



414 Nicollet Mall  
Minneapolis, Minnesota 55401

—Via Electronic Filing—

January 28, 2011

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

**Re: February 2011 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 February 2011.

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 February 2011 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 December 2010 calendar month.

Beginning this month, the actual billed fuel cost (i.e., the actual fuel costs recovered from customers) is used as an input in the determination of the true-up factor instead of a calculated billed fuel cost using sales and fuel cost charges. This will improve the precision of the true-up factors it reflects the fact that, when the Company bills out its fuel costs using the FCC, each customer's energy use is prorated to calendar month and then billed using the FCC specific to the applicable calendar month in the billing cycle.

There is no change in the mathematical calculation of the FCC, true-up, the application of the FCC, or to the Rider tariff language; the improvement is essentially an administrative change to use the direct source of the billed fuel cost amount.

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

<b>February 2011</b>	<b>Fuel Cost Charge (\$/kWh)</b>
<b>Residential</b>	0.02384
<b>C &amp; I Non-Demand</b>	0.02526
<b>C &amp; I Demand</b>	0.02447
<b>C &amp; I Demand Time of Day On-Peak</b>	0.03146
<b>C &amp; I Demand Time of Day Off-Peak</b>	0.01850
<b>Outdoor Lighting</b>	0.01698

## **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 PU-07-776, Xcel Energy is authorized to recover MISO Day 2 costs. The March FCC 2009 reflected the new MISO Day 2 charge types: 3 Auction Revenue Rights (ARR) and 3 new Financial Transmission Rights (FTR) charge types<sup>1</sup>, to be reflected in Fuel Cost Rider. Consistent with this Order and the required “net” accounting of Day 2 costs and revenues, we have included in the February 2011 FCC, the net MISO Day 2 costs for December 2010 as recorded in Account 555. The MISO Day 2 cost recovery included in this February FCC is \$13,342,915, 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.

<sup>1</sup> 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 charges 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 February FCC, the net MISO ASM costs for December 2010 as recorded in Account 555. The MISO ASM cost recovery included in this February FCC is \$125,361, 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 December 2010 Asset Based Margin amount of \$44,836 has been included in the February 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 February FCC is \$4,666, or 0.002¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

## **OTHER REPORTING ITEM**

Attachment is the calculation of the February 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 & Wholly Owned Subsidiary of Xcel Energy Inc.  
 Electric Operations - State of North Dakota  
 Derivation of Adjustment for Fuel Clause Rider  
 Current Period Cost of Energy for Feb-2011

Feb-2011 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
<b>System</b>	<b>\$0.02463</b>	<b>-\$0.00044</b>	<b>-\$0.00024</b>	<b>\$0.02395</b>
<b>Residential</b>	<b>\$0.02452</b>	<b>-\$0.00043</b>	<b>-\$0.00024</b>	<b>\$0.02384</b>
<b>C &amp; I Non-Demand</b>	<b>\$0.02598</b>	<b>-\$0.00046</b>	<b>-\$0.00026</b>	<b>\$0.02526</b>
<b>C &amp; I Demand Non-TOD</b>	<b>\$0.02517</b>	<b>-\$0.00045</b>	<b>-\$0.00025</b>	<b>\$0.02447</b>
<b>C &amp; I Demand TOD On-Peak</b>	<b>\$0.03235</b>	<b>-\$0.00057</b>	<b>-\$0.00032</b>	<b>\$0.03146</b>
<b>C &amp; I Demand TOD Off-Peak</b>	<b>\$0.01903</b>	<b>-\$0.00034</b>	<b>-\$0.00019</b>	<b>\$0.01850</b>
<b>Outdoor Lighting</b>	<b>\$0.01746</b>	<b>-\$0.00031</b>	<b>-\$0.00017</b>	<b>\$0.01698</b>
<b>Residential</b>				
Residential Service	\$ 0.02452	\$ (0.00043)	\$ (0.00024)	\$ 0.02384
Residential TOD	\$ 0.02452	\$ (0.00043)	\$ (0.00024)	\$ 0.02384
Residential - Underground	\$ 0.02452	\$ (0.00043)	\$ (0.00024)	\$ 0.02384
Residential TOD - Underground	\$ 0.02452	\$ (0.00043)	\$ (0.00024)	\$ 0.02384
Energy Control - (Non-Demand)	\$ 0.02452	\$ (0.00043)	\$ (0.00024)	\$ 0.02384
Limit Off Peak	\$ 0.02452	\$ (0.00043)	\$ (0.00024)	\$ 0.02384
<b>C &amp; I Non-Demand</b>				
Energy Controlled - (Non-Demand)	\$ 0.02598	\$ (0.00046)	\$ (0.00026)	\$ 0.02526
Limit Off Peak	\$ 0.02598	\$ (0.00046)	\$ (0.00026)	\$ 0.02526
Small General Service	\$ 0.02598	\$ (0.00046)	\$ (0.00026)	\$ 0.02526
Small General TOD - Metered	\$ 0.02598	\$ (0.00046)	\$ (0.00026)	\$ 0.02526
Small General TOD - Unmetered	\$ 0.02598	\$ (0.00046)	\$ (0.00026)	\$ 0.02526
Fire and Civil Defense Siren	\$ 0.02598	\$ (0.00046)	\$ (0.00026)	\$ 0.02526
Direct Current (Closed)	\$ 0.02598	\$ (0.00046)	\$ (0.00026)	\$ 0.02526
<b>C &amp; I Demand</b>				
General Service	\$ 0.02517	\$ (0.00045)	\$ (0.00025)	\$ 0.02447
General TOD - On Peak	\$ 0.03235	\$ (0.00057)	\$ (0.00032)	\$ 0.03146
General TOD - Off Peak	\$ 0.01903	\$ (0.00034)	\$ (0.00019)	\$ 0.01850
Peak Controlled (Closed)	\$ 0.02517	\$ (0.00045)	\$ (0.00025)	\$ 0.02447
Peak Controlled TOD (Closed) - On Peak	\$ 0.03235	\$ (0.00057)	\$ (0.00032)	\$ 0.03146
Peak Controlled TOD (Closed) - Off Peak	\$ 0.01903	\$ (0.00034)	\$ (0.00019)	\$ 0.01850
Peak Controlled Tiered	\$ 0.02517	\$ (0.00045)	\$ (0.00025)	\$ 0.02447
Peak Controlled Tiered TOD - On Peak	\$ 0.03235	\$ (0.00057)	\$ (0.00032)	\$ 0.03146
Peak Controlled Tiered TOD - Off Peak	\$ 0.01903	\$ (0.00034)	\$ (0.00019)	\$ 0.01850
Energy Controlled (Closed)	\$ 0.02517	\$ (0.00045)	\$ (0.00025)	\$ 0.02447
Tier 1 Energy Controlled Rider	\$ 0.02517	\$ (0.00045)	\$ (0.00025)	\$ 0.02447
Real Time Pricing - Firm - On Peak	\$ 0.03235	\$ (0.00057)	\$ (0.00032)	\$ 0.03146
Real Time Pricing - Firm - Off Peak	\$ 0.01903	\$ (0.00034)	\$ (0.00019)	\$ 0.01850
Real Time Pricing - Controllable - On Peak	\$ 0.03235	\$ (0.00057)	\$ (0.00032)	\$ 0.03146
Real Time Pricing - Controllable - Off Peak	\$ 0.01903	\$ (0.00034)	\$ (0.00019)	\$ 0.01850
Small Municipal Pumping	\$ 0.02517	\$ (0.00045)	\$ (0.00025)	\$ 0.02447
Municipal Pumping	\$ 0.02517	\$ (0.00045)	\$ (0.00025)	\$ 0.02447
Excess Energy - St. Anthony Falls	\$ 0.02517	\$ (0.00045)	\$ (0.00025)	\$ 0.02447
<b>Outdoor Lighting</b>				
Automatic Protective Lighting	\$ 0.01746	\$ (0.00031)	\$ (0.00017)	\$ 0.01698
Street Lighting System	\$ 0.01746	\$ (0.00031)	\$ (0.00017)	\$ 0.01698
Street Lighting Energy	\$ 0.01746	\$ (0.00031)	\$ (0.00017)	\$ 0.01698
Street Lighting Energy - Metered	\$ 0.01746	\$ (0.00031)	\$ (0.00017)	\$ 0.01698
Street Lighting Energy (Closed)	\$ 0.01746	\$ (0.00031)	\$ (0.00017)	\$ 0.01698
Street Lighting - City of St. Paul	\$ 0.01746	\$ (0.00031)	\$ (0.00017)	\$ 0.01698

Northern States Power Company, A Minnesota Corporation & Wholly Owned Subsidiary of Xcel Energy Inc.  
 Electric Operations - State of North Dakota  
 Derivation of Adjustment for Fuel Clause Rider  
 Current Period Cost of Energy for Feb-2011

	Column (A) Sep-10	Column (B) Oct-10	Column (C) Nov-10	Column (D) Dec-10	Column (E) 4 Month Total
<b>Fuel and Purchased Power Costs</b>					
Account 151 - Fossil Fuel	\$32,483,786	\$27,904,463	\$29,250,092	\$42,930,204	\$132,568,545
Account 518 - Nuclear Fuel	\$10,120,300	\$10,528,653	\$8,442,371	\$10,688,880	\$39,780,202
Account 555 - Purchased Power <sup>1</sup>	\$42,858,688	\$35,333,149	\$40,365,101	\$34,161,906	\$152,718,845
Account 555 - MISO Day 2 Charges	\$10,215,984	\$13,229,787	\$17,870,049	\$13,438,358	\$54,754,179
Account 555 MISO Day 2 - Schedule 24	(\$88,143)	(\$91,617)	(\$90,795)	(\$95,443)	(\$365,998)
Account 555 MISO - ASM Charges	(\$465,255)	\$1,826,511	\$1,874,955	\$125,361	\$3,361,572
Total MISO Charges	\$9,662,585	\$14,964,682	\$19,654,210	\$13,468,276	\$57,749,752
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$95,125,359	\$88,730,947	\$97,711,774	\$101,249,265	\$382,817,344
Less Fuel Cost of InterSystem Sales	(\$15,484,547)	(\$6,507,051)	(\$11,869,991)	(\$9,477,298)	(\$43,338,886)
Net System Costs	\$79,640,812	\$82,223,896	\$85,841,783	\$91,771,967	\$339,478,458
<b>System MWh Sales</b>					
Total NSP System Retail	3,737,306	3,133,138	3,097,598	3,539,364	13,507,406
Non-Gen Muni's/Load Pattern	80,260	64,086	62,824	66,245	273,415
Total NSP System MWh Sales	3,817,566	3,197,224	3,160,422	3,605,609	13,780,821
<b>Average Unit Cost of Fuel and Purchased Power</b>					
Fuel Cost per kWh for NSP System	2.086¢	2.572¢	2.716¢	2.545¢	2.463¢
Base Fuel Cost Included in Rates	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢
<b>Class Ratio/TOD Ratio</b>					
(i) Residential	0.9956	0.9956	0.9956	0.9956	0.9956
(ii) C & I Non-Demand	1.0548	1.0548	1.0548	1.0548	1.0548
(iii) C & I Demand Non-TOD	1.0219	1.0219	1.0219	1.0219	1.0219
(iv) C & I Demand TOD On-Peak	1.3135	1.3135	1.3135	1.3135	1.3135
(v) C & I Demand TOD Off-Peak	0.7726	0.7726	0.7726	0.7726	0.7726
(vi) Outdoor Lighting	0.7088	0.7088	0.7088	0.7088	0.7088
<b>North Dakota Fuel Cost Factor (FCF)</b>					
				FCF Ratio	4 Month Average
(i) Residential				0.9956	2.452¢
(ii) C & I Non-Demand				1.0548	2.598¢
(iii) C & I Demand Non-TOD				1.0219	2.517¢
(iv) C & I Demand TOD On-Peak				1.3135	3.235¢
(v) C & I Demand TOD Off-Peak				0.7726	1.903¢
(vi) Outdoor Lighting				0.7088	1.746¢
<b>North Dakota Retail MWh Sales</b>					
(i) Residential	53,979	44,866	51,416	82,934	233,195
(ii) C & I Non-Demand	9,169	8,175	8,696	11,913	37,953
(iii) C & I Demand Non-TOD	60,097	56,339	55,482	62,705	234,623
(iv) C & I Demand TOD On-Peak	19,488	18,625	17,620	18,586	74,319
(v) C & I Demand TOD Off-Peak	30,560	28,988	27,348	30,313	117,209
(vi) Outdoor Lighting	1,405	1,301	1,945	1,951	6,602
(vii) Total	174,698	158,294	162,507	208,402	703,901
<b>Feb-2011 Recovery Provision (True-up Factor) Calculation</b>					
Prior Unrecovered Expenses (Oct-10 Balance of Unrecovered Expenses)					Total
					Oct-10
					(\$242,476)

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

Prior Expenses Recovered in Dec-2010 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	82,934	(\$38,244)
(ii) C & I Non-Demand	11,913	(\$5,613)
(iii) C & I Demand Non-TOD	62,705	(\$26,097)
(iv) C & I Demand TOD On-Peak	18,586	(\$10,643)
(v) C & I Demand TOD Off-Peak	30,313	(\$10,225)
(vi) Outdoor Lighting	1,951	(\$713)
(vii) Total	208,402	(\$91,535)

Actual Cost Should Have Been Recovered in Dec-10				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.545¢	0.000¢	208,402	\$5,303,831

Cost Recovered in Dec-10 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	82,934	\$2,156,678
(ii) C & I Non-Demand	11,913	\$329,025
(iii) C & I Demand Non-TOD	62,705	\$1,684,185
(iv) C & I Demand TOD On-Peak	18,586	\$640,173
(v) C & I Demand TOD Off-Peak	30,313	\$613,939
(vi) Outdoor Lighting	1,951	\$36,118
(vii) Total	208,402	\$5,460,118

Total Balance of Unrecovered Expenses (Feb-11 Balance of Unrecovered Expenses)	
Feb-2011 Recovery Provision	(\$307,228)
4 Month ND Retail Total MWh Sales	703,901
Feb-2011 Recovery Provision per KWH	-0.044¢

Feb-2011 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9956	-0.044¢	-0.043¢
(ii) C & I Non-Demand	1.0548	-0.044¢	-0.046¢
(iii) C & I Demand Non-TOD	1.0219	-0.044¢	-0.045¢
(iv) C & I Demand TOD On-Peak	1.3135	-0.044¢	-0.057¢
(v) C & I Demand TOD Off-Peak	0.7726	-0.044¢	-0.034¢
(vi) Outdoor Lighting	0.7088	-0.044¢	-0.031¢

Feb-2011 Margin Sharing Refunds			
Refund/Special Charge Amount	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
	(\$44,836)	(\$4,666)	(\$49,502)
(i) Residential	-0.022¢	-0.002¢	-0.024¢
(ii) C & I Non-Demand	-0.023¢	-0.002¢	-0.026¢
(iii) C & I Demand Non-TOD	-0.023¢	-0.002¢	-0.025¢
(iv) C & I Demand TOD On-Peak	-0.029¢	-0.003¢	-0.032¢
(v) C & I Demand TOD Off-Peak	-0.017¢	-0.002¢	-0.019¢
(vi) Outdoor Lighting	-0.016¢	-0.002¢	-0.017¢

Feb-2011 Factors	
	Total
(i) Residential	2.384¢
(ii) C & I Non-Demand	2.526¢
(iii) C & I Demand Non-TOD	2.447¢
(iv) C & I Demand TOD On-Peak	3.146¢
(v) C & I Demand TOD Off-Peak	1.850¢
(vi) Outdoor Lighting	1.698¢

Northern States Power Company, A Minnesota Corporation  
 Electric Operations - State of North Dakota  
 FUEL CLAUSE ADJUSTMENT (FCA) COMPARISON -  
 Prior Month Compared to Current Month FCA

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Jan-11	Feb-11	Differ- ence	Percent Change	FCA Application Jan-11	Feb-11	Differ- ence
<b>** COSTS (Millions) **</b>							
1 Fossil	\$148.1	\$132.6	(\$15.5)	-10.5%	35.2%	34.6%	-0.6%
2 Nuclear	\$39.5	\$39.8	\$0.3	0.6%	9.4%	10.4%	1.0%
3 Purchases	\$170.4	\$152.7	(\$17.7)	-10.4%	40.6%	39.9%	-0.7%
MISO related Purchases	\$62.1	\$57.7	(\$4.4)	-7.1%	14.8%	15.1%	0.3%
4 Total System Costs	420.2	382.8	(\$37.4)	-8.9%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$50.7	\$43.3	(\$7.3)	-14.5%	12.1%	11.3%	-0.8%
6 Net System Costs	\$369.5	\$339.5	(\$30.1)	-8.1%	87.9%	88.7%	0.8%
7							
8 <b>** GWH OUTPUT **</b>							
9 Fossil	4,981	4,941	(40)	-0.8%	29.1%	30.3%	1.2%
10 Nuclear	4,453	4,532	79	1.8%	26.0%	27.8%	1.8%
11 Purchases	5,663	5,046	(617)	-10.9%	33.0%	30.9%	-2.1%
12 Hydro & Other	1,353	963	(390)	-28.8%	7.9%	5.9%	-2.0%
13 Net Interchange	666	828	142	20.7%	4.0%	5.1%	1.1%
14 Total Output	17,136	16,310	(826)	-4.8%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,879	1,735	(144)	-7.7%	11.0%	10.6%	-0.4%
16 Native Requirement	15,257	14,575	(682)	-4.5%	89.0%	89.4%	0.4%
17							
18 <b>** COST per KWH OUTPUT (\$) **</b>							
19 Fossil	2.973	2.683	-0.290	-9.8%			
20 Nuclear	0.868	0.878	-0.010	-1.1%			
21 Purchases	3.010	3.027	0.017	0.6%			
22 Total System Costs	2.452	2.347	-0.105	-4.3%			
23 Intersystem Sales	2.696	2.498	-0.199	-7.4%			
24 Net System Costs	2.422	2.329	-0.093	-3.8%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,502	13,781	(721)	-5.0%			
28							
29 COST per KWH SALES (\$)	2.548	2.463	-0.085	-3.3%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.022	-0.044	-0.021				
(i) Residential	-0.022	-0.043	-0.021				
(ii) C & I Non-Demand	-0.023	-0.046	-0.023				
(iii) C & I Demand Non-TOD	-0.023	-0.045	-0.022				
(iv) C & I Demand TOD On-Peak	-0.029	-0.057	-0.028				
(v) C & I Demand TOD Off-Peak	-0.017	-0.034	-0.017				
(vi) Outdoor Lighting	-0.016	-0.031	-0.015				
32 REFUND	-0.019	-0.024	-0.005				
(i) Residential	-0.019	-0.024					
(ii) C & I Non-Demand	-0.020	-0.026					
(iii) C & I Demand Non-TOD	-0.019	-0.025					
(iv) C & I Demand TOD On-Peak	-0.025	-0.032					
(v) C & I Demand TOD Off-Peak	-0.015	-0.019					
(vi) Outdoor Lighting	-0.013	-0.017					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.507	2.395	-0.111	-4.4%			
(i) Residential	2.496	2.384	-0.112				
(ii) C & I Non-Demand	2.644	2.526					
(iii) C & I Demand Non-TOD	2.561	2.447					
(iv) C & I Demand TOD On-Peak	3.292	3.146					
(v) C & I Demand TOD Off-Peak	1.937	1.850					
(vi) Outdoor Lighting	1.777	1.698					

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	(\$0.11)
250	(\$0.28)
500	(\$0.56)
750	(\$0.84)
1,000	(\$1.12)

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>	
	Jan-11	Feb-11
<b>** GWH OUTPUT **</b>		
Thermal	916,639	554,312
Disper gen	(57)	(63)
Hydro plus Wind	436,088	409,136
Hydro and Other	1,352,670	963,385
Rounded to nearest thousand:	1,353	963
<b>Sales</b>		
Non Gen Munic Total	285,007,000	273,415,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,878,888,000	1,735,121,000
Rounded to nearest million:	1878.888	1735.121

		System	Intersystem	Retail
<b>December 2010 Actual</b>				
<b>Energy and Loss Charges</b>				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 18,464,752.98	\$ 2,422,528.94	\$ 20,887,281.92
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 4,302,683.14	\$ -	\$ 4,302,683.14
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (13,362,534.55)	\$ -	\$ (13,362,534.55)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,045,626.89	\$ -	\$ 1,045,626.89
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)	\$ (180,815.73)	\$ 1,195,861.69	\$ 1,015,045.96
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (4,527.87)	\$ -	\$ (4,527.87)
14	Real-Time Distribution of Losses Amount	\$ (2,211,812.83)	\$ -	\$ (2,211,812.83)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (192,101.77)	\$ -	\$ (192,101.77)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 10,290.32	\$ -	\$ 10,290.32
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (1,221.71)	\$ -	\$ (1,221.71)
<b>Congestion Related Charges</b>				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 1,955,396.44	\$ -	\$ 1,955,396.44
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 929,400.19	\$ -	\$ 929,400.19
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)	\$ (38,122.33)	\$ -	\$ (38,122.33)
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)	\$ (580.17)	\$ -	\$ (580.17)
<b>FTR Related Charges</b>				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (1,470,648.85)	\$ -	\$ (1,470,648.85)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (118,860.07)	\$ -	\$ (118,860.07)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (29,143.51)	\$ -	\$ (29,143.51)
37	Financial Transmission Rights Guarantee Uplift Amount	\$ 29,143.10	\$ -	\$ 29,143.10
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
<b>Uplift Charges</b>				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 612,720.42	\$ -	\$ 612,720.42
<b>Revenue Sufficiency Guarantee (RSG) Charges</b>				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 99,680.48	\$ -	\$ 99,680.48
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (150,290.40)	\$ 7,367.54	\$ (142,922.86)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 713,197.74	\$ -	\$ 713,197.74
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (714,502.63)	\$ 48,116.93	\$ (666,385.70)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (419,788.77)	\$ 11,491.77	\$ (408,297.00)
<b>Market Administration Charges</b>				
4	Day-Ahead Market Administration Amount	\$ 756,769.60	\$ (7,845.15)	\$ 748,924.45
19	Real-Time Market Administration Amount	\$ 46,002.92	\$ (5,657.90)	\$ 40,345.02
29	Financial Transmission Rights Market Administration Amount	\$ 65,413.04	\$ -	\$ 65,413.04
33	Day-Ahead Schedule 24 Allocation Amount	\$ 91,538.26	\$ (970.76)	\$ 90,567.50
34	Real-Time Schedule 24 Allocation Amount	\$ 5,568.02	\$ (692.32)	\$ 4,875.70
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	\$ (10,080.10)	\$ -	\$ (10,080.10)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
<b>Auction Revenue Rights (ARR)</b>				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 689,179.66	\$ -	\$ 689,179.66
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (731,991.70)	\$ -	\$ (731,991.70)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (471,122.84)	\$ -	\$ (471,122.84)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 58,939.94	\$ -	\$ 58,939.94
<b>TOTAL MISO CHARGES</b>		<b>\$ 9,768,157.31</b>	<b>\$ 3,670,200.74</b>	<b>\$ 13,438,358.05</b>
<b>SCHEDULE 24 (FOR RETAIL)</b>				<b>\$ 95,443.20</b>
<b>TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)</b>				<b>\$ 13,342,914.85</b>

Northern States Power Company, A Minnesota Corporation  
**MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES**

Attachment 2

Page 2

		System	Intersystem	Retail
December 2010 Actual				
<b>Procurement Charges</b>				
1	Day-Ahead Regulation Amount	\$ (392,051.11)	\$ -	\$ (392,051.11)
2	Day-Ahead Spinning Reserve Amount	\$ (53,079.45)	\$ -	\$ (53,079.45)
3	Day-Ahead Supplemental Reserve	\$ (108,370.95)	\$ -	\$ (108,370.95)
4	Real-Time Regulation Amount	\$ 78,687.84	\$ 115,441.90	\$ 194,129.74
5	Real-Time Spinning Reserve Amount	\$ (1,527.44)	\$ 21,376.81	\$ 19,849.37
6	Real-Time Supplemental Reserve Amount	\$ 35,084.15	\$ 51,252.29	\$ 86,336.44
<b>Resource Energy Charges</b>				
7a	Real Time Excessive Energy Amount	\$ (16,007.05)		\$ (16,007.05)
7b	Real Time Excessive Energy Congestion	\$ -		\$ -
7c	Real Time Excessive Energy Loss	\$ -		\$ -
8a	Real Time Non Excessive Energy Amount	\$ 457,771.76		\$ 457,771.76
8b	Real Time Non Excessive Energy Congestion	\$ (338,213.68)		\$ (338,213.68)
8c	Real Time Non Excessive Energy Loss	\$ (124,248.33)		\$ (124,248.33)
9	Real Time Net Regulation Adjustment Amount	\$ 5,198.62	\$ (2,861.14)	\$ 2,337.48
<b>Cost Distribution Charges</b>				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 238,958.56	\$ -	\$ 238,958.56
11	Real Time Spinning Reserve Cost Distribution	\$ 92,216.97	\$ -	\$ 92,216.97
12	Real Time Supplemental Reserve Cost Distribution	\$ 60,015.94	\$ -	\$ 60,015.94
<b>Penalty Charges</b>				
13	Real Time Excessive/Dificient Energy Deployment	\$ 6,111.12	\$ (396.09)	\$ 5,715.03
14	Real Time Contingency Reserve Deployment Failure	\$ -	\$ -	\$ -
<b>TOTAL MISO ASM CHARGES</b>		<b>\$ (59,453.05)</b>	<b>\$ 184,813.77</b>	<b>\$ 125,360.72</b>



