\$ 1,544,989.57
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (13,243,985.45)	\$ -	\$ (13,243,985.45)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 2,083,318.16	\$ -	\$ 2,083,318.16
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)	\$ 684,918.92	\$ 490,322.40	\$ 1,175,241.32
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (89,507.93)	\$ -	\$ (89,507.93)
14	Real-Time Distribution of Losses Amount	\$ (1,236,219.52)	\$ -	\$ (1,236,219.52)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (17,496.49)	\$ -	\$ (17,496.49)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ (66,122.81)	\$ -	\$ (66,122.81)
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ 12,062.86	\$ -	\$ 12,062.86
<b>Congestion-Related Charges</b>				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 1,557,314.37	\$ -	\$ 1,557,314.37
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 2,203,708.14	\$ -	\$ 2,203,708.14
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)	\$ 26,808.59	\$ -	\$ 26,808.59
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)	\$ 32,457.10	\$ -	\$ 32,457.10
<b>FTR Related Charges</b>				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (680,697.64)	\$ -	\$ (680,697.64)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (58,376.98)	\$ -	\$ (58,376.98)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (126,240.40)	\$ -	\$ (126,240.40)
37	Financial Transmission Rights Guarantee Uplift Amount	\$ 161,816.09	\$ -	\$ 161,816.09
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
<b>Uplift Charges</b>				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 580,258.23	\$ -	\$ 580,258.23
<b>Revenue Sufficiency Guarantee (RSG) Charges</b>				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 141,140.89	\$ -	\$ 141,140.89
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (76,741.73)	\$ 2,434.05	\$ (74,307.68)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 118,242.97	\$ -	\$ 118,242.97
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ (80,079.52)	\$ 274.32	\$ (79,805.20)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (190,092.76)	\$ 5,271.25	\$ (184,821.51)
<b>Market Administration Charges</b>				
4	Day-Ahead Market Administration Amount	\$ 623,893.56	\$ (14,003.84)	\$ 609,889.72
19	Real-Time Market Administration Amount	\$ 34,446.14	\$ (3,009.68)	\$ 31,436.46
29	Financial Transmission Rights Market Administration Amount	\$ 44,720.88	\$ -	\$ 44,720.88
33	Day-Ahead Schedule 24 Allocation Amount	\$ 98,476.03	\$ (2,209.16)	\$ 96,266.87
34	Real-Time Schedule 24 Allocation Amount	\$ 5,421.92	\$ (473.30)	\$ 4,948.62
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	\$ -	\$ -	\$ -
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
<b>Auction Revenue Rights (ARR)</b>				
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	\$ (799,327.18)	\$ -	\$ (799,327.18)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 165,174.62	\$ -	\$ 165,174.62
<b>TOTAL MISO CHARGES</b>		<b>\$ 8,076,786.35</b>	<b>\$ 4,046,509.40</b>	<b>\$ 12,123,295.75</b>
<b>SCHEDULE 24 (FOR RETAIL)</b>				<b>\$ 101,215.49</b>
<b>TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)</b>				<b>\$ 12,022,080.26</b>

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

		System	Intersystem	Retail
<b>October 2012 Actual</b>				
<b>Procurement Charges</b>				
1	Day-Ahead Regulation Amount	\$ (81,327.46)	\$ -	\$ (81,327.46)
2	Day-Ahead Spinning Reserve Amount	\$ (45,321.36)	\$ -	\$ (45,321.36)
3	Day-Ahead Supplemental Reserve	\$ (97,242.45)	\$ -	\$ (97,242.45)
4	Real-Time Regulation Amount	\$ (46,541.06)	\$ 42,061.18	\$ (4,479.88)
5	Real-Time Spinning Reserve Amount	\$ 7,655.96	\$ 8,566.85	\$ 16,222.81
6	Real-Time Supplemental Reserve Amount	\$ (164.02)	\$ 3,367.33	\$ 3,203.31
<b>Resource Energy Charges</b>				
7a	Real Time Excessive Energy Amount	\$ (12,022.98)	\$ -	\$ (12,022.98)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 229,051.97	\$ -	\$ 229,051.97
8b	Real Time Non Excessive Energy Congestion	\$ 502,380.03	\$ -	\$ 502,380.03
8c	Real Time Non Excessive Energy Loss	\$ 230,578.00	\$ -	\$ 230,578.00
9	Real Time Net Regulation Adjustment Amount	\$ 482.13	\$ 61.70	\$ 543.83
<b>Cost Distribution Charges</b>				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 215,617.39	\$ -	\$ 215,617.39
11	Real Time Spinning Reserve Cost Distribution	\$ 113,510.48	\$ -	\$ 113,510.48
12	Real Time Supplemental Reserve Cost Distribution	\$ 92,851.37	\$ -	\$ 92,851.37
<b>Penalty Charges</b>				
13	Real Time Excessive/Dificient Energy Deployment	\$ 5,010.47	\$ (764.68)	\$ 4,245.79
14	Real Time Contingency Reserve Deployment Failure	\$ -	\$ -	\$ -
<b>TOTAL MISO ASM CHARGES</b>		<b>\$ 1,114,518.47</b>	<b>\$ 53,292.38</b>	<b>\$ 1,167,810.85</b>

Northern States Power Company, A Minnesota Corporation  
Electric Operations - State of North Dakota  
Deviation of Adjustment for Fuel Clause Rider  
Asset Based Margin Sharing

	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13
1 Forecast Month	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
2 True-up Month												
3												
4 Monthly Refund	(37,060)	(48,106)	(20,855)	(21,116)	(45,351)	(9,086)	(110,114)	(35,437)	(13,659)	(60,004)		
5												
6 Forecast North Dakota Sales	204,480	176,872	172,668	167,827	186,675	198,082	165,774	179,024	171,102	193,427	241,910	204,198
7												
8 Current Month Refund Factor	(0.018)	(0.027)	(0.012)	(0.013)	(0.025)	(0.005)	(0.066)	(0.020)	(0.008)	(0.031)		
9												
14 Expected Refund	(30,199)	(42,867)	(36,737)	(58,058)	(20,517)	(39,456)	(27,680)	(19,991)	(100,226)	(29,196)	(58,610)	(20,252)
15 Actual Refunded	(30,522)	(32,915)	(37,673)	(39,718)	(36,189)	(28,551)	(37,568)	(26,230)	(53,275)	(68,950)		
16 Deviation	323	(9,952)	336	(18,340)	17,671	(10,905)	9,888	6,239	(44,951)	39,752	(58,610)	(20,252)
17												
18 True-up Factor	0.000	(0.006)	0.000	(0.011)	0.010	(0.006)	0.006	0.003	(0.029)	0.021		
19												
20 Realized Margin	(0.018)	(0.033)	(0.012)	(0.024)	(0.015)	(0.010)	(0.060)	(0.016)	(0.034)	(0.010)		
21												
22 Class Ratios												
23 Residential	0.9956	0.9956	0.9974	0.9991	1.0009	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
24 C&I Non-Demand	1.0548	1.0548	1.0481	1.0445	1.0348	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281
25 C&I Demand Non-TOD	1.0219	1.0219	1.0207	1.0195	1.0182	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170
26 C&I Demand TOD On-Peak	1.3135	1.3135	1.3072	1.3009	1.2946	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883
27 C&I Demand TOD Off-Peak	0.7726	0.7726	0.7767	0.7808	0.7848	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889
28 Outdoor Lighting	0.7088	0.7088	0.7176	0.7264	0.7352	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440
29												
30 Realized Margin Adj for Class Ratios												
31 Residential	(0.018)	(0.033)	(0.012)	(0.023)	(0.015)	(0.010)	(0.061)	(0.016)	(0.034)	(0.010)		
32 C&I Non-Demand	(0.019)	(0.035)	(0.012)	(0.024)	(0.016)	(0.010)	(0.062)	(0.017)	(0.035)	(0.011)		
33 C&I Demand Non-TOD	(0.018)	(0.034)	(0.012)	(0.024)	(0.016)	(0.010)	(0.061)	(0.017)	(0.035)	(0.011)		
34 C&I Demand TOD On-Peak	(0.024)	(0.043)	(0.016)	(0.031)	(0.020)	(0.013)	(0.076)	(0.021)	(0.044)	(0.013)		
35 C&I Demand TOD Off-Peak	(0.014)	(0.025)	(0.009)	(0.018)	(0.012)	(0.008)	(0.048)	(0.013)	(0.027)	(0.008)		
36 Outdoor Lighting	(0.013)	(0.023)	(0.009)	(0.017)	(0.011)	(0.008)	(0.045)	(0.012)	(0.025)	(0.008)		



