



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

August 31, 2011

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

Re: September 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 September 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 September 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 July 2011 calendar month.

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

September 2011	Fuel Cost Charge (\$/kWh)
Residential	0.03099
C & I Non-Demand	0.03283
C & I Demand	0.03181
C & I Demand Time of Day On-Peak	0.04088
C & I Demand Time of Day Off-Peak	0.02405
Outdoor Lighting	0.02206

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 September 2011 FCC, the net MISO Day 2 costs for July 2011 as recorded in Account 555. The MISO Day 2 cost recovery included in this September FCC is \$22,658,291, 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 September FCC, the net MISO ASM costs for July 2011 as recorded in Account 555. The MISO ASM cost recovery included in this September FCC is \$2,519,375, 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 July 2011 Asset Based Margin amount of \$34,464 has been included in the September 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 September FCC is \$6,492, 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 September 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 Sep-2011

Sep-2011 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02961	\$0.00174	-\$0.00023	\$0.03113
Residential	\$0.02948	\$0.00174	-\$0.00023	\$0.03099
C & I Non-Demand	\$0.03123	\$0.00184	-\$0.00024	\$0.03283
C & I Demand Non-TOD	\$0.03026	\$0.00178	-\$0.00023	\$0.03181
C & I Demand TOD On-Peak	\$0.03889	\$0.00229	-\$0.00030	\$0.04088
C & I Demand TOD Off-Peak	\$0.02288	\$0.00135	-\$0.00018	\$0.02405
Outdoor Lighting	\$0.02099	\$0.00124	-\$0.00016	\$0.02206
Residential				
Residential Service	\$ 0.02948	\$ 0.00174	\$ (0.00023)	\$ 0.03099
Residential TOD	\$ 0.02948	\$ 0.00174	\$ (0.00023)	\$ 0.03099
Residential - Underground	\$ 0.02948	\$ 0.00174	\$ (0.00023)	\$ 0.03099
Residential TOD - Underground	\$ 0.02948	\$ 0.00174	\$ (0.00023)	\$ 0.03099
Energy Control - (Non-Demand)	\$ 0.02948	\$ 0.00174	\$ (0.00023)	\$ 0.03099
Limit Off Peak	\$ 0.02948	\$ 0.00174	\$ (0.00023)	\$ 0.03099
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.03123	\$ 0.00184	\$ (0.00024)	\$ 0.03283
Limit Off Peak	\$ 0.03123	\$ 0.00184	\$ (0.00024)	\$ 0.03283
Small General Service	\$ 0.03123	\$ 0.00184	\$ (0.00024)	\$ 0.03283
Small General TOD - Metered	\$ 0.03123	\$ 0.00184	\$ (0.00024)	\$ 0.03283
Small General TOD - Unmetered	\$ 0.03123	\$ 0.00184	\$ (0.00024)	\$ 0.03283
Fire and Civil Defense Siren	\$ 0.03123	\$ 0.00184	\$ (0.00024)	\$ 0.03283
Direct Current (Closed)	\$ 0.03123	\$ 0.00184	\$ (0.00024)	\$ 0.03283
C & I Demand				
General Service	\$ 0.03026	\$ 0.00178	\$ (0.00023)	\$ 0.03181
General TOD - On Peak	\$ 0.03889	\$ 0.00229	\$ (0.00030)	\$ 0.04088
General TOD - Off Peak	\$ 0.02288	\$ 0.00135	\$ (0.00018)	\$ 0.02405
Peak Controlled (Closed)	\$ 0.03026	\$ 0.00178	\$ (0.00023)	\$ 0.03181
Peak Controlled TOD (Closed) - On Peak	\$ 0.03889	\$ 0.00229	\$ (0.00030)	\$ 0.04088
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02288	\$ 0.00135	\$ (0.00018)	\$ 0.02405
Peak Controlled Tiered	\$ 0.03026	\$ 0.00178	\$ (0.00023)	\$ 0.03181
Peak Controlled Tiered TOD - On Peak	\$ 0.03889	\$ 0.00229	\$ (0.00030)	\$ 0.04088
Peak Controlled Tiered TOD - Off Peak	\$ 0.02288	\$ 0.00135	\$ (0.00018)	\$ 0.02405
Energy Controlled (Closed)	\$ 0.03026	\$ 0.00178	\$ (0.00023)	\$ 0.03181
Tier 1 Energy Controlled Rider	\$ 0.03026	\$ 0.00178	\$ (0.00023)	\$ 0.03181
Real Time Pricing - Firm - On Peak	\$ 0.03889	\$ 0.00229	\$ (0.00030)	\$ 0.04088
Real Time Pricing - Firm - Off Peak	\$ 0.02288	\$ 0.00135	\$ (0.00018)	\$ 0.02405
Real Time Pricing - Controllable - On Peak	\$ 0.03889	\$ 0.00229	\$ (0.00030)	\$ 0.04088
Real Time Pricing - Controllable - Off Peak	\$ 0.02288	\$ 0.00135	\$ (0.00018)	\$ 0.02405
Small Municipal Pumping	\$ 0.03026	\$ 0.00178	\$ (0.00023)	\$ 0.03181
Municipal Pumping	\$ 0.03026	\$ 0.00178	\$ (0.00023)	\$ 0.03181
Excess Energy - St. Anthony Falls	\$ 0.03026	\$ 0.00178	\$ (0.00023)	\$ 0.03181
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.02099	\$ 0.00124	\$ (0.00016)	\$ 0.02206
Street Lighting System	\$ 0.02099	\$ 0.00124	\$ (0.00016)	\$ 0.02206
Street Lighting Energy	\$ 0.02099	\$ 0.00124	\$ (0.00016)	\$ 0.02206
Street Lighting Energy - Metered	\$ 0.02099	\$ 0.00124	\$ (0.00016)	\$ 0.02206
Street Lighting Energy (Closed)	\$ 0.02099	\$ 0.00124	\$ (0.00016)	\$ 0.02206
Street Lighting - City of St. Paul	\$ 0.02099	\$ 0.00124	\$ (0.00016)	\$ 0.02206

	Column (A) Apr-11	Column (B) May-11	Column (C) Jun-11	Column (D) Jul-11	Column (E) 4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$28,258,842	\$35,283,583	\$37,703,245	\$59,929,940	\$161,175,610
Account 518 - Nuclear Fuel	\$6,778,412	\$3,922,509	\$8,998,877	\$11,208,057	\$30,907,855
Account 555 - Purchased Power ¹	\$47,631,320	\$49,169,423	\$44,306,074	\$44,383,414	\$185,490,232
Account 555 - MISO Day 2 Charges	\$23,401,459	\$21,065,785	\$17,352,507	\$22,767,976	\$84,587,727
Account 555 MISO Day 2 - Schedule 24	(\$82,110)	(\$82,724)	(\$99,973)	(\$109,686)	(\$374,492)
Account 555 MISO - ASM Charges	\$1,953,522	\$770,873	(\$704,521)	\$2,519,375	\$4,539,249
Total MISO Charges	\$25,272,871	\$21,753,935	\$16,548,012	\$25,177,665	\$88,752,483
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$107,941,445	\$110,129,450	\$107,556,209	\$140,699,077	\$466,326,181
Less Fuel Cost of InterSystem Sales	(\$17,536,970)	(\$16,801,539)	(\$13,538,555)	(\$13,090,852)	(\$60,967,916)
Net System Costs	\$90,404,475	\$93,327,911	\$94,017,654	\$127,608,225	\$405,358,264
System MWh Sales					
Total NSP System Retail	3,070,703	3,181,530	3,473,679	3,774,374	13,500,286
Non-Gen Muni's/Load Pattern	51,955	47,236	43,823	45,964	188,978
Total NSP System MWh Sales	3,122,658	3,228,766	3,517,502	3,820,338	13,689,264
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.895¢	2.891¢	2.673¢	3.340¢	2.961¢
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	2.948¢
(ii) C & I Non-Demand				1.0548	3.123¢
(iii) C & I Demand Non-TOD				1.0219	3.026¢
(iv) C & I Demand TOD On-Peak				1.3135	3.889¢
(v) C & I Demand TOD Off-Peak				0.7726	2.288¢
(vi) Outdoor Lighting				0.7088	2.099¢
North Dakota Retail MWh Sales					
(i) Residential	59,524	53,251	51,748	57,265	221,788
(ii) C & I Non-Demand	9,574	10,155	8,668	8,378	36,775
(iii) C & I Demand Non-TOD	53,152	58,714	58,924	61,664	232,454
(iv) C & I Demand TOD On-Peak	18,572	17,438	19,267	18,395	73,672
(v) C & I Demand TOD Off-Peak	27,669	27,857	30,957	30,048	116,531
(vi) Outdoor Lighting	1,574	1,312	1,221	1,108	5,215
(vii) Total	170,065	168,727	170,785	176,858	686,435
Sep-2011 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (May-11 Balance of Unrecovered Expenses)					Total
					May-11
					\$111,227

¹ Excludes demand-related expenses

Prior Expenses Recovered in Jul-2011 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	57,265	\$30,633
(ii) C & I Non-Demand	8,378	\$4,884
(iii) C & I Demand Non-TOD	61,664	\$33,496
(iv) C & I Demand TOD On-Peak	18,395	\$14,001
(v) C & I Demand TOD Off-Peak	30,048	\$13,223
(vi) Outdoor Lighting	1,108	\$615
(vii) Total	176,858	\$96,852

Actual Cost Should Have Been Recovered in Jul-11				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	3.340¢	0.000¢	176,858	\$5,907,057

Cost Recovered in Jul-11 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	57,265	\$1,527,803
(ii) C & I Non-Demand	8,378	\$235,930
(iii) C & I Demand Non-TOD	61,664	\$1,677,606
(iv) C & I Demand TOD On-Peak	18,395	\$643,572
(v) C & I Demand TOD Off-Peak	30,048	\$618,862
(vi) Outdoor Lighting	1,108	\$20,671
(vii) Total	176,858	\$4,724,444

Total Balance of Unrecovered Expenses (Sep-11 Balance of Unrecovered Expenses)	
Sep-2011 Recovery Provision	\$1,196,988
4 Month ND Retail Total MWh Sales	686,435
Sep-2011 Recovery Provision per KWH	0.174¢

Sep-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	0.174¢	0.174¢
(ii) C & I Non-Demand	1.0548	0.174¢	0.184¢
(iii) C & I Demand Non-TOD	1.0219	0.174¢	0.178¢
(iv) C & I Demand TOD On-Peak	1.3135	0.174¢	0.229¢
(v) C & I Demand TOD Off-Peak	0.7726	0.174¢	0.135¢
(vi) Outdoor Lighting	0.7088	0.174¢	0.124¢

Sep-2011 Margin Sharing Refunds			
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
Refund/Special Charge Amount	(\$34,464)	(\$6,492)	(\$40,956)
(i) Residential	-0.019¢	-0.004¢	-0.023¢
(ii) C & I Non-Demand	-0.020¢	-0.004¢	-0.024¢
(iii) C & I Demand Non-TOD	-0.020¢	-0.004¢	-0.023¢
(iv) C & I Demand TOD On-Peak	-0.025¢	-0.005¢	-0.030¢
(v) C & I Demand TOD Off-Peak	-0.015¢	-0.003¢	-0.018¢
(vi) Outdoor Lighting	-0.014¢	-0.003¢	-0.016¢

Sep-2011 Factors	
	Total
(i) Residential	3.099¢
(ii) C & I Non-Demand	3.283¢
(iii) C & I Demand Non-TOD	3.181¢
(iv) C & I Demand TOD On-Peak	4.088¢
(v) C & I Demand TOD Off-Peak	2.405¢
(vi) Outdoor Lighting	2.206¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Aug-11	Sep-11	Differ- ence	Percent Change	FCA Application Aug-11	Sep-11	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$145.0	\$161.2	\$16.2	11.2%	33.5%	34.6%	1.1%
2 Nuclear	\$27.5	\$30.9	\$3.4	12.5%	6.3%	6.6%	0.3%
3 Purchases	\$180.0	\$185.5	\$5.5	3.0%	41.6%	39.8%	-1.8%
MISO related Purchases	\$80.6	\$88.8	\$8.1	10.1%	18.6%	19.0%	0.4%
4 Total System Costs	433.1	466.3	\$33.3	7.7%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$62.1	\$61.0	(\$1.1)	-1.8%	14.3%	13.1%	-1.2%
6 Net System Costs	\$371.0	\$405.4	\$34.4	9.3%	85.7%	86.9%	1.2%
7							
** GWH OUTPUT **							
9 Fossil	5,417	5,444	27	0.5%	34.8%	33.2%	-1.6%
10 Nuclear	2,974	3,273	299	10.1%	19.1%	20.0%	0.9%
11 Purchases	5,434	5,711	277	5.1%	34.9%	34.9%	0.0%
12 Hydro & Other	1,032	1,350	318	30.8%	6.6%	8.2%	1.6%
13 Net Interchange	730	606	(124)	-17.0%	4.7%	3.7%	-1.0%
14 Total Output	15,587	16,384	797	5.1%	100.0%	100.0%	0.0%
15 Intersystem Sales	492	870	378	76.9%	3.2%	5.3%	2.1%
16 Native Requirement	15,095	15,514	419	2.8%	96.8%	94.7%	-2.1%
17							
** COST per KWH OUTPUT (\$) **							
19 Fossil	2.676	2.961	0.284	10.6%			
20 Nuclear	0.924	0.944	0.020	2.2%			
21 Purchases	3.313	3.248	-0.065	-2.0%			
22 Total System Costs	2.778	2.846	0.068	2.4%			
23 Intersystem Sales	12.619	7.004	-5.615	-44.5%			
24 Net System Costs	2.458	2.613	0.155	6.3%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,545	13,689	144	1.1%			
28							
29 COST per KWH SALES (\$)	2.739	2.961	0.222	8.1%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	0.137	0.174	0.037				
(i) Residential	0.136	0.174	0.037				
(ii) C & I Non-Demand	0.145	0.184	0.039				
(iii) C & I Demand Non-TOD	0.140	0.178	0.038				
(iv) C & I Demand TOD On-Peak	0.180	0.229	0.049				
(v) C & I Demand TOD Off-Peak	0.106	0.135	0.029				
(vi) Outdoor Lighting	0.097	0.124	0.026				
32 REFUND	-0.008	0.000	0.008				
(i) Residential	-0.008	-0.023					
(ii) C & I Non-Demand	-0.008	-0.024					
(iii) C & I Demand Non-TOD	-0.008	-0.023					
(iv) C & I Demand TOD On-Peak	-0.011	-0.030					
(v) C & I Demand TOD Off-Peak	-0.006	-0.018					
(vi) Outdoor Lighting	-0.006	-0.016					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.868	3.135	0.267	9.3%			
(i) Residential	2.855	3.099	0.244				
(ii) C & I Non-Demand	3.025	3.283					
(iii) C & I Demand Non-TOD	2.931	3.181					
(iv) C & I Demand TOD On-Peak	3.767	4.088					
(v) C & I Demand TOD Off-Peak	2.216	2.405					
(vi) Outdoor Lighting	2.033	2.206					

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	\$2.44

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>	
	Aug-11	Sep-11
** GWH OUTPUT **		
Thermal	418,857	790,284
Disper gen	(55)	(56)
Hydro plus Wind	612,790	559,331
Hydro and Other	1,031,592	1,349,559
Rounded to nearest thousand:	1,032	1,350
Sales		
Non Gen Munic Total	194,892,000	188,978,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	492,004,000	870,471,000
Rounded to nearest million:	492.004	870.471

		July 2011 Actual		
		System	Intersystem	Retail
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 37,744,145.56	\$ 2,124,891.70	\$ 39,869,037.26
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 4,732,495.39	\$ -	\$ 4,732,495.39
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (24,461,666.34)	\$ -	\$ (24,461,666.34)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 2,779,453.58	\$ -	\$ 2,779,453.58
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)	\$ 1,672,199.92	\$ 988,985.93	\$ 2,661,185.85
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 198,233.71	\$ -	\$ 198,233.71
14	Real-Time Distribution of Losses Amount	\$ (2,204,837.07)	\$ -	\$ (2,204,837.07)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (149,559.54)	\$ -	\$ (149,559.54)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ (5,641.70)	\$ -	\$ (5,641.70)
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ 772.22	\$ -	\$ 772.22
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 47,810.40	\$ -	\$ 47,810.40
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 2,233,006.25	\$ -	\$ 2,233,006.25
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)	\$ 477,844.43	\$ -	\$ 477,844.43
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)	\$ 717.87	\$ -	\$ 717.87
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (4,393,315.61)	\$ -	\$ (4,393,315.61)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (53,127.69)	\$ -	\$ (53,127.69)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (5,689.81)	\$ -	\$ (5,689.81)
37	Financial Transmission Guarantee Uplift Amount	\$ 5,689.81	\$ -	\$ 5,689.81
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 548,416.03	\$ -	\$ 548,416.03
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 366,037.53	\$ -	\$ 366,037.53
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (148,221.70)	\$ 10,579.50	\$ (137,642.20)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 868,945.47	\$ -	\$ 868,945.47
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ (902,735.49)	\$ 52,695.81	\$ (850,039.68)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (279,473.86)	\$ 4,931.29	\$ (274,542.57)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 657,801.54	\$ (3,859.18)	\$ 653,942.36
19	Real-Time Market Administration Amount	\$ 48,544.45	\$ (2,130.02)	\$ 46,414.43
29	Financial Transmission Rights Market Administration Amount	\$ 58,909.52	\$ -	\$ 58,909.52
33	Day-Ahead Schedule 24 Allocation Amount	\$ 103,095.04	\$ (629.08)	\$ 102,465.96
34	Real -Time Schedule 24 Allocation Amount	\$ 7,570.30	\$ (350.69)	\$ 7,219.61
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	\$ (2,176.47)	\$ -	\$ (2,176.47)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 2,832,430.59	\$ -	\$ 2,832,430.59
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (2,913,019.77)	\$ -	\$ (2,913,019.77)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (371,010.89)	\$ -	\$ (371,010.89)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 99,217.14	\$ -	\$ 99,217.14
TOTAL MISO CHARGES		\$ 19,592,860.81	\$ 3,175,115.26	\$ 22,767,976.07
SCHEDULE 24 (FOR RETAIL)				\$ 109,685.57
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 22,658,290.50

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
July 2011 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (735,662.57)	\$ -	\$ (735,662.57)
2	Day-Ahead Spinning Reserve Amount	\$ (56,813.69)	\$ -	\$ (56,813.69)
3	Day-Ahead Supplemental Reserve	\$ (149,856.90)	\$ -	\$ (149,856.90)
4	Real-Time Regulation Amount	\$ (34,388.80)	\$ 386,405.05	\$ 352,016.25
5	Real-Time Spinning Reserve Amount	\$ (202,337.08)	\$ 127,770.05	\$ (74,567.03)
6	Real-Time Supplemental Reserve Amount.	\$ 65,857.81	\$ 43,241.71	\$ 109,099.52
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (36,813.20)	\$ -	\$ (36,813.20)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 2,778,668.35	\$ -	\$ 2,778,668.35
8b	Real Time Non Excessive Energy Congestion	\$ (401,198.21)	\$ -	\$ (401,198.21)
8c	Real Time Non Excessive Energy Loss	\$ (26,875.97)	\$ -	\$ (26,875.97)
9	Real Time Net Regulation Adjustment Amount	\$ 60,639.71	\$ (2,203.41)	\$ 58,436.30
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 383,771.30	\$ -	\$ 383,771.30
11	Real Time Spinning Reserve Cost Distribution	\$ 186,158.43	\$ -	\$ 186,158.43
12	Real Time Supplemental Reserve Cost Distribution	\$ 111,695.85	\$ -	\$ 111,695.85
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 23,520.78	\$ (2,204.26)	\$ 21,316.52
14	Real Time Contignecy Reserve Deployment Failure	\$ -	\$ -	\$ -
TOTAL MISO ASM CHARGES		\$ 1,966,365.81	\$ 553,009.14	\$ 2,519,374.95

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
 Asset Based Margin Sharing

	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12
1 Forecast Month	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
2 True-up Month												
3												
4 Monthly Refund	(72,651)	(19,186)	(84,041)	(55,415)	(21,946)	(18,191)	(48,511)					
5												
6 Forecast North Dakota Sales	203,850	171,035	168,639	174,150	172,841	198,618	180,234	167,256	170,405	-	-	-
7												
8 Current Month Refund Factor	(0.036)	(0.011)	(0.050)	(0.032)	(0.013)	(0.009)	(0.024)	-	-	-	-	-
9												
14 Expected Refund	(25,037)	(44,836)	(29,737)	(32,785)	(72,439)	(59,388)	(44,704)	(12,248)	(34,464)	-	-	-
15 Actual Refunded	(38,347)	(31,238)	(41,339)	(28,812)	(49,681)	(65,331)	(53,751)					
16 Deviation	42,914	(13,599)	11,602	(3,973)	(22,758)	5,943	9,047	(12,248)	(34,464)	-	-	-
17												
18 True-up Factor	0.021	(0.008)	0.007	(0.002)	(0.013)	0.003	0.005	-	-	-	-	-
19												
20 Realized Margin	(0.015)	(0.019)	(0.043)	(0.034)	(0.026)	(0.006)	(0.019)	-	-	-	-	-
21												
22 Class Ratios												
23 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
24 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
25 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
26 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
27 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
28 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
29												
30 Realized Margin Adj for Class Ratios												
31 Residential	(0.015)	(0.019)	(0.043)	(0.034)	(0.026)	(0.006)	(0.019)	-	-	-	-	-
32 C&I Non-Demand	(0.015)	(0.020)	(0.045)	(0.036)	(0.027)	(0.007)	(0.020)	-	-	-	-	-
33 C&I Demand Non-TOD	(0.015)	(0.020)	(0.044)	(0.035)	(0.026)	(0.006)	(0.020)	-	-	-	-	-
34 C&I Demand TOD On-Peak	(0.019)	(0.025)	(0.056)	(0.045)	(0.034)	(0.008)	(0.025)	-	-	-	-	-
35 C&I Demand TOD Off-Peak	(0.011)	(0.015)	(0.033)	(0.026)	(0.020)	(0.005)	(0.015)	-	-	-	-	-
36 Outdoor Lighting	(0.010)	(0.014)	(0.030)	(0.024)	(0.018)	(0.004)	(0.014)	-	-	-	-	-

