Xcel Energy®

414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

March 29, 2013

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

Re: April 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 April 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

7 PU-13-12 Filed 03/29/2013 Pages: 13
April 2013 fuel cost adjustment
Northern States Power Company

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

April 2013	Fuel Cost Charge ($/kWh)
Residential	0.02722
C & I Non-Demand	0.02791
C & I Demand	0.02761
C & I Demand Time of Day On-Peak	0.03497
C & I Demand Time of Day Off-Peak	0.02142
Outdoor Lighting	0.02020

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 types[1], 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 April 2013 FCC the net MISO Day 2 costs for February 2013 as recorded in Account 555. The MISO Day 2 cost recovery included in this April 2013 FCC is $10,062,705, 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 April FCC the net MISO ASM costs for February 2013 as recorded in Account 555. The MISO ASM cost recovery included in this April FCC is $2,987,340, 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 April 2013 Asset Based Margin amount of $65,176 has been included as a credit, or offset, to the April 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 April 2013 FCC is $14,257, 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 recent 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 this March 2013 FCR filing, the Company will exclude 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 will file 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.

The Commission should note that some "test energy" was generated at the PRW facility during a testing and start-up phase in November and December 2012 and the related costs and volumes were included in the January and February 2013 FCR calculations. The energy from this testing phase was priced lower than the PPA contract price and was also lower than the system average cost of fuel. Excluding the "test energy" from our FCR calculation would have resulted in slightly higher costs to North Dakota customers. After discussions with Staff, the Company, consequently, did not exclude the test energy costs and volumes from our FCR given the low pricing and the benefits to our customers. If the Commission prefers that the Company not include this "test energy" in its FCR calculations for January and February, the Company will work with Staff to make the appropriate adjustments.

OTHER REPORTING ITEM

Attached is the calculation of the April 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 Apr-2013

Apr-2013 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	**$0.02812**	**-$0.00008**	**-$0.00090**	**$0.02715**
Residential	**$0.02819**	**-$0.00008**	**-$0.00090**	**$0.02722**
C & I Non-Demand	**$0.02891**	**-$0.00008**	**-$0.00092**	**$0.02791**
C & I Demand Non-TOD	**$0.02860**	**-$0.00008**	**-$0.00091**	**$0.02761**
C & I Demand TOD On-Peak	**$0.03623**	**-$0.00010**	**-$0.00116**	**$0.03497**
C & I Demand TOD Off-Peak	**$0.02218**	**-$0.00006**	**-$0.00071**	**$0.02142**
Outdoor Lighting	**$0.02092**	**-$0.00006**	**-$0.00067**	**$0.02020**
Residential				
Residential Service	$ 0.02819	$ (0.00008)	$ (0.00090)	$ 0.02722
Residential TOD	$ 0.02819	$ (0.00008)	$ (0.00090)	$ 0.02722
Residential - Underground	$ 0.02819	$ (0.00008)	$ (0.00090)	$ 0.02722
Residential TOD - Underground	$ 0.02819	$ (0.00008)	$ (0.00090)	$ 0.02722
Energy Control - (Non-Demand)	$ 0.02819	$ (0.00008)	$ (0.00090)	$ 0.02722
Limit Off Peak	$ 0.02819	$ (0.00008)	$ (0.00090)	$ 0.02722
C & I Non-Demand				
Energy Controlled - (Non-Demand)	$ 0.02891	$ (0.00008)	$ (0.00092)	$ 0.02791
Limit Off Peak	$ 0.02891	$ (0.00008)	$ (0.00092)	$ 0.02791
Small General Service	$ 0.02891	$ (0.00008)	$ (0.00092)	$ 0.02791
Small General TOD - Metered	$ 0.02891	$ (0.00008)	$ (0.00092)	$ 0.02791
Small General TOD - Unmetered	$ 0.02891	$ (0.00008)	$ (0.00092)	$ 0.02791
Fire and Civil Defense Siren	$ 0.02891	$ (0.00008)	$ (0.00092)	$ 0.02791
Direct Current (Closed)	$ 0.02891	$ (0.00008)	$ (0.00092)	$ 0.02791
C & I Demand				
General Service	$ 0.02860	$ (0.00008)	$ (0.00091)	$ 0.02761
General TOD - On Peak	$ 0.03623	$ (0.00010)	$ (0.00116)	$ 0.03497
General TOD - Off Peak	$ 0.02218	$ (0.00006)	$ (0.00071)	$ 0.02142
Peak Controlled (Closed)	$ 0.02860	$ (0.00008)	$ (0.00091)	$ 0.02761
Peak Controlled TOD (Closed) - On Peak	$ 0.03623	$ (0.00010)	$ (0.00116)	$ 0.03497
Peak Controlled TOD (Closed) - Off Peak	$ 0.02218	$ (0.00006)	$ (0.00071)	$ 0.02142
Peak Controlled Tiered	$ 0.02860	$ (0.00008)	$ (0.00091)	$ 0.02761
Peak Controlled Tiered TOD - On Peak	$ 0.03623	$ (0.00010)	$ (0.00116)	$ 0.03497
Peak Controlled Tiered TOD - Off Peak	$ 0.02218	$ (0.00006)	$ (0.00071)	$ 0.02142
Energy Controlled (Closed)	$ 0.02860	$ (0.00008)	$ (0.00091)	$ 0.02761
Tier 1 Energy Controlled Rider	$ 0.02860	$ (0.00008)	$ (0.00091)	$ 0.02761
Real Time Pricing - Firm - On Peak	$ 0.03623	$ (0.00010)	$ (0.00116)	$ 0.03497
Real Time Pricing - Firm - Off Peak	$ 0.02218	$ (0.00006)	$ (0.00071)	$ 0.02142
Real Time Pricing - Controllable - On Peak	$ 0.03623	$ (0.00010)	$ (0.00116)	$ 0.03497
Real Time Pricing - Controllable - Off Peak	$ 0.02218	$ (0.00006)	$ (0.00071)	$ 0.02142
Small Municipal Pumping	$ 0.02860	$ (0.00008)	$ (0.00091)	$ 0.02761
Municipal Pumping	$ 0.02860	$ (0.00008)	$ (0.00091)	$ 0.02761
Excess Energy - St. Anthony Falls	$ 0.02860	$ (0.00008)	$ (0.00091)	$ 0.02761
Outdoor Lighting				
Automatic Protective Lighting	$ 0.02092	$ (0.00006)	$ (0.00067)	$ 0.02020
Street Lighting System	$ 0.02092	$ (0.00006)	$ (0.00067)	$ 0.02020
Street Lighting Energy	$ 0.02092	$ (0.00006)	$ (0.00067)	$ 0.02020
Street Lighting Energy - Metered	$ 0.02092	$ (0.00006)	$ (0.00067)	$ 0.02020
Street Lighting Energy (Closed)	$ 0.02092	$ (0.00006)	$ (0.00067)	$ 0.02020
Street Lighting - City of St. Paul	$ 0.02092	$ (0.00006)	$ (0.00067)	$ 0.02020

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 Apr-2013

	Column (A)	*Column (B)*	*Column (C)*	*Column (D)*	*Column (E)*
	Nov-12	Dec-12	Jan-13	Feb-13	**4 Month Total**
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	$37,226,702	$50,135,186	$45,930,917	$36,174,662	$169,467,467
Account 518 - Nuclear Fuel	$7,435,032	$7,716,782	$11,120,517	$10,604,158	$36,876,489
Account 555 - Purchased Power[1]	$38,976,096	$36,519,011	$35,027,255	$29,234,114	$139,756,476
Account 555 - Pr. Rose PPA Adjustment	$0	$0	($300,689)	($281,598)	($582,287)
MISO Day 2 Charges	$13,313,564	$11,716,178	$8,366,319	$10,165,928	$43,561,989
MISO Day 2 - Schedule 24	($102,938)	($102,268)	($107,137)	($103,222)	($415,565)
MISO - ASM Charges	$1,799,365	$2,665,138	$2,463,279	$2,987,340	$9,915,122
Account 555 - Total MISO Charges	$15,009,991	$14,279,049	$10,722,461	$13,050,045	$53,061,546
Financial Instruments	$0	$0	$0	$0	$0
Total System Costs	$98,647,821	$108,650,027	$102,500,461	$88,781,381	$398,579,690
Less Fuel Cost of InterSystem Sales	($4,636,470)	($5,361,131)	($3,573,405)	($3,461,697)	($17,032,702)
Net System Costs	$94,011,352	$103,288,897	$98,927,056	$85,319,685	$381,546,989
System MWH Sales					
Total NSP System Retail	3,094,884	3,275,050	3,855,371	3,238,495	13,463,800
Non-Gen Muni's/Load Pattern	35,488	35,350	32,488	1,656	104,982
Total NSP System MWh Sales	3,130,372	3,310,400	3,887,859	3,240,151	13,568,782
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System					
Adjusted System Cost without Pr. Rose PPA	**3.003¢**	**3.120¢**	**2.545¢**	**2.633¢**	**2.812¢**
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			2.812¢	1.0026	**2.819¢**
(ii) C & I Non-Demand			2.812¢	1.0281	**2.891¢**
(iii) C & I Demand Non-TOD			2.812¢	1.0170	**2.860¢**
(iv) C & I Demand TOD On-Peak			2.812¢	1.2883	**3.623¢**
(v) C & I Demand TOD Off-Peak			2.812¢	0.7889	**2.218¢**
(vi) Outdoor Lighting			2.812¢	0.7440	**2.092¢**
North Dakota Retail MWh Sales					
(i) Residential	59,206	70,948	102,481	84,608	317,243
(ii) C & I Non-Demand	8,935	11,009	14,884	12,107	46,935
(iii) C & I Demand Non-TOD	53,335	65,184	69,852	60,164	248,535
(iv) C & I Demand TOD On-Peak	17,259	17,658	18,097	17,132	70,146
(v) C & I Demand TOD Off-Peak	26,864	28,922	31,503	27,298	114,587
(vi) Outdoor Lighting	1,887	2,004	2,164	1,992	8,047
(vii) Total	167,486	195,725	238,981	203,301	805,493
Apr-2013 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Dec-12 Balance of Unrecovered Expenses)					Total
					Dec-12
					$270,965

[1] Excludes demand-related expenses and includeds Prairie Rose Wind PPA expenses

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 Apr-2013

Prior Expenses Recovered in Feb-2013 [Billing Record]

	ND Billed MWh Sales	Prior Receovered Expenses
(i) Residential	84,608	$46,183
(ii) C & I Non-Demand	12,107	$6,530
(iii) C & I Demand Non-TOD	60,164	$31,349
(iv) C & I Demand TOD On-Peak	17,132	$11,689
(v) C & I Demand TOD Off-Peak	27,298	$11,369
(vi) Outdoor Lighting	1,992	$890
(vii) Total	203,301	$108,010

Actual Cost Should Have Been Recovered in Feb-13

Actual	Base	Actual ND MWh Sales	Expected Recovery
2.633¢	0.000¢	203,301	$5,352,915

Cost Recovered in Feb-13 [Billing Record]

	ND Billed MWh Sales	Actual Recovery
(i) Residential	84,608	$2,325,960
(ii) C & I Non-Demand	12,107	$341,063
(iii) C & I Demand Non-TOD	60,164	$1,675,707
(iv) C & I Demand TOD On-Peak	17,132	$604,185
(v) C & I Demand TOD Off-Peak	27,298	$589,392
(vi) Outdoor Lighting	1,992	$40,153
(vii) Total	203,301	$5,576,460

Total Balance of Unrecovered Expenses (Apr-13 Balance of Unrecovered Expenses)

Apr-2013 Recovery Provision	($60,590)
4 Month ND Retail Total MWh Sales	805,493
Apr-2013 Recovery Provision per KWH	**-0.008¢**

Apr-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	-0.008¢	**-0.008¢**
(ii) C & I Non-Demand	1.0281	-0.008¢	**-0.008¢**
(iii) C & I Demand Non-TOD	1.0170	-0.008¢	**-0.008¢**
(iv) C & I Demand TOD On-Peak	1.2883	-0.008¢	**-0.010¢**
(v) C & I Demand TOD Off-Peak	0.7889	-0.008¢	**-0.006¢**
(vi) Outdoor Lighting	0.7440	-0.008¢	**-0.006¢**

Apr-2013 Refunds/Additional Charges

	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Refund	Total
Refund/Special Charge Amount	($65,176)	($14,257)	($94,613)	**($159,789)**
(i) Residential	-0.034¢	-0.007¢	-0.049¢	**-0.090¢**
(ii) C & I Non-Demand	-0.035¢	-0.008¢	-0.050¢	**-0.092¢**
(iii) C & I Demand Non-TOD	-0.034¢	-0.007¢	-0.050¢	**-0.091¢**
(iv) C & I Demand TOD On-Peak	-0.043¢	-0.009¢	-0.063¢	**-0.116¢**
(v) C & I Demand TOD Off-Peak	-0.027¢	-0.006¢	-0.038¢	**-0.071¢**
(vi) Outdoor Lighting	-0.025¢	-0.005¢	-0.036¢	**-0.067¢**

Apr-2013 Factors

	Total
(i) Residential	**2.722¢**
(ii) C & I Non-Demand	**2.791¢**
(iii) C & I Demand Non-TOD	**2.761¢**
(iv) C & I Demand TOD On-Peak	**3.497¢**
(v) C & I Demand TOD Off-Peak	**2.142¢**
(vi) Outdoor Lighting	**2.020¢**

Northern States Power Company, A Minnesota Corporation
Electric Operations - State of North Dakota
FUEL CLAUSE ADJUSTMENT (FCA) COMPARISON -
Prior Month Compared to Current Month FCA

	FCA Application		Comparison		Generation Type by Percent		
			Differ-ence	Percent Change	FCA Application		Differ-ence
	Mar-13	Apr-13			Mar-13	Apr-13	
** COSTS (Millions) **							
1 Fossil	$166.6	$169.5	$2.8	1.7%	41.1%	42.5%	1.4%
2 Nuclear	$36.7	$36.9	$0.2	0.5%	9.1%	9.3%	0.2%
3 Purchases	$148.5	$139.2	($9.3)	-6.3%	36.7%	34.9%	-1.8%
MISO related Purchases	$53.2	$53.1	($0.1)	-0.3%	13.1%	13.3%	0.2%
4 Total System Costs	405.0	398.6	($6.4)	-1.6%	100.0%	100.0%	0.0%
5 Intersystem Sales	$16.3	$17.0	$0.8	4.7%	4.0%	4.3%	0.3%
6 Net System Costs	$388.7	$381.5	($7.2)	-1.8%	96.0%	95.7%	-0.3%
7							
8 ** GWH OUTPUT **							
9 Fossil	5,316	5,155	(161)	-3.0%	33.6%	33.2%	-0.4%
10 Nuclear	3,909	3,935	26	0.7%	24.7%	25.3%	0.6%
11 Purchases	4,244	4,039	(205)	-4.8%	26.8%	26.0%	-0.8%
12 Hydro & Other	1,582	1,785	203	12.8%	10.0%	11.5%	1.5%
13 Net Interchange	768	626	(142)	-18.5%	4.9%	4.0%	-0.9%
14 Total Output	15,819	15,540	(279)	-1.8%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,084	928	(156)	-14.4%	6.9%	6.0%	-0.9%
16 Native Requirement	14,735	14,612	(123)	-0.8%	93.1%	94.0%	0.9%
17							
18 ** COST per KWH OUTPUT (¢) **							
19 Fossil	3.134	3.287	0.153	4.9%			
20 Nuclear	0.938	0.937	-0.001	-0.1%			
21 Purchases	3.498	3.446	-0.052	-1.5%			
22 Total System Costs	2.560	2.565	0.005	0.2%			
23 Intersystem Sales	1.500	1.835	0.335	22.4%			
24 Net System Costs	2.638	2.611	-0.027	-1.0%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,748	13,569	(179)	-1.3%			
28							
29 COST per KWH SALES (¢)	2.827	2.812	-0.015	-0.5%			
30							
31 RECOVERY PROV (¢ / KWH) - SYS	0.013	-0.008	-0.021				
(i) Residential	0.013	-0.008	-0.021				
(ii) C & I Non-Demand	0.014	-0.008	-0.021				
(iii) C & I Demand Non-TOD	0.014	-0.008	-0.021				
(iv) C & I Demand TOD On-Peak	0.017	-0.010	-0.027				
(v) C & I Demand TOD Off-Peak	0.010	-0.006	-0.016				
(vi) Outdoor Lighting	0.010	-0.006	-0.015				
32 REFUND	-0.284	-0.089	0.195				
(i) Residential	-0.285	-0.090					
(ii) C & I Non-Demand	-0.292	-0.092					
(iii) C & I Demand Non-TOD	-0.289	-0.091					
(iv) C & I Demand TOD On-Peak	-0.366	-0.116					
(v) C & I Demand TOD Off-Peak	-0.224	-0.071					
(vi) Outdoor Lighting	-0.211	-0.067					
33 SYSTEM FCC IMPACT (¢ / KWH)	2.556	2.715	0.159	6.2%			
(i) Residential	2.561	2.722	0.161				
(ii) C & I Non-Demand	2.626	2.791					
(iii) C & I Demand Non-TOD	2.598	2.761					
(iv) C & I Demand TOD On-Peak	3.291	3.497					
(v) C & I Demand TOD Off-Peak	2.015	2.142					
(vi) Outdoor Lighting	1.900	2.020					

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]

Residential BILL IMPACT ($'s)

kWh	Change from Previous Month
100	$0.16
250	$0.40
500	$0.80
750	$1.21
1,000	$1.61

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 Mar-13	Apr-13
** GWH OUTPUT **		
Thermal	1,171,622	1,400,957
Disper gen	(94)	(91)
Hydro plus Wind	410,340	383,810
Hydro and Other	1,581,868	1,784,676
Rounded to nearest thousand:	1,582	1,785
Sales		
Non Gen Munic Total	135,930,000	104,982,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,084,174,000	927,994,000
Rounded to nearest million:	1084.174	927.994

Northern States Power Company, A Minnesota Corporation

Attachment 2

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail
February 2013 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	$ 11,498,325.95	$ 2,244,007.21	$ 13,742,333.16
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	$ 2,706,384.83	$ -	$ 2,706,384.83
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	$ (9,558,961.57)	$ -	$ (9,558,961.57)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	$ 452,569.22	$ -	$ 452,569.22
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)	$ 1,423,919.51	$ 307,723.26	$ 1,731,642.77
13 c	Real-Time Asset Energy Amount - Loss Component (1)	$ 101,141.79	$ -	$ 101,141.79
14	Real-Time Distribution of Losses Amount	$ (1,500,182.78)	$ -	$ (1,500,182.78)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (59,981.31)	$ -	$ (59,981.31)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	$ 6,905.93	$ -	$ 6,905.93
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	$ (518.25)	$ -	$ (518.25)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	$ 3,837,250.60	$ -	$ 3,837,250.60
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ -	$ -	$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	$ 507,883.86	$ -	$ 507,883.86
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)	$ 74,853.83	$ -	$ 74,853.83
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)	$ (512.74)	$ -	$ (512.74)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,631,371.70)	$ -	$ (2,631,371.70)
30	Financial Transmission Rights Monthly Allocation Amount	$ (4,957.31)	$ -	$ (4,957.31)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (431,001.77)	$ -	$ (431,001.77)
37	Financial Transmission Guarantee Uplift Amount	$ 458,488.89	$ -	$ 458,488.89
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	$ 414,303.55	$ -	$ 414,303.55
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 64,581.69	$ -	$ 64,581.69
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (91,539.75)	$ 2,152.38	$ (89,387.37)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 64,362.45	$ -	$ 64,362.45
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (151.34)	$ (498.93)	$ (650.27)
43	Real-Time Price Volatility Make Whole Payment Amount	$ (88,098.39)	$ 7,810.85	$ (80,287.54)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	$ 700,317.64	$ (9,716.39)	$ 690,601.25
19	Real-Time Market Administration Amount	$ 42,595.32	$ (1,321.13)	$ 41,274.19
29	Financial Transmission Rights Market Administration Amount	$ 51,119.68	$ -	$ 51,119.68
33	Day-Ahead Schedule 24 Allocation Amount	$ 98,762.70	$ (1,371.41)	$ 97,391.29
34	Real -Time Schedule 24 Allocation Amount	$ 6,021.97	$ (191.04)	$ 5,830.93
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	$ 16.97	$ -	$ 16.97
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,107,735.62	$ -	$ 3,107,735.62
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,012,240.92)	$ -	$ (3,012,240.92)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (645,283.31)	$ -	$ (645,283.31)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 24,591.89	$ -	$ 24,591.89
	TOTAL MISO CHARGES	**$ 7,617,332.75**	**$ 2,548,594.80**	**$ 10,165,927.55**
	SCHEDULE 24 (FOR RETAIL)			**$ 103,222.22**
	TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)			**$ 10,062,705.33**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
	February 2013 Actual			
	Procurement Charges			
1	Day-Ahead Regulation Amount	$ (118,160.98)	$ -	$ (118,160.98)
2	Day-Ahead Spinning Reserve Amount	$ (48,643.45)	$ -	$ (48,643.45)
3	Day-Ahead Supplemental Reserve	$ (52,333.65)	$ -	$ (52,333.65)
4	Real-Time Regulation Amount	$ (49,172.53)	$ 77,082.45	$ 27,909.92
5	Real-Time Spinning Reserve Amount	$ (296.96)	$ 18,186.60	$ 17,889.64
6	Real-Time Supplemental Reserve Amount.	$ 16.96	$ 16,258.84	$ 16,275.80
	Resource Energy Charges			
7a	Real Time Excessive Energy Amount	$ 44,335.60		$ 44,335.60
7b	Real Time Excessive Energy Congestion	$ -		$ -
7c	Real Time Excessive Energy Loss	$ -		$ -
8a	Real Time Non Excessive Energy Amount	$ 2,804,110.25		$ 2,804,110.25
8b	Real Time Non Excessive Energy Congestion	$ (55,934.01)		$ (55,934.01)
8c	Real Time Non Excessive Energy Loss	$ (1,322.88)		$ (1,322.88)
9	Real Time Net Regulation Adjustment Amount	$ 17,106.88	$ (682.27)	$ 16,424.61
	Cost Distribution Charges			
10	Real Time Regulation Reserve Cost Distribution Amount	$ 64,356.09	$ -	$ 64,356.09
11	Real Time Spinnng Reserve Cost Distribution	$ 93,494.45	$ -	$ 93,494.45
12	Real Time Supplemental Reserve Cost Distribution	$ 37,043.42	$ -	$ 37,043.42
	Penalty Charges			
13	Real Time Excessive/Dificient Energy Deployment	$ 150,688.43	$ (8,793.10)	$ 141,895.33
14	Real Time Contigency Reserve Deployment Failure	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	$ 2,885,287.62	$ 102,052.52	$ 2,987,340.14

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)										
5													
6	Forecast North Dakota Sales	190,659	193,918	172,034	162,994	-	-	-	-	-	-	-	-
7													
8	**Current Month Refund Factor**	(0.059)	(0.029)	-	-	-	-	-	-	-	-	-	-
9													
14	Expected Refund	(44,630)	(52,527)	(121,803)	(65,176)	-	-	-	-	-	-	-	-
15	Actual Refunded	(34,718)	(43,979)										
16	Deviation	(9,912)	(8,548)	(121,803)	(65,176)	-	-	-	-	-	-	-	-
17													
18	**True-up Factor**	(0.005)	(0.004)	-	-	-	-	-	-	-	-	-	-
19													
20	**Realized Margin**	(0.064)	(0.034)	-	-	-	-	-	-	-	-	-	-
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)	-	-	-	-	-	-	-	-	-	-
32	C&I Non-Demand	(0.066)	(0.035)	-	-	-	-	-	-	-	-	-	-
33	C&I Demand Non-TOD	(0.065)	(0.034)	-	-	-	-	-	-	-	-	-	-
34	C&I Demand TOD On-Peak	(0.082)	(0.043)	-	-	-	-	-	-	-	-	-	-
35	C&I Demand TOD Off-Peak	(0.050)	(0.027)	-	-	-	-	-	-	-	-	-	-
36	Outdoor Lighting	(0.048)	(0.025)	-	-	-	-	-	-	-	-	-	-

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	-	-	-	-	-	-	-	-	-
7													
8	**Current Month Refund Factor**	(0.007)	(0.007)	(0.007)	-	-	-	-	-	-	-	-	-
13													
14	Expected Refund	(11,060)	(13,140)	(12,137)	-	-	-	-	-	-	-	-	-
15	Actual Refund	(12,560)	(13,605)	(11,517)									
16	Deviation	1,500	465	(620)	-	-	-	-	-	-	-	-	-
17													
18	**True-up Factor**	0.001	0.000	(0.000)	-	-	-	-	-	-	-	-	-
19													
20	**Realized Margin**	(0.006)	(0.007)	(0.007)	-	-	-	-	-	-	-	-	-
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	(0.006)	(0.007)	(0.007)	-	-	-	-	-	-	-	-	-
32	C&I Non-Demand	(0.006)	(0.007)	(0.008)	-	-	-	-	-	-	-	-	-
33	C&I Demand Non-TOD	(0.006)	(0.007)	(0.007)	-	-	-	-	-	-	-	-	-
34	C&I Demand TOD On-Peak	(0.008)	(0.009)	(0.009)	-	-	-	-	-	-	-	-	-
35	C&I Demand TOD Off-Peak	(0.005)	(0.005)	(0.006)	-	-	-	-	-	-	-	-	-
36	Outdoor Lighting	(0.004)	(0.005)	(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)							
5													
6	Forecast North Dakota Sales	193,427	241,910	204,198	190,659	193,918							
7													
8	**Current Month Refund Factor**	(0.145)	-	-	(0.310)	(0.004)							-
13													
14	Expected Refund	-	-	(280,039)	-	(161,476)	-	-	-	-	-	-	-
15	Actual Refund			(118,563)	(183,731)	(75,050)							
16	Deviation	-	-	(161,476)	183,731	(86,426)	-	-	-	-	-	-	-
17													
18	**True-up Factor**	-	-	(0.079)	0.096	(0.045)							-
19													
20	**Realized Margin**	(0.145)	-	(0.079)	(0.213)	**(0.049)**							-
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	(0.145)	-	(0.079)	(0.214)	(0.049)	-	-	-	-	-	-	-
32	C&I Non-Demand	(0.149)	-	(0.081)	(0.219)	(0.050)	-	-	-	-	-	-	-
33	C&I Demand Non-TOD	(0.147)	-	(0.080)	(0.217)	(0.050)	-	-	-	-	-	-	-
34	C&I Demand TOD On-Peak	(0.187)	-	(0.102)	(0.275)	(0.063)	-	-	-	-	-	-	-
35	C&I Demand TOD Off-Peak	(0.114)	-	(0.062)	(0.168)	(0.038)	-	-	-	-	-	-	-
36	Outdoor Lighting	(0.108)	-	(0.059)	(0.159)	(0.036)	-	-	-	-	-	-	-