



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

July 31, 2013

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

Re: August 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 August 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	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:

August 2013	Fuel Cost Charge (\$/kWh)
Residential	0.03575
C & I Non-Demand	0.03666
C & I Demand	0.03626
C & I Demand Time of Day On-Peak	0.04594
C & I Demand Time of Day Off-Peak	0.02813
Outdoor Lighting	0.02653

MISO CHARGES IMPLEMENTATION

MISO Day 2 Charges

This filing includes our reporting of the Midwest Independent Transmission System Operator, Inc. (MISO) charges under the Day 2 Market. Pursuant to the Commission's April 6, 2005 Order in Case No. PU-05-147 and the Order in Case No. PU-07-776, Xcel Energy is authorized to recover MISO Day 2 costs. The March 2009 FCC reflected the MISO Day 2 charge types: 3 Auction Revenue Rights (ARR) and 3 Financial Transmission Rights (FTR) charge 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 August 2013 FCC the net MISO Day 2 costs for June 2013 as recorded in Account 555. The MISO Day 2 cost recovery included in this August 2013 FCC is \$32,103,472, 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 August FCC the net MISO ASM costs for June 2013 as recorded in Account 555. The MISO ASM cost recovery included in this August FCC is \$2,731,861, 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 August 2013 Asset Based Margin amount of \$27,522 has been included as a credit, or offset, to the August 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 August 2013 FCC is \$14,765, or 0.008¢ 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 August 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 Aug-2013

Aug-2013 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.03150	\$0.00343	\$0.00072	\$0.03566
Residential	\$0.03158	\$0.00344	\$0.00073	\$0.03575
C & I Non-Demand	\$0.03239	\$0.00353	\$0.00074	\$0.03666
C & I Demand Non-TOD	\$0.03204	\$0.00349	\$0.00074	\$0.03626
C & I Demand TOD On-Peak	\$0.04058	\$0.00442	\$0.00093	\$0.04594
C & I Demand TOD Off-Peak	\$0.02485	\$0.00271	\$0.00057	\$0.02813
Outdoor Lighting	\$0.02344	\$0.00255	\$0.00054	\$0.02653
Residential				
Residential Service	\$ 0.03158	\$ 0.00344	\$ 0.00073	\$ 0.03575
Residential TOD	\$ 0.03158	\$ 0.00344	\$ 0.00073	\$ 0.03575
Residential - Underground	\$ 0.03158	\$ 0.00344	\$ 0.00073	\$ 0.03575
Residential TOD - Underground	\$ 0.03158	\$ 0.00344	\$ 0.00073	\$ 0.03575
Energy Control - (Non-Demand)	\$ 0.03158	\$ 0.00344	\$ 0.00073	\$ 0.03575
Limit Off Peak	\$ 0.03158	\$ 0.00344	\$ 0.00073	\$ 0.03575
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.03239	\$ 0.00353	\$ 0.00074	\$ 0.03666
Limit Off Peak	\$ 0.03239	\$ 0.00353	\$ 0.00074	\$ 0.03666
Small General Service	\$ 0.03239	\$ 0.00353	\$ 0.00074	\$ 0.03666
Small General TOD - Metered	\$ 0.03239	\$ 0.00353	\$ 0.00074	\$ 0.03666
Small General TOD - Unmetered	\$ 0.03239	\$ 0.00353	\$ 0.00074	\$ 0.03666
Fire and Civil Defense Siren	\$ 0.03239	\$ 0.00353	\$ 0.00074	\$ 0.03666
Direct Current (Closed)	\$ 0.03239	\$ 0.00353	\$ 0.00074	\$ 0.03666
C & I Demand				
General Service	\$ 0.03204	\$ 0.00349	\$ 0.00074	\$ 0.03626
General TOD - On Peak	\$ 0.04058	\$ 0.00442	\$ 0.00093	\$ 0.04594
General TOD - Off Peak	\$ 0.02485	\$ 0.00271	\$ 0.00057	\$ 0.02813
Peak Controlled (Closed)	\$ 0.03204	\$ 0.00349	\$ 0.00074	\$ 0.03626
Peak Controlled TOD (Closed) - On Peak	\$ 0.04058	\$ 0.00442	\$ 0.00093	\$ 0.04594
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02485	\$ 0.00271	\$ 0.00057	\$ 0.02813
Peak Controlled Tiered	\$ 0.03204	\$ 0.00349	\$ 0.00074	\$ 0.03626
Peak Controlled Tiered TOD - On Peak	\$ 0.04058	\$ 0.00442	\$ 0.00093	\$ 0.04594
Peak Controlled Tiered TOD - Off Peak	\$ 0.02485	\$ 0.00271	\$ 0.00057	\$ 0.02813
Energy Controlled (Closed)	\$ 0.03204	\$ 0.00349	\$ 0.00074	\$ 0.03626
Tier 1 Energy Controlled Rider	\$ 0.03204	\$ 0.00349	\$ 0.00074	\$ 0.03626
Real Time Pricing - Firm - On Peak	\$ 0.04058	\$ 0.00442	\$ 0.00093	\$ 0.04594
Real Time Pricing - Firm - Off Peak	\$ 0.02485	\$ 0.00271	\$ 0.00057	\$ 0.02813
Real Time Pricing - Controllable - On Peak	\$ 0.04058	\$ 0.00442	\$ 0.00093	\$ 0.04594
Real Time Pricing - Controllable - Off Peak	\$ 0.02485	\$ 0.00271	\$ 0.00057	\$ 0.02813
Small Municipal Pumping	\$ 0.03204	\$ 0.00349	\$ 0.00074	\$ 0.03626
Municipal Pumping	\$ 0.03204	\$ 0.00349	\$ 0.00074	\$ 0.03626
Excess Energy - St. Anthony Falls	\$ 0.03204	\$ 0.00349	\$ 0.00074	\$ 0.03626
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.02344	\$ 0.00255	\$ 0.00054	\$ 0.02653
Street Lighting System	\$ 0.02344	\$ 0.00255	\$ 0.00054	\$ 0.02653
Street Lighting Energy	\$ 0.02344	\$ 0.00255	\$ 0.00054	\$ 0.02653
Street Lighting Energy - Metered	\$ 0.02344	\$ 0.00255	\$ 0.00054	\$ 0.02653
Street Lighting Energy (Closed)	\$ 0.02344	\$ 0.00255	\$ 0.00054	\$ 0.02653
Street Lighting - City of St. Paul	\$ 0.02344	\$ 0.00255	\$ 0.00054	\$ 0.02653

	Column (A) Mar-13	Column (B) Apr-13	Column (C) May-13	Column (D) Jun-13	Column (E) 4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$39,664,107	\$35,714,843	\$29,187,911	\$30,055,242	\$134,622,103
Account 518 - Nuclear Fuel	\$8,129,429	\$7,928,444	\$7,881,823	\$7,625,738	\$31,565,434
Account 555 - Purchased Power ¹	\$32,608,013	\$36,915,144	\$40,825,865	\$39,781,933	\$150,130,954
Account 555 - Pr. Rose PPA Adjustment	(\$302,484)	(\$245,881)	(\$179,008)	(\$79,357)	(\$806,730)
MISO Day 2 Charges	\$23,699,289	\$20,200,320	\$20,346,311	\$32,197,013	\$96,442,932
MISO Day 2 - Schedule 24	(\$100,745)	(\$105,670)	(\$95,649)	(\$93,541)	(\$395,605)
MISO - ASM Charges	\$1,107,837	\$2,993,845	\$4,308,216	\$2,731,861	\$11,141,758
Account 555 - Total MISO Charges	\$24,706,380	\$23,088,494	\$24,558,878	\$34,835,333	\$107,189,086
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$104,805,445	\$103,401,044	\$102,275,469	\$112,218,889	\$422,700,847
Less Fuel Cost of InterSystem Sales	(\$2,393,630)	(\$3,073,114)	(\$2,707,087)	(\$4,232,490)	(\$12,406,321)
Net System Costs	\$102,411,815	\$100,327,930	\$99,568,382	\$107,986,398	\$410,294,526
System MWh Sales					
Total NSP System Retail	3,357,790	3,378,291	3,209,691	3,072,176	13,017,948
Non-Gen Muni's/Load Pattern	1,470	1,583	1,435	1,478	5,966
Total NSP System MWh Sales	3,359,260	3,379,874	3,211,126	3,073,654	13,023,914
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System					
Adjusted System Cost without Pr. Rose PPA	3.049¢	2.968¢	3.101¢	3.513¢	3.150¢
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)					
			Avg Unit Cost	FCF Ratio	4 Month Average
(i) Residential			3.150¢	1.0026	3.158¢
(ii) C & I Non-Demand			3.150¢	1.0281	3.239¢
(iii) C & I Demand Non-TOD			3.150¢	1.0170	3.204¢
(iv) C & I Demand TOD On-Peak			3.150¢	1.2883	4.058¢
(v) C & I Demand TOD Off-Peak			3.150¢	0.7889	2.485¢
(vi) Outdoor Lighting			3.150¢	0.7440	2.344¢
North Dakota Retail MWh Sales					
(i) Residential	75,688	77,422	56,984	47,215	257,309
(ii) C & I Non-Demand	11,702	11,358	9,208	7,654	39,922
(iii) C & I Demand Non-TOD	64,144	61,841	59,676	54,586	240,247
(iv) C & I Demand TOD On-Peak	16,520	17,131	18,879	17,781	70,311
(v) C & I Demand TOD Off-Peak	29,798	28,505	29,459	28,184	115,946
(vi) Outdoor Lighting	1,701	1,682	1,365	1,200	5,948
(vii) Total	199,553	197,939	175,571	156,620	729,683
Aug-2013 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Apr-13 Balance of Unrecovered Expenses)					Total
					Apr-13
					\$1,589,429

¹ Excludes demand-related expenses and includes Prairie Rose Wind PPA expenses

Prior Expenses Recovered in Jun-2013 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	47,215	\$56,873
(ii) C & I Non-Demand	7,654	\$8,918
(iii) C & I Demand Non-TOD	54,586	\$61,417
(iv) C & I Demand TOD On-Peak	17,781	\$26,453
(v) C & I Demand TOD Off-Peak	28,184	\$25,624
(vi) Outdoor Lighting	1,200	\$804
(vii) Total	156,620	\$180,089

Actual Cost Should Have Been Recovered in Jun-13				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	3.513¢	0.000¢	156,620	\$5,502,061

Cost Recovered in Jun-13 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	47,215	\$1,330,036
(ii) C & I Non-Demand	7,654	\$221,213
(iii) C & I Demand Non-TOD	54,586	\$1,560,637
(iv) C & I Demand TOD On-Peak	17,781	\$643,805
(v) C & I Demand TOD Off-Peak	28,184	\$624,831
(vi) Outdoor Lighting	1,200	\$25,172
(vii) Total	156,620	\$4,405,694

Total Balance of Unrecovered Expenses (Aug-13 Balance of Unrecovered Expenses)	
Aug-2013 Recovery Provision	\$2,505,707
4 Month ND Retail Total MWh Sales	729,683
Aug-2013 Recovery Provision per KWH	0.343¢

Aug-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	0.343¢	0.344¢
(ii) C & I Non-Demand	1.0281	0.343¢	0.353¢
(iii) C & I Demand Non-TOD	1.0170	0.343¢	0.349¢
(iv) C & I Demand TOD On-Peak	1.2883	0.343¢	0.442¢
(v) C & I Demand TOD Off-Peak	0.7889	0.343¢	0.271¢
(vi) Outdoor Lighting	0.7440	0.343¢	0.255¢

Aug-2013 Refunds/Additional Charges					
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Refund	June FCC Error Refund	Total
Refund/Special Charge Amount	(\$27,522)	(\$14,765)	\$180,388		\$152,866
(i) Residential	-0.014¢	-0.008¢	0.095¢		0.073¢
(ii) C & I Non-Demand	-0.015¢	-0.008¢	0.097¢		0.074¢
(iii) C & I Demand Non-TOD	-0.015¢	-0.008¢	0.096¢		0.074¢
(iv) C & I Demand TOD On-Peak	-0.019¢	-0.010¢	0.122¢		0.093¢
(v) C & I Demand TOD Off-Peak	-0.011¢	-0.006¢	0.075¢		0.057¢
(vi) Outdoor Lighting	-0.011¢	-0.006¢	0.070¢		0.054¢

Aug-2013 Factors	
	Total
(i) Residential	3.575¢
(ii) C & I Non-Demand	3.666¢
(iii) C & I Demand Non-TOD	3.626¢
(iv) C & I Demand TOD On-Peak	4.594¢
(v) C & I Demand TOD Off-Peak	2.813¢
(vi) Outdoor Lighting	2.653¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Jul-13	Aug-13	Differ- ence	Percent Change	FCA Application Jul-13	Aug-13	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$140.7	\$134.6	(\$6.1)	-4.3%	35.3%	31.8%	-3.5%
2 Nuclear	\$34.5	\$31.6	(\$3.0)	-8.6%	8.7%	7.5%	-1.2%
3 Purchases	\$138.6	\$149.3	\$10.8	7.8%	34.7%	35.3%	0.6%
MISO related Purchases	\$85.4	\$107.2	\$21.8	25.5%	21.4%	25.4%	4.0%
4 Total System Costs	399.3	422.7	\$23.4	5.9%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$11.6	\$12.4	\$0.8	6.6%	2.9%	2.9%	0.0%
6 Net System Costs	\$387.6	\$410.3	\$22.7	5.8%	97.1%	97.1%	0.0%
7							
8 ** GWH OUTPUT **							
9 Fossil	3,520	3,336	(184)	-5.2%	24.3%	22.5%	-1.8%
10 Nuclear	3,482	3,052	(430)	-12.3%	24.0%	20.6%	-3.4%
11 Purchases	4,940	5,829	889	18.0%	34.1%	39.3%	5.2%
12 Hydro & Other	2,043	2,040	(3)	-0.1%	14.1%	13.8%	-0.3%
13 Net Interchange	520	565	45	8.7%	3.6%	3.8%	0.2%
14 Total Output	14,505	14,822	317	2.2%	100.0%	100.0%	0.0%
15 Intersystem Sales	564	525	(38)	-6.8%	3.9%	3.5%	-0.4%
16 Native Requirement	13,941	14,297	355	2.5%	96.1%	96.5%	0.4%
17							
18 ** COST per KWH OUTPUT (\$) **							
19 Fossil	3.998	4.035	0.037	0.9%			
20 Nuclear	0.992	1.034	0.042	4.3%			
21 Purchases	2.805	2.562	-0.243	-8.7%			
22 Total System Costs	2.753	2.852	0.099	3.6%			
23 Intersystem Sales	2.064	2.361	0.297	14.4%			
24 Net System Costs	2.780	2.870	0.089	3.2%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,190	13,024	(166)	-1.3%			
28							
29 COST per KWH SALES (\$)	2.939	3.150	0.211	7.2%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	0.124	0.343	0.219				
(i) Residential	0.124	0.344	0.220				
(ii) C & I Non-Demand	0.127	0.353	0.226				
(iii) C & I Demand Non-TOD	0.126	0.349	0.223				
(iv) C & I Demand TOD On-Peak	0.160	0.442	0.283				
(v) C & I Demand TOD Off-Peak	0.098	0.271	0.173				
(vi) Outdoor Lighting	0.092	0.255	0.163				
32 REFUND	-0.767	0.073	0.840				
(i) Residential	-0.769	0.073					
(ii) C & I Non-Demand	-0.789	0.074					
(iii) C & I Demand Non-TOD	-0.780	0.074					
(iv) C & I Demand TOD On-Peak	-0.988	0.093					
(v) C & I Demand TOD Off-Peak	-0.605	0.057					
(vi) Outdoor Lighting	-0.571	0.054					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.296	3.566	1.270	55.3%			
(i) Residential	2.302	3.575	1.273				
(ii) C & I Non-Demand	2.361	3.666					
(iii) C & I Demand Non-TOD	2.335	3.626					
(iv) C & I Demand TOD On-Peak	2.958	4.594					
(v) C & I Demand TOD Off-Peak	1.812	2.813					
(vi) Outdoor Lighting	1.709	2.653					

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	\$1.27
250	\$3.18
500	\$6.37
750	\$9.55
1,000	\$12.73

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>	
	Jul-13	Aug-13
** GWH OUTPUT **		
Thermal	1,445,933	1,335,655
Disper gen	(72)	(72)
Hydro plus Wind	596,932	704,698
Hydro and Other	2,042,793	2,040,281
Rounded to nearest thousand:	2,043	2,040
Sales		
Non Gen Munic Total	6,144,000	5,966,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	563,625,000	525,363,000
Rounded to nearest million:	563,625	525,363

		System	Intersystem	Retail
June 2013 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 37,438,520.94	\$ 1,779,010.86	\$ 39,217,531.80
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 1,815,423.68	\$ -	\$ 1,815,423.68
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (14,170,009.08)	\$ -	\$ (14,170,009.08)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,694,823.53	\$ -	\$ 1,694,823.53
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)	\$ 1,268,808.40	\$ 455,355.75	\$ 1,724,164.15
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 27,884.70	\$ -	\$ 27,884.70
14	Real-Time Distribution of Losses Amount	\$ (1,580,382.91)	\$ -	\$ (1,580,382.91)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ 31,693.99	\$ -	\$ 31,693.99
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ (19,473.84)	\$ -	\$ (19,473.84)
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ 2,877.37	\$ -	\$ 2,877.37
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 1,515,800.19	\$ -	\$ 1,515,800.19
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 1,081,802.47	\$ -	\$ 1,081,802.47
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)	\$ 108,926.19	\$ -	\$ 108,926.19
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)	\$ 3,014.43	\$ -	\$ 3,014.43
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (875,990.62)	\$ -	\$ (875,990.62)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (86,149.93)	\$ -	\$ (86,149.93)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (134,712.49)	\$ -	\$ (134,712.49)
37	Financial Transmission Guarantee Uplift Amount	\$ 195,016.56	\$ -	\$ 195,016.56
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 1,182,469.72	\$ -	\$ 1,182,469.72
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 99,401.68	\$ -	\$ 99,401.68
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (66,124.99)	\$ 2,178.34	\$ (63,946.65)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 261,903.86	\$ -	\$ 261,903.86
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (222,745.61)	\$ 65,633.42	\$ (157,112.19)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (109,360.45)	\$ (1,815.22)	\$ (111,175.67)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 637,195.51	\$ (5,264.30)	\$ 631,931.21
19	Real-Time Market Administration Amount	\$ 54,996.66	\$ (1,726.55)	\$ 53,270.11
29	Financial Transmission Rights Market Administration Amount	\$ 49,574.40	\$ -	\$ 49,574.40
33	Day-Ahead Schedule 24 Allocation Amount	\$ 86,980.23	\$ (714.83)	\$ 86,265.40
34	Real-Time Schedule 24 Allocation Amount	\$ 7,502.09	\$ (226.99)	\$ 7,275.10
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	\$ (531.06)	\$ -	\$ (531.06)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 4,791,800.92	\$ -	\$ 4,791,800.92
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (4,919,264.59)	\$ -	\$ (4,919,264.59)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (464,951.10)	\$ -	\$ (464,951.10)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 197,861.33	\$ -	\$ 197,861.33
TOTAL MISO CHARGES		\$ 29,904,582.18	\$ 2,292,430.48	\$ 32,197,012.66
SCHEDULE 24 (FOR RETAIL)				\$ 93,540.50
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 32,103,472.16

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
June 2013 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (117,565.44)	\$ -	\$ (117,565.44)
2	Day-Ahead Spinning Reserve Amount	\$ (174,577.91)	\$ -	\$ (174,577.91)
3	Day-Ahead Supplemental Reserve	\$ (56,976.07)	\$ -	\$ (56,976.07)
4	Real-Time Regulation Amount	\$ (69,437.71)	\$ 15,815.22	\$ (53,622.49)
5	Real-Time Spinning Reserve Amount	\$ 71,873.13	\$ 7,266.13	\$ 79,139.26
6	Real-Time Supplemental Reserve Amount	\$ 7,511.09	\$ (4,344.09)	\$ 3,167.00
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ 33,672.85	\$ -	\$ 33,672.85
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 2,180,369.81	\$ -	\$ 2,180,369.81
8b	Real Time Non Excessive Energy Congestion	\$ 261,818.07	\$ -	\$ 261,818.07
8c	Real Time Non Excessive Energy Loss	\$ 94,149.34	\$ -	\$ 94,149.34
9	Real Time Net Regulation Adjustment Amount	\$ 10,047.84	\$ (1,273.69)	\$ 8,774.15
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 127,737.77	\$ -	\$ 127,737.77
11	Real Time Spinning Reserve Cost Distribution	\$ 203,915.53	\$ -	\$ 203,915.53
12	Real Time Supplemental Reserve Cost Distribution	\$ 85,825.36	\$ -	\$ 85,825.36
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 59,820.17	\$ (3,786.60)	\$ 56,033.57
14	Real Time Contingency Reserve Deployment Failure	\$ -	\$ -	\$ -
TOTAL MISO ASM CHARGES		\$ 2,718,183.83	\$ 13,676.97	\$ 2,731,860.80

	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	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	(111,891)	(56,628)	(48,164)	(91,255)	(46,210)	(38,419)						
3	190,659	193,918	172,034	162,994	190,995	190,839	175,314	177,072				
4												
5												
6												
7												
8	(0.059)	(0.029)	(0.028)	(0.056)	(0.024)	(0.020)						
9	(44,630)	(32,527)	(121,803)	(65,176)	(85,565)	(56,127)	(88,687)	(27,522)				
10	(34,718)	(43,979)	(84,402)	(100,304)	(73,088)	(67,024)						
11	(9,912)	(8,548)	(37,401)	35,128	(12,477)	10,897	(58,687)	(27,522)				
12	(0.005)	(0.004)	(0.022)	0.022	(0.007)	0.006						
13	(0.064)	(0.034)	(0.050)	(0.034)	(0.031)	(0.014)						
14	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
15	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281
16	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170
17	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883
18	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889
19	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440
20	(0.064)	(0.034)	(0.050)	(0.035)	(0.031)	(0.014)						
21	(0.066)	(0.035)	(0.051)	(0.035)	(0.032)	(0.015)						
22	(0.065)	(0.034)	(0.051)	(0.035)	(0.031)	(0.015)						
23	(0.082)	(0.043)	(0.064)	(0.044)	(0.040)	(0.019)						
24	(0.050)	(0.027)	(0.039)	(0.027)	(0.024)	(0.011)						
25	(0.048)	(0.025)	(0.037)	(0.026)	(0.023)	(0.011)						

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	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13
2	(280,039)	-	-	(590,344)	(8,187)	-	-	(2,054)	-	-	-	-
3	193,427	241,910	204,198	190,659	193,918	172,934	162,994	190,995	190,839	-	-	-
4	(0.145)	-	-	(0.310)	(0.004)	-	-	(0.001)	-	-	-	-
5	-	-	(280,039)	-	(161,476)	(406,613)	(94,613)	(137,192)	187,000	-	-	-
6	-	-	(118,563)	(183,731)	(75,050)	(269,421)	(281,613)	(116,841)	6,612	-	-	-
7	-	-	(161,476)	183,731	(86,426)	(137,192)	187,000	(20,351)	180,388	-	-	-
8	-	-	(0.079)	0.096	(0.045)	(0.080)	0.115	(0.011)	0.095	-	-	-
9	(0.145)	-	(0.079)	(0.213)	(0.049)	(0.080)	0.115	(0.012)	0.095	-	-	-
10	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
11	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281
12	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170
13	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883
14	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889
15	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440
16	(0.145)	-	(0.079)	(0.214)	(0.049)	(0.080)	0.115	(0.012)	0.095	-	-	-
17	(0.149)	-	(0.081)	(0.219)	(0.050)	(0.082)	0.118	(0.012)	0.097	-	-	-
18	(0.147)	-	(0.080)	(0.217)	(0.050)	(0.081)	0.117	(0.012)	0.096	-	-	-
19	(0.187)	-	(0.102)	(0.275)	(0.063)	(0.103)	0.148	(0.015)	0.122	-	-	-
20	(0.114)	-	(0.062)	(0.168)	(0.038)	(0.063)	0.091	(0.009)	0.075	-	-	-
21	(0.108)	-	(0.059)	(0.159)	(0.036)	(0.059)	0.085	(0.009)	0.070	-	-	-
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
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
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
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
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
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
29	Realized Margin Adj for Class Ratios											
30	Residential	(0.145)	(0.079)	(0.214)	(0.049)	(0.080)	0.115	(0.012)	0.095	-	-	-
31	C&I Non-Demand	(0.149)	(0.081)	(0.219)	(0.050)	(0.082)	0.118	(0.012)	0.097	-	-	-
32	C&I Demand Non-TOD	(0.147)	(0.080)	(0.217)	(0.050)	(0.081)	0.117	(0.012)	0.096	-	-	-
33	C&I Demand TOD On-Peak	(0.187)	(0.102)	(0.275)	(0.063)	(0.103)	0.148	(0.015)	0.122	-	-	-
34	C&I Demand TOD Off-Peak	(0.114)	(0.062)	(0.168)	(0.038)	(0.063)	0.091	(0.009)	0.075	-	-	-
35	Outdoor Lighting	(0.108)	(0.059)	(0.159)	(0.036)	(0.059)	0.085	(0.009)	0.070	-	-	-