



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

June 28, 2013

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

Re: July 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 July 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:

July 2013	Fuel Cost Charge (\$/kWh)
Residential	0.02302
C & I Non-Demand	0.02361
C & I Demand	0.02335
C & I Demand Time of Day On-Peak	0.02958
C & I Demand Time of Day Off-Peak	0.01812
Outdoor Lighting	0.01709

Shortly after we had submitted the June Fuel Cost Charge filing on May 31, 2013, we discovered there was a data problem related to April recovery in the true up calculation. This data error caused a smaller true up credit which in turn resulted a higher fuel cost charge for the month of June. Since that time we have identified the source of this data problem and verified the issue was only confined to the April record. Given the June Fuel Cost Charges had already been implemented in the billing process it would be complicated to revise the factors during June. Therefore the Company has included a one time refund credit of \$1,368,423 in the July Fuel Cost Charge.

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 July 2013 FCC the net MISO Day 2 costs for May 2013 as recorded in Account 555. The MISO Day 2 cost recovery included in this July 2013 FCC is \$20,250,662, 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.

¹ Previously embedded in other FTR charge types.

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 July FCC the net MISO ASM costs for May 2013 as recorded in Account 555. The MISO ASM cost recovery included in this July FCC is \$4,308,216, 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 July 2013 Asset Based Margin amount of \$56,687 has been included as a credit, or offset, to the July 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 July 2013 FCC is \$14,651, 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 July 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 Jul-2013

Jul-2013 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02939	\$0.00124	-\$0.00767	\$0.02296
Residential	\$0.02947	\$0.00124	-\$0.00769	\$0.02302
C & I Non-Demand	\$0.03022	\$0.00127	-\$0.00788	\$0.02361
C & I Demand Non-TOD	\$0.02989	\$0.00126	-\$0.00780	\$0.02335
C & I Demand TOD On-Peak	\$0.03786	\$0.00160	-\$0.00988	\$0.02958
C & I Demand TOD Off-Peak	\$0.02319	\$0.00098	-\$0.00605	\$0.01812
Outdoor Lighting	\$0.02187	\$0.00092	-\$0.00570	\$0.01709
Residential				
Residential Service	\$ 0.02947	\$ 0.00124	\$ (0.00769)	\$ 0.02302
Residential TOD	\$ 0.02947	\$ 0.00124	\$ (0.00769)	\$ 0.02302
Residential - Underground	\$ 0.02947	\$ 0.00124	\$ (0.00769)	\$ 0.02302
Residential TOD - Underground	\$ 0.02947	\$ 0.00124	\$ (0.00769)	\$ 0.02302
Energy Control - (Non-Demand)	\$ 0.02947	\$ 0.00124	\$ (0.00769)	\$ 0.02302
Limit Off Peak	\$ 0.02947	\$ 0.00124	\$ (0.00769)	\$ 0.02302
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.03022	\$ 0.00127	\$ (0.00788)	\$ 0.02361
Limit Off Peak	\$ 0.03022	\$ 0.00127	\$ (0.00788)	\$ 0.02361
Small General Service	\$ 0.03022	\$ 0.00127	\$ (0.00788)	\$ 0.02361
Small General TOD - Metered	\$ 0.03022	\$ 0.00127	\$ (0.00788)	\$ 0.02361
Small General TOD - Unmetered	\$ 0.03022	\$ 0.00127	\$ (0.00788)	\$ 0.02361
Fire and Civil Defense Siren	\$ 0.03022	\$ 0.00127	\$ (0.00788)	\$ 0.02361
Direct Current (Closed)	\$ 0.03022	\$ 0.00127	\$ (0.00788)	\$ 0.02361
C & I Demand				
General Service	\$ 0.02989	\$ 0.00126	\$ (0.00780)	\$ 0.02335
General TOD - On Peak	\$ 0.03786	\$ 0.00160	\$ (0.00988)	\$ 0.02958
General TOD - Off Peak	\$ 0.02319	\$ 0.00098	\$ (0.00605)	\$ 0.01812
Peak Controlled (Closed)	\$ 0.02989	\$ 0.00126	\$ (0.00780)	\$ 0.02335
Peak Controlled TOD (Closed) - On Peak	\$ 0.03786	\$ 0.00160	\$ (0.00988)	\$ 0.02958
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02319	\$ 0.00098	\$ (0.00605)	\$ 0.01812
Peak Controlled Tiered	\$ 0.02989	\$ 0.00126	\$ (0.00780)	\$ 0.02335
Peak Controlled Tiered TOD - On Peak	\$ 0.03786	\$ 0.00160	\$ (0.00988)	\$ 0.02958
Peak Controlled Tiered TOD - Off Peak	\$ 0.02319	\$ 0.00098	\$ (0.00605)	\$ 0.01812
Energy Controlled (Closed)	\$ 0.02989	\$ 0.00126	\$ (0.00780)	\$ 0.02335
Tier 1 Energy Controlled Rider	\$ 0.02989	\$ 0.00126	\$ (0.00780)	\$ 0.02335
Real Time Pricing - Firm - On Peak	\$ 0.03786	\$ 0.00160	\$ (0.00988)	\$ 0.02958
Real Time Pricing - Firm - Off Peak	\$ 0.02319	\$ 0.00098	\$ (0.00605)	\$ 0.01812
Real Time Pricing - Controllable - On Peak	\$ 0.03786	\$ 0.00160	\$ (0.00988)	\$ 0.02958
Real Time Pricing - Controllable - Off Peak	\$ 0.02319	\$ 0.00098	\$ (0.00605)	\$ 0.01812
Small Municipal Pumping	\$ 0.02989	\$ 0.00126	\$ (0.00780)	\$ 0.02335
Municipal Pumping	\$ 0.02989	\$ 0.00126	\$ (0.00780)	\$ 0.02335
Excess Energy - St. Anthony Falls	\$ 0.02989	\$ 0.00126	\$ (0.00780)	\$ 0.02335
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.02187	\$ 0.00092	\$ (0.00570)	\$ 0.01709
Street Lighting System	\$ 0.02187	\$ 0.00092	\$ (0.00570)	\$ 0.01709
Street Lighting Energy	\$ 0.02187	\$ 0.00092	\$ (0.00570)	\$ 0.01709
Street Lighting Energy - Metered	\$ 0.02187	\$ 0.00092	\$ (0.00570)	\$ 0.01709
Street Lighting Energy (Closed)	\$ 0.02187	\$ 0.00092	\$ (0.00570)	\$ 0.01709
Street Lighting - City of St. Paul	\$ 0.02187	\$ 0.00092	\$ (0.00570)	\$ 0.01709

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 Jul-2013

	Column (A) Feb-13	Column (B) Mar-13	Column (C) Apr-13	Column (D) May-13	Column (E) 4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$36,174,662	\$39,664,107	\$35,714,843	\$29,187,911	\$140,741,523
Account 518 - Nuclear Fuel	\$10,604,158	\$8,129,429	\$7,928,444	\$7,881,823	\$34,543,854
Account 555 - Purchased Power ¹	\$29,234,114	\$32,608,013	\$36,915,144	\$40,825,865	\$139,583,136
Account 555 - Pr. Rose PPA Adjustment	(\$281,598)	(\$302,484)	(\$245,881)	(\$179,008)	(\$1,008,971)
MISO Day 2 Charges	\$10,165,928	\$23,699,289	\$20,200,320	\$20,346,311	\$74,411,847
MISO Day 2 - Schedule 24	(\$103,222)	(\$100,745)	(\$105,670)	(\$95,649)	(\$405,287)
MISO - ASM Charges	\$2,987,340	\$1,107,837	\$2,993,845	\$4,308,216	\$11,397,238
Account 555 - Total MISO Charges	\$13,050,045	\$24,706,380	\$23,088,494	\$24,558,878	\$85,403,798
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$88,781,381	\$104,805,445	\$103,401,044	\$102,275,469	\$399,263,340
Less Fuel Cost of InterSystem Sales	(\$3,461,697)	(\$2,393,630)	(\$3,073,114)	(\$2,707,087)	(\$11,635,527)
Net System Costs	\$85,319,685	\$102,411,815	\$100,327,930	\$99,568,382	\$387,627,813
System MWh Sales					
Total NSP System Retail	3,238,495	3,357,790	3,378,291	3,209,691	13,184,267
Non-Gen Muni's/Load Pattern	1,656	1,470	1,583	1,435	6,144
Total NSP System MWh Sales	3,240,151	3,359,260	3,379,874	3,211,126	13,190,411
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System					
Adjusted System Cost without Pr. Rose PPA	2.633¢	3.049¢	2.968¢	3.101¢	2.939¢
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			2.939¢	1.0026	2.947¢
(ii) C & I Non-Demand			2.939¢	1.0281	3.022¢
(iii) C & I Demand Non-TOD			2.939¢	1.0170	2.989¢
(iv) C & I Demand TOD On-Peak			2.939¢	1.2883	3.786¢
(v) C & I Demand TOD Off-Peak			2.939¢	0.7889	2.319¢
(vi) Outdoor Lighting			2.939¢	0.7440	2.187¢
North Dakota Retail MWh Sales					
(i) Residential	84,608	75,688	77,422	56,984	294,702
(ii) C & I Non-Demand	12,107	11,702	11,358	9,208	44,375
(iii) C & I Demand Non-TOD	60,164	64,144	61,841	59,676	245,825
(iv) C & I Demand TOD On-Peak	17,132	16,520	17,131	18,879	69,662
(v) C & I Demand TOD Off-Peak	27,298	29,798	28,505	29,459	115,060
(vi) Outdoor Lighting	1,992	1,701	1,682	1,365	6,740
(vii) Total	203,301	199,553	197,939	175,571	776,364
Jul-2013 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Mar-13 Balance of Unrecovered Expenses)					Total Mar-13
					\$515,636

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

Prior Expenses Recovered in May-2013 [Billing Record]		
	ND Billed MWh Sales	Prior Rccovered Expenses
(i) Residential	56,984	\$13,429
(ii) C & I Non-Demand	9,208	\$2,031
(iii) C & I Demand Non-TOD	59,676	\$13,686
(iv) C & I Demand TOD On-Peak	18,879	\$5,734
(v) C & I Demand TOD Off-Peak	29,459	\$5,588
(vi) Outdoor Lighting	1,365	\$90
(vii) Total	175,571	\$40,558

Actual Cost Should Have Been Recovered in May-13				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	3.101¢	0.000¢	175,571	\$5,444,457

Cost Recovered in May-13 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	56,984	\$1,610,284
(ii) C & I Non-Demand	9,208	\$266,768
(iii) C & I Demand Non-TOD	59,676	\$1,710,564
(iv) C & I Demand TOD On-Peak	18,879	\$685,583
(v) C & I Demand TOD Off-Peak	29,459	\$655,088
(vi) Outdoor Lighting	1,365	\$28,596
(vii) Total	175,571	\$4,956,883

Total Balance of Unrecovered Expenses (Jul-13 Balance of Unrecovered Expenses)	
Jul-2013 Recovery Provision	\$962,652
4 Month ND Retail Total MWh Sales	776,364
Jul-2013 Recovery Provision per KWH	0.124¢

Jul-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	0.124¢	0.124¢
(ii) C & I Non-Demand	1.0281	0.124¢	0.127¢
(iii) C & I Demand Non-TOD	1.0170	0.124¢	0.126¢
(iv) C & I Demand TOD On-Peak	1.2883	0.124¢	0.160¢
(v) C & I Demand TOD Off-Peak	0.7889	0.124¢	0.098¢
(vi) Outdoor Lighting	0.7440	0.124¢	0.092¢

Jul-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	(\$58,687)	(\$14,651)	(\$22,405)	(\$1,368,423)	(\$81,092)
(i) Residential	-0.031¢	-0.008¢	-0.012¢	-0.718¢	-0.769¢
(ii) C & I Non-Demand	-0.032¢	-0.008¢	-0.012¢	-0.737¢	-0.788¢
(iii) C & I Demand Non-TOD	-0.031¢	-0.008¢	-0.012¢	-0.729¢	-0.780¢
(iv) C & I Demand TOD On-Peak	-0.040¢	-0.010¢	-0.015¢	-0.923¢	-0.988¢
(v) C & I Demand TOD Off-Peak	-0.024¢	-0.006¢	-0.009¢	-0.565¢	-0.605¢
(vi) Outdoor Lighting	-0.023¢	-0.006¢	-0.009¢	-0.533¢	-0.570¢

Jul-2013 Factors	
	Total
(i) Residential	2.302¢
(ii) C & I Non-Demand	2.361¢
(iii) C & I Demand Non-TOD	2.335¢
(iv) C & I Demand TOD On-Peak	2.958¢
(v) C & I Demand TOD Off-Peak	1.812¢
(vi) Outdoor Lighting	1.709¢

	FCA Application		Comparison		Generation Type by Percent		
	Jun-13	Jul-13	Difference	Percent Change	Jun-13	Jul-13	Difference
** COSTS (Millions) **							
1 Fossil	\$157.5	\$140.7	(\$16.7)	-10.6%	39.4%	35.3%	-4.1%
2 Nuclear	\$37.8	\$34.5	(\$3.2)	-8.6%	9.5%	8.7%	-0.8%
3 Purchases	\$132.7	\$138.6	\$5.9	4.5%	33.2%	34.7%	1.5%
MISO related Purchases	\$71.6	\$85.4	\$13.8	19.3%	17.9%	21.4%	3.5%
4 Total System Costs	399.5	399.3	(\$0.2)	-0.1%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$12.5	\$11.6	(\$0.9)	-6.9%	3.1%	2.9%	-0.2%
6 Net System Costs	\$387.0	\$387.6	\$0.6	0.2%	96.9%	97.1%	0.2%
7							
8 ** GWH OUTPUT **							
9 Fossil	4,088	3,520	(568)	-13.9%	26.9%	24.3%	-2.6%
10 Nuclear	3,898	3,482	(416)	-10.7%	25.7%	24.0%	-1.7%
11 Purchases	4,476	4,940	464	10.4%	29.5%	34.1%	4.6%
12 Hydro & Other	2,092	2,043	(49)	-2.3%	13.8%	14.1%	0.3%
13 Net Interchange	620	520	(100)	-16.1%	4.1%	3.6%	-0.5%
14 Total Output	15,174	14,505	(669)	-4.4%	100.0%	100.0%	0.0%
15 Intersystem Sales	768	564	(204)	-26.6%	5.1%	3.9%	-1.2%
16 Native Requirement	14,405	13,941	(465)	-3.2%	94.9%	96.1%	1.2%
17							
18 ** COST per KWH OUTPUT (\$) **							
19 Fossil	3.852	3.998	0.146	3.8%			
20 Nuclear	0.969	0.992	0.023	2.4%			
21 Purchases	2.964	2.805	-0.159	-5.3%			
22 Total System Costs	2.633	2.753	0.120	4.6%			
23 Intersystem Sales	1.628	2.064	0.437	26.8%			
24 Net System Costs	2.686	2.780	0.094	3.5%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,887	13,190	(677)	-4.9%			
28							
29 COST per KWH SALES (\$)	2.791	2.939	0.148	5.3%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	0.189	0.124	-0.065				
(i) Residential	0.190	0.124	-0.065				
(ii) C & I Non-Demand	0.195	0.127	-0.067				
(iii) C & I Demand Non-TOD	0.192	0.126	-0.066				
(iv) C & I Demand TOD On-Peak	0.244	0.160	-0.084				
(v) C & I Demand TOD Off-Peak	0.149	0.098	-0.051				
(vi) Outdoor Lighting	0.141	0.092	-0.049				
32 REFUND	0.072	-0.767	-0.839				
(i) Residential	0.072	-0.769					
(ii) C & I Non-Demand	0.074	-0.788					
(iii) C & I Demand Non-TOD	0.073	-0.780					
(iv) C & I Demand TOD On-Peak	0.093	-0.988					
(v) C & I Demand TOD Off-Peak	0.057	-0.605					
(vi) Outdoor Lighting	0.054	-0.570					
33 SYSTEM FCC IMPACT (\$ / KWH)	3.052	2.296	-0.756	-24.8%			
(i) Residential	3.060	2.302	-0.758				
(ii) C & I Non-Demand	3.138	2.361					
(iii) C & I Demand Non-TOD	3.104	2.335					
(iv) C & I Demand TOD On-Peak	3.932	2.958					
(v) C & I Demand TOD Off-Peak	2.408	1.812					
(vi) Outdoor Lighting	2.271	1.709					

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	(\$0.76)
250	(\$1.89)
500	(\$3.79)
750	(\$5.68)
1,000	(\$7.58)

Some miscellaneous totals refer to so many terms that their formula would be too long. So intermediate totals are developed here, then an overall total is taken and is rounded, and finally it's simply referred to above.

	FCA Application	
	Jun-13	Jul-13
** GWH OUTPUT **		
Thermal	1,620,382	1,445,933
Disper gen	(79)	(72)
Hydro plus Wind	471,271	595,932
Hydro and Other	2,091,574	2,042,793
Rounded to nearest thousand:	2,092	2,043
Sales		
Non Gen Munic Total	37,197,000	6,144,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	768,042,000	563,625,000
Rounded to nearest million:	768,042	563,625

		System	Intersystem	Retail
May 2013 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 26,092,606.67	\$ 713,084.22	\$ 26,805,690.89
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,988,752.15	\$ -	\$ 2,988,752.15
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (14,261,657.71)	\$ -	\$ (14,261,657.71)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,346,886.96	\$ -	\$ 1,346,886.96
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)	\$ (265,696.58)	\$ 531,334.74	\$ 265,638.16
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 23,851.68	\$ -	\$ 23,851.68
14	Real-Time Distribution of Losses Amount	\$ (1,085,102.52)	\$ -	\$ (1,085,102.52)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ 5,375.52	\$ -	\$ 5,375.52
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 9,490.57	\$ -	\$ 9,490.57
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (719.58)	\$ -	\$ (719.58)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 2,577,532.39	\$ -	\$ 2,577,532.39
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 2,850,447.91	\$ -	\$ 2,850,447.91
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)	\$ 260,525.94	\$ -	\$ 260,525.94
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)	\$ (42,223.50)	\$ -	\$ (42,223.50)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (1,740,265.41)	\$ -	\$ (1,740,265.41)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (87,689.47)	\$ -	\$ (87,689.47)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (407,469.19)	\$ -	\$ (407,469.19)
37	Financial Transmission Guarantee Uplift Amount	\$ 402,174.69	\$ -	\$ 402,174.69
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 750,477.26	\$ -	\$ 750,477.26
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 173,064.77	\$ -	\$ 173,064.77
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (267,241.54)	\$ 17,602.17	\$ (249,639.37)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 565,249.36	\$ -	\$ 565,249.36
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (410,745.32)	\$ (43,079.15)	\$ (453,824.47)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (306,497.00)	\$ 9,080.19	\$ (297,416.81)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 576,950.09	\$ (2,804.95)	\$ 574,145.14
19	Real-Time Market Administration Amount	\$ 43,202.04	\$ (1,717.36)	\$ 41,484.68
29	Financial Transmission Rights Market Administration Amount	\$ 34,045.52	\$ -	\$ 34,045.52
33	Day-Ahead Schedule 24 Allocation Amount	\$ 89,616.88	\$ (431.02)	\$ 89,185.86
34	Real-Time Schedule 24 Allocation Amount	\$ 6,725.52	\$ (262.70)	\$ 6,462.82
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	\$ 33.11	\$ -	\$ 33.11
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 3,172,718.47	\$ -	\$ 3,172,718.47
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (3,155,049.56)	\$ -	\$ (3,155,049.56)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (852,064.56)	\$ -	\$ (852,064.56)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 36,199.29	\$ -	\$ 36,199.29
TOTAL MISO CHARGES		\$ 19,123,504.85	\$ 1,222,806.14	\$ 20,346,310.99

SCHEDULE 24 (FOR RETAIL) \$ 95,648.68

TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL) \$ 20,250,662.31

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
May 2013 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (482,494.83)	\$ -	\$ (482,494.83)
2	Day-Ahead Spinning Reserve Amount	\$ (424,216.57)	\$ -	\$ (424,216.57)
3	Day-Ahead Supplemental Reserve	\$ (141,676.65)	\$ -	\$ (141,676.65)
4	Real-Time Regulation Amount	\$ (22,517.56)	\$ 363,736.31	\$ 341,218.75
5	Real-Time Spinning Reserve Amount	\$ 131,351.43	\$ 147,650.65	\$ 279,002.08
6	Real-Time Supplemental Reserve Amount	\$ 43,324.31	\$ 24,098.89	\$ 67,423.20
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ 60,990.27	\$ -	\$ 60,990.27
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 3,185,150.09	\$ -	\$ 3,185,150.09
8b	Real Time Non Excessive Energy Congestion	\$ 233,098.87	\$ -	\$ 233,098.87
8c	Real Time Non Excessive Energy Loss	\$ 98,373.15	\$ -	\$ 98,373.15
9	Real Time Net Regulation Adjustment Amount	\$ 54,183.81	\$ 712.62	\$ 54,896.43
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 205,225.66	\$ -	\$ 205,225.66
11	Real Time Spinning Reserve Cost Distribution	\$ 373,850.27	\$ -	\$ 373,850.27
12	Real Time Supplemental Reserve Cost Distribution	\$ 121,860.57	\$ -	\$ 121,860.57
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 345,093.06	\$ (22,178.46)	\$ 322,914.60
14	Real Time Contingency Reserve Deployment Failure	\$ 12,600.30	\$ -	\$ 12,600.30
TOTAL MISO ASM CHARGES		\$ 3,794,196.18	\$ 514,020.01	\$ 4,308,216.19

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	(111,891)	(56,628)	(48,164)	(91,255)	(46,210)							
5												
6 Forecast North Dakota Sales	190,659	193,918	172,034	162,994	190,995	193,587	177,095					
7												
8 Current Month Refund Factor	(0.059)	(0.029)	(0.028)	(0.056)	(0.024)							
9												
14 Expected Refund	(44,630)	(52,327)	(121,803)	(65,176)	(85,545)	(56,127)	(58,687)					
15 Actual Refunded	(84,718)	(43,979)	(84,402)	(100,304)	(73,088)							
16 Deviation	(9,912)	(8,548)	(37,401)	35,128	(12,477)	(56,127)	(58,687)					
17												
18 True-up Factor	(0.005)	(0.004)	(0.022)	0.022	(0.007)							
19												
20 Realized Margin	(0.064)	(0.034)	(0.050)	(0.034)	(0.031)							
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)							
32 C&I Non-Demand	(0.066)	(0.035)	(0.051)	(0.035)	(0.032)							
33 C&I Demand Non-TOD	(0.065)	(0.034)	(0.051)	(0.035)	(0.031)							
34 C&I Demand TOD On-Peak	(0.082)	(0.043)	(0.064)	(0.044)	(0.040)							
35 C&I Demand TOD Off-Peak	(0.050)	(0.027)	(0.039)	(0.027)	(0.024)							
36 Outdoor Lighting	(0.048)	(0.025)	(0.037)	(0.026)	(0.023)							

