



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

December 28, 2012

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

Re: January 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 January 2013.

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

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

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

January 2013	Fuel Cost Charge (\$/kWh)
Residential	0.02726
C & I Non-Demand	0.02795
C & I Demand	0.02765
C & I Demand Time of Day On-Peak	0.03502
C & I Demand Time of Day Off-Peak	0.02145
Outdoor Lighting	0.02023

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 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 2013 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 2013 FCC is \$13,210,626, 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 January FCC the net MISO ASM costs for November 2012 as recorded in Account 555. The MISO ASM cost recovery included in this January FCC is \$1,799,365, which is the net of many items. The detailed records are contained in Attachment 2, page 2.

¹ 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 January 2013 Asset Based Margin amount of \$44,630 has been included as a credit, or offset, to the January 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 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 January 2013 FCC is \$13,140, or 0.005¢ 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). (See attachment 3, page 3).

OTHER REPORTING ITEM

Attached is the calculation of the January 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 Jan-2013

Jan-2013 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02674	\$0.00068	-\$0.00024	\$0.02718
Residential	\$0.02681	\$0.00069	-\$0.00024	\$0.02726
C & I Non-Demand	\$0.02749	\$0.00070	-\$0.00025	\$0.02795
C & I Demand Non-TOD	\$0.02719	\$0.00070	-\$0.00024	\$0.02765
C & I Demand TOD On-Peak	\$0.03445	\$0.00088	-\$0.00031	\$0.03502
C & I Demand TOD Off-Peak	\$0.02110	\$0.00054	-\$0.00019	\$0.02145
Outdoor Lighting	\$0.01989	\$0.00051	-\$0.00018	\$0.02023
Residential				
Residential Service	\$ 0.02681	\$ 0.00069	\$ (0.00024)	\$ 0.02726
Residential TOD	\$ 0.02681	\$ 0.00069	\$ (0.00024)	\$ 0.02726
Residential - Underground	\$ 0.02681	\$ 0.00069	\$ (0.00024)	\$ 0.02726
Residential TOD - Underground	\$ 0.02681	\$ 0.00069	\$ (0.00024)	\$ 0.02726
Energy Control - (Non-Demand)	\$ 0.02681	\$ 0.00069	\$ (0.00024)	\$ 0.02726
Limit Off Peak	\$ 0.02681	\$ 0.00069	\$ (0.00024)	\$ 0.02726
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02749	\$ 0.00070	\$ (0.00025)	\$ 0.02795
Limit Off Peak	\$ 0.02749	\$ 0.00070	\$ (0.00025)	\$ 0.02795
Small General Service	\$ 0.02749	\$ 0.00070	\$ (0.00025)	\$ 0.02795
Small General TOD - Metered	\$ 0.02749	\$ 0.00070	\$ (0.00025)	\$ 0.02795
Small General TOD - Unmetered	\$ 0.02749	\$ 0.00070	\$ (0.00025)	\$ 0.02795
Fire and Civil Defense Siren	\$ 0.02749	\$ 0.00070	\$ (0.00025)	\$ 0.02795
Direct Current (Closed)	\$ 0.02749	\$ 0.00070	\$ (0.00025)	\$ 0.02795
C & I Demand				
General Service	\$ 0.02719	\$ 0.00070	\$ (0.00024)	\$ 0.02765
General TOD - On Peak	\$ 0.03445	\$ 0.00088	\$ (0.00031)	\$ 0.03502
General TOD - Off Peak	\$ 0.02110	\$ 0.00054	\$ (0.00019)	\$ 0.02145
Peak Controlled (Closed)	\$ 0.02719	\$ 0.00070	\$ (0.00024)	\$ 0.02765
Peak Controlled TOD (Closed) - On Peak	\$ 0.03445	\$ 0.00088	\$ (0.00031)	\$ 0.03502
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02110	\$ 0.00054	\$ (0.00019)	\$ 0.02145
Peak Controlled Tiered	\$ 0.02719	\$ 0.00070	\$ (0.00024)	\$ 0.02765
Peak Controlled Tiered TOD - On Peak	\$ 0.03445	\$ 0.00088	\$ (0.00031)	\$ 0.03502
Peak Controlled Tiered TOD - Off Peak	\$ 0.02110	\$ 0.00054	\$ (0.00019)	\$ 0.02145
Energy Controlled (Closed)	\$ 0.02719	\$ 0.00070	\$ (0.00024)	\$ 0.02765
Tier 1 Energy Controlled Rider	\$ 0.02719	\$ 0.00070	\$ (0.00024)	\$ 0.02765
Real Time Pricing - Firm - On Peak	\$ 0.03445	\$ 0.00088	\$ (0.00031)	\$ 0.03502
Real Time Pricing - Firm - Off Peak	\$ 0.02110	\$ 0.00054	\$ (0.00019)	\$ 0.02145
Real Time Pricing - Controllable - On Peak	\$ 0.03445	\$ 0.00088	\$ (0.00031)	\$ 0.03502
Real Time Pricing - Controllable - Off Peak	\$ 0.02110	\$ 0.00054	\$ (0.00019)	\$ 0.02145
Small Municipal Pumping	\$ 0.02719	\$ 0.00070	\$ (0.00024)	\$ 0.02765
Municipal Pumping	\$ 0.02719	\$ 0.00070	\$ (0.00024)	\$ 0.02765
Excess Energy - St. Anthony Falls	\$ 0.02719	\$ 0.00070	\$ (0.00024)	\$ 0.02765
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01989	\$ 0.00051	\$ (0.00018)	\$ 0.02023
Street Lighting System	\$ 0.01989	\$ 0.00051	\$ (0.00018)	\$ 0.02023
Street Lighting Energy	\$ 0.01989	\$ 0.00051	\$ (0.00018)	\$ 0.02023
Street Lighting Energy - Metered	\$ 0.01989	\$ 0.00051	\$ (0.00018)	\$ 0.02023
Street Lighting Energy (Closed)	\$ 0.01989	\$ 0.00051	\$ (0.00018)	\$ 0.02023
Street Lighting - City of St. Paul	\$ 0.01989	\$ 0.00051	\$ (0.00018)	\$ 0.02023

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Aug-12	Sep-12	Oct-12	Nov-12	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$46,184,773	\$33,831,915	\$33,325,277	\$37,226,702	\$150,568,667
Account 518 - Nuclear Fuel	\$9,668,555	\$10,950,542	\$10,412,782	\$7,435,032	\$38,466,911
Account 555 - Purchased Power ¹	\$38,850,330	\$32,831,145	\$37,933,779	\$38,976,096	\$148,591,351
Account 555 - MISO Day 2 Charges	\$17,553,245	\$11,957,866	\$12,123,296	\$13,313,564	\$54,947,971
Account 555 MISO Day 2 - Schedule 24	(\$93,360)	(\$97,169)	(\$101,215)	(\$102,938)	(\$394,683)
Account 555 MISO - ASM Charges	\$968,698	\$222,751	\$1,167,811	\$1,799,365	\$4,158,625
Total MISO Charges	\$18,428,582	\$12,083,449	\$13,189,891	\$15,009,991	\$58,711,913
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$113,132,240	\$89,697,051	\$94,861,729	\$98,647,821	\$396,338,842
Less Fuel Cost of InterSystem Sales	(\$3,716,520)	(\$2,716,704)	(\$2,690,921)	(\$4,636,470)	(\$13,760,615)
Net System Costs	\$109,415,720	\$86,980,347	\$92,170,808	\$94,011,352	\$382,578,226
System MWh Sales					
Total NSP System Retail	4,241,939	3,435,726	3,387,097	3,094,884	14,159,646
Non-Gen Muni's/Load Pattern	42,444	37,855	32,604	35,488	148,391
Total NSP System MWh Sales	4,284,383	3,473,581	3,419,701	3,130,372	14,308,037
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.554¢	2.504¢	2.695¢	3.003¢	2.674¢
Base Fuel Cost Included in Rates	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢
Class Ratio/TOD Ratio					
(i) Residential	1.0026	1.0026	1.0026	1.0026	1.0026
(ii) C & I Non-Demand	1.0281	1.0281	1.0281	1.0281	1.0281
(iii) C & I Demand Non-TOD	1.0170	1.0170	1.0170	1.0170	1.0170
(iv) C & I Demand TOD On-Peak	1.2883	1.2883	1.2883	1.2883	1.2883
(v) C & I Demand TOD Off-Peak	0.7889	0.7889	0.7889	0.7889	0.7889
(vi) Outdoor Lighting	0.7440	0.7440	0.7440	0.7440	0.7440
North Dakota Fuel Cost Factor (FCF)					
				FCF Ratio	4 Month Average
(i) Residential				1.0026	2.681¢
(ii) C & I Non-Demand				1.0281	2.749¢
(iii) C & I Demand Non-TOD				1.0170	2.719¢
(iv) C & I Demand TOD On-Peak				1.2883	3.445¢
(v) C & I Demand TOD Off-Peak				0.7889	2.110¢
(vi) Outdoor Lighting				0.7440	1.989¢
North Dakota Retail MWh Sales					
(i) Residential	70,089	50,802	52,225	59,206	232,322
(ii) C & I Non-Demand	9,627	8,088	8,822	8,935	35,472
(iii) C & I Demand Non-TOD	69,444	62,803	65,092	53,335	250,674
(iv) C & I Demand TOD On-Peak	20,606	20,106	18,623	17,259	76,594
(v) C & I Demand TOD Off-Peak	31,310	30,876	28,368	26,864	117,418
(vi) Outdoor Lighting	1,201	1,377	1,599	1,887	6,064
(vii) Total	202,277	174,052	174,729	167,486	718,544
Jan-2013 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Sep-12 Balance of Unrecovered Expenses)					Total
					Sep-12
					\$294,906

¹ Excludes demand-related expenses

Prior Expenses Recovered in Nov-2012 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	59,206	\$18,272
(ii) C & I Non-Demand	8,935	\$2,945
(iii) C & I Demand Non-TOD	53,335	\$19,211
(iv) C & I Demand TOD On-Peak	17,259	\$6,995
(v) C & I Demand TOD Off-Peak	26,864	\$6,712
(vi) Outdoor Lighting	1,887	\$374
(vii) Total	167,486	\$54,509

Actual Cost Should Have Been Recovered in Nov-12				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	3.003¢	0.000¢	167,486	\$5,029,605

Cost Recovered in Nov-12 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	59,206	\$1,687,841
(ii) C & I Non-Demand	8,935	\$261,823
(iii) C & I Demand Non-TOD	53,335	\$1,548,441
(iv) C & I Demand TOD On-Peak	17,259	\$635,365
(v) C & I Demand TOD Off-Peak	26,864	\$605,184
(vi) Outdoor Lighting	1,887	\$40,244
(vii) Total	167,486	\$4,778,898

Total Balance of Unrecovered Expenses (Jan-13 Balance of Unrecovered Expenses)	
Jan-2013 Recovery Provision	\$491,104
4 Month ND Retail Total MWh Sales	718,544
Jan-2013 Recovery Provision per KWH	0.068¢

Jan-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	0.068¢	0.069¢
(ii) C & I Non-Demand	1.0281	0.068¢	0.070¢
(iii) C & I Demand Non-TOD	1.0170	0.068¢	0.070¢
(iv) C & I Demand TOD On-Peak	1.2883	0.068¢	0.088¢
(v) C & I Demand TOD Off-Peak	0.7889	0.068¢	0.054¢
(vi) Outdoor Lighting	0.7440	0.068¢	0.051¢

Jan-2013 Refunds/Additional Charges				
Refund/Special Charge Amount	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Refund	Total
	(\$44,630)	(\$13,140)	\$0	(\$44,630)
(i) Residential	-0.018¢	-0.005¢	0.000¢	-0.024¢
(ii) C & I Non-Demand	-0.019¢	-0.006¢	0.000¢	-0.025¢
(iii) C & I Demand Non-TOD	-0.019¢	-0.006¢	0.000¢	-0.024¢
(iv) C & I Demand TOD On-Peak	-0.024¢	-0.007¢	0.000¢	-0.031¢
(v) C & I Demand TOD Off-Peak	-0.015¢	-0.004¢	0.000¢	-0.019¢
(vi) Outdoor Lighting	-0.014¢	-0.004¢	0.000¢	-0.018¢

Jan-2013 Factors	
	Total
(i) Residential	2.726¢
(ii) C & I Non-Demand	2.795¢
(iii) C & I Demand Non-TOD	2.765¢
(iv) C & I Demand TOD On-Peak	3.502¢
(v) C & I Demand TOD Off-Peak	2.145¢
(vi) Outdoor Lighting	2.023¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Dec-12	Jan-13	Differ- ence	Percent Change	FCA Application Dec-12	Jan-13	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$172.1	\$150.6	(\$21.6)	-12.5%	39.7%	38.0%	-1.7%
2 Nuclear	\$42.5	\$38.5	(\$4.0)	-9.5%	9.8%	9.7%	-0.1%
3 Purchases	\$150.7	\$148.6	(\$2.1)	-1.4%	34.7%	37.5%	2.8%
MISO related Purchases	\$68.2	\$58.7	(\$9.5)	-14.0%	15.7%	14.8%	-0.9%
4 Total System Costs	433.5	396.3	(\$37.2)	-8.6%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$13.9	\$13.8	(\$0.1)	-0.6%	3.2%	3.5%	0.3%
6 Net System Costs	\$419.7	\$382.6	(\$37.1)	-8.8%	96.8%	96.5%	-0.3%
7							
** GWH OUTPUT **							
9 Fossil	5,124	4,998	(126)	-2.5%	29.7%	31.7%	2.0%
10 Nuclear	4,411	4,034	(377)	-8.5%	25.6%	25.6%	0.0%
11 Purchases	5,231	4,867	(364)	-7.0%	30.3%	30.8%	0.5%
12 Hydro & Other	1,786	1,194	(592)	-33.1%	10.4%	7.6%	-2.8%
13 Net Interchange	692	684	(8)	-1.2%	4.0%	4.3%	0.3%
14 Total Output	17,244	15,777	(1,467)	-8.5%	100.0%	100.0%	0.0%
15 Intersystem Sales	997	951	(46)	-4.6%	5.8%	6.0%	0.2%
16 Native Requirement	16,247	14,826	(1,421)	-8.7%	94.2%	94.0%	-0.2%
17							
** COST per KWH OUTPUT (¢) **							
19 Fossil	3.359	3.013	-0.347	-10.3%			
20 Nuclear	0.964	0.954	-0.010	-1.0%			
21 Purchases	2.880	3.053	0.173	6.0%			
22 Total System Costs	2.514	2.512	-0.002	-0.1%			
23 Intersystem Sales	1.390	1.447	0.058	4.1%			
24 Net System Costs	2.583	2.580	-0.003	-0.1%			
25							
26							
27 TOTAL SYSTEM GWH SALES	15,379	14,308	(1,071)	-7.0%			
28							
29 COST per KWH SALES (¢)	2.729	2.674	-0.055	-2.0%			
30							
31 RECOVERY PROV (¢ / KWH) - SYS	-0.055	0.068	0.123				
(i) Residential	-0.055	0.069	0.123				
(ii) C & I Non-Demand	-0.056	0.070	0.126				
(iii) C & I Demand Non-TOD	-0.056	0.070	0.125				
(iv) C & I Demand TOD On-Peak	-0.070	0.088	0.159				
(v) C & I Demand TOD Off-Peak	-0.043	0.054	0.097				
(vi) Outdoor Lighting	-0.041	0.051	0.092				
32 REFUND	-0.161	-0.023	0.138				
(i) Residential	-0.161	-0.024	0.138				
(ii) C & I Non-Demand	-0.166	-0.025	0.141				
(iii) C & I Demand Non-TOD	-0.164	-0.024	0.140				
(iv) C & I Demand TOD On-Peak	-0.207	-0.031	0.176				
(v) C & I Demand TOD Off-Peak	-0.127	-0.019	0.108				
(vi) Outdoor Lighting	-0.120	-0.018	0.102				
33 SYSTEM FCC IMPACT (¢ / KWH)	2.513	2.719	0.206	8.2%			
(i) Residential	2.520	2.726	0.206				
(ii) C & I Non-Demand	2.584	2.795	0.211				
(iii) C & I Demand Non-TOD	2.556	2.765	0.209				
(iv) C & I Demand TOD On-Peak	3.238	3.502	0.264				
(v) C & I Demand TOD Off-Peak	1.986	2.145	0.159				
(vi) Outdoor Lighting	1.870	2.023	0.153				

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	\$0.21
250	\$0.51
500	\$1.03
750	\$1.54
1,000	\$2.06

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-12	Jan-13
** GWH OUTPUT **		
Thermal	1,449,623	833,825
Disper gen	(99)	(84)
Hydro plus Wind	336,788	360,534
Hydro and Other	1,786,312	1,194,275
Rounded to nearest thousand:	1,786	1,194
Sales		
Non Gen Munic Total	150,637,000	148,391,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	996,573,000	950,733,000
Rounded to nearest million:	996.573	950.733

		System	Intersystem	Retail
November 2012 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 12,971,999.90	\$ 1,729,602.43	\$ 14,701,602.33
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 3,062,386.66	\$ -	\$ 3,062,386.66
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (9,796,092.60)	\$ -	\$ (9,796,092.60)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 766,055.37	\$ -	\$ 766,055.37
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)	\$ 327,880.03	\$ 865,517.44	\$ 1,193,397.47
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 44,931.97	\$ -	\$ 44,931.97
14	Real-Time Distribution of Losses Amount	\$ (1,080,774.58)	\$ -	\$ (1,080,774.58)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (7,302.67)	\$ -	\$ (7,302.67)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 32,191.43	\$ -	\$ 32,191.43
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (2,276.54)	\$ -	\$ (2,276.54)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 6,800,256.24	\$ -	\$ 6,800,256.24
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 651,614.63	\$ -	\$ 651,614.63
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)	\$ 191,611.98	\$ -	\$ 191,611.98
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)	\$ (561.19)	\$ -	\$ (561.19)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (4,770,894.15)	\$ -	\$ (4,770,894.15)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (117,462.38)	\$ -	\$ (117,462.38)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (624,471.78)	\$ -	\$ (624,471.78)
37	Financial Transmission Guarantee Uplift Amount	\$ 619,896.43	\$ -	\$ 619,896.43
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 1,187,332.86	\$ -	\$ 1,187,332.86
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 113,790.79	\$ -	\$ 113,790.79
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (330,240.05)	\$ 14,457.37	\$ (315,782.68)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 374,986.93	\$ -	\$ 374,986.93
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (376,872.67)	\$ 17,607.53	\$ (359,265.14)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (184,293.43)	\$ 10,467.35	\$ (173,826.08)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 658,067.29	\$ (7,767.27)	\$ 650,300.02
19	Real-Time Market Administration Amount	\$ 50,417.94	\$ (4,495.20)	\$ 45,922.74
29	Financial Transmission Rights Market Administration Amount	\$ 48,427.20	\$ -	\$ 48,427.20
33	Day-Ahead Schedule 24 Allocation Amount	\$ 97,293.32	\$ (1,137.91)	\$ 96,155.41
34	Real-Time Schedule 24 Allocation Amount	\$ 7,443.69	\$ (660.91)	\$ 6,782.78
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	\$ 656,444.98	\$ -	\$ 656,444.98
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 3,207,268.38	\$ -	\$ 3,207,268.38
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (3,254,929.87)	\$ -	\$ (3,254,929.87)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (799,327.24)	\$ -	\$ (799,327.24)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 165,174.62	\$ -	\$ 165,174.62
TOTAL MISO CHARGES		\$ 10,689,973.49	\$ 2,623,590.83	\$ 13,313,564.32
SCHEDULE 24 (FOR RETAIL)				\$ 102,938.19
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 13,210,626.13

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
November 2012 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (131,526.28)	\$ -	\$ (131,526.28)
2	Day-Ahead Spinning Reserve Amount	\$ (105,749.31)	\$ -	\$ (105,749.31)
3	Day-Ahead Supplemental Reserve	\$ (130,764.90)	\$ -	\$ (130,764.90)
4	Real-Time Regulation Amount	\$ (7,383.74)	\$ 25,253.97	\$ 17,870.23
5	Real-Time Spinning Reserve Amount	\$ 33,819.90	\$ 29,566.84	\$ 63,386.74
6	Real-Time Supplemental Reserve Amount.	\$ 5,492.07	\$ 38,045.15	\$ 43,537.22
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (9,277.25)	\$ -	\$ (9,277.25)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 2,038,588.41	\$ -	\$ 2,038,588.41
8b	Real Time Non Excessive Energy Congestion	\$ (363,340.96)	\$ -	\$ (363,340.96)
8c	Real Time Non Excessive Energy Loss	\$ (33,207.97)	\$ -	\$ (33,207.97)
9	Real Time Net Regulation Adjustment Amount	\$ (813.45)	\$ 870.09	\$ 56.64
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 189,493.44	\$ -	\$ 189,493.44
11	Real Time Spinning Reserve Cost Distribution	\$ 113,797.42	\$ -	\$ 113,797.42
12	Real Time Supplemental Reserve Cost Distribution	\$ 100,421.06	\$ -	\$ 100,421.06
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 6,824.74	\$ (744.41)	\$ 6,080.33
14	Real Time Contignecy Reserve Deployment Failure	\$ -	\$ -	\$ -
TOTAL MISO ASM CHARGES		\$ 1,706,373.18	\$ 92,991.64	\$ 1,799,364.82

Northern States Power Company, A Minnesota Corporation
Electric Operations - State of North Dakota
Derivation 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	(37,060)	(48,106)	(20,853)	(21,116)	(45,351)	(9,086)	(110,114)	(35,437)	(13,659)	(60,004)	(28,513)	
3 Monthly Refund												
4 Forecast North Dakota Sales	204,480	176,872	172,668	167,827	180,675	198,082	165,774	179,024	171,102	193,427	241,910	204,198
5 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)	
6 Expected Refund	(30,199)	(42,867)	(36,737)	(58,058)	(20,517)	(39,456)	(27,680)	(19,991)	(100,226)	(29,198)	(58,610)	(20,252)
7 Actual Refunded	(30,522)	(32,915)	(37,073)	(39,718)	(38,188)	(28,551)	(37,568)	(26,230)	(55,275)	(68,950)	(42,493)	
8 Deviation	323	(9,952)	336	(18,340)	17,671	(10,905)	9,888	6,239	(44,951)	39,752	(16,117)	(20,252)
9 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)	
10 Realized Margin	(0.018)	(0.033)	(0.012)	(0.024)	(0.015)	(0.010)	(0.060)	(0.016)	(0.034)	(0.010)	(0.018)	
11 Class Ratios												
12 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
13 C&I Non-Demand	1.0548	1.0548	1.0481	1.0415	1.0348	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281
14 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
15 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
16 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
17 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
18 Realized Margin Adj for Class Ratios												
19 Residential	(0.018)	(0.033)	(0.012)	(0.023)	(0.015)	(0.010)	(0.061)	(0.016)	(0.034)	(0.010)	(0.018)	
20 C&I Non-Demand	(0.019)	(0.035)	(0.012)	(0.024)	(0.016)	(0.010)	(0.062)	(0.017)	(0.035)	(0.011)	(0.019)	
21 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)	(0.019)	
22 C&I Demand TOD On-Peak	(0.024)	(0.043)	(0.016)	(0.031)	(0.020)	(0.013)	(0.078)	(0.021)	(0.044)	(0.013)	(0.024)	
23 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)	(0.015)	
24 Outdoor Lighting	(0.013)	(0.023)	(0.009)	(0.017)	(0.011)	(0.008)	(0.045)	(0.012)	(0.025)	(0.008)	(0.014)	

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

	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13
1 Forecast Month	Oct-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		Nov-12										
3												
4 Monthly Refund	(280,039)											
5												
6 Forecast North Dakota Sales	193,427	241,910										
7												

8 Current Month Refund Factor (0.145)

9 Expected Refund -

10 Actual Refund -

11 Deviation -

12 True-up Factor -

13 Realized Margin (0.145)

14 Class Ratios

15 Residential 1.0026 1.0026

16 C&I Non-Demand 1.0281 1.0281

17 C&I Demand Non-TOD 1.0170 1.0170

18 C&I Demand TOD On-Peak 1.2883 1.2883

19 C&I Demand TOD Off-Peak 0.7889 0.7889

20 Outdoor Lighting 0.7440 0.7440

21 Realized Margin Adj for Class Ratios

22 Residential (0.145) (0.145)

23 C&I Non-Demand (0.149) (0.149)

24 C&I Demand Non-TOD (0.147) (0.147)

25 C&I Demand TOD On-Peak (0.187) (0.187)

26 C&I Demand TOD Off-Peak (0.114) (0.114)

27 Outdoor Lighting (0.108) (0.108)