



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

November 30, 2010

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

Re: December 2010 Fuel Cost Charge

Dear Mr. Nitschke:

Northern States Power Company, a Minnesota corporation operating in North Dakota hereby submits electric fuel cost charge (FCC) for December 2010.

Pursuant to the Commission authorization of the final compliance tariffs in Company's 2007 rate proceeding (Docket No. PU-07-776) to implement new rates beginning March 1, 2009, a "multi-class" fuel cost mechanism replaced the previously single-factor mechanism. The December 2010 system FCC is based on the average of the most recent four-month actual fuel cost plus the "True-up" factor, reflecting cost recovery deviations from the October 2010 calendar month.

The former system average monthly fuel cost charge is now differentiated into 6 customer class categories (see derivation of these factors on Attachment 1, page 2 to 4).

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

December 2010	Fuel Cost Charge (\$/kWh)
Residential	0.02539
C & I Non-Demand	0.02690
C & I Demand	0.02606
C & I Demand Time of Day On-Peak	0.03350
C & I Demand Time of Day Off-Peak	0.01970
Outdoor Lighting	0.01808

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 PU-07-776, Xcel Energy is authorized to recover MISO Day 2 costs. The March FCC 2009 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 Fuel Cost Rider. Consistent with this Order and the required “net” accounting of Day 2 costs and revenues, we have included in the December FCC, the net MISO Day 2 costs for October 2010 as recorded in Account 555. The MISO Day 2 cost recovery included in this December FCC is \$13,138,171, 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.

On May 6, 2009 FERC issued Order (Docket No. EL07-86-005, *et al.*) reversing portions of the prior decision (November 2008) on MISO RSG that resulted in a resettlement adjustment in FCC. The Company is in the process of evaluating this reversal impact and will reflect this adjustment in the subsequent FCC.

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 new ASM charges types are included in the Fuel Cost Rider, pursuant to the Commission guidance in Docket No. PU-09-016. Consistent with the MISO order and the required “net” accounting of ASM costs and revenues, we include in the December FCC, the net MISO ASM costs for October 2010 as recorded in Account 555. The MISO ASM cost recovery included in this December FCC is \$1,826,511, 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 October 2010 Asset Based Margin amount of \$41,503 has been included in the December Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. Starting from February 2010, the 2009 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 2009 Non-Asset Based Margin credit is \$201,971 and this credit amount will be distributed equally each month over the following 12-month period. The refund reflected in the December FCC is \$17,897, or 0.008¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

OTHER REPORTING ITEM

Attachment is the calculation of the December 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

Dec-2010 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02613	-\$0.00034	-\$0.00028	\$0.02550
Residential	\$0.02602	-\$0.00034	-\$0.00028	\$0.02539
C & I Non-Demand	\$0.02756	-\$0.00036	-\$0.00030	\$0.02690
C & I Demand Non-TOD	\$0.02670	-\$0.00035	-\$0.00029	\$0.02606
C & I Demand TOD On-Peak	\$0.03432	-\$0.00045	-\$0.00037	\$0.03350
C & I Demand TOD Off-Peak	\$0.02019	-\$0.00027	-\$0.00022	\$0.01970
Outdoor Lighting	\$0.01852	-\$0.00024	-\$0.00020	\$0.01808
Residential				
Residential Service	\$ 0.02602	\$ (0.00034)	\$ (0.00028)	\$ 0.02539
Residential TOD	\$ 0.02602	\$ (0.00034)	\$ (0.00028)	\$ 0.02539
Residential - Underground	\$ 0.02602	\$ (0.00034)	\$ (0.00028)	\$ 0.02539
Residential TOD - Underground	\$ 0.02602	\$ (0.00034)	\$ (0.00028)	\$ 0.02539
Energy Control - (Non-Demand)	\$ 0.02602	\$ (0.00034)	\$ (0.00028)	\$ 0.02539
Limit Off Peak	\$ 0.02602	\$ (0.00034)	\$ (0.00028)	\$ 0.02539
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02756	\$ (0.00036)	\$ (0.00030)	\$ 0.02690
Limit Off Peak	\$ 0.02756	\$ (0.00036)	\$ (0.00030)	\$ 0.02690
Small General Service	\$ 0.02756	\$ (0.00036)	\$ (0.00030)	\$ 0.02690
Small General TOD - Metered	\$ 0.02756	\$ (0.00036)	\$ (0.00030)	\$ 0.02690
Small General TOD - Unmetered	\$ 0.02756	\$ (0.00036)	\$ (0.00030)	\$ 0.02690
Fire and Civil Defense Siren	\$ 0.02756	\$ (0.00036)	\$ (0.00030)	\$ 0.02690
Direct Current (Closed)	\$ 0.02756	\$ (0.00036)	\$ (0.00030)	\$ 0.02690
C & I Demand				
General Service	\$ 0.02670	\$ (0.00035)	\$ (0.00029)	\$ 0.02606
General TOD - On Peak	\$ 0.03432	\$ (0.00045)	\$ (0.00037)	\$ 0.03350
General TOD - Off Peak	\$ 0.02019	\$ (0.00027)	\$ (0.00022)	\$ 0.01970
Peak Controlled (Closed)	\$ 0.02670	\$ (0.00035)	\$ (0.00029)	\$ 0.02606
Peak Controlled TOD (Closed) - On Peak	\$ 0.03432	\$ (0.00045)	\$ (0.00037)	\$ 0.03350
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02019	\$ (0.00027)	\$ (0.00022)	\$ 0.01970
Peak Controlled Tiered	\$ 0.02670	\$ (0.00035)	\$ (0.00029)	\$ 0.02606
Peak Controlled Tiered TOD - On Peak	\$ 0.03432	\$ (0.00045)	\$ (0.00037)	\$ 0.03350
Peak Controlled Tiered TOD - Off Peak	\$ 0.02019	\$ (0.00027)	\$ (0.00022)	\$ 0.01970
Energy Controlled (Closed)	\$ 0.02670	\$ (0.00035)	\$ (0.00029)	\$ 0.02606
Tier 1 Energy Controlled Rider	\$ 0.02670	\$ (0.00035)	\$ (0.00029)	\$ 0.02606
Real Time Pricing - Firm - On Peak	\$ 0.03432	\$ (0.00045)	\$ (0.00037)	\$ 0.03350
Real Time Pricing - Firm - Off Peak	\$ 0.02019	\$ (0.00027)	\$ (0.00022)	\$ 0.01970
Real Time Pricing - Controllable - On Peak	\$ 0.03432	\$ (0.00045)	\$ (0.00037)	\$ 0.03350
Real Time Pricing - Controllable - Off Peak	\$ 0.02019	\$ (0.00027)	\$ (0.00022)	\$ 0.01970
Small Municipal Pumping	\$ 0.02670	\$ (0.00035)	\$ (0.00029)	\$ 0.02606
Municipal Pumping	\$ 0.02670	\$ (0.00035)	\$ (0.00029)	\$ 0.02606
Excess Energy - St. Anthony Falls	\$ 0.02670	\$ (0.00035)	\$ (0.00029)	\$ 0.02606
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01852	\$ (0.00024)	\$ (0.00020)	\$ 0.01808
Street Lighting System	\$ 0.01852	\$ (0.00024)	\$ (0.00020)	\$ 0.01808
Street Lighting Energy	\$ 0.01852	\$ (0.00024)	\$ (0.00020)	\$ 0.01808
Street Lighting Energy - Metered	\$ 0.01852	\$ (0.00024)	\$ (0.00020)	\$ 0.01808
Street Lighting Energy (Closed)	\$ 0.01852	\$ (0.00024)	\$ (0.00020)	\$ 0.01808
Street Lighting - City of St. Paul	\$ 0.01852	\$ (0.00024)	\$ (0.00020)	\$ 0.01808

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 Dec-2010

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Jul-10	Aug-10	Sep-10	Oct-10	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$55,067,341	\$58,449,676	\$32,483,786	\$27,904,463	\$173,905,266
Account 518 - Nuclear Fuel	\$10,499,991	\$10,436,900	\$10,120,300	\$10,528,653	\$41,585,842
Account 555 - Purchased Power ¹	\$56,703,451	\$51,892,571	\$42,858,688	\$35,333,149	\$186,787,859
Account 555 - MISO Day 2 Charges	\$19,722,045	\$19,796,437	\$10,215,984	\$13,229,787	\$62,964,253
Account 555 MISO Day 2 - Schedule 24	(\$96,885)	(\$102,950)	(\$88,143)	(\$91,617)	(\$379,595)
Account 555 MISO - ASM Charges	(\$3,335,760)	(\$1,843,516)	(\$465,255)	\$1,826,511	(\$3,818,020)
Total MISO Charges	\$16,289,400	\$17,849,971	\$9,662,585	\$14,964,682	\$58,766,638
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$138,560,182	\$138,629,117	\$95,125,359	\$88,730,947	\$461,045,605
Less Fuel Cost of InterSystem Sales	(\$23,721,609)	(\$16,801,461)	(\$15,484,547)	(\$6,507,051)	(\$62,514,668)
Net System Costs	\$114,838,573	\$121,827,656	\$79,640,812	\$82,223,896	\$398,530,938
System MWH Sales					
Total NSP System Retail	3,841,078	4,249,406	3,737,306	3,133,138	14,960,928
Non-Gen Muni's/Load Pattern	67,976	77,837	80,260	64,086	290,159
Total NSP System MWh Sales	3,909,054	4,327,243	3,817,566	3,197,224	15,251,087
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.938¢	2.815¢	2.086¢	2.572¢	2.613¢
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	2.602¢
(ii) C & I Non-Demand				1.0548	2.756¢
(iii) C & I Demand Non-TOD				1.0219	2.670¢
(iv) C & I Demand TOD On-Peak				1.3135	3.432¢
(v) C & I Demand TOD Off-Peak				0.7726	2.019¢
(vi) Outdoor Lighting				0.7088	1.852¢

¹ Excludes demand-related expenses

North Dakota Retail MWh Sales					
(i) Residential	59,551	66,473	53,979	44,866	224,869
(ii) C & I Non-Demand	10,009	10,272	9,169	8,175	37,625
(iii) C & I Demand Non-TOD	60,762	63,143	60,097	56,339	240,341
(iv) C & I Demand TOD On-Peak	18,832	20,271	19,488	18,625	77,216
(v) C & I Demand TOD Off-Peak	29,571	31,083	30,560	28,988	120,202
(vi) Outdoor Lighting	1,129	1,195	1,405	1,301	5,030
(vii) Total	179,854	192,437	174,698	158,294	705,283

Dec-2010 Recovery Provision (True-up Factor) Calculation	
Prior Unrecovered Expenses (Aug-10 Balance of Unrecovered Expenses)	Total
	Aug-10
	\$376,263

Prior Expenses Recovered in Oct-2010				
	FCF Ratio	True-Up Factor per kWh	Actual ND MWh Sales	Prior Received Expenses in
(i) Residential				
(ii) C & I Non-Demand	0.9956	0.054¢	44,866	\$24,252
(iii) C & I Demand Non-TOD	1.0548	0.057¢	8,175	\$4,682
(iv) C & I Demand TOD On-Peak	1.0219	0.055¢	56,339	\$31,259
(v) C & I Demand TOD Off-Peak	1.3135	0.071¢	18,625	\$13,282
(vi) Outdoor Lighting	0.7726	0.042¢	28,988	\$12,160
(vii) Total	0.7088	0.038¢	1,301	\$501
			158,294	\$86,136

Actual Cost Should Have Been Recovered in Oct-10				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.572¢	0.000¢	158,294	\$4,071,322

Cost Recovered in Oct-10				
	FCF Ratio	Fuel Cost Recovered	Actual ND MWh Sales	Actual Recovery
(i) Residential	0.9956	2.889¢	44,866	\$1,296,282
(ii) C & I Non-Demand	1.0548	3.061¢	8,175	\$250,239
(iii) C & I Demand Non-TOD	1.0219	2.966¢	56,339	\$1,670,763
(iv) C & I Demand TOD On-Peak	1.3135	3.812¢	18,625	\$709,943
(v) C & I Demand TOD Off-Peak	0.7726	2.242¢	28,988	\$649,936
(vi) Outdoor Lighting	0.7088	2.057¢	1,301	\$26,761
(vii) Total			158,294	\$4,603,925

Total Balance of Unrecovered Expenses (Dec-10 Balance of Unrecovered Expenses)	
Dec-2010 Recovery Provision	(\$242,476)
4 Month ND Retail Total MWh Sales	705,283
Dec-2010 Recovery Provision per KWH	-0.034¢

Dec-2010 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9956	-0.034¢	-0.034¢
(ii) C & I Non-Demand	1.0548	-0.034¢	-0.036¢
(iii) C & I Demand Non-TOD	1.0219	-0.034¢	-0.035¢
(iv) C & I Demand TOD On-Peak	1.3135	-0.034¢	-0.045¢
(v) C & I Demand TOD Off-Peak	0.7726	-0.034¢	-0.027¢
(vi) Outdoor Lighting	0.7088	-0.034¢	-0.024¢
Dec-2010 Margin Sharing Refunds			
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
Refund/Special Charge Amount	(\$41,503)	(\$17,897)	(\$59,400)
(i) Residential	-0.020¢	-0.008¢	-0.028¢
(ii) C & I Non-Demand	-0.021¢	-0.009¢	-0.030¢
(iii) C & I Demand Non-TOD	-0.020¢	-0.009¢	-0.029¢
(iv) C & I Demand TOD On-Peak	-0.026¢	-0.011¢	-0.037¢
(v) C & I Demand TOD Off-Peak	-0.015¢	-0.007¢	-0.022¢
(vi) Outdoor Lighting	-0.014¢	-0.006¢	-0.020¢
Dec-2010 Factors			
	Total		
(i) Residential	2.539¢		
(ii) C & I Non-Demand	2.690¢		
(iii) C & I Demand Non-TOD	2.606¢		
(iv) C & I Demand TOD On-Peak	3.350¢		
(v) C & I Demand TOD Off-Peak	1.970¢		
(vi) Outdoor Lighting	1.808¢		

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		
	Nov-10	Dec-10	Differ- ence	Percent Change	FCA Application Nov-10	Dec-10	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$185.9	\$173.9	(\$12.0)	-6.5%	39.0%	37.7%	-1.3%
2 Nuclear	\$41.3	\$41.6	\$0.3	0.7%	8.7%	9.0%	0.3%
3 Purchases	\$191.7	\$186.8	(\$4.9)	-2.5%	40.2%	40.5%	0.3%
MISO related Purchases	\$57.7	\$58.8	\$1.0	1.8%	12.1%	12.7%	0.6%
4 Total System Costs	476.6	461.0	(\$15.6)	-3.3%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$65.2	\$62.5	(\$2.6)	-4.0%	13.7%	13.6%	-0.1%
6 Net System Costs	\$411.5	\$398.5	(\$12.9)	-3.1%	86.3%	86.4%	0.1%
7							
** GWH OUTPUT **							
9 Fossil	6,096	5,431	(665)	-10.9%	16.2%	16.3%	0.1%
10 Nuclear	4,648	4,705	57	1.2%	12.4%	14.1%	1.7%
11 Purchases	5,488	5,590	102	1.9%	14.6%	16.8%	2.2%
12 Hydro & Other	1,666	1,730	64	3.8%	4.4%	5.2%	0.8%
13 Net Interchange	19,686	15,905	(3,781)	-19.2%	52.4%	47.7%	-4.7%
14 Total Output	37,584	33,361	(4,223)	-11.2%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,914	1,855	(59)	-3.1%	5.1%	5.6%	0.5%
16 Native Requirement	35,670	31,506	(4,164)	-11.7%	94.9%	94.4%	-0.5%
17							
** COST per KWH OUTPUT (\$) **							
19 Fossil	3.050	3.202	0.152	5.0%			
20 Nuclear	0.889	0.884	-0.005	-0.5%			
21 Purchases	3.492	3.341	-0.151	-4.3%			
22 Total System Costs	1.268	1.382	0.114	9.0%			
23 Intersystem Sales	3.403	3.370	-0.034	-1.0%			
24 Net System Costs	1.154	1.265	0.111	9.7%			
25							
26							
27 TOTAL SYSTEM GWH SALES	15,768	15,251	(517)	-3.3%			
28							
29 COST per KWH SALES (\$)	2.609	2.613	0.004	0.2%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.057	-0.034	0.023				
(i) Residential	-0.057	-0.034	0.023				
(ii) C & I Non-Demand	-0.060	-0.036	0.024				
(iii) C & I Demand Non-TOD	-0.058	-0.035	0.023				
(iv) C & I Demand TOD On-Peak	-0.075	-0.045	0.030				
(v) C & I Demand TOD Off-Peak	-0.044	-0.027	0.018				
(vi) Outdoor Lighting	-0.040	-0.024	0.016				
32 REFUND	-0.036	0.000	0.036				
(i) Residential	-0.036	-0.028					
(ii) C & I Non-Demand	-0.038	-0.030					
(iii) C & I Demand Non-TOD	-0.037	-0.029					
(iv) C & I Demand TOD On-Peak	-0.047	-0.037					
(v) C & I Demand TOD Off-Peak	-0.028	-0.022					
(vi) Outdoor Lighting	-0.026	-0.020					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.516	2.579	0.063	2.5%			
(i) Residential	2.505	2.539	0.034				
(ii) C & I Non-Demand	2.654	2.690					
(iii) C & I Demand Non-TOD	2.571	2.606					
(iv) C & I Demand TOD On-Peak	3.305	3.350					
(v) C & I Demand TOD Off-Peak	1.944	1.970					
(vi) Outdoor Lighting	1.783	1.808					

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	\$0.03
250	\$0.09
500	\$0.17
750	\$0.26
1,000	\$0.34

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	
	Nov-10	Dec-10
** GWH OUTPUT **		
Thermal	1,239,485	1,292,022
Wind plus disper gen	(61)	(62)
Hydro	426,872	438,143
Hydro and Other	1,666,296	1,730,103
Rounded to nearest thousand:	1,666	1,730
Sales		
Non Gen Munic Total	291,074,000	290,159,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,914,319,000	1,855,081,000
Rounded to nearest million:	1914.319	1855.081

		System	Intersystem	Retail
October 2010 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 17,752,595.75	\$ 1,419,895.83	\$ 19,172,491.58
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 1,655,373.93	\$ -	\$ 1,655,373.93
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 577.48	\$ -	\$ 577.48
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (11,449,943.34)	\$ -	\$ (11,449,943.34)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,281,171.01	\$ -	\$ 1,281,171.01
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)	\$ 797,562.37	\$ 193,356.93	\$ 990,919.30
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (10,729.41)	\$ -	\$ (10,729.41)
14	Real-Time Distribution of Losses Amount	\$ (1,270,407.36)	\$ -	\$ (1,270,407.36)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (106,742.34)	\$ -	\$ (106,742.34)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 18,073.65	\$ -	\$ 18,073.65
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (2,831.45)	\$ -	\$ (2,831.45)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 2,476,782.27	\$ -	\$ 2,476,782.27
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ 176.01	\$ -	\$ 176.01
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 1,065,297.18	\$ -	\$ 1,065,297.18
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)	\$ 78,631.39	\$ -	\$ 78,631.39
15	Real-Time Financial Bilateral Transaction Congestion Amount	\$ -	\$ -	\$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component (1)	\$ (3,149.27)	\$ -	\$ (3,149.27)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (2,090,336.41)	\$ -	\$ (2,090,336.41)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (133,908.74)	\$ -	\$ (133,908.74)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (223,937.83)	\$ -	\$ (223,937.83)
37	Financial Transmission Rights Guarantee Uplift Amount	\$ 228,122.04	\$ -	\$ 228,122.04
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 760,434.18	\$ -	\$ 760,434.18
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 134,088.44	\$ -	\$ 134,088.44
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (139,143.19)	\$ 13,849.16	\$ (125,294.03)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 621,360.33	\$ -	\$ 621,360.33
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (175,507.23)	\$ 29,210.28	\$ (146,296.95)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (232,802.11)	\$ 13,322.18	\$ (219,479.93)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 717,507.43	\$ (5,912.80)	\$ 711,594.63
19	Real-Time Market Administration Amount	\$ 41,140.53	\$ (1,810.48)	\$ 39,330.05
29	Financial Transmission Rights Market Administration Amount	\$ 44,719.44	\$ -	\$ 44,719.44
33	Day-Ahead Schedule 24 Allocation Amount	\$ 87,501.49	\$ (708.24)	\$ 86,793.25
34	Real-Time Schedule 24 Allocation Amount	\$ 5,032.85	\$ (209.26)	\$ 4,823.59
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	\$ (11,606.97)	\$ -	\$ (11,606.97)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 1,009,551.70	\$ -	\$ 1,009,551.70
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (1,035,574.92)	\$ -	\$ (1,035,574.92)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (446,089.90)	\$ -	\$ (446,089.90)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 125,804.75	\$ -	\$ 125,804.75
TOTAL MISO CHARGES		\$ 11,568,793.75	\$ 1,660,993.60	\$ 13,229,787.35
SCHEDULE 24 (FOR RETAIL)				\$ 91,616.84
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 13,138,170.51

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
October 2010 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (240,896.11)	\$ -	\$ (240,896.11)
2	Day-Ahead Spinning Reserve Amount	\$ (46,750.97)	\$ -	\$ (46,750.97)
3	Day-Ahead Supplemental Reserve	\$ (91,685.70)	\$ -	\$ (91,685.70)
4	Real-Time Regulation Amount	\$ (61,957.96)	\$ 142,895.49	\$ 80,937.53
5	Real-Time Spinning Reserve Amount	\$ (5,922.12)	\$ 10,959.61	\$ 5,037.49
6	Real-Time Supplemental Reserve Amount.	\$ 2,387.79	\$ 22,446.64	\$ 24,834.43
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (6,907.81)	\$ -	\$ (6,907.81)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 891,673.81	\$ -	\$ 891,673.81
8b	Real Time Non Excessive Energy Congestion	\$ 633,179.95	\$ -	\$ 633,179.95
8c	Real Time Non Excessive Energy Loss	\$ 154,727.08	\$ -	\$ 154,727.08
9	Real Time Net Regulation Adjustment Amount	\$ 8,978.01	\$ 1,068.94	\$ 10,046.95
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 212,676.77	\$ -	\$ 212,676.77
11	Real Time Spinning Reserve Cost Distribution	\$ 133,601.30	\$ -	\$ 133,601.30
12	Real Time Supplemental Reserve Cost Distribution	\$ 60,618.58	\$ -	\$ 60,618.58
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 6,192.04	\$ (675.78)	\$ 5,516.26
14	Real Time Contignecy Reserve Deployment Failure	\$ -	\$ (98.32)	\$ (98.32)
TOTAL MISO ASM CHARGES		\$ 1,649,914.66	\$ 176,596.58	\$ 1,826,511.24

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

Forecast Month	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11
True-up Month	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Monthly Refund	(161,371)	10,622	(54,285)	(21,836)	(155,670)	(141,793)	(89,740)	(93,985)	(46,840)	(35,659)		
Forecast North Dakota Sales	194,554	163,606	164,425	165,070	188,515	188,034	168,026	179,415	187,205	210,810	-	-
Current Month Refund Factor	(0.083)	0.006	(0.033)	(0.013)	(0.083)	(0.075)	(0.053)	(0.052)	(0.025)	(0.017)	-	-
Forecasted North Dakota Sales	215,527	196,388	194,554	163,606	164,425	165,070	188,515	188,034	168,026	179,415	187,205	210,810
Actual North Dakota Sales (Cal. Mo.)	222,254	189,946	190,655	151,863	160,154	167,487	195,892	194,367	162,030	167,662	-	-
Deviation	(6,727)	6,442	3,899	11,743	4,271	(2,417)	(7,377)	(6,333)	5,996	11,753	187,205	210,810
Expected Refund	(13,480)	(81,774)	(160,951)	7,940	(57,511)	(21,266)	(157,164)	(141,482)	(83,589)	(89,219)	(49,824)	(41,503)
Actual Refund	(13,900)	(79,092)	(157,725)	7,370	(56,017)	(21,577)	(163,315)	(146,248)	(80,605)	(83,375)	-	-
Deviation	420	(2,682)	(3,226)	570	(1,494)	311	6,151	4,766	(2,984)	(5,844)	(49,824)	(41,503)
True-up Factor	0.000	(0.002)	(0.002)	0.000	(0.001)	0.000	0.004	0.003	(0.002)	(0.003)	-	-
Realized Margin	(0.083)	0.005	(0.035)	(0.013)	(0.083)	(0.075)	(0.050)	(0.050)	(0.027)	(0.020)	-	-
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	(0.082)	0.005	(0.035)	(0.013)	(0.083)	(0.075)	(0.050)	(0.050)	(0.026)	(0.020)	-	-
C&I Non-Demand	(0.087)	0.005	(0.037)	(0.014)	(0.088)	(0.079)	(0.052)	(0.052)	(0.028)	(0.021)	-	-
C&I Demand Non-TOD	(0.085)	0.005	(0.036)	(0.013)	(0.085)	(0.077)	(0.051)	(0.051)	(0.027)	(0.020)	-	-
C&I Demand TOD On-Peak	(0.109)	0.006	(0.046)	(0.017)	(0.110)	(0.099)	(0.065)	(0.065)	(0.035)	(0.026)	-	-
C&I Demand TOD Off-Peak	(0.064)	0.004	(0.027)	(0.010)	(0.064)	(0.058)	(0.038)	(0.038)	(0.021)	(0.015)	-	-
Outdoor Lighting	(0.059)	0.003	(0.025)	(0.009)	(0.059)	(0.053)	(0.035)	(0.035)	(0.019)	(0.014)	-	-

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

1 Forecast Month	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11
2 True-up Month			Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10
3												
4 Monthly Refund	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,830)
5												
6 Forecast North Dakota Sales	196,388	194,554	163,606	164,425	165,070	188,515	188,034	168,026	179,415	187,205	210,810	-
7												
8 Current Month Refund Factor	(0.009)	(0.009)	(0.010)	(0.010)	(0.010)	(0.009)	(0.009)	(0.010)	(0.009)	(0.009)	(0.008)	-
9												
10 Forecasted North Dakota Sales			196,388	194,554	163,606	164,425	165,070	188,515	188,034	168,026	179,415	-
11 Actual North Dakota Sales (Cal. Mo.)			189,946	190,655	151,863	160,154	167,487	195,892	194,367	162,030	167,662	-
12 Deviation			6,442	3,899	11,743	4,271	(2,417)	(7,377)	(6,333)	5,996	11,753	-
13												
14 Expected Refund			(16,831)	(16,831)	(17,384)	(17,168)	(18,078)	(17,278)	(16,567)	(16,155)	(16,272)	-
15 Actual Refund			(16,278)	(16,494)	(16,137)	(16,722)	(18,342)	(17,954)	(17,126)	(15,579)	(15,207)	-
16 Deviation			(553)	(337)	(1,247)	(447)	264	676	559	(576)	(1,066)	-
17												
18 True-up Factor	-	-	(0.000)	(0.000)	(0.001)	(0.000)	0.000	0.000	0.000	(0.000)	(0.001)	-
19												
20 Realized Margin	(0.009)	(0.009)	(0.011)	(0.010)	(0.011)	(0.009)	(0.009)	(0.010)	(0.009)	(0.009)	(0.008)	-
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	(0.009)	(0.009)	(0.011)	(0.010)	(0.011)	(0.009)	(0.009)	(0.010)	(0.009)	(0.009)	(0.008)	-
32 C&I Non-Demand	(0.009)	(0.009)	(0.011)	(0.011)	(0.012)	(0.010)	(0.009)	(0.010)	(0.010)	(0.010)	(0.009)	-
33 C&I Demand Non-TOD	(0.009)	(0.009)	(0.011)	(0.011)	(0.011)	(0.009)	(0.009)	(0.010)	(0.009)	(0.010)	(0.009)	-
34 C&I Demand TOD On-Peak	(0.011)	(0.011)	(0.014)	(0.014)	(0.014)	(0.012)	(0.012)	(0.013)	(0.012)	(0.012)	(0.011)	-
35 C&I Demand TOD Off-Peak	(0.007)	(0.007)	(0.008)	(0.008)	(0.008)	(0.007)	(0.007)	(0.007)	(0.007)	(0.007)	(0.007)	-
36 Outdoor Lighting	(0.006)	(0.006)	(0.008)	(0.007)	(0.008)	(0.006)	(0.006)	(0.007)	(0.006)	(0.007)	(0.006)	-