



—Via Electronic Filing—

November 25, 2009

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

Re: December 2009 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 2009.

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 new "multi-class" fuel cost mechanism replaced the previously single-factor mechanism. The December 2009 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 2009 calendar month.

The former system average monthly fuel cost adjustment factor 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 2009	Fuel Cost Charge (\$/kWh)
Residential	0.02264
C & I Non-Demand	0.02399
C & I Demand	0.02324
C & I Demand Time of Day On-Peak	0.02987
C & I Demand Time of Day Off-Peak	0.01757
Outdoor Lighting	0.01612

MISO CHARGES IMPLEMENTATION

MISO Day 2 Charges

This filing includes our reporting of the Midwest Independent System Operator (“MISO”) charges under the Day 2 Market. Pursuant to the Commission’s Order (Docket No. PU-05-147) dated April 6, 2005, Xcel Energy is authorized to recover on an interim basis, subject to refund, the MISO Day 2 costs. The March 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 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 2009 as recorded in Account 555. The MISO Day 2 cost recovery included in this December FCC is \$16,799,961, 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 FCA. The Company is in the process of evaluating this reversal impact and will reflect this adjustment in the subsequent FCA.

MISO ASM Charges

¹ Previously embedded in other FTR charge types.

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. 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 2009 as recorded in Account 555. The MISO ASM cost recovery included in this December FCC is \$-1,061,115, 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 2009 Asset Based Margin amount of \$32,675 has been included in the December Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. The 2009 North Dakota retail share of the Non-Asset Based Margins will be determined after the close of the calendar year and will be credited to the FCC during 2010.

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,



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 Dec-2009

Dec-2009 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02407	-\$0.00117	-\$0.00016	\$0.02274
Residential	\$0.02396	-\$0.00117	-\$0.00016	\$0.02264
C & I Non-Demand	\$0.02539	-\$0.00124	-\$0.00017	\$0.02399
C & I Demand Non-TOD	\$0.02460	-\$0.00120	-\$0.00016	\$0.02324
C & I Demand TOD On-Peak	\$0.03162	-\$0.00154	-\$0.00021	\$0.02987
C & I Demand TOD Off-Peak	\$0.01860	-\$0.00090	-\$0.00012	\$0.01757
Outdoor Lighting	\$0.01706	-\$0.00083	-\$0.00011	\$0.01612
Residential				
Residential Service	\$ 0.02396	\$ (0.00117)	\$ (0.00016)	\$ 0.02264
Residential TOD	\$ 0.02396	\$ (0.00117)	\$ (0.00016)	\$ 0.02264
Residential - Underground	\$ 0.02396	\$ (0.00117)	\$ (0.00016)	\$ 0.02264
Residential TOD - Underground	\$ 0.02396	\$ (0.00117)	\$ (0.00016)	\$ 0.02264
Energy Control - (Non-Demand)	\$ 0.02396	\$ (0.00117)	\$ (0.00016)	\$ 0.02264
Limit Off Peak	\$ 0.02396	\$ (0.00117)	\$ (0.00016)	\$ 0.02264
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02539	\$ (0.00124)	\$ (0.00017)	\$ 0.02399
Limit Off Peak	\$ 0.02539	\$ (0.00124)	\$ (0.00017)	\$ 0.02399
Small General Service	\$ 0.02539	\$ (0.00124)	\$ (0.00017)	\$ 0.02399
Small General TOD - Metered	\$ 0.02539	\$ (0.00124)	\$ (0.00017)	\$ 0.02399
Small General TOD - Unmetered	\$ 0.02539	\$ (0.00124)	\$ (0.00017)	\$ 0.02399
Fire and Civil Defense Siren	\$ 0.02539	\$ (0.00124)	\$ (0.00017)	\$ 0.02399
Direct Current (Closed)	\$ 0.02539	\$ (0.00124)	\$ (0.00017)	\$ 0.02399
C & I Demand				
General Service	\$ 0.02460	\$ (0.00120)	\$ (0.00016)	\$ 0.02324
General TOD - On Peak	\$ 0.03162	\$ (0.00154)	\$ (0.00021)	\$ 0.02987
General TOD - Off Peak	\$ 0.01860	\$ (0.00090)	\$ (0.00012)	\$ 0.01757
Peak Controlled (Closed)	\$ 0.02460	\$ (0.00120)	\$ (0.00016)	\$ 0.02324
Peak Controlled TOD (Closed) - On Peak	\$ 0.03162	\$ (0.00154)	\$ (0.00021)	\$ 0.02987
Peak Controlled TOD (Closed) - Off Peak	\$ 0.01860	\$ (0.00090)	\$ (0.00012)	\$ 0.01757
Peak Controlled Tiered	\$ 0.02460	\$ (0.00120)	\$ (0.00016)	\$ 0.02324
Peak Controlled Tiered TOD - On Peak	\$ 0.03162	\$ (0.00154)	\$ (0.00021)	\$ 0.02987
Peak Controlled Tiered TOD - Off Peak	\$ 0.01860	\$ (0.00090)	\$ (0.00012)	\$ 0.01757
Energy Controlled (Closed)	\$ 0.02460	\$ (0.00120)	\$ (0.00016)	\$ 0.02324
Tier 1 Energy Controlled Rider	\$ 0.02460	\$ (0.00120)	\$ (0.00016)	\$ 0.02324
Real Time Pricing - Firm - On Peak	\$ 0.03162	\$ (0.00154)	\$ (0.00021)	\$ 0.02987
Real Time Pricing - Firm - Off Peak	\$ 0.01860	\$ (0.00090)	\$ (0.00012)	\$ 0.01757
Real Time Pricing - Controllable - On Peak	\$ 0.03162	\$ (0.00154)	\$ (0.00021)	\$ 0.02987
Real Time Pricing - Controllable - Off Peak	\$ 0.01860	\$ (0.00090)	\$ (0.00012)	\$ 0.01757
Small Municipal Pumping	\$ 0.02460	\$ (0.00120)	\$ (0.00016)	\$ 0.02324
Municipal Pumping	\$ 0.02460	\$ (0.00120)	\$ (0.00016)	\$ 0.02324
Excess Energy - St. Anthony Falls	\$ 0.02460	\$ (0.00120)	\$ (0.00016)	\$ 0.02324
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01706	\$ (0.00083)	\$ (0.00011)	\$ 0.01612
Street Lighting System	\$ 0.01706	\$ (0.00083)	\$ (0.00011)	\$ 0.01612
Street Lighting Energy	\$ 0.01706	\$ (0.00083)	\$ (0.00011)	\$ 0.01612
Street Lighting Energy - Metered	\$ 0.01706	\$ (0.00083)	\$ (0.00011)	\$ 0.01612
Street Lighting Energy (Closed)	\$ 0.01706	\$ (0.00083)	\$ (0.00011)	\$ 0.01612
Street Lighting - City of St. Paul	\$ 0.01706	\$ (0.00083)	\$ (0.00011)	\$ 0.01612

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-2009

	Column (A) Jul-09	Column (B) Aug-09	Column (C) Sep-09	Column (D) Oct-09	Column (E) 4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$34,884,806	\$37,083,990	\$37,932,723	\$33,768,296	\$143,669,815
Account 518 - Nuclear Fuel	\$8,758,100	\$8,753,879	\$6,826,856	\$6,097,905	\$30,436,739
Account 555 - Purchased Power ¹	\$41,316,745	\$48,107,021	\$34,174,573	\$33,897,312	\$157,495,651
Account 555 - MISO Day 2 Charges	\$14,757,076	\$11,227,373	\$12,205,549	\$16,893,303	\$55,083,301
Account 555 MISO Day 2 - Schedule 24	(\$95,225)	(\$97,286)	(\$95,853)	(\$93,342)	(\$381,706)
Account 555 MISO - ASM Charges	\$135,795	\$2,374,116	\$926,518	(\$1,061,115)	\$2,375,313
Total MISO Charges	\$14,797,647	\$13,504,203	\$13,036,213	\$15,738,845	\$57,076,908
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$99,757,298	\$107,449,093	\$91,970,365	\$89,502,358	\$388,679,113
Less Fuel Cost of InterSystem Sales	(\$10,952,672)	(\$14,341,684)	(\$5,238,676)	(\$7,920,494)	(\$38,453,526)
Net System Costs	\$88,804,626	\$93,107,409	\$86,731,689	\$81,581,864	\$350,225,587
System MWh Sales					
Total NSP System Retail	3,719,953	3,521,273	3,510,437	3,392,905	14,144,568
Non-Gen Muni's/Load Pattern	101,974	102,634	102,098	99,178	405,884
Total NSP System MWh Sales	3,821,927	3,623,907	3,612,535	3,492,083	14,550,452
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.324¢	2.569¢	2.401¢	2.336¢	2.407¢
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	2.396¢
(ii) C & I Non-Demand				1.0548	2.539¢
(iii) C & I Demand Non-TOD				1.0219	2.460¢
(iv) C & I Demand TOD On-Peak				1.3135	3.162¢
(v) C & I Demand TOD Off-Peak				0.7726	1.860¢
(vi) Outdoor Lighting				0.7088	1.706¢

¹ Excludes demand-related expenses

North Dakota Retail MWh Sales					
(i) Residential	55,045	50,529	52,742	54,084	212,400
(ii) C & I Non-Demand	9,741	9,225	10,129	9,638	38,733
(iii) C & I Demand Non-TOD	57,975	56,576	54,590	56,461	225,602
(iv) C & I Demand TOD On-Peak	21,107	18,500	16,772	22,100	78,479
(v) C & I Demand TOD Off-Peak	33,092	28,364	27,621	32,420	121,497
(vi) Outdoor Lighting	1,107	1,173	1,372	1,546	5,198
(vii) Total	178,067	164,367	163,226	176,249	681,909

Dec-2009 Recovery Provision (True-up Factor) Calculation	
Prior Unrecovered Expenses (Aug-09 Balance of Unrecovered Expenses)	Total Aug-09 (\$782,166)

Prior Expenses Recovered in Oct-2009				
	FCF Ratio	True-Up Factor per kWh	Actual ND MWh Sales	Prior Recovered Expenses in
(i) Residential				
(ii) C & I Non-Demand	0.9956	-0.118¢	54,084	(\$63,600)
(iii) C & I Demand Non-TOD	1.0548	-0.125¢	9,638	(\$12,008)
(iv) C & I Demand TOD On-Peak	1.0219	-0.121¢	56,461	(\$68,150)
(v) C & I Demand TOD Off-Peak	1.3135	-0.155¢	22,100	(\$34,287)
(vi) Outdoor Lighting	0.7726	-0.091¢	32,420	(\$29,585)
(vii) Total	0.7088	-0.084¢	176,249	(\$208,924)

Actual Cost Should Have Been Recovered in Oct-09			
	Actual	Base	Expected Recovery
	2.336¢	0.000¢	\$4,117,177

Cost Recovered in Oct-09				
	FCF Ratio	Fuel Cost Recovered	Actual ND MWh Sales	Actual Recovery
(i) Residential	0.9956	2.444¢	54,084	\$1,321,920
(ii) C & I Non-Demand	1.0548	2.590¢	9,638	\$249,579
(iii) C & I Demand Non-TOD	1.0219	2.509¢	56,461	\$1,416,474
(iv) C & I Demand TOD On-Peak	1.3135	3.225¢	22,100	\$712,646
(v) C & I Demand TOD Off-Peak	0.7726	1.897¢	32,420	\$614,921
(vi) Outdoor Lighting	0.7088	1.740¢	1,546	\$26,902
(vii) Total			176,249	\$4,342,442

Total Balance of Unrecovered Expenses (Dec-09 Balance of Unrecovered Expenses)	
Dec-2009 Recovery Provision	(\$798,507)
4 Month ND Retail Total MWh Sales	681,909
Dec-2009 Recovery Provision per KWH	-0.117¢

Dec-2009 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9956	-0.117¢	-0.117¢
(ii) C & I Non-Demand	1.0548	-0.117¢	-0.124¢
(iii) C & I Demand Non-TOD	1.0219	-0.117¢	-0.120¢
(iv) C & I Demand TOD On-Peak	1.3135	-0.117¢	-0.154¢
(v) C & I Demand TOD Off-Peak	0.7726	-0.117¢	-0.090¢
(vi) Outdoor Lighting	0.7088	-0.117¢	-0.083¢
Dec-2009 Margin Sharing Refunds			
	Asset Based Margin Sharing Refund		Total
Refund/Special Charge Amount	(\$32,675)		(\$32,675)
(i) Residential	-0.016¢		-0.016¢
(ii) C & I Non-Demand	-0.017¢		-0.017¢
(iii) C & I Demand Non-TOD	-0.016¢		-0.016¢
(iv) C & I Demand TOD On-Peak	-0.021¢		-0.021¢
(v) C & I Demand TOD Off-Peak	-0.012¢		-0.012¢
(vi) Outdoor Lighting	-0.011¢		-0.011¢
Dec-2009 Factors			
			Total
(i) Residential			2.264¢
(ii) C & I Non-Demand			2.399¢
(iii) C & I Demand Non-TOD			2.324¢
(iv) C & I Demand TOD On-Peak			2.987¢
(v) C & I Demand TOD Off-Peak			1.757¢
(vi) Outdoor Lighting			1.612¢

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-09	Dec-09	Differ- ence	Percent Change	FCA Application Nov-09	Dec-09	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$141.8	\$143.7	\$1.9	1.3%	36.5%	37.0%	0.5%
2 Nuclear	\$32.8	\$30.4	(\$2.4)	-7.2%	8.4%	7.8%	-0.6%
3 Purchases	\$159.6	\$157.5	(\$2.1)	-1.3%	41.1%	40.5%	-0.6%
MISO related Purchases	\$54.3	\$57.1	\$2.8	5.1%	14.0%	14.7%	0.7%
4 Total System Costs	388.6	388.7	\$0.1	0.0%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$35.6	\$38.5	\$2.8	7.9%	9.2%	9.9%	0.7%
6 Net System Costs	\$352.9	\$350.2	(\$2.7)	-0.8%	90.8%	90.1%	-0.7%
7							
8 ** GWH OUTPUT **							
9 Fossil	6,041	6,280	239	4.0%	27.4%	29.0%	1.6%
10 Nuclear	4,473	4,133	(340)	-7.6%	20.3%	19.1%	-1.2%
11 Purchases	6,098	5,877	(221)	-3.6%	27.7%	27.1%	-0.6%
12 Hydro & Other	697	643	(54)	-7.7%	3.2%	3.0%	-0.2%
13 Net Interchange	4,713	4,758	45	1.0%	21.4%	21.9%	0.5%
14 Total Output	22,022	21,691	(331)	-1.5%	100.0%	100.0%	0.0%
15 Intersystem Sales	2,495	2,372	(123)	-4.9%	11.3%	10.9%	-0.4%
16 Native Requirement	19,527	19,319	(208)	-1.1%	88.7%	89.1%	0.4%
17							
18 ** COST per KWH OUTPUT (\$) **							
19 Fossil	2.348	2.288	-0.060	-2.5%			
20 Nuclear	0.733	0.736	0.003	0.4%			
21 Purchases	2.617	2.680	0.062	2.4%			
22 Total System Costs	1.764	1.792	0.028	1.6%			
23 Intersystem Sales	1.428	1.621	0.193	13.5%			
24 Net System Costs	1.807	1.813	0.005	0.3%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,482	14,550	68	0.5%			
28							
29 COST per KWH SALES (\$)	2.437	2.407	-0.030	-1.2%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.061	-0.117	-0.057				
(i) Residential	-0.060	-0.117	-0.056				
(ii) C & I Non-Demand	-0.064	-0.124	-0.060				
(iii) C & I Demand Non-TOD	-0.062	-0.120	-0.058				
(iv) C & I Demand TOD On-Peak	-0.080	-0.154	-0.074				
(v) C & I Demand TOD Off-Peak	-0.047	-0.090	-0.044				
(vi) Outdoor Lighting	-0.043	-0.083	-0.040				
32 REFUND	-0.013	-0.016	-0.003				
(i) Residential	-0.013	-0.016					
(ii) C & I Non-Demand	-0.014	-0.017					
(iii) C & I Demand Non-TOD	-0.013	-0.016					
(iv) C & I Demand TOD On-Peak	-0.017	-0.021					
(v) C & I Demand TOD Off-Peak	-0.010	-0.012					
(vi) Outdoor Lighting	-0.009	-0.011					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.363	2.274	-0.090	-3.8%			
(i) Residential	2.353	2.264	-0.089				
(ii) C & I Non-Demand	2.493	2.399					
(iii) C & I Demand Non-TOD	2.415	2.324					
(iv) C & I Demand TOD On-Peak	3.105	2.987					
(v) C & I Demand TOD Off-Peak	1.826	1.757					
(vi) Outdoor Lighting	1.675	1.612					

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	(\$0.09)
250	(\$0.22)
500	(\$0.45)
750	(\$0.67)
1,000	(\$0.89)

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-09	Dec-09
** GWH OUTPUT **		
Thermal	576,134	508,614
Wind plus disper gen	(79)	(81)
Hydro	121,188	136,707
Hydro and Other	697,243	643,240
Rounded to nearest thousand:	697	643
Sales		
Non Gen Munic Total	402,972,000	405,884,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	2,494,875,000	2,371,982,000
Rounded to nearest million:	2494.875	2371.982

		System	Intersystem	Retail
October 2009 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 21,554,005.24	\$ 1,699,487.52	\$ 23,253,492.76
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,384,377.73	\$ -	\$ 2,384,377.73
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 1,521.56	\$ -	\$ 1,521.56
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (11,508,868.74)	\$ -	\$ (11,508,868.74)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 768,122.50	\$ -	\$ 768,122.50
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)	\$ 1,079,837.91	\$ 1,286,620.60	\$ 2,366,458.51
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (31,722.60)	\$ -	\$ (31,722.60)
14	Real-Time Distribution of Losses Amount	\$ (1,395,713.60)	\$ -	\$ (1,395,713.60)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (39,636.18)	\$ -	\$ (39,636.18)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 175,118.07	\$ -	\$ 175,118.07
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (2,936.96)	\$ -	\$ (2,936.96)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 1,833,641.79	\$ -	\$ 1,833,641.79
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ (1.78)	\$ -	\$ (1.78)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 68,661.42	\$ -	\$ 68,661.42
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)	\$ (80,474.22)	\$ -	\$ (80,474.22)
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)	\$ (34,897.43)	\$ -	\$ (34,897.43)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (1,265,425.35)	\$ -	\$ (1,265,425.35)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (239,724.22)	\$ -	\$ (239,724.22)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (57,473.71)	\$ -	\$ (57,473.71)
37	Financial Transmission Guarantee Uplift Amount	\$ 87,292.36	\$ -	\$ 87,292.36
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 363,585.47	\$ -	\$ 363,585.47
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 89,777.29	\$ -	\$ 89,777.29
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (70,244.05)	\$ 2,379.37	\$ (67,864.68)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 309,012.40	\$ -	\$ 309,012.40
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (369,090.95)	\$ 86,764.54	\$ (282,326.41)
42	Real-Time Price Volatility Make Whole Payment Amount	\$ (178,767.04)	\$ 5,280.55	\$ (173,486.49)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 715,171.19	\$ (7,910.83)	\$ 707,260.36
19	Real-Time Market Administration Amount	\$ 46,173.58	\$ (7,784.15)	\$ 38,389.43
29	Financial Transmission Rights Market Administration Amount	\$ 57,960.64	\$ -	\$ 57,960.64
33	Day-Ahead Schedule 24 Allocation Amount	\$ 89,821.61	\$ (1,286.69)	\$ 88,534.92
34	Real-Time Schedule 24 Allocation Amount	\$ 5,820.55	\$ (1,013.27)	\$ 4,807.28
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	\$ 28,302.81	\$ -	\$ 28,302.81
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 1,168,950.46	\$ -	\$ 1,168,950.46
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (1,270,642.46)	\$ -	\$ (1,270,642.46)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (450,770.23)	\$ -	\$ (450,770.23)
TOTAL MISO CHARGES		\$ 13,830,765.06	\$ 3,062,537.64	\$ 16,893,302.70

SCHEDULE 24 (FOR RETAIL) \$ 93,342.20

TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL) \$ 16,799,960.50

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
October 2009 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (550,916.25)	\$ -	\$ (550,916.25)
2	Day-Ahead Spinning Reserve Amount	\$ (130,956.50)	\$ -	\$ (130,956.50)
3	Day-Ahead Supplemental Reserve	\$ (37,702.95)	\$ -	\$ (37,702.95)
4	Real-Time Regulation Amount	\$ 178,505.69	\$ 154,595.33	\$ 333,101.02
5	Real-Time Spinning Reserve Amount	\$ (4,148.73)	\$ 28,410.55	\$ 24,261.82
6	Real-Time Supplemental Reserve Amount	\$ 2,993.01	\$ 16,040.95	\$ 19,033.96
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (10,944.46)	\$ -	\$ (10,944.46)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ (1,379,570.21)	\$ -	\$ (1,379,570.21)
8b	Real Time Non Excessive Energy Congestion	\$ 68,921.15	\$ -	\$ 68,921.15
8c	Real Time Non Excessive Energy Loss	\$ (22,118.97)	\$ -	\$ (22,118.97)
9	Real Time Net Regulation Adjustment Amount	\$ (11,522.34)	\$ 2,774.98	\$ (8,747.36)
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 297,676.93	\$ -	\$ 297,676.93
11	Real Time Spinning Reserve Cost Distribution	\$ 275,441.76	\$ -	\$ 275,441.76
12	Real Time Supplemental Reserve Cost Distribution	\$ 32,280.26	\$ -	\$ 32,280.26
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 31,978.60	\$ (3,476.05)	\$ 28,502.55
14	Real Time Contignecy Reserve Deployment Failure	\$ 621.85	\$ -	\$ 621.85
TOTAL MISO ASM CHARGES		\$ (1,259,461.16)	\$ 198,345.76	\$ (1,061,115.40)

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-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10
1 Forecast Month												
2 True-up Month												
3												
4 Monthly Refund	(173,372)	(82,316)	(64,153)	(156)	(45,284)	7,115	(47,027)	(24,155)	(18,585)	(33,710)		
5												
6 Forecaster North Dakota Sales	191,827	174,423	167,216	169,094	182,677	182,651	177,780	169,550	181,835	204,705	215,527	196,388
7												
8 Current Month Refund Factor	(0.090)	(0.047)	(0.038)	(0.000)	(0.025)	0.004	(0.026)	(0.014)	(0.010)	(0.016)	-	-
9												
10 Forecasted North Dakota Sales												
11 Actual North Dakota Sales (Cal. Mo.)												
12 Deviation												
13												
14 Expected Refund												
15 Actual Refund												
16 Deviation												
17												
18 True-up Factor	-	-	0.041	(0.003)	0.000	(0.000)	(0.001)	0.000	(0.003)	0.001	-	-
19												
20 Realized Margin	(0.090)	(0.047)	0.003	(0.003)	(0.025)	0.004	(0.027)	(0.014)	(0.013)	(0.016)	-	-
21												
22 Class Ratios												
23 Residential	0.9989	0.9978	0.9967	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956
24 C&I Non-Demand	1.0137	1.0274	1.0411	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548
25 C&I Demand Non-TOD	1.0055	1.0110	1.0164	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	1.0784	1.1568	1.2351	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	0.9432	0.8863	0.8295	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726
28 Outdoor Lighting	0.9272	0.8544	0.7816	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	(0.090)	(0.047)	0.003	(0.003)	(0.025)	0.004	(0.027)	(0.014)	(0.013)	(0.016)	-	-
32 C&I Non-Demand	(0.092)	(0.048)	0.003	(0.003)	(0.026)	0.004	(0.029)	(0.015)	(0.013)	(0.017)	-	-
33 C&I Demand Non-TOD	(0.091)	(0.048)	0.003	(0.003)	(0.025)	0.004	(0.028)	(0.014)	(0.013)	(0.016)	-	-
34 C&I Demand TOD On-Peak	(0.097)	(0.055)	0.004	(0.003)	(0.032)	0.005	(0.036)	(0.018)	(0.017)	(0.021)	-	-
35 C&I Demand TOD Off-Peak	(0.085)	(0.042)	0.003	(0.002)	(0.019)	0.003	(0.021)	(0.011)	(0.010)	(0.012)	-	-
36 Outdoor Lighting	(0.084)	(0.040)	0.002	(0.002)	(0.017)	0.003	(0.019)	(0.010)	(0.009)	(0.011)	-	-