



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

May 27, 2011

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

Re: June 2011 Fuel Cost Charge

Dear Mr. Nitschke:

Northern States Power Company, a Minnesota corporation operating in North Dakota hereby submits its electric fuel cost charge (“FCC”) for June 2011.

Pursuant to the Commission authorization of the final compliance tariffs in the Company’s 2007 rate proceeding (Case No. PU-07-776) to implement new rates beginning March 1, 2009, a “multi-class” fuel cost mechanism replaced the previous single-factor mechanism. The June 2011 system FCC is based on the average of the most recent four-month actual fuel cost plus a “true-up” factor, reflecting cost recovery deviations during the April 2011 calendar month.

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

June 2011	Fuel Cost Charge (\$/kWh)
Residential	0.02646
C & I Non-Demand	0.02804
C & I Demand	0.02716
C & I Demand Time of Day On-Peak	0.03491
C & I Demand Time of Day Off-Peak	0.02054
Outdoor Lighting	0.01884

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 Order (Docket No. PU-05-147) dated April 6, 2005 and the Order in Docket No. PU-07-776, Xcel Energy is authorized to recover MISO Day 2 costs. The March 2009 FCC reflected the new MISO Day 2 charge types: 3 Auction Revenue Rights (“ARR”) and 3 new 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 June 2011 FCC, the net MISO Day 2 costs for April 2011 as recorded in Account 555. The MISO Day 2 cost recovery included in this June FCC is \$23,319,349, 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 new ASM charge types are included in the Fuel Cost Rider, pursuant to the Commission guidance in Docket No. PU-09-016. Consistent

¹ Previously embedded in other FTR charge types.

with the MISO order and the required “net” accounting of ASM costs and revenues, we include in the June FCC, the net MISO ASM costs for April 2011 as recorded in Account 555. The MISO ASM cost recovery included in this June FCC is \$1,953,522, which is the net of many items. The detailed records are contained in Attachment 2, page 2.

REFUNDS

Pursuant to the above referenced Order Adopting Settlement, the April 2011 Asset Based Margin amount of \$59,388 has been included in the June Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. Starting from February 2011, the 2010 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 2010 Non-Asset Based Margin credit is \$56,225 and this credit amount will be distributed equally each month over the following 12-month period. The refund reflected in the June FCC is \$6,663, or 0.004¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

OTHER REPORTING ITEM

Attached is the calculation of the June 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 /

Phillip J. Zins
Manager, Pricing and Planning
Enclosures (2)
CC: David H. Sederquist

Northern States Power Company, A Minnesota Corporation & Wholly Owned Subsidiary of Xcel Energy Inc.
 Electric Operations - State of North Dakota
 Derivation of Adjustment for Fuel Clause Rider
 Current Period Cost of Energy for Jun-2011

Jun-2011 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02595	\$0.00101	-\$0.00038	\$0.02658
Residential	\$0.02584	\$0.00101	-\$0.00038	\$0.02646
C & I Non-Demand	\$0.02737	\$0.00107	-\$0.00040	\$0.02804
C & I Demand Non-TOD	\$0.02652	\$0.00103	-\$0.00039	\$0.02716
C & I Demand TOD On-Peak	\$0.03409	\$0.00133	-\$0.00050	\$0.03491
C & I Demand TOD Off-Peak	\$0.02005	\$0.00078	-\$0.00029	\$0.02054
Outdoor Lighting	\$0.01839	\$0.00072	-\$0.00027	\$0.01884
Residential				
Residential Service	\$ 0.02584	\$ 0.00101	\$ (0.00038)	\$ 0.02646
Residential TOD	\$ 0.02584	\$ 0.00101	\$ (0.00038)	\$ 0.02646
Residential - Underground	\$ 0.02584	\$ 0.00101	\$ (0.00038)	\$ 0.02646
Residential TOD - Underground	\$ 0.02584	\$ 0.00101	\$ (0.00038)	\$ 0.02646
Energy Control - (Non-Demand)	\$ 0.02584	\$ 0.00101	\$ (0.00038)	\$ 0.02646
Limit Off Peak	\$ 0.02584	\$ 0.00101	\$ (0.00038)	\$ 0.02646
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02737	\$ 0.00107	\$ (0.00040)	\$ 0.02804
Limit Off Peak	\$ 0.02737	\$ 0.00107	\$ (0.00040)	\$ 0.02804
Small General Service	\$ 0.02737	\$ 0.00107	\$ (0.00040)	\$ 0.02804
Small General TOD - Metered	\$ 0.02737	\$ 0.00107	\$ (0.00040)	\$ 0.02804
Small General TOD - Unmetered	\$ 0.02737	\$ 0.00107	\$ (0.00040)	\$ 0.02804
Fire and Civil Defense Siren	\$ 0.02737	\$ 0.00107	\$ (0.00040)	\$ 0.02804
Direct Current (Closed)	\$ 0.02737	\$ 0.00107	\$ (0.00040)	\$ 0.02804
C & I Demand				
General Service	\$ 0.02652	\$ 0.00103	\$ (0.00039)	\$ 0.02716
General TOD - On Peak	\$ 0.03409	\$ 0.00133	\$ (0.00050)	\$ 0.03491
General TOD - Off Peak	\$ 0.02005	\$ 0.00078	\$ (0.00029)	\$ 0.02054
Peak Controlled (Closed)	\$ 0.02652	\$ 0.00103	\$ (0.00039)	\$ 0.02716
Peak Controlled TOD (Closed) - On Peak	\$ 0.03409	\$ 0.00133	\$ (0.00050)	\$ 0.03491
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02005	\$ 0.00078	\$ (0.00029)	\$ 0.02054
Peak Controlled Tiered	\$ 0.02652	\$ 0.00103	\$ (0.00039)	\$ 0.02716
Peak Controlled Tiered TOD - On Peak	\$ 0.03409	\$ 0.00133	\$ (0.00050)	\$ 0.03491
Peak Controlled Tiered TOD - Off Peak	\$ 0.02005	\$ 0.00078	\$ (0.00029)	\$ 0.02054
Energy Controlled (Closed)	\$ 0.02652	\$ 0.00103	\$ (0.00039)	\$ 0.02716
Tier 1 Energy Controlled Rider	\$ 0.02652	\$ 0.00103	\$ (0.00039)	\$ 0.02716
Real Time Pricing - Firm - On Peak	\$ 0.03409	\$ 0.00133	\$ (0.00050)	\$ 0.03491
Real Time Pricing - Firm - Off Peak	\$ 0.02005	\$ 0.00078	\$ (0.00029)	\$ 0.02054
Real Time Pricing - Controllable - On Peak	\$ 0.03409	\$ 0.00133	\$ (0.00050)	\$ 0.03491
Real Time Pricing - Controllable - Off Peak	\$ 0.02005	\$ 0.00078	\$ (0.00029)	\$ 0.02054
Small Municipal Pumping	\$ 0.02652	\$ 0.00103	\$ (0.00039)	\$ 0.02716
Municipal Pumping	\$ 0.02652	\$ 0.00103	\$ (0.00039)	\$ 0.02716
Excess Energy - St. Anthony Falls	\$ 0.02652	\$ 0.00103	\$ (0.00039)	\$ 0.02716
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01839	\$ 0.00072	\$ (0.00027)	\$ 0.01884
Street Lighting System	\$ 0.01839	\$ 0.00072	\$ (0.00027)	\$ 0.01884
Street Lighting Energy	\$ 0.01839	\$ 0.00072	\$ (0.00027)	\$ 0.01884
Street Lighting Energy - Metered	\$ 0.01839	\$ 0.00072	\$ (0.00027)	\$ 0.01884
Street Lighting Energy (Closed)	\$ 0.01839	\$ 0.00072	\$ (0.00027)	\$ 0.01884
Street Lighting - City of St. Paul	\$ 0.01839	\$ 0.00072	\$ (0.00027)	\$ 0.01884

Northern States Power Company, A Minnesota Corporation & Wholly Owned Subsidiary of Xcel Energy Inc.
 Electric Operations - State of North Dakota
 Derivation of Adjustment for Fuel Clause Rider
 Current Period Cost of Energy for Jun-2011

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Jan-11	Feb-11	Mar-11	Apr-11	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$45,110,406	\$38,537,323	\$43,721,305	\$28,258,842	\$155,627,876
Account 518 - Nuclear Fuel	\$10,741,550	\$9,532,671	\$7,780,334	\$6,778,412	\$34,832,967
Account 555 - Purchased Power ¹	\$41,752,106	\$40,007,408	\$38,906,437	\$47,631,320	\$168,297,271
Account 555 - MISO Day 2 Charges	\$12,635,170	\$12,934,596	\$18,257,815	\$23,401,459	\$67,229,039
Account 555 MISO Day 2 - Schedule 24	(\$90,163)	(\$81,156)	(\$85,583)	(\$82,110)	(\$339,012)
Account 555 MISO - ASM Charges	\$119,964	\$4,442,828	(\$1,143,120)	\$1,953,522	\$5,373,195
Total MISO Charges	\$12,664,972	\$17,296,268	\$17,029,112	\$25,272,871	\$72,263,222
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$110,269,033	\$105,373,669	\$107,437,188	\$107,941,445	\$431,021,336
Less Fuel Cost of InterSystem Sales	(\$17,097,148)	(\$13,188,195)	(\$14,210,295)	(\$17,536,970)	(\$62,032,609)
Net System Costs	\$93,171,886	\$92,185,474	\$93,226,893	\$90,404,475	\$368,988,727
System MWh Sales					
Total NSP System Retail	3,962,011	3,324,893	3,624,446	3,070,703	13,982,053
Non-Gen Muni's/Load Pattern	76,589	57,656	51,878	51,955	238,078
Total NSP System MWh Sales	4,038,600	3,382,549	3,676,324	3,122,658	14,220,131
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.307¢	2.725¢	2.536¢	2.895¢	2.595¢
Base Fuel Cost Included in Rates	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢
Class Ratio/TOD Ratio					
(i) Residential	0.9956	0.9956	0.9956	0.9956	0.9956
(ii) C & I Non-Demand	1.0548	1.0548	1.0548	1.0548	1.0548
(iii) C & I Demand Non-TOD	1.0219	1.0219	1.0219	1.0219	1.0219
(iv) C & I Demand TOD On-Peak	1.3135	1.3135	1.3135	1.3135	1.3135
(v) C & I Demand TOD Off-Peak	0.7726	0.7726	0.7726	0.7726	0.7726
(vi) Outdoor Lighting	0.7088	0.7088	0.7088	0.7088	0.7088
North Dakota Fuel Cost Factor (FCF)					
				FCF Ratio	4 Month Average
(i) Residential				0.9956	2.584¢
(ii) C & I Non-Demand				1.0548	2.737¢
(iii) C & I Demand Non-TOD				1.0219	2.652¢
(iv) C & I Demand TOD On-Peak				1.3135	3.409¢
(v) C & I Demand TOD Off-Peak				0.7726	2.005¢
(vi) Outdoor Lighting				0.7088	1.839¢
North Dakota Retail MWh Sales					
(i) Residential	99,111	83,320	86,238	59,524	328,193
(ii) C & I Non-Demand	14,191	11,949	12,922	9,574	48,636
(iii) C & I Demand Non-TOD	72,443	57,938	70,769	53,152	254,302
(iv) C & I Demand TOD On-Peak	16,560	16,999	22,007	18,572	74,138
(v) C & I Demand TOD Off-Peak	29,313	27,539	32,833	27,669	117,354
(vi) Outdoor Lighting	2,237	1,948	1,700	1,574	7,459
(vii) Total	233,855	199,693	226,469	170,065	830,082
Jun-2011 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Feb-11 Balance of Unrecovered Expenses)					Total
					Feb-11
					\$169,474

¹ Excludes demand-related expenses

Prior Expenses Recovered in Apr-2011 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	59,524	(\$24,088)
(ii) C & I Non-Demand	9,574	(\$4,360)
(iii) C & I Demand Non-TOD	53,152	(\$22,438)
(iv) C & I Demand TOD On-Peak	18,572	(\$10,798)
(v) C & I Demand TOD Off-Peak	27,669	(\$9,646)
(vi) Outdoor Lighting	1,574	(\$759)
(vii) Total	170,065	(\$72,089)

Actual Cost Should Have Been Recovered in Apr-11				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.895¢	0.000¢	170,065	\$4,923,382

Cost Recovered in Apr-11 [Billing Record]			
	ND Billed MWh Sales	Actual Recovery	
(i) Residential	59,524	\$1,504,362	
(ii) C & I Non-Demand	9,574	\$256,239	
(iii) C & I Demand Non-TOD	53,152	\$1,377,307	
(iv) C & I Demand TOD On-Peak	18,572	\$618,358	
(v) C & I Demand TOD Off-Peak	27,669	\$541,890	
(vi) Outdoor Lighting	1,574	\$28,184	
(vii) Total	170,065	\$4,326,340	

Total Balance of Unrecovered Expenses (Jun-11 Balance of Unrecovered Expenses)	
Jun-2011 Recovery Provision	\$838,605
4 Month ND Retail Total MWh Sales	830,082
Jun-2011 Recovery Provision per KWH	0.101¢

Jun-2011 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9956	0.101¢	0.101¢
(ii) C & I Non-Demand	1.0548	0.101¢	0.107¢
(iii) C & I Demand Non-TOD	1.0219	0.101¢	0.103¢
(iv) C & I Demand TOD On-Peak	1.3135	0.101¢	0.133¢
(v) C & I Demand TOD Off-Peak	0.7726	0.101¢	0.078¢
(vi) Outdoor Lighting	0.7088	0.101¢	0.072¢

Jun-2011 Margin Sharing Refunds			
Refund/Special Charge Amount	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
	(\$59,388)	(\$6,663)	(\$66,051)
(i) Residential	-0.034¢	-0.004¢	-0.038¢
(ii) C & I Non-Demand	-0.036¢	-0.004¢	-0.040¢
(iii) C & I Demand Non-TOD	-0.035¢	-0.004¢	-0.039¢
(iv) C & I Demand TOD On-Peak	-0.045¢	-0.005¢	-0.050¢
(v) C & I Demand TOD Off-Peak	-0.026¢	-0.003¢	-0.029¢
(vi) Outdoor Lighting	-0.024¢	-0.003¢	-0.027¢

Jun-2011 Factors	
	Total
(i) Residential	2.646¢
(ii) C & I Non-Demand	2.804¢
(iii) C & I Demand Non-TOD	2.716¢
(iv) C & I Demand TOD On-Peak	3.491¢
(v) C & I Demand TOD Off-Peak	2.054¢
(vi) Outdoor Lighting	1.884¢

	FCA Application		Comparison		Generation Type by Percent		
	May-11	Jun-11	Differ- ence	Percent Change	FCA Application May-11	Jun-11	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$170.3	\$155.6	(\$14.7)	-8.6%	40.1%	36.1%	-4.0%
2 Nuclear	\$38.7	\$34.8	(\$3.9)	-10.1%	9.1%	8.1%	-1.0%
3 Purchases	\$154.8	\$168.3	\$13.5	8.7%	36.5%	39.0%	2.5%
MISO related Purchases	\$60.5	\$72.3	\$11.8	19.5%	14.2%	16.8%	2.6%
4 Total System Costs	424.3	431.0	\$6.7	1.6%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$54.0	\$62.0	\$8.1	14.9%	12.7%	14.4%	1.7%
6 Net System Costs	\$370.4	\$369.0	(\$1.4)	-0.4%	87.3%	85.6%	-1.7%
7							
8 ** GWH OUTPUT **							
9 Fossil	6,211	5,617	(594)	-9.6%	36.7%	34.6%	-2.1%
10 Nuclear	4,498	4,006	(492)	-10.9%	26.6%	24.7%	-1.9%
11 Purchases	4,219	4,712	493	11.7%	24.9%	29.0%	4.1%
12 Hydro & Other	1,136	1,176	40	3.5%	6.7%	7.2%	0.5%
13 Net Interchange	871	718	(153)	-17.6%	5.1%	4.4%	-0.7%
14 Total Output	16,935	16,229	(706)	-4.2%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,127	1,017	(110)	-9.8%	6.7%	6.3%	-0.4%
16 Native Requirement	15,808	15,212	(596)	-3.8%	93.3%	93.7%	0.4%
17							
18 ** COST per KWH OUTPUT (\$) **							
19 Fossil	2.742	2.771	0.029	1.0%			
20 Nuclear	0.861	0.870	0.008	0.9%			
21 Purchases	3.670	3.572	-0.098	-2.7%			
22 Total System Costs	2.506	2.656	0.150	6.0%			
23 Intersystem Sales	4.787	6.097	1.310	27.4%			
24 Net System Costs	2.343	2.426	0.083	3.5%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,703	14,220	(483)	-3.3%			
28							
29 COST per KWH SALES (\$)	2.519	2.595	0.076	3.0%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.058	0.101	0.159				
(i) Residential	-0.057	0.101	0.158				
(ii) C & I Non-Demand	-0.061	0.107	0.167				
(iii) C & I Demand Non-TOD	-0.059	0.103	0.162				
(iv) C & I Demand TOD On-Peak	-0.076	0.133	0.208				
(v) C & I Demand TOD Off-Peak	-0.045	0.078	0.123				
(vi) Outdoor Lighting	-0.041	0.072	0.112				
32 REFUND	0.000	0.000	0.000				
(i) Residential	0.000	-0.038					
(ii) C & I Non-Demand	0.000	-0.040					
(iii) C & I Demand Non-TOD	0.000	-0.039					
(iv) C & I Demand TOD On-Peak	0.000	-0.050					
(v) C & I Demand TOD Off-Peak	0.000	-0.029					
(vi) Outdoor Lighting	0.000	-0.027					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.461	2.696	0.235	9.5%			
(i) Residential	2.403	2.646	0.243				
(ii) C & I Non-Demand	2.546	2.804					
(iii) C & I Demand Non-TOD	2.466	2.716					
(iv) C & I Demand TOD On-Peak	3.170	3.491					
(v) C & I Demand TOD Off-Peak	1.865	2.054					
(vi) Outdoor Lighting	1.711	1.884					

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	\$0.24
250	\$0.61
500	\$1.22
750	\$1.83
1,000	\$2.43

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	
	May-11	Jun-11
** GWH OUTPUT **		
Thermal	681,847	612,722
Disper gen	(85)	(77)
Hydro plus Wind	454,363	562,967
Hydro and Other	1,136,125	1,175,612
Rounded to nearest thousand:	1,136	1,176
Sales		
Non Gen Munic Total	252,368,000	238,078,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,127,488,000	1,017,393,000
Rounded to nearest million:	1127.488	1017.393

		System	Intersystem	Retail
April 2011 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 27,760,034.91	\$ 1,958,932.21	\$ 29,718,967.12
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,355,362.93	\$ -	\$ 2,355,362.93
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (11,369,184.96)	\$ -	\$ (11,369,184.96)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,379,301.40	\$ -	\$ 1,379,301.40
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)	\$ (649,837.58)	\$ 1,216,473.96	\$ 566,636.38
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 26,564.19	\$ -	\$ 26,564.19
14	Real-Time Distribution of Losses Amount	\$ (1,451,593.80)	\$ -	\$ (1,451,593.80)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ 9,688.75	\$ -	\$ 9,688.75
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 22,495.91	\$ -	\$ 22,495.91
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (1,794.31)	\$ -	\$ (1,794.31)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 1,746,416.54	\$ -	\$ 1,746,416.54
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 1,596,668.61	\$ -	\$ 1,596,668.61
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)	\$ 58,020.92	\$ -	\$ 58,020.92
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)	\$ (1,974.89)	\$ -	\$ (1,974.89)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (1,739,691.68)	\$ -	\$ (1,739,691.68)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (162,489.81)	\$ -	\$ (162,489.81)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ (224,144.77)	\$ -	\$ (224,144.77)
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ 179,024.39	\$ -	\$ 179,024.39
37	Financial Transmission Guarantee Uplift Amount	\$ (31,935.47)	\$ -	\$ (31,935.47)
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 742,289.57	\$ -	\$ 742,289.57
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 146,962.51	\$ -	\$ 146,962.51
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (167,519.94)	\$ 31,414.48	\$ (136,105.46)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 245,603.31	\$ -	\$ 245,603.31
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (316,533.47)	\$ 73,882.28	\$ (242,651.19)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (515,567.43)	\$ 23,507.67	\$ (492,059.76)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 623,214.42	\$ (6,779.50)	\$ 616,434.92
19	Real-Time Market Administration Amount	\$ 42,925.45	\$ (5,708.44)	\$ 37,217.01
29	Financial Transmission Rights Market Administration Amount	\$ 57,865.92	\$ -	\$ 57,865.92
33	Day-Ahead Schedule 24 Allocation Amount	\$ 78,293.65	\$ (853.60)	\$ 77,440.05
34	Real-Time Schedule 24 Allocation Amount	\$ 5,387.75	\$ (718.18)	\$ 4,669.57
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	\$ 1.25	\$ -	\$ 1.25
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 1,229,776.23	\$ -	\$ 1,229,776.23
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (1,192,084.39)	\$ -	\$ (1,192,084.39)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (445,089.60)	\$ -	\$ (445,089.60)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 74,851.15	\$ -	\$ 74,851.15
TOTAL MISO CHARGES		\$ 20,111,307.66	\$ 3,290,150.88	\$ 23,401,458.54
SCHEDULE 24 (FOR RETAIL)				\$ 82,109.62
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 23,319,348.92

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
April 2011 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (355,185.66)	\$ -	\$ (355,185.66)
2	Day-Ahead Spinning Reserve Amount	\$ (88,536.58)	\$ -	\$ (88,536.58)
3	Day-Ahead Supplemental Reserve	\$ (105,109.35)	\$ -	\$ (105,109.35)
4	Real-Time Regulation Amount	\$ 20,887.04	\$ 252,150.70	\$ 273,037.74
5	Real-Time Spinning Reserve Amount	\$ (10,740.32)	\$ 44,694.76	\$ 33,954.44
6	Real-Time Supplemental Reserve Amount	\$ 4,901.27	\$ 32,549.11	\$ 37,450.38
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (8,473.44)	\$ -	\$ (8,473.44)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ (449,751.86)	\$ -	\$ (449,751.86)
8b	Real Time Non Excessive Energy Congestion	\$ 1,820,678.24	\$ -	\$ 1,820,678.24
8c	Real Time Non Excessive Energy Loss	\$ 195,484.66	\$ -	\$ 195,484.66
9	Real Time Net Regulation Adjustment Amount	\$ 12,725.78	\$ (4,966.29)	\$ 7,759.49
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 286,296.11	\$ -	\$ 286,296.11
11	Real Time Spinning Reserve Cost Distribution	\$ 218,501.07	\$ -	\$ 218,501.07
12	Real Time Supplemental Reserve Cost Distribution	\$ 85,231.44	\$ -	\$ 85,231.44
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 4,125.87	\$ (1,940.54)	\$ 2,185.33
14	Real Time Contignecy Reserve Deployment Failure	\$ -	\$ -	\$ -
TOTAL MISO ASM CHARGES		\$ 1,631,034.27	\$ 322,487.74	\$ 1,953,522.01

Northern States Power Company, A Minnesota Corporation & Wholly Owned Subsidiary of Xcel Energy Inc.
 Electric Operations - State of North Dakota
 Derivation of Adjustment for Fuel Clause Rider
 Non-Asset Based Margin Sharing

Forecast Month	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12
True-up Month	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11
Monthly Refund	(4,685)	(4,685)	(4,685)	(4,685)	(4,685)	(4,685)	(4,685)	(4,685)	(4,685)	(4,685)	(4,685)	(4,685)
Forecast North Dakota Sales	203,291	203,850	171,095	168,639	174,150	172,841	198,618	180,234	167,256	170,405	202,792	-
Current Month Refund Factor	(0.002)	(0.002)	(0.003)	(0.009)	(0.003)	-	-	-	-	-	-	-
Expected Refund	(17,897)	(16,914)	(4,666)	7,377	2,316	(8,362)	(6,663)	(13,047)	(11,348)	(17,733)	(16,034)	(22,419)
Actual Refund	(17,916)	(18,780)	(11,666)	858	4,294	-	-	-	-	-	-	-
Deviation	19	12,062	7,001	6,519	(1,978)	(8,362)	(6,663)	(13,047)	(11,348)	(17,733)	(16,034)	(22,419)
True-up Factor	0.000	0.006	0.004	0.004	(0.001)	-	-	-	-	-	-	-
Realized Margin	(0.002)	0.004	0.001	(0.005)	(0.004)	-	-	-	-	-	-	-
Class Ratios												
Residential	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956
C&I Non-Demand	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548
C&I Demand Non-TOD	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219
C&I Demand TOD On-Peak	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135
C&I Demand TOD Off-Peak	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726
Outdoor Lighting	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088
Realized Margin Adj for Class Ratios												
Residential	(0.002)	0.004	0.001	(0.005)	(0.004)	-	-	-	-	-	-	-
C&I Non-Demand	(0.002)	0.004	0.001	(0.005)	(0.004)	-	-	-	-	-	-	-
C&I Demand Non-TOD	(0.002)	0.004	0.001	(0.005)	(0.004)	-	-	-	-	-	-	-
C&I Demand TOD On-Peak	(0.003)	0.005	0.002	(0.007)	(0.005)	-	-	-	-	-	-	-
C&I Demand TOD Off-Peak	(0.002)	0.003	0.001	(0.004)	(0.003)	-	-	-	-	-	-	-
Outdoor Lighting	(0.002)	0.003	0.001	(0.004)	(0.003)	-	-	-	-	-	-	-