



414 Nicollet Mall  
Minneapolis, Minnesota 55401

—Via Electronic Filing—

January 31, 2013

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

**Re: February 2013 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 February 2013.

Pursuant to Commission authorization of the final compliance tariffs in the Company's 2010 rate proceeding (Case 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>February 2013</b>	<b>Fuel Cost Charge (\$/kWh)</b>
<b>Residential</b>	0.02757
<b>C &amp; I Non-Demand</b>	0.02828
<b>C &amp; I Demand</b>	0.02797
<b>C &amp; I Demand Time of Day On-Peak</b>	0.03543
<b>C &amp; I Demand Time of Day Off-Peak</b>	0.02170
<b>Outdoor Lighting</b>	0.02046

## **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 Case No. PU-05-147 and the Order in Case 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 February 2013 FCC the net MISO Day 2 costs for December 2012 as recorded in Account 555. The MISO Day 2 cost recovery included in this February 2013 FCC is \$11,613,910, 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 Case 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 2012 as recorded in Account 555. The MISO ASM cost recovery included in this February FCC is \$2,665,138, 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 February 2013 Asset Based Margin amount of \$52,527 has been included as a credit, or offset, to the February 2013 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 2012 Non-Asset Based Margin credit is \$163,647 and this credit amount will be distributed equally each month over the following 12-month period. The refund reflected in the February 2013 FCC is \$12,137, 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 Case 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). (See attachment 3, page 3).

## **OTHER REPORTING ITEM**

Attached is the calculation of the February 2013 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 Feb-2013

Feb-2013 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
<b>System</b>	\$0.02823	\$0.00038	-\$0.00032	\$0.02829
<b>Residential</b>	\$0.02830	\$0.00038	-\$0.00111	\$0.02757
<b>C &amp; I Non-Demand</b>	\$0.02902	\$0.00039	-\$0.00114	\$0.02828
<b>C &amp; I Demand Non-TOD</b>	\$0.02871	\$0.00039	-\$0.00113	\$0.02797
<b>C &amp; I Demand TOD On-Peak</b>	\$0.03637	\$0.00049	-\$0.00143	\$0.03543
<b>C &amp; I Demand TOD Off-Peak</b>	\$0.02227	\$0.00030	-\$0.00087	\$0.02170
<b>Outdoor Lighting</b>	\$0.02100	\$0.00028	-\$0.00082	\$0.02046
<b>Residential</b>				
Residential Service	\$ 0.02830	\$ 0.00038	\$ (0.00111)	\$ 0.02757
Residential TOD	\$ 0.02830	\$ 0.00038	\$ (0.00111)	\$ 0.02757
Residential - Underground	\$ 0.02830	\$ 0.00038	\$ (0.00111)	\$ 0.02757
Residential TOD - Underground	\$ 0.02830	\$ 0.00038	\$ (0.00111)	\$ 0.02757
Energy Control - (Non-Demand)	\$ 0.02830	\$ 0.00038	\$ (0.00111)	\$ 0.02757
Limit Off Peak	\$ 0.02830	\$ 0.00038	\$ (0.00111)	\$ 0.02757
<b>C &amp; I Non-Demand</b>				
Energy Controlled - (Non-Demand)	\$ 0.02902	\$ 0.00039	\$ (0.00114)	\$ 0.02828
Limit Off Peak	\$ 0.02902	\$ 0.00039	\$ (0.00114)	\$ 0.02828
Small General Service	\$ 0.02902	\$ 0.00039	\$ (0.00114)	\$ 0.02828
Small General TOD - Metered	\$ 0.02902	\$ 0.00039	\$ (0.00114)	\$ 0.02828
Small General TOD - Unmetered	\$ 0.02902	\$ 0.00039	\$ (0.00114)	\$ 0.02828
Fire and Civil Defense Siren	\$ 0.02902	\$ 0.00039	\$ (0.00114)	\$ 0.02828
Direct Current (Closed)	\$ 0.02902	\$ 0.00039	\$ (0.00114)	\$ 0.02828
<b>C &amp; I Demand</b>				
General Service	\$ 0.02871	\$ 0.00039	\$ (0.00113)	\$ 0.02797
General TOD - On Peak	\$ 0.03637	\$ 0.00049	\$ (0.00143)	\$ 0.03543
General TOD - Off Peak	\$ 0.02227	\$ 0.00030	\$ (0.00087)	\$ 0.02170
Peak Controlled (Closed)	\$ 0.02871	\$ 0.00039	\$ (0.00113)	\$ 0.02797
Peak Controlled TOD (Closed) - On Peak	\$ 0.03637	\$ 0.00049	\$ (0.00143)	\$ 0.03543
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02227	\$ 0.00030	\$ (0.00087)	\$ 0.02170
Peak Controlled Tiered	\$ 0.02871	\$ 0.00039	\$ (0.00113)	\$ 0.02797
Peak Controlled Tiered TOD - On Peak	\$ 0.03637	\$ 0.00049	\$ (0.00143)	\$ 0.03543
Peak Controlled Tiered TOD - Off Peak	\$ 0.02227	\$ 0.00030	\$ (0.00087)	\$ 0.02170
Energy Controlled (Closed)	\$ 0.02871	\$ 0.00039	\$ (0.00113)	\$ 0.02797
Tier 1 Energy Controlled Rider	\$ 0.02871	\$ 0.00039	\$ (0.00113)	\$ 0.02797
Real Time Pricing - Firm - On Peak	\$ 0.03637	\$ 0.00049	\$ (0.00143)	\$ 0.03543
Real Time Pricing - Firm - Off Peak	\$ 0.02227	\$ 0.00030	\$ (0.00087)	\$ 0.02170
Real Time Pricing - Controllable - On Peak	\$ 0.03637	\$ 0.00049	\$ (0.00143)	\$ 0.03543
Real Time Pricing - Controllable - Off Peak	\$ 0.02227	\$ 0.00030	\$ (0.00087)	\$ 0.02170
Small Municipal Pumping	\$ 0.02871	\$ 0.00039	\$ (0.00113)	\$ 0.02797
Municipal Pumping	\$ 0.02871	\$ 0.00039	\$ (0.00113)	\$ 0.02797
Excess Energy - St. Anthony Falls	\$ 0.02871	\$ 0.00039	\$ (0.00113)	\$ 0.02797
<b>Outdoor Lighting</b>				
Automatic Protective Lighting	\$ 0.02100	\$ 0.00028	\$ (0.00082)	\$ 0.02046
Street Lighting System	\$ 0.02100	\$ 0.00028	\$ (0.00082)	\$ 0.02046
Street Lighting Energy	\$ 0.02100	\$ 0.00028	\$ (0.00082)	\$ 0.02046
Street Lighting Energy - Metered	\$ 0.02100	\$ 0.00028	\$ (0.00082)	\$ 0.02046
Street Lighting Energy (Closed)	\$ 0.02100	\$ 0.00028	\$ (0.00082)	\$ 0.02046
Street Lighting - City of St. Paul	\$ 0.02100	\$ 0.00028	\$ (0.00082)	\$ 0.02046

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 Feb-2013

	Column (A) Sep-12	Column (B) Oct-12	Column (C) Nov-12	Column (D) Dec-12	Column (E) 4 Month Total
<b>Fuel and Purchased Power Costs</b>					
Account 151 - Fossil Fuel	\$33,831,915	\$33,325,277	\$37,226,702	\$50,135,186	\$154,519,080
Account 518 - Nuclear Fuel	\$10,950,542	\$10,412,782	\$7,435,032	\$7,716,782	\$36,515,138
Account 555 - Purchased Power <sup>1</sup>	\$32,831,145	\$37,933,779	\$38,976,096	\$36,519,011	\$146,260,031
Account 555 - MISO Day 2 Charges	\$11,957,866	\$12,123,296	\$13,313,564	\$11,716,178	\$49,110,905
Account 555 MISO Day 2 - Schedule 24	(\$97,169)	(\$101,215)	(\$102,938)	(\$102,268)	(\$403,591)
Account 555 MISO - ASM Charges	\$222,751	\$1,167,811	\$1,799,365	\$2,665,138	\$5,855,065
Total MISO Charges	\$12,083,449	\$13,189,891	\$15,009,991	\$14,279,049	\$54,562,379
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$89,697,051	\$94,861,729	\$98,647,821	\$108,650,027	\$391,856,629
Less Fuel Cost of InterSystem Sales	(\$2,716,704)	(\$2,690,921)	(\$4,636,470)	(\$5,361,131)	(\$15,405,226)
Net System Costs	\$86,980,347	\$92,170,808	\$94,011,352	\$103,288,897	\$376,451,403
<b>System MWH Sales</b>					
Total NSP System Retail	3,435,726	3,387,097	3,094,884	3,275,050	13,192,757
Non-Gen Muni's/Load Pattern	37,855	32,604	35,488	35,350	141,297
Total NSP System MWH Sales	3,473,581	3,419,701	3,130,372	3,310,400	13,334,054
<b>Average Unit Cost of Fuel and Purchased Power</b>					
Fuel Cost per kWh for NSP System	2.504¢	2.695¢	3.003¢	3.120¢	2.823¢
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	2.830¢
(ii) C & I Non-Demand				1.0281	2.902¢
(iii) C & I Demand Non-TOD				1.0170	2.871¢
(iv) C & I Demand TOD On-Peak				1.2883	3.637¢
(v) C & I Demand TOD Off-Peak				0.7889	2.227¢
(vi) Outdoor Lighting				0.7440	2.100¢
<b>North Dakota Retail MWh Sales</b>					
(i) Residential	50,802	52,225	59,206	70,948	233,181
(ii) C & I Non-Demand	8,088	8,822	8,935	11,009	36,854
(iii) C & I Demand Non-TOD	62,803	65,092	53,335	65,184	246,414
(iv) C & I Demand TOD On-Peak	20,106	18,623	17,259	17,658	73,646
(v) C & I Demand TOD Off-Peak	30,876	28,368	26,864	28,922	115,030
(vi) Outdoor Lighting	1,377	1,599	1,887	2,004	6,867
(vii) Total	174,052	174,729	167,486	195,725	711,992
<b>Feb-2013 Recovery Provision (True-up Factor) Calculation</b>					
Prior Unrecovered Expenses (Oct-12 Balance of Unrecovered Expenses)					Total
					Oct-12
					(\$408,599)

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

Prior Expenses Recovered in Dec-2012 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	70,948	(\$2,704)
(ii) C & I Non-Demand	11,009	(\$87)
(iii) C & I Demand Non-TOD	65,184	\$809
(iv) C & I Demand TOD On-Peak	17,658	\$840
(v) C & I Demand TOD Off-Peak	28,922	\$708
(vi) Outdoor Lighting	2,004	\$216
(vii) Total	195,725	(\$218)

Actual Cost Should Have Been Recovered in Dec-12				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	3.120¢	0.000¢	195,725	\$6,106,620

Cost Recovered in Dec-12 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	70,948	\$1,967,737
(ii) C & I Non-Demand	11,009	\$313,660
(iii) C & I Demand Non-TOD	65,184	\$1,840,393
(iv) C & I Demand TOD On-Peak	17,658	\$631,158
(v) C & I Demand TOD Off-Peak	28,922	\$632,860
(vi) Outdoor Lighting	2,004	\$41,466
(vii) Total	195,725	\$5,427,274

Total Balance of Unrecovered Expenses (Feb-13 Balance of Unrecovered Expenses)	
Feb-2013 Recovery Provision	\$270,965
4 Month ND Retail Total MWh Sales	711,992
Feb-2013 Recovery Provision per KWH	0.038¢

Feb-2013 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	1.0026	0.038¢	0.038¢
(ii) C & I Non-Demand	1.0281	0.038¢	0.039¢
(iii) C & I Demand Non-TOD	1.0170	0.038¢	0.039¢
(iv) C & I Demand TOD On-Peak	1.2883	0.038¢	0.049¢
(v) C & I Demand TOD Off-Peak	0.7889	0.038¢	0.030¢
(vi) Outdoor Lighting	0.7440	0.038¢	0.028¢

Feb-2013 Refunds/Additional Charges				
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Refund	Total
<b>Refund/Special Charge Amount</b>	<b>(\$52,527)</b>	<b>(\$12,137)</b>	<b>(\$161,476)</b>	<b>(\$214,003)</b>
(i) Residential	-0.026¢	-0.006¢	-0.079¢	-0.111¢
(ii) C & I Non-Demand	-0.026¢	-0.006¢	-0.081¢	-0.114¢
(iii) C & I Demand Non-TOD	-0.026¢	-0.006¢	-0.080¢	-0.113¢
(iv) C & I Demand TOD On-Peak	-0.033¢	-0.008¢	-0.102¢	-0.143¢
(v) C & I Demand TOD Off-Peak	-0.020¢	-0.005¢	-0.062¢	-0.087¢
(vi) Outdoor Lighting	-0.019¢	-0.004¢	-0.059¢	-0.082¢

Feb-2013 Factors	
	Total
(i) Residential	2.757¢
(ii) C & I Non-Demand	2.828¢
(iii) C & I Demand Non-TOD	2.797¢
(iv) C & I Demand TOD On-Peak	3.543¢
(v) C & I Demand TOD Off-Peak	2.170¢
(vi) Outdoor Lighting	2.046¢

	FCA Application		Comparison		Generation Type by Percent		
	Jan-13	Feb-13	Differ- ence	Percent Change	FCA Application Jan-13	Feb-13	Differ- ence
<b>** COSTS (Millions) **</b>							
1 Fossil	\$150.6	\$154.5	\$4.0	2.6%	38.0%	39.4%	1.4%
2 Nuclear	\$38.5	\$36.5	(\$2.0)	-5.1%	9.7%	9.3%	-0.4%
3 Purchases	\$148.6	\$146.3	(\$2.3)	-1.6%	37.5%	37.3%	-0.2%
MISO related Purchases	\$58.7	\$54.6	(\$4.1)	-7.1%	14.8%	13.9%	-0.9%
4 Total System Costs	396.3	391.9	(\$4.5)	-1.1%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$13.8	\$15.4	\$1.6	12.0%	3.5%	3.9%	0.4%
6 Net System Costs	\$382.6	\$376.5	(\$6.1)	-1.6%	96.5%	96.1%	-0.4%
7							
8 <b>** GWH OUTPUT **</b>							
9 Fossil	4,998	5,169	171	3.4%	31.7%	33.7%	2.0%
10 Nuclear	4,034	3,876	(158)	-3.9%	25.6%	25.2%	-0.4%
11 Purchases	4,867	4,386	(481)	-9.9%	30.8%	28.6%	-2.2%
12 Hydro & Other	1,194	1,253	59	4.9%	7.6%	8.2%	0.6%
13 Net Interchange	684	675	(9)	-1.3%	4.3%	4.4%	0.1%
14 Total Output	15,777	15,359	(418)	-2.6%	100.0%	100.0%	0.0%
15 Intersystem Sales	951	995	44	4.6%	6.0%	6.5%	0.5%
16 Native Requirement	14,826	14,364	(462)	-3.1%	94.0%	93.5%	-0.5%
17							
18 <b>** COST per KWH OUTPUT (\$) **</b>							
19 Fossil	3.013	2.989	-0.023	-0.8%			
20 Nuclear	0.954	0.942	-0.011	-1.2%			
21 Purchases	3.053	3.335	0.282	9.2%			
22 Total System Costs	2.512	2.551	0.039	1.6%			
23 Intersystem Sales	1.447	1.548	0.101	7.0%			
24 Net System Costs	2.580	2.621	0.040	1.6%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,308	13,334	(974)	-6.8%			
28							
29 COST per KWH SALES (\$) :	2.674	2.823	0.149	5.6%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	0.068	0.038	-0.030				
(i) Residential	0.069	0.038	-0.030				
(ii) C & I Non-Demand	0.070	0.039	-0.031				
(iii) C & I Demand Non-TOD	0.070	0.039	-0.031				
(iv) C & I Demand TOD On-Peak	0.088	0.049	-0.039				
(v) C & I Demand TOD Off-Peak	0.054	0.030	-0.024				
(vi) Outdoor Lighting	0.051	0.028	-0.023				
32 REFUND	-0.023	0.000	0.023				
(i) Residential	-0.023	-0.111	-0.111				
(ii) C & I Non-Demand	-0.024	-0.114	-0.114				
(iii) C & I Demand Non-TOD	-0.023	-0.113	-0.113				
(iv) C & I Demand TOD On-Peak	-0.030	-0.143	-0.143				
(v) C & I Demand TOD Off-Peak	-0.018	-0.087	-0.087				
(vi) Outdoor Lighting	-0.017	-0.082	-0.082				
33 SYSTEM FCC IMPACT (\$ / KWH)	2.719	2.861	0.142	5.2%			
(i) Residential	2.726	2.757	0.031				
(ii) C & I Non-Demand	2.795	2.828					
(iii) C & I Demand Non-TOD	2.765	2.797					
(iv) C & I Demand TOD On-Peak	3.502	3.543					
(v) C & I Demand TOD Off-Peak	2.145	2.170					
(vi) Outdoor Lighting	2.023	2.046					

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	\$0.03
250	\$0.08
500	\$0.16
750	\$0.24
1,000	\$0.31

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	
	Jan-13	Feb-13
<b>** GWH OUTPUT **</b>		
Thermal	833,825	869,185
Disper gen	(84)	(87)
Hydro plus Wind	360,534	384,193
Hydro and Other	1,194,275	1,253,291
Rounded to nearest thousand:	1,194	1,253
<b>Sales</b>		
Non Gen Munic Total	148,391,000	141,297,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	950,733,000	994,849,000
Rounded to nearest million:	950.733	994.849

		System	Intersystem	Retail
<b>December 2012 Actual</b>				
<b>Energy and Loss Charges</b>				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 10,128,801.91	\$ 3,810,577.63	\$ 13,939,379.54
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 3,398,844.40	\$ -	\$ 3,398,844.40
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (10,266,477.80)	\$ -	\$ (10,266,477.80)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 615,807.83	\$ -	\$ 615,807.83
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)	\$ 983,428.86	\$ 570,714.25	\$ 1,554,143.11
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (19,822.21)	\$ -	\$ (19,822.21)
14	Real-Time Distribution of Losses Amount	\$ (1,728,262.93)	\$ -	\$ (1,728,262.93)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ 2,594.97	\$ -	\$ 2,594.97
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 8,879.16	\$ -	\$ 8,879.16
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (288.73)	\$ -	\$ (288.73)
<b>Congestion Related Charges</b>				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 6,471,877.11	\$ -	\$ 6,471,877.11
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ (353,296.15)	\$ -	\$ (353,296.15)
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)	\$ (33,413.49)	\$ -	\$ (33,413.49)
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)	\$ (462.26)	\$ -	\$ (462.26)
<b>FTR Related Charges</b>				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (2,493,063.91)	\$ -	\$ (2,493,063.91)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (123,556.97)	\$ -	\$ (123,556.97)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ (724,975.29)	\$ -	\$ (724,975.29)
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (306,068.05)	\$ -	\$ (306,068.05)
37	Financial Transmission Guarantee Uplift Amount	\$ 406,501.08	\$ -	\$ 406,501.08
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
<b>Uplift Charges</b>				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 1,023,580.30	\$ -	\$ 1,023,580.30
<b>Revenue Sufficiency Guarantee (RSG) Charges</b>				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 77,136.17	\$ -	\$ 77,136.17
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (143,067.96)	\$ 15,547.77	\$ (127,520.19)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 300,235.00	\$ -	\$ 300,235.00
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (53,999.19)	\$ 13,508.24	\$ (40,490.95)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (145,605.13)	\$ 5,224.62	\$ (140,380.51)
<b>Market Administration Charges</b>				
4	Day-Ahead Market Administration Amount	\$ 628,823.52	\$ (11,688.12)	\$ 617,135.40
19	Real-Time Market Administration Amount	\$ 42,696.76	\$ (2,216.60)	\$ 40,480.16
29	Financial Transmission Rights Market Administration Amount	\$ 48,575.20	\$ -	\$ 48,575.20
33	Day-Ahead Schedule 24 Allocation Amount	\$ 97,783.78	\$ (1,816.25)	\$ 95,967.53
34	Real-Time Schedule 24 Allocation Amount	\$ 6,645.24	\$ (344.87)	\$ 6,300.37
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	\$ 3,103,587.40	\$ -	\$ 3,103,587.40
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (3,030,021.97)	\$ -	\$ (3,030,021.97)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (631,372.89)	\$ -	\$ (631,372.89)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 24,627.82	\$ -	\$ 24,627.82
<b>TOTAL MISO CHARGES</b>		<b>\$ 7,316,671.58</b>	<b>\$ 4,399,506.67</b>	<b>\$ 11,716,178.25</b>

**SCHEDULE 24 (FOR RETAIL)** \$ 102,267.90

**TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)** \$ 11,613,910.35

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

		System	Intersystem	Retail
<b>December 2012 Actual</b>				
<b>Procurement Charges</b>				
1	Day-Ahead Regulation Amount	\$ (88,798.13)	\$ -	\$ (88,798.13)
2	Day-Ahead Spinning Reserve Amount	\$ (47,002.60)	\$ -	\$ (47,002.60)
3	Day-Ahead Supplemental Reserve	\$ (70,573.95)	\$ -	\$ (70,573.95)
4	Real-Time Regulation Amount	\$ (92,203.40)	\$ 102,202.39	\$ 9,998.99
5	Real-Time Spinning Reserve Amount	\$ 13,577.29	\$ 12,599.26	\$ 26,176.55
6	Real-Time Supplemental Reserve Amount	\$ (591.47)	\$ 22,360.26	\$ 21,768.79
<b>Resource Energy Charges</b>				
7a	Real Time Excessive Energy Amount	\$ 60,070.72	\$ -	\$ 60,070.72
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 2,153,848.56	\$ -	\$ 2,153,848.56
8b	Real Time Non Excessive Energy Congestion	\$ 207,979.91	\$ -	\$ 207,979.91
8c	Real Time Non Excessive Energy Loss	\$ 64,427.81	\$ -	\$ 64,427.81
9	Real Time Net Regulation Adjustment Amount	\$ 13,378.93	\$ (595.18)	\$ 12,783.75
<b>Cost Distribution Charges</b>				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 175,312.13	\$ -	\$ 175,312.13
11	Real Time Spinning Reserve Cost Distribution	\$ 84,698.60	\$ -	\$ 84,698.60
12	Real Time Supplemental Reserve Cost Distribution	\$ 50,110.66	\$ -	\$ 50,110.66
<b>Penalty Charges</b>				
13	Real Time Excessive/Dificient Energy Deployment	\$ 5,314.76	\$ (978.18)	\$ 4,336.58
14	Real Time Contingency Reserve Deployment Failure	\$ -	\$ -	\$ -
<b>TOTAL MISO ASM CHARGES</b>		<b>\$ 2,529,549.82</b>	<b>\$ 135,588.55</b>	<b>\$ 2,665,138.37</b>

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

Forecast Month	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13
True-up 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
1	(37,060)	(48,106)	(20,853)	(21,116)	(45,351)	(9,086)	(110,114)	(35,437)	(13,659)	(60,004)	(28,513)	(76,639)
2	204,480	176,872	172,668	167,827	180,675	198,082	165,774	179,024	171,102	193,427	241,910	204,198
3	(0.018)	(0.027)	(0.012)	(0.013)	(0.025)	(0.005)	(0.066)	(0.020)	(0.008)	(0.031)	(0.012)	(0.039)
4	(30,199)	(42,867)	(36,737)	(38,058)	(20,517)	(39,456)	(27,680)	(19,991)	(100,226)	(29,198)	(58,610)	(20,252)
5	(30,522)	(32,915)	(37,073)	(39,718)	(38,188)	(28,551)	(37,568)	(26,230)	(55,275)	(68,950)	(42,493)	(46,364)
6	323	(9,952)	336	(18,340)	17,671	(10,905)	9,888	6,239	(44,951)	39,752	(16,117)	26,112
7	0.000	(0.006)	0.000	(0.011)	0.010	(0.006)	0.006	0.003	(0.026)	0.021	(0.007)	0.013

Current Month Refund Factor	0.018	0.027	0.012	0.013	0.025	0.005	0.066	0.020	0.008	0.031	0.012	0.039
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Expected Refund	30,199	42,867	36,737	38,058	20,517	39,456	27,680	19,991	100,226	29,198	58,610	20,252
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Actual Refunded	30,522	32,915	37,073	39,718	38,188	28,551	37,568	26,230	55,275	68,950	42,493	46,364
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Deviation	323	(9,952)	336	(18,340)	17,671	(10,905)	9,888	6,239	(44,951)	39,752	(16,117)	26,112
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True-up Factor	0.000	(0.006)	0.000	(0.011)	0.010	(0.006)	0.006	0.003	(0.026)	0.021	(0.007)	0.013
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Realized Margin	(0.018)	(0.023)	(0.012)	(0.024)	(0.015)	(0.010)	(0.060)	(0.016)	(0.034)	(0.010)	(0.018)	(0.026)
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Class Ratios	0.9956	0.9974	0.9991	0.9991	1.0009	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
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Residential	1.0548	1.0548	1.0481	1.0415	1.0348	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281
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C&I Non-Demand	1.0219	1.0219	1.0207	1.0195	1.0182	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170
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C&I Demand Non-TOD	1.3135	1.3135	1.3072	1.3009	1.2946	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883
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C&I Demand TOD On-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
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C&I Demand TOD Off-Peak	0.7088	0.7088	0.7176	0.7264	0.7352	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440
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Outdoor Lighting	(0.018)	(0.023)	(0.012)	(0.023)	(0.015)	(0.010)	(0.061)	(0.016)	(0.034)	(0.010)	(0.018)	(0.026)
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Residential	(0.019)	(0.012)	(0.012)	(0.024)	(0.016)	(0.010)	(0.062)	(0.017)	(0.035)	(0.011)	(0.019)	(0.026)
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C&I Non-Demand	(0.018)	(0.012)	(0.012)	(0.024)	(0.016)	(0.010)	(0.061)	(0.017)	(0.035)	(0.011)	(0.019)	(0.026)
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C&I Demand Non-TOD	(0.024)	(0.043)	(0.016)	(0.031)	(0.020)	(0.013)	(0.078)	(0.021)	(0.044)	(0.013)	(0.024)	(0.033)
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C&I Demand TOD On-Peak	(0.014)	(0.025)	(0.009)	(0.018)	(0.012)	(0.008)	(0.048)	(0.013)	(0.027)	(0.008)	(0.015)	(0.020)
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C&I Demand TOD Off-Peak	(0.013)	(0.023)	(0.009)	(0.017)	(0.011)	(0.008)	(0.045)	(0.012)	(0.025)	(0.008)	(0.014)	(0.019)
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Outdoor Lighting	(0.018)	(0.023)	(0.012)	(0.023)	(0.015)	(0.010)	(0.061)	(0.016)	(0.034)	(0.010)	(0.018)	(0.026)
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Northern States Power Company, A Minnesota Corporation  
Electric Operations - State of North Dakota  
Derivation of Adjustment for Fuel Clause Rider  
Non-Asset Based Margin Sharing

Forecast Month	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14
1 True-up Month	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
2	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13
3											
4 Monthly Refund	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)
5	204,198	-	-	-	-	-	-	-	-	-	-
6											
7											

8 Current Month Refund Factor (0.907)

9 Expected Refund (11,060)

10 Actual Refund (12,560)

11 Deviation 1,500

12 True-up Factor 0.901

13 Realized Margin (0.906)

Class Ratios	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440
14 Residential	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440
15 C&I Non-Demand	1,0281	1,0281	1,0170	1,2883	0,7889	0,7440
16 C&I Demand Non-TOD	1,0170	1,0170	1,0170	1,2883	0,7889	0,7440
17 C&I Demand TOD On-Peak	1,2883	1,2883	1,2883	1,2883	0,7889	0,7440
18 C&I Demand TOD Off-Peak	0,7889	0,7889	0,7889	0,7889	0,7889	0,7440
19 Outdoor Lighting	0,7440	0,7440	0,7440	0,7440	0,7440	0,7440

20 Realized Margin Adj for Class Ratios

21 Residential (0.006)

22 C&I Non-Demand (0.006)

23 C&I Demand Non-TOD (0.006)

24 C&I Demand TOD On-Peak (0.008)

25 C&I Demand TOD Off-Peak (0.005)

26 Outdoor Lighting (0.004)

Northern States Power Company, A Minnesota Corporation  
Electric Operations - State of North Dakota  
Deviation of Adjustment for Fuel Clause Rider  
Sales of Renewable Energy Credits

1	Forecast Month	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13
2	True-up Month	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13
3	Monthly Refund	(280,039)	-	-	-	-	-	-	-	-	-	-	-
4	Forecast North Dakota Sales	193,427	241,910	204,198	-	-	-	-	-	-	-	-	-

5	Current Month Refund Factor	(0.145)											
6	Expected Refund	-	-	(280,039)	-	-	-	-	-	-	-	-	-
7	Actual Refund	-	-	(118,503)	-	-	-	-	-	-	-	-	-
8	Deviation	-	-	(161,476)	-	-	-	-	-	-	-	-	-

9	True-up Factor	(0.079)											
10	Realized Margin	(0.079)											

11	Class Ratios	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440
12	Residential	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440
13	C&I Non-Demand	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026
14	C&I Demand Non-TOD	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281
15	C&I Demand TOD On-Peak	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170
16	C&I Demand TOD Off-Peak	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883
17	Outdoor Lighting	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889	0,7440	1,0026	1,0281	1,0170	1,2883	0,7889

18	Realized Margin Adj for Class Ratios	(0.145)	(0.079)	(0.081)	(0.080)	(0.102)	(0.062)	(0.059)
19	Residential	(0.145)	(0.079)	(0.081)	(0.080)	(0.102)	(0.062)	(0.059)
20	C&I Non-Demand	(0.149)	(0.081)	(0.080)	(0.102)	(0.062)	(0.059)	
21	C&I Demand Non-TOD	(0.147)	(0.080)	(0.102)	(0.062)	(0.059)		
22	C&I Demand TOD On-Peak	(0.187)	(0.102)	(0.062)	(0.059)			
23	C&I Demand TOD Off-Peak	(0.114)	(0.062)	(0.059)				
24	Outdoor Lighting	(0.108)	(0.059)					