



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

May 28, 2010

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

Re: June 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 June 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 June 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 April 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:

June 2010	Fuel Cost Charge (\$/kWh)
Residential	0.02362
C & I Non-Demand	0.02503
C & I Demand	0.02425
C & I Demand Time of Day On-Peak	0.03117
C & I Demand Time of Day Off-Peak	0.01833
Outdoor Lighting	0.01682

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 June FCC, the net MISO Day 2 costs for April 2010 as recorded in Account 555. The MISO Day 2 cost recovery included in this June FCC is \$18,693,990, 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 June FCC, the net MISO ASM costs for April 2010 as recorded in Account 555. The MISO ASM cost recovery included in this June FCC is \$186,146 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 2010 Asset Based Margin amount of \$21,266 has been included in the June 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 June FCC is \$18,078, or 0.011¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

OTHER REPORTING ITEM

Attachment 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

Jun-2010 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02416	-\$0.00019	-\$0.00013	\$0.02384
Residential	\$0.02405	-\$0.00019	-\$0.00024	\$0.02362
C & I Non-Demand	\$0.02548	-\$0.00021	-\$0.00025	\$0.02503
C & I Demand Non-TOD	\$0.02469	-\$0.00020	-\$0.00024	\$0.02425
C & I Demand TOD On-Peak	\$0.03173	-\$0.00026	-\$0.00031	\$0.03117
C & I Demand TOD Off-Peak	\$0.01867	-\$0.00015	-\$0.00018	\$0.01833
Outdoor Lighting	\$0.01712	-\$0.00014	-\$0.00017	\$0.01682
Residential				
Residential Service	\$ 0.02405	\$ (0.00019)	\$ (0.00024)	\$ 0.02362
Residential TOD	\$ 0.02405	\$ (0.00019)	\$ (0.00024)	\$ 0.02362
Residential - Underground	\$ 0.02405	\$ (0.00019)	\$ (0.00024)	\$ 0.02362
Residential TOD - Underground	\$ 0.02405	\$ (0.00019)	\$ (0.00024)	\$ 0.02362
Energy Control - (Non-Demand)	\$ 0.02405	\$ (0.00019)	\$ (0.00024)	\$ 0.02362
Limit Off Peak	\$ 0.02405	\$ (0.00019)	\$ (0.00024)	\$ 0.02362
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02548	\$ (0.00021)	\$ (0.00025)	\$ 0.02503
Limit Off Peak	\$ 0.02548	\$ (0.00021)	\$ (0.00025)	\$ 0.02503
Small General Service	\$ 0.02548	\$ (0.00021)	\$ (0.00025)	\$ 0.02503
Small General TOD - Metered	\$ 0.02548	\$ (0.00021)	\$ (0.00025)	\$ 0.02503
Small General TOD - Unmetered	\$ 0.02548	\$ (0.00021)	\$ (0.00025)	\$ 0.02503
Fire and Civil Defense Siren	\$ 0.02548	\$ (0.00021)	\$ (0.00025)	\$ 0.02503
Direct Current (Closed)	\$ 0.02548	\$ (0.00021)	\$ (0.00025)	\$ 0.02503
C & I Demand				
General Service	\$ 0.02469	\$ (0.00020)	\$ (0.00024)	\$ 0.02425
General TOD - On Peak	\$ 0.03173	\$ (0.00026)	\$ (0.00031)	\$ 0.03117
General TOD - Off Peak	\$ 0.01867	\$ (0.00015)	\$ (0.00018)	\$ 0.01833
Peak Controlled (Closed)	\$ 0.02469	\$ (0.00020)	\$ (0.00024)	\$ 0.02425
Peak Controlled TOD (Closed) - On Peak	\$ 0.03173	\$ (0.00026)	\$ (0.00031)	\$ 0.03117
Peak Controlled TOD (Closed) - Off Peak	\$ 0.01867	\$ (0.00015)	\$ (0.00018)	\$ 0.01833
Peak Controlled Tiered	\$ 0.02469	\$ (0.00020)	\$ (0.00024)	\$ 0.02425
Peak Controlled Tiered TOD - On Peak	\$ 0.03173	\$ (0.00026)	\$ (0.00031)	\$ 0.03117
Peak Controlled Tiered TOD - Off Peak	\$ 0.01867	\$ (0.00015)	\$ (0.00018)	\$ 0.01833
Energy Controlled (Closed)	\$ 0.02469	\$ (0.00020)	\$ (0.00024)	\$ 0.02425
Tier 1 Energy Controlled Rider	\$ 0.02469	\$ (0.00020)	\$ (0.00024)	\$ 0.02425
Real Time Pricing - Firm - On Peak	\$ 0.03173	\$ (0.00026)	\$ (0.00031)	\$ 0.03117
Real Time Pricing - Firm - Off Peak	\$ 0.01867	\$ (0.00015)	\$ (0.00018)	\$ 0.01833
Real Time Pricing - Controllable - On Peak	\$ 0.03173	\$ (0.00026)	\$ (0.00031)	\$ 0.03117
Real Time Pricing - Controllable - Off Peak	\$ 0.01867	\$ (0.00015)	\$ (0.00018)	\$ 0.01833
Small Municipal Pumping	\$ 0.02469	\$ (0.00020)	\$ (0.00024)	\$ 0.02425
Municipal Pumping	\$ 0.02469	\$ (0.00020)	\$ (0.00024)	\$ 0.02425
Excess Energy - St. Anthony Falls	\$ 0.02469	\$ (0.00020)	\$ (0.00024)	\$ 0.02425
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01712	\$ (0.00014)	\$ (0.00017)	\$ 0.01682
Street Lighting System	\$ 0.01712	\$ (0.00014)	\$ (0.00017)	\$ 0.01682
Street Lighting Energy	\$ 0.01712	\$ (0.00014)	\$ (0.00017)	\$ 0.01682
Street Lighting Energy - Metered	\$ 0.01712	\$ (0.00014)	\$ (0.00017)	\$ 0.01682
Street Lighting Energy (Closed)	\$ 0.01712	\$ (0.00014)	\$ (0.00017)	\$ 0.01682
Street Lighting - City of St. Paul	\$ 0.01712	\$ (0.00014)	\$ (0.00017)	\$ 0.01682

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-2010

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Jan-10	Feb-10	Mar-10	Apr-10	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$42,972,111	\$38,278,709	\$27,468,130	\$28,892,464	\$137,611,414
Account 518 - Nuclear Fuel	\$10,021,593	\$8,941,917	\$9,775,774	\$8,045,935	\$36,785,218
Account 555 - Purchased Power ¹	\$41,322,966	\$28,152,883	\$34,011,198	\$32,827,975	\$136,315,021
Account 555 - MISO Day 2 Charges	\$21,515,761	\$14,484,703	\$20,208,392	\$18,780,094	\$74,988,950
Account 555 MISO Day 2 - Schedule 24	(\$95,015)	(\$86,498)	(\$86,548)	(\$86,104)	(\$354,164)
Account 555 MISO - ASM Charges	(\$2,393,364)	(\$214,099)	(\$1,583,580)	\$186,146	(\$4,004,896)
Total MISO Charges	\$19,027,383	\$14,184,106	\$18,538,264	\$18,880,137	\$70,629,890
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$113,344,053	\$89,557,614	\$89,793,366	\$88,646,511	\$381,341,543
Less Fuel Cost of InterSystem Sales	(\$18,446,370)	(\$7,919,136)	(\$7,682,321)	(\$7,335,161)	(\$41,382,988)
Net System Costs	\$94,897,683	\$81,638,478	\$82,111,045	\$81,311,350	\$339,958,555
System MWh Sales					
Total NSP System Retail	3,750,363	3,303,570	3,553,751	3,129,808	13,737,492
Non-Gen Muni's/Load Pattern	115,112	80,653	71,253	67,601	334,619
Total NSP System MWh Sales	3,865,475	3,384,223	3,625,004	3,197,409	14,072,111
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.455¢	2.412¢	2.265¢	2.543¢	2.416¢
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	2.405¢
(ii) C & I Non-Demand				1.0548	2.548¢
(iii) C & I Demand Non-TOD				1.0219	2.469¢
(iv) C & I Demand TOD On-Peak				1.3135	3.173¢
(v) C & I Demand TOD Off-Peak				0.7726	1.867¢
(vi) Outdoor Lighting				0.7088	1.712¢

¹ Excludes demand-related expenses

North Dakota Retail MWh Sales					
(i) Residential	95,482	80,469	76,676	55,786	308,413
(ii) C & I Non-Demand	14,539	12,538	13,603	10,380	51,060
(iii) C & I Demand Non-TOD	60,391	58,775	67,572	54,120	240,858
(iv) C & I Demand TOD On-Peak	16,696	17,869	22,810	17,650	75,025
(v) C & I Demand TOD Off-Peak	28,351	28,482	36,695	27,666	121,194
(vi) Outdoor Lighting	2,411	1,654	1,989	1,569	7,623
(vii) Total	217,870	199,787	219,345	167,171	804,173

Jun-2010 Recovery Provision (True-up Factor) Calculation	
Prior Unrecovered Expenses (Feb-10 Balance of Unrecovered Expenses)	Total Feb-10 (\$297,755)

Prior Expenses Recovered in Apr-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	-0.039¢	55,786	(\$21,503)
(iii) C & I Demand Non-TOD	1.0548	-0.041¢	10,380	(\$4,239)
(iv) C & I Demand TOD On-Peak	1.0219	-0.040¢	54,120	(\$21,411)
(v) C & I Demand TOD Off-Peak	1.3135	-0.051¢	17,650	(\$8,975)
(vi) Outdoor Lighting	0.7726	-0.030¢	27,666	(\$8,275)
(vii) Total	0.7088	-0.027¢	167,171	(\$64,834)

Actual Cost Should Have Been Recovered in Apr-10				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.543¢	0.000¢	167,171	\$4,251,159

Cost Recovered in Apr-10				
	FCF Ratio	Fuel Cost Recovered	Actual ND MWh Sales	Actual Recovery
(i) Residential	0.9956	2.482¢	55,786	\$1,384,626
(ii) C & I Non-Demand	1.0548	2.630¢	10,380	\$272,954
(iii) C & I Demand Non-TOD	1.0219	2.548¢	54,120	\$1,378,759
(iv) C & I Demand TOD On-Peak	1.3135	3.275¢	17,650	\$577,959
(v) C & I Demand TOD Off-Peak	0.7726	1.926¢	27,666	\$532,873
(vi) Outdoor Lighting	0.7088	1.767¢	1,569	\$27,725
(vii) Total			167,171	\$4,174,896

Total Balance of Unrecovered Expenses (Jun-10 Balance of Unrecovered Expenses)	
Jun-2010 Recovery Provision	(\$156,658)
4 Month ND Retail Total MWh Sales	804,173
Jun-2010 Recovery Provision per KWH	-0.019¢

Jun-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	-0.019¢	-0.019¢
(ii) C & I Non-Demand	1.0548	-0.019¢	-0.021¢
(iii) C & I Demand Non-TOD	1.0219	-0.019¢	-0.020¢
(iv) C & I Demand TOD On-Peak	1.3135	-0.019¢	-0.026¢
(v) C & I Demand TOD Off-Peak	0.7726	-0.019¢	-0.015¢
(vi) Outdoor Lighting	0.7088	-0.019¢	-0.014¢
Jun-2010 Margin Sharing Refunds			
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
Refund/Special Charge Amount	(\$21,266)	(\$18,078)	(\$39,344)
(i) Residential	-0.013¢	-0.011¢	-0.024¢
(ii) C & I Non-Demand	-0.014¢	-0.012¢	-0.025¢
(iii) C & I Demand Non-TOD	-0.013¢	-0.011¢	-0.024¢
(iv) C & I Demand TOD On-Peak	-0.017¢	-0.014¢	-0.031¢
(v) C & I Demand TOD Off-Peak	-0.010¢	-0.008¢	-0.018¢
(vi) Outdoor Lighting	-0.009¢	-0.008¢	-0.017¢
Jun-2010 Factors			
	Total		
(i) Residential	2.362¢		
(ii) C & I Non-Demand	2.503¢		
(iii) C & I Demand Non-TOD	2.425¢		
(iv) C & I Demand TOD On-Peak	3.117¢		
(v) C & I Demand TOD Off-Peak	1.833¢		
(vi) Outdoor Lighting	1.682¢		

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

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	May-10	Jun-10	Differ- ence	Percent Change	FCA Application May-10	Jun-10	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$146.8	\$137.6	(\$9.2)	-6.2%	36.8%	36.1%	-0.7%
2 Nuclear	\$39.6	\$36.8	(\$2.8)	-7.0%	9.9%	9.6%	-0.3%
3 Purchases	\$141.3	\$136.3	(\$5.0)	-3.6%	35.5%	35.7%	0.2%
MISO related Purchases	\$71.0	\$70.6	(\$0.4)	-0.5%	17.8%	18.5%	0.7%
4 Total System Costs	398.7	381.3	(\$17.4)	-4.4%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$47.2	\$41.4	(\$5.8)	-12.2%	11.8%	10.9%	-0.9%
6 Net System Costs	\$351.5	\$340.0	(\$11.6)	-3.3%	88.2%	89.1%	0.9%
7							
** GWH OUTPUT **							
9 Fossil	5,808	5,207	(601)	-10.3%	16.8%	15.8%	-1.0%
10 Nuclear	4,834	4,585	(249)	-5.2%	14.0%	13.9%	-0.1%
11 Purchases	4,591	4,787	196	4.3%	13.3%	14.5%	1.2%
12 Hydro & Other	851	779	(72)	-8.5%	2.5%	2.4%	-0.1%
13 Net Interchange	18,398	17,575	(823)	-4.5%	53.4%	53.4%	0.0%
14 Total Output	34,482	32,933	(1,549)	-4.5%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,622	1,525	(98)	-6.0%	4.7%	4.6%	-0.1%
16 Native Requirement	32,860	31,408	(1,451)	-4.4%	95.3%	95.4%	0.1%
17							
** COST per KWH OUTPUT (¢) **							
19 Fossil	2.527	2.643	0.116	4.6%			
20 Nuclear	0.818	0.802	-0.016	-2.0%			
21 Purchases	3.079	2.848	-0.231	-7.5%			
22 Total System Costs	1.156	1.158	0.002	0.1%			
23 Intersystem Sales	2.906	2.714	-0.192	-6.6%			
24 Net System Costs	1.070	1.082	0.013	1.2%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,505	14,072	(433)	-3.0%			
28							
29 COST per KWH SALES (¢)	2.424	2.416	-0.008	-0.3%			
30							
31 RECOVERY PROV (¢ / KWH) - SYS	-0.064	-0.019	0.045				
(i) Residential	-0.064	-0.019	0.045				
(ii) C & I Non-Demand	-0.068	-0.021	0.047				
(iii) C & I Demand Non-TOD	-0.066	-0.020	0.046				
(iv) C & I Demand TOD On-Peak	-0.085	-0.026	0.059				
(v) C & I Demand TOD Off-Peak	-0.050	-0.015	0.035				
(vi) Outdoor Lighting	-0.046	-0.014	0.032				
32 REFUND	-0.045	-0.024	0.021				
(i) Residential	-0.045	-0.024					
(ii) C & I Non-Demand	-0.047	-0.025					
(iii) C & I Demand Non-TOD	-0.046	-0.024					
(iv) C & I Demand TOD On-Peak	-0.059	-0.031					
(v) C & I Demand TOD Off-Peak	-0.035	-0.018					
(vi) Outdoor Lighting	-0.032	-0.017					
33 SYSTEM FCC IMPACT (¢ / KWH)	2.315	2.373	0.058	2.5%			
(i) Residential	2.304	2.362	0.058				
(ii) C & I Non-Demand	2.441	2.503					
(iii) C & I Demand Non-TOD	2.365	2.425					
(iv) C & I Demand TOD On-Peak	3.040	3.117					
(v) C & I Demand TOD Off-Peak	1.788	1.833					
(vi) Outdoor Lighting	1.640	1.682					

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	\$0.06
250	\$0.15
500	\$0.29
750	\$0.44
1,000	\$0.58

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>	
	May-10	Jun-10
** GWH OUTPUT **		
Thermal	670,538	586,140
Wind plus disper gen	(94)	(65)
Hydro	180,253	193,073
Hydro and Other	850,697	779,148
Rounded to nearest thousand:	851	779
Sales		
Non Gen Munic Total	364,398,000	334,619,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,622,261,000	1,524,599,000
Rounded to nearest million:	1622.261	1524.599

		System	Intersystem	Retail
April 2010 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 20,789,751.12	\$ 1,382,865.12	\$ 22,172,616.24
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 1,581,544.73	\$ -	\$ 1,581,544.73
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 1,767.04	\$ -	\$ 1,767.04
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (9,763,946.49)	\$ -	\$ (9,763,946.49)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,584,385.13	\$ -	\$ 1,584,385.13
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)	\$ 1,163,288.40	\$ 636,439.48	\$ 1,799,727.88
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (29,432.65)	\$ -	\$ (29,432.65)
14	Real-Time Distribution of Losses Amount	\$ (1,040,811.62)	\$ -	\$ (1,040,811.62)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ 40,061.98	\$ -	\$ 40,061.98
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 90,037.06	\$ -	\$ 90,037.06
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (5,693.46)	\$ -	\$ (5,693.46)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 1,775,842.80	\$ -	\$ 1,775,842.80
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ (1,722.43)	\$ -	\$ (1,722.43)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 2,305,097.19	\$ -	\$ 2,305,097.19
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)	\$ 13,446.99	\$ -	\$ 13,446.99
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)	\$ (12,299.38)	\$ -	\$ (12,299.38)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (2,319,166.81)	\$ -	\$ (2,319,166.81)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (263,891.30)	\$ -	\$ (263,891.30)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ 42,286.67	\$ -	\$ 42,286.67
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (480,777.82)	\$ -	\$ (480,777.82)
37	Financial Transmission Guarantee Uplift Amount	\$ 609,331.53	\$ -	\$ 609,331.53
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 905,550.54	\$ -	\$ 905,550.54
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 87,716.15	\$ -	\$ 87,716.15
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (52,020.37)	\$ 5,140.06	\$ (46,880.31)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 183,812.61	\$ -	\$ 183,812.61
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ (342,833.78)	\$ 51,636.92	\$ (291,196.86)
42	Real-Time Price Volatility Make Whole Payment Amount	\$ (324,938.51)	\$ 12,452.73	\$ (312,485.78)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 555,078.74	\$ (4,821.29)	\$ 550,257.45
19	Real-Time Market Administration Amount	\$ 37,398.24	\$ (2,912.58)	\$ 34,485.66
29	Financial Transmission Rights Market Administration Amount	\$ 54,018.72	\$ -	\$ 54,018.72
33	Day-Ahead Schedule 24 Allocation Amount	\$ 81,721.78	\$ (713.37)	\$ 81,008.41
34	Real-Time Schedule 24 Allocation Amount	\$ 5,525.79	\$ (430.42)	\$ 5,095.37
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	\$ (10,090.05)	\$ -	\$ (10,090.05)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 353,569.43	\$ -	\$ 353,569.43
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (299,042.59)	\$ -	\$ (299,042.59)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (614,127.77)	\$ -	\$ (614,127.77)
TOTAL MISO CHARGES		\$ 16,700,437.61	\$ 2,079,656.65	\$ 18,780,094.26
SCHEDULE 24 (FOR RETAIL)				\$ 86,103.78
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 18,693,990.48

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
April 2010 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (388,669.54)	\$ -	\$ (388,669.54)
2	Day-Ahead Spinning Reserve Amount	\$ (74,289.90)	\$ -	\$ (74,289.90)
3	Day-Ahead Supplemental Reserve	\$ (216,993.00)	\$ -	\$ (216,993.00)
4	Real-Time Regulation Amount	\$ 40,670.22	\$ 126,396.79	\$ 167,067.01
5	Real-Time Spinning Reserve Amount	\$ (29,615.18)	\$ 7,884.22	\$ (21,730.96)
6	Real-Time Supplemental Reserve Amount.	\$ 10,586.69	\$ 59,567.43	\$ 70,154.12
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (8,489.65)		\$ (8,489.65)
7b	Real Time Excessive Energy Congestion	\$ -		\$ -
7c	Real Time Excessive Energy Loss	\$ -		\$ -
8a	Real Time Non Excessive Energy Amount	\$ 162,063.99		\$ 162,063.99
8b	Real Time Non Excessive Energy Congestion	\$ (141,137.06)		\$ (141,137.06)
8c	Real Time Non Excessive Energy Loss	\$ (55,868.62)		\$ (55,868.62)
9	Real Time Net Regulation Adjustment Amount	\$ (10,531.69)	\$ (677.70)	\$ (11,209.39)
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 297,959.42	\$ -	\$ 297,959.42
11	Real Time Spinning Reserve Cost Distribution	\$ 237,083.99	\$ -	\$ 237,083.99
12	Real Time Supplemental Reserve Cost Distribution	\$ 161,237.34	\$ -	\$ 161,237.34
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 6,469.33	\$ (803.60)	\$ 5,665.73
14	Real Time Contignecy Reserve Deployment Failure	\$ 3,388.66	\$ (85.79)	\$ 3,302.87
TOTAL MISO ASM CHARGES		\$ (6,135.00)	\$ 192,281.35	\$ 186,146.35

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-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11
1	Forecast Month	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,830)
2	True-up Month	196,388	194,554	163,606	164,425	165,070	-	-	-	-	-	-	-
3		(0,009)	(0,009)	(0,010)	(0,010)	(0,010)	-	-	-	-	-	-	-
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	Forecast North Dakota Sales	196,388	194,554	163,606	164,425	165,070	-	-	-	-	-	-	-
6		(0,009)	(0,009)	(0,010)	(0,010)	(0,010)	-	-	-	-	-	-	-
7	Current Month Refund Factor	(0,009)	(0,009)	(0,010)	(0,010)	(0,010)	-	-	-	-	-	-	-
8		(0,009)	(0,009)	(0,010)	(0,010)	(0,010)	-	-	-	-	-	-	-
9	Forecasted North Dakota Sales	196,388	194,554	163,606	163,606	163,606	-	-	-	-	-	-	-
10	Actual North Dakota Sales (Cal. Mo.)	189,946	190,655	151,863	151,863	151,863	-	-	-	-	-	-	-
11	Deviation	6,442	3,899	11,743	11,743	11,743	-	-	-	-	-	-	-
12		(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	-	-	-	-	-	-	-
13	Expected Refund	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	-	-	-	-	-	-	-
14	Actual Refund	(16,278)	(16,494)	(16,137)	(16,494)	(16,137)	-	-	-	-	-	-	-
15	Deviation	(553)	(337)	(1,247)	(337)	(1,247)	-	-	-	-	-	-	-
16		(0,000)	(0,000)	(0,000)	(0,000)	(0,000)	-	-	-	-	-	-	-
17	True-up Factor	(0,000)	(0,000)	(0,000)	(0,000)	(0,000)	-	-	-	-	-	-	-
18		(0,000)	(0,000)	(0,000)	(0,000)	(0,000)	-	-	-	-	-	-	-
19	Realized Margin	(0,009)	(0,009)	(0,011)	(0,010)	(0,010)	-	-	-	-	-	-	-
20		(0,009)	(0,009)	(0,011)	(0,010)	(0,010)	-	-	-	-	-	-	-
21	Class Ratios	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956
22	Residential	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548
23	C&I Non-Demand	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219
24	C&I Demand Non-TOD	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135
25	C&I Demand TOD On-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
26	C&I Demand TOD Off-Peak	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088
27	Outdoor Lighting	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956
28		0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956
29	Realized Margin Adj for Class Ratios	(0,009)	(0,009)	(0,011)	(0,010)	(0,010)	-	-	-	-	-	-	-
30	Residential	(0,009)	(0,009)	(0,011)	(0,010)	(0,010)	-	-	-	-	-	-	-
31	C&I Non-Demand	(0,009)	(0,009)	(0,011)	(0,011)	(0,012)	-	-	-	-	-	-	-
32	C&I Demand Non-TOD	(0,009)	(0,009)	(0,011)	(0,011)	(0,011)	-	-	-	-	-	-	-
33	C&I Demand TOD On-Peak	(0,011)	(0,011)	(0,014)	(0,014)	(0,014)	-	-	-	-	-	-	-
34	C&I Demand TOD Off-Peak	(0,007)	(0,007)	(0,008)	(0,008)	(0,008)	-	-	-	-	-	-	-
35	Outdoor Lighting	(0,006)	(0,006)	(0,008)	(0,007)	(0,008)	-	-	-	-	-	-	-
36		(0,006)	(0,006)	(0,008)	(0,007)	(0,008)	-	-	-	-	-	-	-