



414 Nicollet Mall  
Minneapolis, Minnesota 55401

—Via Electronic Filing—

October 31, 2013

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

**Re: November 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 November 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:

Service Category Ratios	Previous	Current
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:

November 2013	Fuel Cost Charge (\$/kWh)
<b>Residential</b>	0.02868
<b>C &amp; I Non-Demand</b>	0.02941
<b>C &amp; I Demand</b>	0.02909
<b>C &amp; I Demand Time of Day On-Peak</b>	0.03685
<b>C &amp; I Demand Time of Day Off-Peak</b>	0.02257
<b>Outdoor Lighting</b>	0.02128

## 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 November 2013 FCC the net MISO Day 2 costs for September 2013 as recorded in Account 555. The MISO Day 2 cost recovery included in this November 2013 FCC is \$22,930,413, 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 November FCC the net MISO ASM costs for September 2013 as recorded in Account 555. The MISO ASM cost recovery included in this November FCC is

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

\$2,440,355, 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 November 2013 Asset Based Margin amount of \$81,835 has been included as a credit, or offset, to the November 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 November 2013 FCC is \$11,390, or 0.007¢ 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 November 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 Nov-2013

Nov-2013 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
<b>System</b>	\$0.03093	-\$0.00001	-\$0.00232	\$0.02861
<b>Residential</b>	\$0.03101	-\$0.00001	-\$0.00232	\$0.02868
<b>C &amp; I Non-Demand</b>	\$0.03180	-\$0.00001	-\$0.00238	\$0.02941
<b>C &amp; I Demand Non-TOD</b>	\$0.03146	-\$0.00001	-\$0.00236	\$0.02909
<b>C &amp; I Demand TOD On-Peak</b>	\$0.03985	-\$0.00001	-\$0.00298	\$0.03685
<b>C &amp; I Demand TOD Off-Peak</b>	\$0.02440	-\$0.00001	-\$0.00183	\$0.02257
<b>Outdoor Lighting</b>	\$0.02301	-\$0.00001	-\$0.00172	\$0.02128
<b>Residential</b>				
Residential Service	\$ 0.03101	\$ (0.00001)	\$ (0.00232)	\$ 0.02868
Residential TOD	\$ 0.03101	\$ (0.00001)	\$ (0.00232)	\$ 0.02868
Residential - Underground	\$ 0.03101	\$ (0.00001)	\$ (0.00232)	\$ 0.02868
Residential TOD - Underground	\$ 0.03101	\$ (0.00001)	\$ (0.00232)	\$ 0.02868
Energy Control - (Non-Demand)	\$ 0.03101	\$ (0.00001)	\$ (0.00232)	\$ 0.02868
Limit Off Peak	\$ 0.03101	\$ (0.00001)	\$ (0.00232)	\$ 0.02868
<b>C &amp; I Non-Demand</b>				
Energy Controlled - (Non-Demand)	\$ 0.03180	\$ (0.00001)	\$ (0.00238)	\$ 0.02941
Limit Off Peak	\$ 0.03180	\$ (0.00001)	\$ (0.00238)	\$ 0.02941
Small General Service	\$ 0.03180	\$ (0.00001)	\$ (0.00238)	\$ 0.02941
Small General TOD - Metered	\$ 0.03180	\$ (0.00001)	\$ (0.00238)	\$ 0.02941
Small General TOD - Unmetered	\$ 0.03180	\$ (0.00001)	\$ (0.00238)	\$ 0.02941
Fire and Civil Defense Siren	\$ 0.03180	\$ (0.00001)	\$ (0.00238)	\$ 0.02941
Direct Current (Closed)	\$ 0.03180	\$ (0.00001)	\$ (0.00238)	\$ 0.02941
<b>C &amp; I Demand</b>				
General Service	\$ 0.03146	\$ (0.00001)	\$ (0.00236)	\$ 0.02909
General TOD - On Peak	\$ 0.03985	\$ (0.00001)	\$ (0.00298)	\$ 0.03685
General TOD - Off Peak	\$ 0.02440	\$ (0.00001)	\$ (0.00183)	\$ 0.02257
Peak Controlled (Closed)	\$ 0.03146	\$ (0.00001)	\$ (0.00236)	\$ 0.02909
Peak Controlled TOD (Closed) - On Peak	\$ 0.03985	\$ (0.00001)	\$ (0.00298)	\$ 0.03685
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02440	\$ (0.00001)	\$ (0.00183)	\$ 0.02257
Peak Controlled Tiered	\$ 0.03146	\$ (0.00001)	\$ (0.00236)	\$ 0.02909
Peak Controlled Tiered TOD - On Peak	\$ 0.03985	\$ (0.00001)	\$ (0.00298)	\$ 0.03685
Peak Controlled Tiered TOD - Off Peak	\$ 0.02440	\$ (0.00001)	\$ (0.00183)	\$ 0.02257
Energy Controlled (Closed)	\$ 0.03146	\$ (0.00001)	\$ (0.00236)	\$ 0.02909
Tier 1 Energy Controlled Rider	\$ 0.03146	\$ (0.00001)	\$ (0.00236)	\$ 0.02909
Real Time Pricing - Firm - On Peak	\$ 0.03985	\$ (0.00001)	\$ (0.00298)	\$ 0.03685
Real Time Pricing - Firm - Off Peak	\$ 0.02440	\$ (0.00001)	\$ (0.00183)	\$ 0.02257
Real Time Pricing - Controllable - On Peak	\$ 0.03985	\$ (0.00001)	\$ (0.00298)	\$ 0.03685
Real Time Pricing - Controllable - Off Peak	\$ 0.02440	\$ (0.00001)	\$ (0.00183)	\$ 0.02257
Small Municipal Pumping	\$ 0.03146	\$ (0.00001)	\$ (0.00236)	\$ 0.02909
Municipal Pumping	\$ 0.03146	\$ (0.00001)	\$ (0.00236)	\$ 0.02909
Excess Energy - St. Anthony Falls	\$ 0.03146	\$ (0.00001)	\$ (0.00236)	\$ 0.02909
<b>Outdoor Lighting</b>				
Automatic Protective Lighting	\$ 0.02301	\$ (0.00001)	\$ (0.00172)	\$ 0.02128
Street Lighting System	\$ 0.02301	\$ (0.00001)	\$ (0.00172)	\$ 0.02128
Street Lighting Energy	\$ 0.02301	\$ (0.00001)	\$ (0.00172)	\$ 0.02128
Street Lighting Energy - Metered	\$ 0.02301	\$ (0.00001)	\$ (0.00172)	\$ 0.02128
Street Lighting Energy (Closed)	\$ 0.02301	\$ (0.00001)	\$ (0.00172)	\$ 0.02128
Street Lighting - City of St. Paul	\$ 0.02301	\$ (0.00001)	\$ (0.00172)	\$ 0.02128

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Jun-13	Jul-13	Aug-13	Sep-13	4 Month Total
<b>Fuel and Purchased Power Costs</b>					
Account 151 - Fossil Fuel	\$30,055,242	\$45,631,501	\$45,410,138	\$36,507,594	\$157,604,475
Account 518 - Nuclear Fuel	\$7,625,738	\$8,175,496	\$11,242,069	\$9,639,647	\$36,682,950
Account 555 - Purchased Power <sup>1</sup>	\$39,781,933	\$37,842,727	\$37,604,844	\$39,236,352	\$154,465,856
Account 555 - Pr. Rose PPA Adjustment	(\$79,357)	(\$58,918)	(\$44,921)	(\$116,046)	(\$299,242)
MISO Day 2 Charges	\$32,197,013	\$32,118,523	\$24,320,465	\$23,044,198	\$111,680,198
MISO Day 2 - Schedule 24	(\$93,541)	(\$98,447)	(\$113,223)	(\$113,785)	(\$418,995)
MISO - ASM Charges	\$2,731,861	\$2,176,112	\$1,760,793	\$2,440,355	\$9,109,121
Account 555 - Total MISO Charges	\$34,835,333	\$34,196,188	\$25,968,036	\$25,370,767	\$120,370,324
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$112,218,889	\$125,786,994	\$120,180,166	\$110,638,315	\$468,824,363
Less Fuel Cost of InterSystem Sales	(\$4,232,490)	(\$2,040,932)	(\$5,022,275)	(\$3,704,767)	(\$15,000,465)
Net System Costs	\$107,986,398	\$123,746,062	\$115,157,891	\$106,933,547	\$453,823,899
<b>System MWh Sales</b>					
Total NSP System Retail	3,072,176	4,009,193	3,788,747	3,794,388	14,664,504
Non-Gen Muni's/Load Pattern	1,478	1,518	1,699	1,629	6,324
Total NSP System MWh Sales	3,073,654	4,010,711	3,790,446	3,796,017	14,670,828
<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	3.513¢	3.085¢	3.038¢	2.817¢	3.093¢
<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			3.093¢	1.0026	3.101¢
(ii) C & I Non-Demand			3.093¢	1.0281	3.180¢
(iii) C & I Demand Non-TOD			3.093¢	1.0170	3.146¢
(iv) C & I Demand TOD On-Peak			3.093¢	1.2883	3.985¢
(v) C & I Demand TOD Off-Peak			3.093¢	0.7889	2.440¢
(vi) Outdoor Lighting			3.093¢	0.7440	2.301¢
<b>North Dakota Retail MWh Sales</b>					
(i) Residential	47,215	66,645	61,039	57,405	232,304
(ii) C & I Non-Demand	7,654	9,393	8,922	8,387	34,356
(iii) C & I Demand Non-TOD	54,586	72,433	61,754	67,538	256,311
(iv) C & I Demand TOD On-Peak	17,781	20,609	18,670	19,897	76,957
(v) C & I Demand TOD Off-Peak	28,184	32,946	28,678	31,560	121,368
(vi) Outdoor Lighting	1,200	1,168	1,236	1,597	5,201
(vii) Total	156,620	203,194	180,299	186,384	726,497
<b>Nov-2013 Recovery Provision (True-up Factor) Calculation</b>					
Prior Unrecovered Expenses (Jul-13 Balance of Unrecovered Expenses)					Total
					Jul-13
					\$1,094,136

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

Prior Expenses Recovered in Sep-2013 [Billing Record]			ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential			57,405	\$145,900
(ii) C & I Non-Demand			8,387	\$22,231
(iii) C & I Demand Non-TOD			67,538	\$177,575
(iv) C & I Demand TOD On-Peak			19,897	\$65,744
(v) C & I Demand TOD Off-Peak			31,560	\$63,840
(vi) Outdoor Lighting			1,597	\$3,045
(vii) Total			186,384	\$478,335

Actual Cost Should Have Been Recovered in Sep-13				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.817¢	0.000¢	186,384	\$5,250,437

Cost Recovered in Sep-13 [Billing Record]			ND Billed MWh Sales	Actual Recovery
(i) Residential			57,405	\$1,815,479
(ii) C & I Non-Demand			8,387	\$271,444
(iii) C & I Demand Non-TOD			67,538	\$2,160,117
(iv) C & I Demand TOD On-Peak			19,897	\$806,889
(v) C & I Demand TOD Off-Peak			31,560	\$783,603
(vi) Outdoor Lighting			1,597	\$35,061
(vii) Total			186,384	\$5,872,593

Total Balance of Unrecovered Expenses (Nov-13 Balance of Unrecovered Expenses)	
Nov-2013 Recovery Provision	(\$6,355)
4 Month ND Retail Total MWh Sales	726,497
Nov-2013 Recovery Provision per KWH	-0.001¢

Nov-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	-0.001¢	-0.001¢
(ii) C & I Non-Demand	1.0281	-0.001¢	-0.001¢
(iii) C & I Demand Non-TOD	1.0170	-0.001¢	-0.001¢
(iv) C & I Demand TOD On-Peak	1.2883	-0.001¢	-0.001¢
(v) C & I Demand TOD Off-Peak	0.7889	-0.001¢	-0.001¢
(vi) Outdoor Lighting	0.7440	-0.001¢	-0.001¢

Nov-2013 Refunds/Additional Charges				
Refund/Special Charge Amount	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Refund	Total
	(\$81,835)	(\$11,390)	(\$279,043)	(\$360,878)
(i) Residential	-0.051¢	-0.007¢	-0.174¢	-0.232¢
(ii) C & I Non-Demand	-0.052¢	-0.007¢	-0.178¢	-0.238¢
(iii) C & I Demand Non-TOD	-0.052¢	-0.007¢	-0.177¢	-0.236¢
(iv) C & I Demand TOD On-Peak	-0.066¢	-0.009¢	-0.224¢	-0.298¢
(v) C & I Demand TOD Off-Peak	-0.040¢	-0.006¢	-0.137¢	-0.183¢
(vi) Outdoor Lighting	-0.038¢	-0.005¢	-0.129¢	-0.172¢

Nov-2013 Factors		Total
(i) Residential		2.868¢
(ii) C & I Non-Demand		2.941¢
(iii) C & I Demand Non-TOD		2.909¢
(iv) C & I Demand TOD On-Peak		3.685¢
(v) C & I Demand TOD Off-Peak		2.257¢
(vi) Outdoor Lighting		2.128¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Oct-13	Nov-13	Differ- ence	Percent Change	FCA Application Oct-13	Nov-13	Differ- ence
<b>** COSTS (Millions) **</b>							
1 Fossil	\$150.3	\$157.6	\$7.3	4.9%	32.6%	33.6%	1.0%
2 Nuclear	\$34.9	\$36.7	\$1.8	5.0%	7.6%	7.8%	0.2%
3 Purchases	\$155.7	\$154.2	(\$1.5)	-1.0%	33.8%	32.9%	-0.9%
MISO related Purchases	\$119.6	\$120.4	\$0.8	0.7%	26.0%	25.7%	-0.3%
4 Total System Costs	460.5	468.8	\$8.4	1.8%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$14.0	\$15.0	\$1.0	7.1%	3.0%	3.2%	0.2%
6 Net System Costs	\$446.5	\$453.8	\$7.4	1.6%	97.0%	96.8%	-0.2%
7							
<b>** GWH OUTPUT **</b>							
9 Fossil	4,160	4,447	287	6.9%	25.1%	26.3%	1.2%
10 Nuclear	3,341	3,567	226	6.8%	20.2%	21.1%	0.9%
11 Purchases	6,711	6,637	(74)	-1.1%	40.5%	39.2%	-1.3%
12 Hydro & Other	1,793	1,682	(111)	-6.2%	10.8%	9.9%	-0.9%
13 Net Interchange	554	601	47	8.5%	3.3%	3.5%	0.2%
14 Total Output	16,559	16,934	375	2.3%	100.0%	100.0%	0.0%
15 Intersystem Sales	503	647	144	28.6%	3.0%	3.8%	0.8%
16 Native Requirement	16,056	16,287	231	1.4%	97.0%	96.2%	-0.8%
17							
<b>** COST per KWH OUTPUT (¢) **</b>							
19 Fossil	3.613	3.544	-0.069	-1.9%			
20 Nuclear	1.045	1.028	-0.017	-1.6%			
21 Purchases	2.320	2.323	0.003	0.1%			
22 Total System Costs	2.781	2.769	-0.012	-0.4%			
23 Intersystem Sales	2.784	2.319	-0.465	-16.7%			
24 Net System Costs	2.781	2.786	0.006	0.2%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,086	14,671	585	4.2%			
28							
29 COST per KWH SALES (¢)	3.170	3.093	-0.077	-2.4%			
30							
31 RECOVERY PROV (¢ / KWH) - SYS	0.293	-0.001	-0.294				
(i) Residential	0.294	-0.001	-0.295				
(ii) C & I Non-Demand	0.302	-0.001	-0.302				
(iii) C & I Demand Non-TOD	0.298	-0.001	-0.299				
(iv) C & I Demand TOD On-Peak	0.378	-0.001	-0.379				
(v) C & I Demand TOD Off-Peak	0.231	-0.001	-0.232				
(vi) Outdoor Lighting	0.218	-0.001	-0.219				
32 REFUND	-0.030	-0.232	-0.202				
(i) Residential	-0.030	-0.232					
(ii) C & I Non-Demand	-0.031	-0.238					
(iii) C & I Demand Non-TOD	-0.031	-0.236					
(iv) C & I Demand TOD On-Peak	-0.039	-0.298					
(v) C & I Demand TOD Off-Peak	-0.024	-0.183					
(vi) Outdoor Lighting	-0.022	-0.172					
33 SYSTEM FCC IMPACT (¢ / KWH)	3.433	2.860	-0.573	-16.7%			
(i) Residential	3.442	2.868	-0.574				
(ii) C & I Non-Demand	3.529	2.941					
(iii) C & I Demand Non-TOD	3.491	2.909					
(iv) C & I Demand TOD On-Peak	4.422	3.685					
(v) C & I Demand TOD Off-Peak	2.708	2.257					
(vi) Outdoor Lighting	2.554	2.128					

**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	(\$0.57)
250	(\$1.44)
500	(\$2.87)
750	(\$4.31)
1,000	(\$5.74)

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>	
	Oct-13	Nov-13
<b>** GWH OUTPUT **</b>		
Thermal	1,208,332	1,236,922
Disper gen	173,434	173,435
Hydro plus Wind	411,665	271,570
Hydro and Other	1,793,431	1,681,927
Rounded to nearest thousand:	1,793	1,682
<b>Sales</b>		
Non Gen Munic Total	6,130,000	6,324,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	502,927,000	646,811,000
Rounded to nearest million:	502.927	646.811

		System	Intersystem	Retail
<b>September 2013 Actual</b>				
<b>Energy and Loss Charges</b>				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 22,375,476.72	\$ 4,510,760.18	\$ 26,886,236.90
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,869,283.02	\$ -	\$ 2,869,283.02
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 5,448.06	\$ -	\$ 5,448.06
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (14,892,423.43)	\$ -	\$ (14,892,423.43)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,172,858.41	\$ -	\$ 1,172,858.41
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	\$ (5,448.06)	\$ -	\$ (5,448.06)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 a	Real-Time Asset Energy Amount - Energy Component (1)	\$ (1,031,119.15)	\$ 1,073,187.63	\$ 42,068.48
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 124,703.42	\$ -	\$ 124,703.42
14	Real-Time Distribution of Losses Amount	\$ (1,473,069.07)	\$ -	\$ (1,473,069.07)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ (743.64)	\$ -	\$ (743.64)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ 743.64	\$ -	\$ 743.64
21	Real-time Net inadvertent Distribution	\$ 145,657.34	\$ -	\$ 145,657.34
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 647,381.74	\$ -	\$ 647,381.74
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (8,322.45)	\$ -	\$ (8,322.45)
<b>Congestion Related Charges</b>				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 7,307,801.96	\$ -	\$ 7,307,801.96
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ 8,047.00	\$ -	\$ 8,047.00
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 2,936,325.73	\$ -	\$ 2,936,325.73
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	\$ (8,047.00)	\$ -	\$ (8,047.00)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	\$ 290,731.32	\$ -	\$ 290,731.32
15	Real-Time Financial Bilateral Transaction Congestion Amount	\$ (1,717.96)	\$ -	\$ (1,717.96)
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	\$ 1,717.96	\$ -	\$ 1,717.96
22 b	Real-Time Non-Asset Energy Amount - Congestion Component (1)	\$ (1,635.23)	\$ -	\$ (1,635.23)
<b>FTR Related Charges</b>				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (3,457,890.73)	\$ -	\$ (3,457,890.73)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (295,105.92)	\$ -	\$ (295,105.92)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ 152,705.57	\$ -	\$ 152,705.57
37	Financial Transmission Guarantee Uplift Amount	\$ (152,705.57)	\$ -	\$ (152,705.57)
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
<b>Uplift Charges</b>				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 491,304.77	\$ -	\$ 491,304.77
<b>Revenue Sufficiency Guarantee (RSG) Charges</b>				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 139,786.15	\$ -	\$ 139,786.15
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (168,726.18)	\$ 9,217.79	\$ (159,508.39)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 449,182.81	\$ -	\$ 449,182.81
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (127,187.98)	\$ 12,653.27	\$ (114,534.71)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (171,447.27)	\$ 3,948.23	\$ (167,499.04)
<b>Market Administration Charges</b>				
4	Day-Ahead Market Administration Amount	\$ 707,267.17	\$ (13,987.21)	\$ 693,279.96
19	Real-Time Market Administration Amount	\$ 52,407.42	\$ (4,983.36)	\$ 47,424.06
29	Financial Transmission Rights Market Administration Amount	\$ 29,431.97	\$ -	\$ 29,431.97
33	Day-Ahead Schedule 24 Allocation Amount	\$ 108,596.72	\$ (2,145.48)	\$ 106,451.24
34	Real-Time Schedule 24 Allocation Amount	\$ (155,491.11)	\$ 162,824.89	\$ 7,333.78
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	\$ 1,284.04	\$ -	\$ 1,284.04
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	\$ (661,744.90)	\$ -	\$ (661,744.90)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 232,987.06	\$ -	\$ 232,987.06
<b>TOTAL MISO CHARGES</b>		<b>\$ 17,292,721.68</b>	<b>\$ 5,751,475.94</b>	<b>\$ 23,044,197.62</b>

<b>SCHEDULE 24 (FOR RETAIL)</b>	<b>\$ 113,785.02</b>
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<b>TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)</b>	<b>\$ 22,930,412.60</b>
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## MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

	System	Intersystem	Retail
<b>September 2013 Actual</b>			
<b>Procurement Charges</b>			
1 Day-Ahead Regulation Amount	\$ (136,905.15)	\$ -	\$ (136,905.15)
2 Day-Ahead Spinning Reserve Amount	\$ (152,912.86)	\$ -	\$ (152,912.86)
3 Day-Ahead Supplemental Reserve	\$ (122,081.31)	\$ -	\$ (122,081.31)
4 Real-Time Regulation Amount	\$ (52,927.63)	\$ 115,404.90	\$ 62,477.27
5 Real-Time Spinning Reserve Amount	\$ 33,635.88	\$ 14,925.80	\$ 48,561.68
6 Real-Time Supplemental Reserve Amount.	\$ 9,436.85	\$ 829.03	\$ 10,265.88
<b>Resource Energy Charges</b>			
7a Real Time Excessive Energy Amount	\$ 255,354.82	\$ -	\$ 255,354.82
7b Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a Real Time Non Excessive Energy Amount	\$ 2,634,303.05	\$ -	\$ 2,634,303.05
8b Real Time Non Excessive Energy Congestion	\$ (709,990.64)	\$ -	\$ (709,990.64)
8c Real Time Non Excessive Energy Loss	\$ (137,954.73)	\$ -	\$ (137,954.73)
9 Real Time Net Regulation Adjustment Amount	\$ 56,602.05	\$ (19,128.11)	\$ 37,473.94
<b>Cost Distribution Charges</b>			
10 Real Time Regulation Reserve Cost Distribution Amount	\$ 123,817.98	\$ -	\$ 123,817.98
11 Real Time Spinning Reserve Cost Distribution	\$ 255,132.63	\$ -	\$ 255,132.63
12 Real Time Supplemental Reserve Cost Distribution	\$ 172,395.38	\$ -	\$ 172,395.38
<b>Penalty Charges</b>			
13 Real Time Excessive/Dificient Energy Deployment	\$ 124,336.14	\$ (23,919.38)	\$ 100,416.76
14 Real Time Contignecy Reserve Deployment Failure	\$ -	\$ -	\$ -
<b>TOTAL MISO ASM CHARGES</b>	<b>\$ 2,352,242.46</b>	<b>\$ 88,112.24</b>	<b>\$ 2,440,354.70</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

1 Forecast Month	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14
2 True-up 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
3												
4 Monthly Refund	(111,891)	(56,628)	(48,164)	(91,255)	(46,210)	(38,419)	(19,892)	(74,848)	(91,958)			
5												
6 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	-
7												
8 <b>Current Month Refund Factor</b>	<b>(0.059)</b>	<b>(0.029)</b>	<b>(0.028)</b>	<b>(0.056)</b>	<b>(0.024)</b>	<b>(0.020)</b>	<b>(0.011)</b>	<b>(0.042)</b>	<b>(0.057)</b>	-	-	-
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)	-
15 Actual Refunded	(34,718)	(43,979)	(84,402)	(100,304)	(73,088)	(67,024)	(67,038)	(42,583)	(21,664)			
16 Deviation	(9,912)	(8,548)	(37,401)	35,128	(12,477)	10,897	8,351	15,061	10,123	(59,787)	(81,835)	-
17												
18 <b>True-up Factor</b>	<b>(0.005)</b>	<b>(0.004)</b>	<b>(0.022)</b>	<b>0.022</b>	<b>(0.007)</b>	<b>0.006</b>	<b>0.005</b>	<b>0.009</b>	<b>0.006</b>	-	-	-
19												
20 <b>Realized Margin</b>	<b>(0.064)</b>	<b>(0.034)</b>	<b>(0.050)</b>	<b>(0.034)</b>	<b>(0.031)</b>	<b>(0.014)</b>	<b>(0.007)</b>	<b>(0.034)</b>	<b>(0.051)</b>	-	-	-
21												
22 <b>Class Ratios</b>												
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 <b>Realized Margin Adj for Class Ratios</b>												
31 Residential	(0.064)	(0.034)	(0.050)	(0.035)	(0.031)	(0.014)	(0.007)	(0.034)	(0.051)	-	-	-
32 C&I Non-Demand	(0.066)	(0.035)	(0.051)	(0.035)	(0.032)	(0.015)	(0.007)	(0.035)	(0.052)	-	-	-
33 C&I Demand Non-TOD	(0.065)	(0.034)	(0.051)	(0.035)	(0.031)	(0.015)	(0.007)	(0.034)	(0.052)	-	-	-
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)	-	-	-
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)	-	-	-
36 Outdoor Lighting	(0.048)	(0.025)	(0.037)	(0.026)	(0.023)	(0.011)	(0.005)	(0.025)	(0.038)	-	-	-

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

1 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
2 True-up 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
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)	(13,637)
5												
6 Forecast North Dakota Sales	204,198	190,659	193,918	172,034	162,994	190,995	190,839	175,314	177,072	160,760	-	-
7												
8 <b>Current Month Refund Factor</b>	(0.007)	(0.007)	(0.007)	(0.008)	(0.008)	(0.007)	(0.007)	(0.008)	(0.008)	(0.008)	-	-
9												
10												
11 Expected Refund	(11,060)	(13,140)	(12,137)	(13,173)	(14,257)	(14,119)	(14,164)	(14,651)	(14,765)	(11,255)	-	-
12												
13 Actual Refund	(12,560)	(13,605)	(11,517)	(12,691)	(13,731)	(13,105)	(13,036)	(17,033)	(14,231)	(13,503)	-	-
14												
15 Deviation	1,500	465	(620)	(482)	(526)	(1,014)	(1,128)	2,382	(534)	2,248	-	-
16												
17												
18 <b>True-up Factor</b>	0.001	0.000	(0.000)	(0.000)	(0.000)	(0.001)	(0.001)	0.001	(0.000)	0.001	-	-
19												
20 <b>Realized Margin</b>	(0.006)	(0.007)	(0.007)	(0.008)	(0.009)	(0.008)	(0.008)	(0.006)	(0.008)	(0.007)	-	-
21												
22 <b>Class Ratios</b>												
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 <b>Realized Margin Adj for Class Ratios</b>												
31 Residential	(0.006)	(0.007)	(0.007)	(0.008)	(0.009)	(0.008)	(0.008)	(0.006)	(0.008)	(0.007)	-	-
32 C&I Non-Demand	(0.006)	(0.007)	(0.008)	(0.008)	(0.009)	(0.008)	(0.008)	(0.007)	(0.008)	(0.007)	-	-
33 C&I Demand Non-TOD	(0.006)	(0.007)	(0.007)	(0.008)	(0.009)	(0.008)	(0.008)	(0.007)	(0.008)	(0.007)	-	-
34 C&I Demand TOD On-Peak	(0.008)	(0.009)	(0.009)	(0.011)	(0.011)	(0.010)	(0.010)	(0.008)	(0.010)	(0.009)	-	-
35 C&I Demand TOD Off-Peak	(0.005)	(0.005)	(0.006)	(0.006)	(0.007)	(0.006)	(0.006)	(0.005)	(0.006)	(0.006)	-	-
36 Outdoor Lighting	(0.004)	(0.005)	(0.005)	(0.006)	(0.006)	(0.006)	(0.006)	(0.005)	(0.006)	(0.005)	-	-

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

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												
4 Monthly Refund	(280,039)	-	-	(590,344)	(8,187)	-	-	(2,054)	-	(129,308)	(91,465)	(39,688)
5												
6 Forecast North Dakota Sales	193,427	241,910	204,198	190,659	193,918	172,034	162,994	190,995	190,839	175,314	177,072	160,760
7												
8 <b>Current Month Refund Factor</b>	(0.145)	-	-	(0.310)	(0.004)	-	-	(0.001)	-	(0.074)	(0.052)	(0.025)
9												
14 Expected Refund	-	-	(280,039)	-	(161,476)	(406,613)	(94,613)	(137,192)	187,000	(22,405)	180,388	(258,005)
15 Actual Refund	-	-	(118,563)	(183,731)	(75,050)	(269,421)	(281,613)	(116,841)	6,612	106,292	69,180	(18,650)
16 Deviation	-	-	(161,476)	183,731	(86,426)	(137,192)	187,000	(20,351)	180,388	(128,697)	111,208	(239,355)
17												
18 <b>True-up Factor</b>	-	-	(0.079)	0.096	(0.045)	(0.080)	0.115	(0.011)	0.095	(0.073)	0.063	(0.149)
19												
20 <b>Realized Refund</b>	(0.145)	-	(0.079)	(0.213)	(0.049)	(0.080)	0.115	(0.012)	0.095	(0.147)	0.011	(0.174)
21												
22 <b>Class Ratios</b>												
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 <b>Realized Margin Adj for Class Ratios</b>												
31 Residential	(0.145)	-	(0.079)	(0.214)	(0.049)	(0.080)	0.115	(0.012)	0.095	(0.148)	0.011	(0.174)
32 C&I Non-Demand	(0.149)	-	(0.081)	(0.219)	(0.050)	(0.082)	0.118	(0.012)	0.097	(0.151)	0.011	(0.178)
33 C&I Demand Non-TOD	(0.147)	-	(0.080)	(0.217)	(0.050)	(0.081)	0.117	(0.012)	0.096	(0.150)	0.011	(0.177)
34 C&I Demand TOD On-Peak	(0.187)	-	(0.102)	(0.275)	(0.063)	(0.103)	0.148	(0.015)	0.122	(0.190)	0.014	(0.224)
35 C&I Demand TOD Off-Peak	(0.114)	-	(0.062)	(0.168)	(0.038)	(0.063)	0.091	(0.009)	0.075	(0.116)	0.009	(0.137)
36 Outdoor Lighting	(0.108)	-	(0.059)	(0.159)	(0.036)	(0.059)	0.085	(0.009)	0.070	(0.109)	0.008	(0.129)