



414 Nicollet Mall  
Minneapolis, Minnesota 55401

—Via Electronic Filing—

December 31, 2013

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

**Re: January 2014 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 2014.

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>Previous</b>	<b>Current</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:

January 2014	Fuel Cost Charge (\$/kWh)
<b>Residential</b>	0.02890
<b>C &amp; I Non-Demand</b>	0.02964
<b>C &amp; I Demand</b>	0.02932
<b>C &amp; I Demand Time of Day On-Peak</b>	0.03714
<b>C &amp; I Demand Time of Day Off-Peak</b>	0.02274
<b>Outdoor Lighting</b>	0.02145

## **MISO CHARGES IMPLEMENTATION**

### MISO Day 2 Charges

This filing includes our reporting of the Midcontinent Independent System Operator, Inc. (MISO, formerly Midwest Independent Transmission System Operator, Inc.) 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 January 2014 FCC the net MISO Day 2 costs for November 2013 as recorded in Account 555. The MISO Day 2 cost recovery included in this January 2014 FCC is \$19,349,799, 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 January FCC the net MISO ASM costs for November 2013 as recorded in Account 555. The MISO ASM cost recovery included in this January FCC is \$1,154,328,

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

which is the net of many items. The detailed records are contained in Attachment 2, page 2.

## REFUNDS

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

Pursuant to the above referenced Order Adopting Settlement, the January 2014 Asset Based Margin amount of \$68,557 has been included as a credit, or offset, to the January 2014 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 January 2014 FCC is \$12,506, 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 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).

## EXCLUSION

### Prairie Rose Wind PPA Exclusion

Pursuant to the Commission's December 21, 2012 Order in the Company's Advanced Determination of Prudence application (Case No. PU-12-59), the energy and costs associated with the January 1, 2013 commencement of the Prairie Rose Wind (PRW) power purchase agreement (PPA) are being excluded from the calculation of the Company's monthly Fuel Cost Rider (FCR). Beginning with the March 2013 FCR filing, the Company has excluded the PRW PPA from any FCR calculations until the Commission has completed a ratemaking proceeding and made a decision regarding the rate treatment for the PRW PPA.

Not reflecting the PRW PPA in our FCR will result in a fuel cost revenue shortfall while the Commission deliberates on this issue in the pending rate case. The Company has filed testimony in its pending electric rate case (Case No. PU-12-813) in support of FCR recovery of PRW PPA costs, and if the Commission ultimately approves FCR recovery, the Company will seek to recover the cumulative shortfall.

**OTHER REPORTING ITEM**

Attached is the calculation of the January 2014 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

Jan-2014 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
<b>System</b>	\$0.03063	\$0.00057	-\$0.00237	\$0.02883
<b>Residential</b>	\$0.03071	\$0.00057	-\$0.00237	\$0.02890
C & I Non-Demand	\$0.03149	\$0.00058	-\$0.00243	\$0.02964
C & I Demand Non-TOD	\$0.03115	\$0.00057	-\$0.00241	\$0.02932
C & I Demand TOD On-Peak	\$0.03946	\$0.00073	-\$0.00305	\$0.03714
C & I Demand TOD Off-Peak	\$0.02416	\$0.00045	-\$0.00187	\$0.02274
Outdoor Lighting	\$0.02279	\$0.00042	-\$0.00176	\$0.02145
<b>Residential</b>				
Residential Service	\$ 0.03071	\$ 0.00057	\$ (0.00237)	\$ 0.02890
Residential TOD	\$ 0.03071	\$ 0.00057	\$ (0.00237)	\$ 0.02890
Residential - Underground	\$ 0.03071	\$ 0.00057	\$ (0.00237)	\$ 0.02890
Residential TOD - Underground	\$ 0.03071	\$ 0.00057	\$ (0.00237)	\$ 0.02890
Energy Control - (Non-Demand)	\$ 0.03071	\$ 0.00057	\$ (0.00237)	\$ 0.02890
Limit Off Peak	\$ 0.03071	\$ 0.00057	\$ (0.00237)	\$ 0.02890
<b>C &amp; I Non-Demand</b>				
Energy Controlled - (Non-Demand)	\$ 0.03149	\$ 0.00058	\$ (0.00243)	\$ 0.02964
Limit Off Peak	\$ 0.03149	\$ 0.00058	\$ (0.00243)	\$ 0.02964
Small General Service	\$ 0.03149	\$ 0.00058	\$ (0.00243)	\$ 0.02964
Small General TOD - Metered	\$ 0.03149	\$ 0.00058	\$ (0.00243)	\$ 0.02964
Small General TOD - Unmetered	\$ 0.03149	\$ 0.00058	\$ (0.00243)	\$ 0.02964
Fire and Civil Defense Siren	\$ 0.03149	\$ 0.00058	\$ (0.00243)	\$ 0.02964
Direct Current (Closed)	\$ 0.03149	\$ 0.00058	\$ (0.00243)	\$ 0.02964
<b>C &amp; I Demand</b>				
General Service	\$ 0.03115	\$ 0.00057	\$ (0.00241)	\$ 0.02932
General TOD - On Peak	\$ 0.03946	\$ 0.00073	\$ (0.00305)	\$ 0.03714
General TOD - Off Peak	\$ 0.02416	\$ 0.00045	\$ (0.00187)	\$ 0.02274
Peak Controlled (Closed)	\$ 0.03115	\$ 0.00057	\$ (0.00241)	\$ 0.02932
Peak Controlled TOD (Closed) - On Peak	\$ 0.03946	\$ 0.00073	\$ (0.00305)	\$ 0.03714
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02416	\$ 0.00045	\$ (0.00187)	\$ 0.02274
Peak Controlled Tiered	\$ 0.03115	\$ 0.00057	\$ (0.00241)	\$ 0.02932
Peak Controlled Tiered TOD - On Peak	\$ 0.03946	\$ 0.00073	\$ (0.00305)	\$ 0.03714
Peak Controlled Tiered TOD - Off Peak	\$ 0.02416	\$ 0.00045	\$ (0.00187)	\$ 0.02274
Energy Controlled (Closed)	\$ 0.03115	\$ 0.00057	\$ (0.00241)	\$ 0.02932
Tier 1 Energy Controlled Rider	\$ 0.03115	\$ 0.00057	\$ (0.00241)	\$ 0.02932
Real Time Pricing - Firm - On Peak	\$ 0.03946	\$ 0.00073	\$ (0.00305)	\$ 0.03714
Real Time Pricing - Firm - Off Peak	\$ 0.02416	\$ 0.00045	\$ (0.00187)	\$ 0.02274
Real Time Pricing - Controllable - On Peak	\$ 0.03946	\$ 0.00073	\$ (0.00305)	\$ 0.03714
Real Time Pricing - Controllable - Off Peak	\$ 0.02416	\$ 0.00045	\$ (0.00187)	\$ 0.02274
Small Municipal Pumping	\$ 0.03115	\$ 0.00057	\$ (0.00241)	\$ 0.02932
Municipal Pumping	\$ 0.03115	\$ 0.00057	\$ (0.00241)	\$ 0.02932
Excess Energy - St. Anthony Falls	\$ 0.03115	\$ 0.00057	\$ (0.00241)	\$ 0.02932
<b>Outdoor Lighting</b>				
Automatic Protective Lighting	\$ 0.02279	\$ 0.00042	\$ (0.00176)	\$ 0.02145
Street Lighting System	\$ 0.02279	\$ 0.00042	\$ (0.00176)	\$ 0.02145
Street Lighting Energy	\$ 0.02279	\$ 0.00042	\$ (0.00176)	\$ 0.02145
Street Lighting Energy - Metered	\$ 0.02279	\$ 0.00042	\$ (0.00176)	\$ 0.02145
Street Lighting Energy (Closed)	\$ 0.02279	\$ 0.00042	\$ (0.00176)	\$ 0.02145
Street Lighting - City of St. Paul	\$ 0.02279	\$ 0.00042	\$ (0.00176)	\$ 0.02145

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-2014

	Column (A) Aug-13	Column (B) Sep-13	Column (C) Oct-13	Column (D) Nov-13	Column (E) 4 Month Total
<b>Fuel and Purchased Power Costs</b>					
Account 151 - Fossil Fuel	\$45,410,138	\$36,507,594	\$31,219,451	\$35,144,174	\$148,281,357
Account 518 - Nuclear Fuel	\$11,242,069	\$9,639,647	\$7,811,889	\$7,744,058	\$36,437,663
Account 555 - Purchased Power <sup>1</sup>	\$37,604,844	\$39,236,352	\$37,388,155	\$47,321,898	\$161,551,249
Account 555 - Pr. Rose PPA Adjustment	(\$44,921)	(\$116,046)	(\$229,062)	(\$204,801)	(\$594,830)
MISO Day 2 Charges	\$24,320,465	\$23,044,198	\$23,751,689	\$19,456,194	\$90,572,546
MISO Day 2 - Schedule 24	(\$113,223)	(\$113,785)	(\$107,178)	(\$106,395)	(\$440,581)
MISO - ASM Charges	\$1,760,793	\$2,440,355	\$2,595,581	\$1,154,328	\$7,951,057
Account 555 - Total MISO Charges	\$25,968,036	\$25,370,767	\$26,240,091	\$20,504,127	\$98,083,021
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$120,180,166	\$110,638,315	\$102,430,524	\$110,509,456	\$443,758,460
Less Fuel Cost of InterSystem Sales	(\$5,022,275)	(\$3,704,767)	(\$693,295)	(\$4,320,339)	(\$13,740,676)
Net System Costs	\$115,157,891	\$106,933,547	\$101,737,229	\$106,189,117	\$430,017,785
<b>System MWh Sales</b>					
Total NSP System Retail	3,788,747	3,794,388	3,454,506	2,994,504	14,032,145
Non-Gen Muni's/Load Pattern	1,699	1,629	1,544	1,383	6,255
Total NSP System MWh Sales	3,790,446	3,796,017	3,456,050	2,995,887	14,038,400
<b>Average Unit Cost of Fuel and Purchased Power</b>					
<b>Fuel Cost per kWh for NSP System</b>					
Adjusted System Cost without Pr. Rose PPA	3.038¢	2.817¢	2.944¢	3.544¢	3.063¢
<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>					
			Avg Unit Cost	FCF Ratio	4 Month Average
(i) Residential			3.063¢	1.0026	3.071¢
(ii) C & I Non-Demand			3.063¢	1.0281	3.149¢
(iii) C & I Demand Non-TOD			3.063¢	1.0170	3.115¢
(iv) C & I Demand TOD On-Peak			3.063¢	1.2883	3.946¢
(v) C & I Demand TOD Off-Peak			3.063¢	0.7889	2.416¢
(vi) Outdoor Lighting			3.063¢	0.7440	2.279¢
<b>North Dakota Retail MWh Sales</b>					
(i) Residential	61,039	57,405	53,649	52,513	224,606
(ii) C & I Non-Demand	8,922	8,387	8,857	8,265	34,431
(iii) C & I Demand Non-TOD	61,754	67,538	65,164	55,698	250,154
(iv) C & I Demand TOD On-Peak	18,670	19,897	17,403	19,158	75,128
(v) C & I Demand TOD Off-Peak	28,678	31,560	25,450	30,526	116,214
(vi) Outdoor Lighting	1,236	1,597	1,429	1,837	6,099
(vii) Total	180,299	186,384	171,952	167,997	706,632
<b>Jan-2014 Recovery Provision (True-up Factor) Calculation</b>					
<b>Prior Unrecovered Expenses (Sep-13 Balance of Unrecovered Expenses)</b>					<b>Total</b>
					Sep-13
					(\$6,355)

<sup>1</sup> Excludes demand-related expenses and includes Prairie Rose Wind PPA expenses

Prior Expenses Recovered in Nov-2013 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	52,513	\$83,506
(ii) C & I Non-Demand	8,265	\$14,214
(iii) C & I Demand Non-TOD	55,698	\$91,243
(iv) C & I Demand TOD On-Peak	19,158	\$44,372
(v) C & I Demand TOD Off-Peak	30,526	\$42,689
(vi) Outdoor Lighting	1,837	\$3,080
(vii) Total	167,997	\$279,104

Actual Cost Should Have Been Recovered in Nov-13				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	3.544¢	0.000¢	167,997	\$5,953,814

Cost Recovered in Nov-13 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	52,513	\$1,650,499
(ii) C & I Non-Demand	8,265	\$266,651
(iii) C & I Demand Non-TOD	55,698	\$1,776,668
(iv) C & I Demand TOD On-Peak	19,158	\$775,358
(v) C & I Demand TOD Off-Peak	30,526	\$756,710
(vi) Outdoor Lighting	1,837	\$43,092
(vii) Total	167,997	\$5,268,978

Total Balance of Unrecovered Expenses (Jan-14 Balance of Unrecovered Expenses)	
Jan-2014 Recovery Provision	\$399,377
4 Month ND Retail Total MWh Sales	706,632
Jan-2014 Recovery Provision per KWH	0.057¢

Jan-2014 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	1.0026	0.057¢	0.057¢
(ii) C & I Non-Demand	1.0281	0.057¢	0.058¢
(iii) C & I Demand Non-TOD	1.0170	0.057¢	0.057¢
(iv) C & I Demand TOD On-Peak	1.2883	0.057¢	0.073¢
(v) C & I Demand TOD Off-Peak	0.7889	0.057¢	0.045¢
(vi) Outdoor Lighting	0.7440	0.057¢	0.042¢

Jan-2014 Refunds/Additional Charges				
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Refund	Total
Refund/Special Charge Amount	(\$68,557)	(\$12,506)	(\$496,354)	(\$564,911)
(i) Residential	-0.028¢	-0.005¢	-0.204¢	-0.237¢
(ii) C & I Non-Demand	-0.029¢	-0.005¢	-0.209¢	-0.243¢
(iii) C & I Demand Non-TOD	-0.029¢	-0.005¢	-0.207¢	-0.241¢
(iv) C & I Demand TOD On-Peak	-0.036¢	-0.007¢	-0.262¢	-0.305¢
(v) C & I Demand TOD Off-Peak	-0.022¢	-0.004¢	-0.160¢	-0.187¢
(vi) Outdoor Lighting	-0.021¢	-0.004¢	-0.151¢	-0.176¢

Jan-2014 Factors		Total
(i) Residential		2.890¢
(ii) C & I Non-Demand		2.964¢
(iii) C & I Demand Non-TOD		2.932¢
(iv) C & I Demand TOD On-Peak		3.714¢
(v) C & I Demand TOD Off-Peak		2.274¢
(vi) Outdoor Lighting		2.145¢

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>		
	Dec-13	Jan-14	Differ- ence	Percent Change	FCA Application Dec-13	Jan-14	Differ- ence
<b>** COSTS (Millions) **</b>							
1 Fossil	\$158.8	\$148.3	(\$10.5)	-6.6%	34.6%	33.4%	-1.2%
2 Nuclear	\$36.9	\$36.4	(\$0.4)	-1.2%	8.0%	8.2%	0.2%
3 Purchases	\$151.6	\$161.0	\$9.3	6.2%	33.0%	36.3%	3.3%
MISO related Purchases	\$111.8	\$98.1	(\$13.7)	-12.2%	24.3%	22.1%	-2.2%
4 Total System Costs	459.0	443.8	(\$15.3)	-3.3%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$11.5	\$13.7	\$2.3	19.9%	2.5%	3.1%	0.6%
6 Net System Costs	\$447.6	\$430.0	(\$17.6)	-3.9%	97.5%	96.9%	-0.6%
7							
8 <b>** GWH OUTPUT **</b>							
9 Fossil	4,591	925,026	920,435	20048.7%	27.5%	21.1%	-6.4%
10 Nuclear	3,702	818,597	814,895	22012.3%	22.2%	18.7%	-3.5%
11 Purchases	6,109	1,283,743	1,277,634	20914.0%	36.6%	29.3%	-7.3%
12 Hydro & Other	1,602	437,425	435,823	27204.9%	9.6%	10.0%	0.4%
13 Net Interchange	667	911,008	910,341	136482.9%	4.0%	20.8%	16.8%
14 Total Output	16,671	4,375,799	4,359,128	26148.0%	100.0%	100.0%	0.0%
15 Intersystem Sales	537	628	91	16.9%	3.2%	0.0%	-3.2%
16 Naive Requirement	16,134	4,375,171	4,359,037	27017.8%	96.8%	100.0%	3.2%
17							
18 <b>** COST per KWH OUTPUT (\$) **</b>							
19 Fossil	3.458	0.016	-3.442	-99.5%			
20 Nuclear	0.996	0.004	-0.991	-99.6%			
21 Purchases	2.482	0.013	-2.469	-99.5%			
22 Total System Costs	2.754	0.010	-2.743	-99.6%			
23 Intersystem Sales	2.134	2.189	0.055	2.6%			
24 Net System Costs	2.774	0.010	-2.764	-99.6%			
25							
26							
27 TOTAL SYSTEM GWH SALES	15,053	14,038	(1,015)	-6.7%			
28							
29 COST per KWH SALES (\$) )	2.973	3.063	0.090	3.0%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	0.178	0.057	-0.122				
(i) Residential	0.179	0.057	-0.122				
(ii) C & I Non-Demand	0.183	0.058	-0.125				
(iii) C & I Demand Non-TOD	0.181	0.057	-0.124				
(iv) C & I Demand TOD On-Peak	0.229	0.073	-0.157				
(v) C & I Demand TOD Off-Peak	0.140	0.045	-0.096				
(vi) Outdoor Lighting	0.132	0.042	-0.090				
32 REFUND	0.036	-0.236	-0.272				
(i) Residential	0.036	-0.237					
(ii) C & I Non-Demand	0.037	-0.243					
(iii) C & I Demand Non-TOD	0.037	-0.241					
(iv) C & I Demand TOD On-Peak	0.046	-0.305					
(v) C & I Demand TOD Off-Peak	0.028	-0.187					
(vi) Outdoor Lighting	0.027	-0.176					
33 SYSTEM FCC IMPACT (\$ / KWH)	3.187	2.884	-0.304	-9.5%			
(i) Residential	3.196	2.890	-0.306				
(ii) C & I Non-Demand	3.277	2.964					
(iii) C & I Demand Non-TOD	3.242	2.932					
(iv) C & I Demand TOD On-Peak	4.107	3.714					
(v) C & I Demand TOD Off-Peak	2.515	2.274					
(vi) Outdoor Lighting	2.372	2.145					

**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	(\$0.31)
250	(\$0.76)
500	(\$1.53)
750	(\$2.29)
1,000	(\$3.06)

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-13	Jan-14
<b>** GWH OUTPUT **</b>		
Thermal	1,221,870	297,044,316
Disper gen	173,447	49,972
<u>Hydro plus Wind</u>	206,513	140,330,536
Hydro and Other	1,601,830	437,424,824
Rounded to nearest thousand:	1,602	437,425
<b>Sales</b>		
Non Gen Munic Total	6,390,000	6,255,000
Load Pattern Power	0	0
<u>Resale &amp; Interchange (Intersystem)</u>	537,047,000	627,688,000
Rounded to nearest million:	537.047	627.688

		System	Intersystem	Retail
<b>November 2013 Actual</b>				
<b>Energy and Loss Charges</b>				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 18,873,918.99	\$ 2,616,813.43	\$ 21,490,732.42
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,761,648.53	\$ -	\$ 2,761,648.53
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 4,524.15	\$ -	\$ 4,524.15
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (10,767,933.44)	\$ -	\$ (10,767,933.44)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 803,905.96	\$ -	\$ 803,905.96
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	\$ (4,524.15)	\$ -	\$ (4,524.15)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 a	Real-Time Asset Energy Amount - Energy Component (1)	\$ 721,730.25	\$ 906,323.86	\$ 1,628,054.11
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (18,630.52)	\$ -	\$ (18,630.52)
14	Real-Time Distribution of Losses Amount	\$ (1,686,809.26)	\$ -	\$ (1,686,809.26)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ (4.35)	\$ -	\$ (4.35)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ 4.35	\$ -	\$ 4.35
21	Real-time Net inadvertent Distribution	\$ (70,992.11)	\$ -	\$ (70,992.11)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 7,864.32	\$ -	\$ 7,864.32
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ 2,697.14	\$ -	\$ 2,697.14
<b>Congestion Related Charges</b>				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 7,276,642.75	\$ -	\$ 7,276,642.75
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ 10,585.19	\$ -	\$ 10,585.19
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 1,899,225.77	\$ -	\$ 1,899,225.77
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	\$ (10,585.19)	\$ -	\$ (10,585.19)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	\$ 88,957.90	\$ -	\$ 88,957.90
15	Real-Time Financial Bilateral Transaction Congestion Amount	\$ (35.58)	\$ -	\$ (35.58)
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	\$ 35.58	\$ -	\$ 35.58
22 b	Real-Time Non-Asset Energy Amount - Congestion Component (1)	\$ (4,031.38)	\$ -	\$ (4,031.38)
<b>FTR Related Charges</b>				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (5,253,772.43)	\$ -	\$ (5,253,772.43)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (102,858.22)	\$ -	\$ (102,858.22)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (446,615.19)	\$ -	\$ (446,615.19)
37	Financial Transmission Guarantee Uplift Amount	\$ 435,355.01	\$ -	\$ 435,355.01
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
<b>Uplift Charges</b>				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 1,487,155.99	\$ -	\$ 1,487,155.99
<b>Revenue Sufficiency Guarantee (RSG) Charges</b>				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 94,054.28	\$ -	\$ 94,054.28
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (89,168.08)	\$ 5,448.11	\$ (83,719.97)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 286,314.50	\$ -	\$ 286,314.50
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ (138,301.19)	\$ (62,492.58)	\$ (200,793.77)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (166,835.36)	\$ (6,290.65)	\$ (173,126.01)
<b>Market Administration Charges</b>				
4	Day-Ahead Market Administration Amount	\$ 574,275.80	\$ (7,995.54)	\$ 566,280.26
19	Real-Time Market Administration Amount	\$ 45,016.72	\$ (3,182.78)	\$ 41,833.94
29	Financial Transmission Rights Market Administration Amount	\$ 35,275.84	\$ -	\$ 35,275.84
33	Day-Ahead Schedule 24 Allocation Amount	\$ 100,145.34	\$ (1,388.56)	\$ 98,756.78
34	Real-Time Schedule 24 Allocation Amount	\$ (153,585.65)	\$ 161,224.36	\$ 7,638.71
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	\$ 8,107.26	\$ -	\$ 8,107.26
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
<b>Auction Revenue Rights (ARR)</b>				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 3,545,047.56	\$ -	\$ 3,545,047.56
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (3,890,630.23)	\$ -	\$ (3,890,630.23)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (640,059.99)	\$ -	\$ (640,059.99)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 230,617.93	\$ -	\$ 230,617.93
<b>TOTAL MISO CHARGES</b>		<b>\$ 15,847,734.79</b>	<b>\$ 3,608,459.65</b>	<b>\$ 19,456,194.44</b>
<b>SCHEDULE 24 (FOR RETAIL)</b>				<b>\$ 106,395.49</b>
<b>TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)</b>				<b>\$ 19,349,798.95</b>

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

		System	Intersystem	Retail
<b>November 2013 Actual</b>				
<b>Procurement Charges</b>				
1	Day-Ahead Regulation Amount	\$ (202,218.30)	\$ -	\$ (202,218.30)
2	Day-Ahead Spinning Reserve Amount	\$ (125,277.67)	\$ -	\$ (125,277.67)
3	Day-Ahead Supplemental Reserve	\$ (60,885.28)	\$ -	\$ (60,885.28)
4	Real-Time Regulation Amount	\$ 85,652.35	\$ 42,106.42	\$ 127,758.77
5	Real-Time Spinning Reserve Amount	\$ 2,539.36	\$ 84,430.38	\$ 86,969.74
6	Real-Time Supplemental Reserve Amount.	\$ 89.12	\$ 299.49	\$ 388.61
<b>Resource Energy Charges</b>				
7a	Real Time Excessive Energy Amount	\$ (3,234.77)	\$ -	\$ (3,234.77)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 1,074,996.51	\$ -	\$ 1,074,996.51
8b	Real Time Non Excessive Energy Congestion	\$ (395,057.65)	\$ -	\$ (395,057.65)
8c	Real Time Non Excessive Energy Loss	\$ 74,668.87	\$ -	\$ 74,668.87
9	Real Time Net Regulation Adjustment Amount	\$ 14,697.42	\$ (348.40)	\$ 14,349.02
<b>Cost Distribution Charges</b>				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 154,416.84	\$ -	\$ 154,416.84
11	Real Time Spinning Reserve Cost Distribution	\$ 202,530.48	\$ -	\$ 202,530.48
12	Real Time Supplemental Reserve Cost Distribution	\$ 163,160.67	\$ -	\$ 163,160.67
<b>Penalty Charges</b>				
13	Real Time Excessive/Dificient Energy Deployment	\$ 46,169.38	\$ (4,552.93)	\$ 41,616.45
14	Real Time Contignecy Reserve Deployment Failure	\$ 145.87	\$ -	\$ 145.87
<b>TOTAL MISO ASM CHARGES</b>		<b>\$ 1,032,393.20</b>	<b>\$ 121,934.96</b>	<b>\$ 1,154,328.16</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

	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14
1 Forecast Month	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
2 True-up Month												
3												
4 Monthly Refund	(11,891)	(56,628)	(48,164)	(91,255)	(46,210)	(38,419)	(19,892)	(74,848)	(91,958)	19,495	(55,905)	
5 Forecast North Dakota Sales	190,659	193,918	172,034	162,994	190,995	190,839	175,314	177,072	160,760	205,971	244,097	198,863
6												
7												
8 Current Month Refund Factor	(0.059)	(0.029)	(0.028)	(0.056)	(0.024)	(0.020)	(0.011)	(0.042)	(0.057)	0.009	(0.022)	
9												
14 Expected Refund	(44,630)	(52,527)	(121,803)	(65,176)	(85,565)	(56,127)	(58,687)	(27,522)	(11,541)	(59,787)	(81,835)	(7,762)
15 Actual Refunded	(34,718)	(43,979)	(84,402)	(100,304)	(73,088)	(67,024)	(67,038)	(42,583)	(21,664)	(32,530)	(67,183)	
16 Deviation	(9,912)	(8,548)	(37,401)	35,128	(12,477)	10,897	8,351	15,061	10,123	(27,257)	(14,652)	(7,762)
17												
18 True-up Factor	(0.005)	(0.004)	(0.022)	0.022	(0.007)	0.006	0.005	0.009	0.006	(0.013)	(0.006)	
19												
20 Realized Margin	(0.064)	(0.034)	(0.050)	(0.034)	(0.031)	(0.014)	(0.007)	(0.034)	(0.051)	(0.004)	(0.028)	
21												
22 Class Ratios												
23 Residential	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
24 C&I Non-Demand	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281
25 C&I Demand Non-TOD	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170
26 C&I Demand TOD On-Peak	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883
27 C&I Demand TOD Off-Peak	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889
28 Outdoor Lighting	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440
29												
30 Realized Margin Adj for Class Ratios												
31 Residential	(0.064)	(0.034)	(0.050)	(0.035)	(0.031)	(0.014)	(0.007)	(0.034)	(0.051)	(0.004)	(0.028)	
32 C&I Non-Demand	(0.066)	(0.035)	(0.051)	(0.035)	(0.032)	(0.015)	(0.007)	(0.035)	(0.052)	(0.004)	(0.029)	
33 C&I Demand Non-TOD	(0.065)	(0.034)	(0.051)	(0.035)	(0.031)	(0.015)	(0.007)	(0.034)	(0.052)	(0.004)	(0.029)	
34 C&I Demand TOD On-Peak	(0.082)	(0.043)	(0.064)	(0.044)	(0.040)	(0.019)	(0.008)	(0.043)	(0.066)	(0.005)	(0.036)	
35 C&I Demand TOD Off-Peak	(0.050)	(0.027)	(0.039)	(0.027)	(0.024)	(0.011)	(0.005)	(0.027)	(0.040)	(0.003)	(0.022)	
36 Outdoor Lighting	(0.048)	(0.025)	(0.037)	(0.026)	(0.023)	(0.011)	(0.005)	(0.025)	(0.038)	(0.003)	(0.021)	

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	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Nov-13
	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14
1	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)
2	204,198	190,659	193,918	172,034	162,994	190,995	190,839	190,839	175,314	177,072	160,760	205,971	244,097	
3	(0.007)	(0.007)	(0.007)	(0.008)	(0.008)	(0.007)	(0.007)	(0.007)	(0.008)	(0.008)	(0.008)	(0.007)	(0.006)	
4	(11,060)	(13,140)	(12,137)	(13,173)	(14,257)	(14,119)	(14,164)	(14,651)	(14,257)	(14,765)	(11,255)	(14,171)	(11,390)	
5	(12,560)	(13,605)	(11,517)	(12,691)	(13,731)	(13,105)	(13,056)	(17,033)	(14,231)	(14,231)	(13,503)	(12,297)	(12,521)	
6	1,500	465	(620)	(482)	(526)	(1,014)	(1,128)	2,382	(534)	(534)	2,248	(1,874)	1,131	
7	0.001	0.000	(0.000)	(0.000)	(0.000)	(0.001)	(0.001)	0.001	(0.000)	(0.000)	0.001	(0.001)	0.000	
8	(0.006)	(0.007)	(0.007)	(0.008)	(0.009)	(0.008)	(0.008)	(0.008)	(0.006)	(0.008)	(0.007)	(0.008)	(0.005)	
9	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	
10	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	
11	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	
12	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	
13	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	
14	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	
15	(0.006)	(0.007)	(0.007)	(0.008)	(0.009)	(0.008)	(0.008)	(0.008)	(0.006)	(0.008)	(0.007)	(0.008)	(0.005)	
16	(0.006)	(0.007)	(0.008)	(0.008)	(0.009)	(0.008)	(0.008)	(0.008)	(0.007)	(0.008)	(0.007)	(0.008)	(0.005)	
17	(0.006)	(0.007)	(0.007)	(0.008)	(0.009)	(0.008)	(0.008)	(0.008)	(0.007)	(0.008)	(0.007)	(0.008)	(0.005)	
18	(0.008)	(0.009)	(0.009)	(0.011)	(0.011)	(0.011)	(0.011)	(0.011)	(0.008)	(0.010)	(0.009)	(0.010)	(0.007)	
19	(0.005)	(0.005)	(0.006)	(0.006)	(0.007)	(0.006)	(0.006)	(0.006)	(0.005)	(0.006)	(0.006)	(0.006)	(0.004)	
20	(0.004)	(0.005)	(0.005)	(0.006)	(0.006)	(0.006)	(0.006)	(0.006)	(0.005)	(0.006)	(0.005)	(0.006)	(0.004)	
21	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	
22	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	
23	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	
24	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	
25	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	
26	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	
27	(0.006)	(0.007)	(0.007)	(0.008)	(0.009)	(0.008)	(0.008)	(0.008)	(0.006)	(0.008)	(0.007)	(0.008)	(0.005)	
28	(0.006)	(0.007)	(0.008)	(0.008)	(0.009)	(0.008)	(0.008)	(0.008)	(0.007)	(0.008)	(0.007)	(0.008)	(0.005)	
29	(0.006)	(0.007)	(0.007)	(0.008)	(0.009)	(0.008)	(0.008)	(0.008)	(0.007)	(0.008)	(0.007)	(0.008)	(0.005)	
30	(0.008)	(0.009)	(0.009)	(0.011)	(0.011)	(0.011)	(0.011)	(0.011)	(0.008)	(0.010)	(0.009)	(0.010)	(0.007)	
31	(0.005)	(0.005)	(0.006)	(0.006)	(0.007)	(0.006)	(0.006)	(0.006)	(0.005)	(0.006)	(0.006)	(0.006)	(0.004)	
32	(0.004)	(0.005)	(0.005)	(0.006)	(0.006)	(0.006)	(0.006)	(0.006)	(0.005)	(0.006)	(0.005)	(0.006)	(0.004)	

