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Minneapolis, Minnesota 55401

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JUL 28 2010

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July 28, 2010

PUBLIC SERVICE COMMISSION

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

Re: August 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 August 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 August 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 June 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:

August 2010	Fuel Cost Charge (\$/kWh)
Residential	0.02588
C & I Non-Demand	0.02742
C & I Demand	0.02657
C & I Demand Time of Day On-Peak	0.03415
C & I Demand Time of Day Off-Peak	0.02009
Outdoor Lighting	0.01843

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 August FCC, the net MISO Day 2 costs for June 2010 as recorded in Account 555. The MISO Day 2 cost recovery included in this August FCC is \$15,019,939, 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 August FCC, the net MISO ASM costs for June 2010 as recorded in Account 555. The MISO ASM cost recovery included in this August FCC is -\$1,078,074 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 June 2010 Asset Based Margin amount of \$141,482 has been included in the August 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 August FCC is \$16,567, or 0.009¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

OTHER REPORTING ITEM

Attachment is the calculation of the August 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 Aug-2010

Aug-2010 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02664	\$0.00020	-\$0.00084	\$0.02600
Residential	\$0.02652	\$0.00020	-\$0.00084	\$0.02588
C & I Non-Demand	\$0.02810	\$0.00021	-\$0.00089	\$0.02742
C & I Demand Non-TOD	\$0.02722	\$0.00020	-\$0.00086	\$0.02657
C & I Demand TOD On-Peak	\$0.03499	\$0.00026	-\$0.00110	\$0.03415
C & I Demand TOD Off-Peak	\$0.02058	\$0.00015	-\$0.00065	\$0.02009
Outdoor Lighting	\$0.01888	\$0.00014	-\$0.00060	\$0.01843
Residential				
Residential Service	\$ 0.02652	\$ 0.00020	\$ (0.00084)	\$ 0.02588
Residential TOD	\$ 0.02652	\$ 0.00020	\$ (0.00084)	\$ 0.02588
Residential - Underground	\$ 0.02652	\$ 0.00020	\$ (0.00084)	\$ 0.02588
Residential TOD - Underground	\$ 0.02652	\$ 0.00020	\$ (0.00084)	\$ 0.02588
Energy Control - (Non-Demand)	\$ 0.02652	\$ 0.00020	\$ (0.00084)	\$ 0.02588
Limit Off Peak	\$ 0.02652	\$ 0.00020	\$ (0.00084)	\$ 0.02588
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02810	\$ 0.00021	\$ (0.00089)	\$ 0.02742
Limit Off Peak	\$ 0.02810	\$ 0.00021	\$ (0.00089)	\$ 0.02742
Small General Service	\$ 0.02810	\$ 0.00021	\$ (0.00089)	\$ 0.02742
Small General TOD - Metered	\$ 0.02810	\$ 0.00021	\$ (0.00089)	\$ 0.02742
Small General TOD - Unmetered	\$ 0.02810	\$ 0.00021	\$ (0.00089)	\$ 0.02742
Fire and Civil Defense Siren	\$ 0.02810	\$ 0.00021	\$ (0.00089)	\$ 0.02742
Direct Current (Closed)	\$ 0.02810	\$ 0.00021	\$ (0.00089)	\$ 0.02742
C & I Demand				
General Service	\$ 0.02722	\$ 0.00020	\$ (0.00086)	\$ 0.02657
General TOD - On Peak	\$ 0.03499	\$ 0.00026	\$ (0.00110)	\$ 0.03415
General TOD - Off Peak	\$ 0.02058	\$ 0.00015	\$ (0.00065)	\$ 0.02009
Peak Controlled (Closed)	\$ 0.02722	\$ 0.00020	\$ (0.00086)	\$ 0.02657
Peak Controlled TOD (Closed) - On Peak	\$ 0.03499	\$ 0.00026	\$ (0.00110)	\$ 0.03415
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02058	\$ 0.00015	\$ (0.00065)	\$ 0.02009
Peak Controlled Tiered	\$ 0.02722	\$ 0.00020	\$ (0.00086)	\$ 0.02657
Peak Controlled Tiered TOD - On Peak	\$ 0.03499	\$ 0.00026	\$ (0.00110)	\$ 0.03415
Peak Controlled Tiered TOD - Off Peak	\$ 0.02058	\$ 0.00015	\$ (0.00065)	\$ 0.02009
Energy Controlled (Closed)	\$ 0.02722	\$ 0.00020	\$ (0.00086)	\$ 0.02657
Tier 1 Energy Controlled Rider	\$ 0.02722	\$ 0.00020	\$ (0.00086)	\$ 0.02657
Real Time Pricing - Firm - On Peak	\$ 0.03499	\$ 0.00026	\$ (0.00110)	\$ 0.03415
Real Time Pricing - Firm - Off Peak	\$ 0.02058	\$ 0.00015	\$ (0.00065)	\$ 0.02009
Real Time Pricing - Controllable - On Peak	\$ 0.03499	\$ 0.00026	\$ (0.00110)	\$ 0.03415
Real Time Pricing - Controllable - Off Peak	\$ 0.02058	\$ 0.00015	\$ (0.00065)	\$ 0.02009
Small Municipal Pumping	\$ 0.02722	\$ 0.00020	\$ (0.00086)	\$ 0.02657
Municipal Pumping	\$ 0.02722	\$ 0.00020	\$ (0.00086)	\$ 0.02657
Excess Energy - St. Anthony Falls	\$ 0.02722	\$ 0.00020	\$ (0.00086)	\$ 0.02657
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01888	\$ 0.00014	\$ (0.00060)	\$ 0.01843
Street Lighting System	\$ 0.01888	\$ 0.00014	\$ (0.00060)	\$ 0.01843
Street Lighting Energy	\$ 0.01888	\$ 0.00014	\$ (0.00060)	\$ 0.01843
Street Lighting Energy - Metered	\$ 0.01888	\$ 0.00014	\$ (0.00060)	\$ 0.01843
Street Lighting Energy (Closed)	\$ 0.01888	\$ 0.00014	\$ (0.00060)	\$ 0.01843
Street Lighting - City of St. Paul	\$ 0.01888	\$ 0.00014	\$ (0.00060)	\$ 0.01843

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Mar-10	Apr-10	May-10	Jun-10	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$27,468,130	\$28,892,464	\$42,295,040	\$39,902,362	\$138,557,996
Account 518 - Nuclear Fuel	\$9,775,774	\$8,045,935	\$7,461,565	\$10,244,323	\$35,527,596
Account 555 - Purchased Power ¹	\$34,011,198	\$32,827,975	\$46,251,093	\$40,206,803	\$153,297,069
Account 555 - MISO Day 2 Charges	\$20,208,392	\$18,780,094	\$16,331,544	\$15,104,838	\$70,424,868
Account 555 MISO Day 2 - Schedule 24	(\$86,548)	(\$86,104)	(\$97,339)	(\$84,899)	(\$354,890)
Account 555 MISO - ASM Charges	(\$1,583,580)	\$186,146	\$3,111,926	(\$1,078,074)	\$636,419
Total MISO Charges	\$18,538,264	\$18,880,137	\$19,346,131	\$13,941,865	\$70,706,397
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$89,793,366	\$88,646,511	\$115,353,828	\$104,295,353	\$398,089,058
Less Fuel Cost of InterSystem Sales	(\$7,682,321)	(\$7,335,161)	(\$14,193,013)	(\$9,145,253)	(\$38,355,748)
Net System Costs	\$82,111,045	\$81,311,350	\$101,160,815	\$95,150,100	\$359,733,310
System MWH Sales					
Total NSP System Retail	3,553,751	3,129,808	2,907,623	3,649,319	13,240,501
Non-Gen Muni's/Load Pattern	71,253	67,601	60,608	65,001	264,463
Total NSP System MWh Sales	3,625,004	3,197,409	2,968,231	3,714,320	13,504,964
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.265¢	2.543¢	3.408¢	2.562¢	2.664¢
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	2.652¢
(ii) C & I Non-Demand				1.0548	2.810¢
(iii) C & I Demand Non-TOD				1.0219	2.722¢
(iv) C & I Demand TOD On-Peak				1.3135	3.499¢
(v) C & I Demand TOD Off-Peak				0.7726	2.058¢
(vi) Outdoor Lighting				0.7088	1.888¢

¹ Excludes demand-related expenses

North Dakota Retail MWh Sales					
(i) Residential	76,676	55,786	45,211	51,563	229,236
(ii) C & I Non-Demand	13,603	10,380	8,456	9,830	42,269
(iii) C & I Demand Non-TOD	67,572	54,120	48,522	60,218	230,432
(iv) C & I Demand TOD On-Peak	22,810	17,650	15,394	21,149	77,003
(v) C & I Demand TOD Off-Peak	36,695	27,666	23,067	34,834	122,262
(vi) Outdoor Lighting	1,989	1,569	1,263	1,210	6,031
(vii) Total	219,345	167,171	141,913	178,804	707,233

Aug-2010 Recovery Provision (True-up Factor) Calculation

Prior Unrecovered Expenses (Apr-10 Balance of Unrecovered Expenses)	Total
	Apr-10
	(\$156,658)

Prior Expenses Recovered in Jun-2010

	FCF Ratio	True-Up Factor per kWh	Actual ND MWh Sales	Prior Recovered Expenses in
(i) Residential				
(ii) C & I Non-Demand	0.9956	-0.019¢	51,563	(\$10,001)
(iii) C & I Demand Non-TOD	1.0548	-0.021¢	9,830	(\$2,020)
(iv) C & I Demand TOD On-Peak	1.0219	-0.020¢	60,218	(\$11,988)
(v) C & I Demand TOD Off-Peak	1.3135	-0.026¢	21,149	(\$5,412)
(vi) Outdoor Lighting	0.7726	-0.015¢	34,834	(\$5,243)
(vii) Total	0.7088	-0.014¢	178,804	(\$34,831)

Actual Cost Should Have Been Recovered in Jun-10

	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.562¢	0.000¢	178,804	\$4,580,958

Cost Recovered in Jun-10

	FCF Ratio	Fuel Cost Recovered	Actual ND MWh Sales	Actual Recovery
(i) Residential	0.9956	2.405¢	51,563	\$1,240,281
(ii) C & I Non-Demand	1.0548	2.548¢	9,830	\$250,507
(iii) C & I Demand Non-TOD	1.0219	2.469¢	60,218	\$1,486,728
(iv) C & I Demand TOD On-Peak	1.3135	3.173¢	21,149	\$671,146
(v) C & I Demand TOD Off-Peak	0.7726	1.867¢	34,834	\$650,212
(vi) Outdoor Lighting	0.7088	1.712¢	1,210	\$20,721
(vii) Total			178,804	\$4,319,595

Total Balance of Unrecovered Expenses (Aug-10 Balance of Unrecovered Expenses)

Aug-2010 Recovery Provision	\$139,536
4 Month ND Retail Total MWh Sales	707,233
Aug-2010 Recovery Provision per KWH	0.020¢

Aug-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	0.020¢	0.020¢
(ii) C & I Non-Demand	1.0548	0.020¢	0.021¢
(iii) C & I Demand Non-TOD	1.0219	0.020¢	0.020¢
(iv) C & I Demand TOD On-Peak	1.3135	0.020¢	0.026¢
(v) C & I Demand TOD Off-Peak	0.7726	0.020¢	0.015¢
(vi) Outdoor Lighting	0.7088	0.020¢	0.014¢

Aug-2010 Margin Sharing Refunds			
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
Refund/Special Charge Amount	(\$141,482)	(\$16,567)	(\$158,049)
(i) Residential	-0.075¢	-0.009¢	-0.084¢
(ii) C & I Non-Demand	-0.079¢	-0.009¢	-0.089¢
(iii) C & I Demand Non-TOD	-0.077¢	-0.009¢	-0.086¢
(iv) C & I Demand TOD On-Peak	-0.099¢	-0.012¢	-0.110¢
(v) C & I Demand TOD Off-Peak	-0.058¢	-0.007¢	-0.065¢
(vi) Outdoor Lighting	-0.053¢	-0.006¢	-0.060¢

Aug-2010 Factors	
	Total
(i) Residential	2.588¢
(ii) C & I Non-Demand	2.742¢
(iii) C & I Demand Non-TOD	2.657¢
(iv) C & I Demand TOD On-Peak	3.415¢
(v) C & I Demand TOD Off-Peak	2.009¢
(vi) Outdoor Lighting	1.843¢

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>		
	Jul-10	Aug-10	Differ- ence	Percent Change	FCA Application Jul-10	Aug-10	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$136.9	\$138.6	\$1.6	1.2%	35.7%	34.8%	-0.9%
2 Nuclear	\$34.2	\$35.5	\$1.3	3.8%	8.9%	8.9%	0.0%
3 Purchases	\$141.2	\$153.3	\$12.1	8.5%	36.8%	38.5%	1.7%
MISO related Purchases	\$70.9	\$70.7	(\$0.2)	-0.3%	18.5%	17.8%	-0.7%
4 Total System Costs	383.4	398.1	\$14.7	3.8%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$37.1	\$38.4	\$1.2	3.3%	9.7%	9.6%	-0.1%
6 Net System Costs	\$346.2	\$359.7	\$13.5	3.9%	90.3%	90.4%	0.1%
7							
8 ** GWH OUTPUT **							
9 Fossil	5,063	5,159	96	1.9%	15.7%	15.6%	-0.1%
10 Nuclear	4,210	4,235	25	0.6%	13.1%	12.8%	-0.3%
11 Purchases	4,957	5,285	328	6.6%	15.4%	16.0%	0.6%
12 Hydro & Other	838	890	42	5.0%	2.6%	2.7%	0.1%
13 Net Interchange	17,104	17,541	437	2.6%	53.2%	53.0%	-0.2%
14 Total Output	32,172	33,100	928	2.9%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,515	1,612	97	6.4%	4.7%	4.9%	0.2%
16 Native Requirement	30,657	31,488	831	2.7%	95.3%	95.1%	-0.2%
17							
18 ** COST per KWH OUTPUT (\$) **							
19 Fossil	2.705	2.686	-0.019	-0.7%			
20 Nuclear	0.813	0.839	0.026	3.2%			
21 Purchases	2.849	2.901	0.051	1.8%			
22 Total System Costs	1.192	1.203	0.011	0.9%			
23 Intersystem Sales	2.450	2.380	-0.071	-2.9%			
24 Net System Costs	1.129	1.142	0.013	1.2%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,175	13,505	330	2.5%			
28							
29 COST per KWH SALES (\$)	2.628	2.664	0.036	1.4%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	0.129	0.020	-0.109				
(i) Residential	0.128	0.020	-0.109				
(ii) C & I Non-Demand	0.136	0.021	-0.115				
(iii) C & I Demand Non-TOD	0.132	0.020	-0.111				
(iv) C & I Demand TOD On-Peak	0.169	0.026	-0.143				
(v) C & I Demand TOD Off-Peak	0.099	0.015	-0.084				
(vi) Outdoor Lighting	0.091	0.014	-0.077				
32 REFUND	-0.092	0.000	0.092				
(i) Residential	-0.092	-0.084	0.008				
(ii) C & I Non-Demand	-0.097	-0.089	0.008				
(iii) C & I Demand Non-TOD	-0.094	-0.086	0.008				
(iv) C & I Demand TOD On-Peak	-0.121	-0.110	0.011				
(v) C & I Demand TOD Off-Peak	-0.071	-0.065	0.006				
(vi) Outdoor Lighting	-0.065	-0.060	0.005				
33 SYSTEM FCC IMPACT (\$ / KWH)	2.665	2.684	0.019	0.7%			
(i) Residential	2.653	2.588	-0.065				
(ii) C & I Non-Demand	2.810	2.742	-0.068				
(iii) C & I Demand Non-TOD	2.723	2.657	-0.066				
(iv) C & I Demand TOD On-Peak	3.499	3.415	-0.084				
(v) C & I Demand TOD Off-Peak	2.058	2.009	-0.049				
(vi) Outdoor Lighting	1.888	1.843	-0.045				

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	(\$0.16)
500	(\$0.32)
750	(\$0.49)
1,000	(\$0.65)

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>	
	Jul-10	Aug-10
** GWH OUTPUT **		
Thermal	623,956	602,288
Wind plus disper gen	(55)	(45)
Hydro	214,151	277,964
Hydro and Other	838,052	880,207
Rounded to nearest thousand:	838	880
Sales		
Non Gen Munic Total	280,115,000	264,463,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,515,270,000	1,611,786,000
Rounded to nearest million:	1515.27	1611.786

		System	Intersystem	Retail
June 2010 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 21,687,658.40	\$ 3,365,549.07	\$ 25,053,207.47
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,714,030.96	\$ -	\$ 2,714,030.96
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 6,459.24	\$ -	\$ 6,459.24
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (20,359,739.50)	\$ -	\$ (20,359,739.50)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 3,104,325.98	\$ -	\$ 3,104,325.98
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)	\$ 3,278,848.21	\$ 1,780,087.30	\$ 5,058,935.51
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (69,796.52)	\$ -	\$ (69,796.52)
14	Real-Time Distribution of Losses Amount	\$ (1,711,333.18)	\$ -	\$ (1,711,333.18)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ 51,665.16	\$ -	\$ 51,665.16
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ (111,312.81)	\$ -	\$ (111,312.81)
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ 14,815.54	\$ -	\$ 14,815.54
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ (468,848.63)	\$ -	\$ (468,848.63)
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ 1,149.62	\$ -	\$ 1,149.62
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 4,278,208.23	\$ -	\$ 4,278,208.23
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)	\$ (200,348.28)	\$ -	\$ (200,348.28)
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)	\$ 26,547.04	\$ -	\$ 26,547.04
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (2,668,281.53)	\$ -	\$ (2,668,281.53)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (148,520.38)	\$ -	\$ (148,520.38)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (133,003.20)	\$ -	\$ (133,003.20)
37	Financial Transmission Guarantee Uplift Amount	\$ 91,304.51	\$ -	\$ 91,304.51
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 356,412.07	\$ -	\$ 356,412.07
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 279,148.29	\$ -	\$ 279,148.29
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (480,016.20)	\$ 176.67	\$ (479,839.53)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 617,556.04	\$ -	\$ 617,556.04
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ (435,903.69)	\$ 62,128.57	\$ (373,775.12)
42	Real-Time Price Volatility Make Whole Payment Amount	\$ (393,692.57)	\$ 23,596.20	\$ (370,096.37)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 721,415.44	\$ (8,294.40)	\$ 713,121.04
19	Real-Time Market Administration Amount	\$ 54,854.80	\$ (8,994.98)	\$ 45,859.82
29	Financial Transmission Rights Market Administration Amount	\$ 70,898.72	\$ -	\$ 70,898.72
33	Day-Ahead Schedule 24 Allocation Amount	\$ 80,667.47	\$ (900.02)	\$ 79,767.45
34	Real-Time Schedule 24 Allocation Amount	\$ 6,147.71	\$ (1,015.79)	\$ 5,131.92
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	\$ (10,950.30)	\$ -	\$ (10,950.30)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 848,140.09	\$ -	\$ 848,140.09
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (796,783.55)	\$ -	\$ (796,783.55)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (409,217.59)	\$ -	\$ (409,217.59)
TOTAL MISO CHARGES		\$ 9,892,505.59	\$ 5,212,332.62	\$ 15,104,838.21

SCHEDULE 24 (FOR RETAIL)	\$ 84,899.37
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TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)	\$ 15,019,938.84
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MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
June 2010 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (485,958.78)	\$ -	\$ (485,958.78)
2	Day-Ahead Spinning Reserve Amount	\$ (165,666.81)	\$ -	\$ (165,666.81)
3	Day-Ahead Supplemental Reserve	\$ (126,534.63)	\$ -	\$ (126,534.63)
4	Real-Time Regulation Amount	\$ 23,673.75	\$ 211,190.07	\$ 234,863.82
5	Real-Time Spinning Reserve Amount	\$ 30,977.95	\$ 67,999.12	\$ 98,977.07
6	Real-Time Supplemental Reserve Amount	\$ 17,544.74	\$ 42,241.65	\$ 59,786.39
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (20,984.52)	\$ -	\$ (20,984.52)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ (1,400,253.81)	\$ -	\$ (1,400,253.81)
8b	Real Time Non Excessive Energy Congestion	\$ (7,917.80)	\$ -	\$ (7,917.80)
8c	Real Time Non Excessive Energy Loss	\$ 112,546.47	\$ -	\$ 112,546.47
9	Real Time Net Regulation Adjustment Amount	\$ 32,187.68	\$ (3,925.21)	\$ 28,262.47
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 318,104.05	\$ -	\$ 318,104.05
11	Real Time Spinning Reserve Cost Distribution	\$ 167,995.27	\$ -	\$ 167,995.27
12	Real Time Supplemental Reserve Cost Distribution	\$ 84,935.14	\$ -	\$ 84,935.14
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 13,835.26	\$ 9,902.48	\$ 23,737.74
14	Real Time Contingency Reserve Deployment Failure	\$ 34.34	\$ -	\$ 34.34
TOTAL MISO ASM CHARGES		\$ (1,405,481.70)	\$ 327,408.11	\$ (1,078,073.59)

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

1 Forecast Month	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10
2 True-up Month	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10
3									
4 Monthly Refund	(161,371)	10,622	(54,285)	(21,836)	(155,670)	(141,793)			
5									
6 Forecast North Dakota Sales	194,554	163,606	164,425	165,070	188,515	188,034	169,302	180,796	-
7									
8 Current Month Refund Factor	(0.083)	0.006	(0.033)	(0.013)	(0.083)	(0.075)	-	-	-
9									
10 Forecasted North Dakota Sales	215,527	196,388	194,554	163,606	164,425	165,070	188,515	188,034	-
11 Actual North Dakota Sales (Cal. Mo.)	222,254	189,946	190,655	151,863	160,154	167,487	-	-	-
12 Deviation	(6,727)	6,442	3,899	11,743	4,271	(2,417)	188,515	188,034	-
13									
14 Expected Refund	(13,480)	(81,774)	(160,951)	7,940	(57,511)	(21,266)	(157,164)	(141,482)	-
15 Actual Refund	(13,900)	(79,092)	(157,725)	7,370	(56,017)	(21,577)	-	-	-
16 Deviation	420	(2,682)	(3,226)	570	(1,494)	311	(157,164)	(141,482)	-
17									
18 True-up Factor	0.000	(0.002)	(0.002)	0.000	(0.001)	0.000	-	-	-
19									
20 Realized Margin	(0.083)	0.005	(0.035)	(0.013)	(0.083)	(0.075)	-	-	-
21									
22 Class Ratios									
23 Residential	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
25 C&I Demand Non-TOD	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
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
28 Outdoor Lighting	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	(0.082)	0.005	(0.035)	(0.013)	(0.083)	(0.075)	-	-	-
32 C&I Non-Demand	(0.087)	0.005	(0.037)	(0.014)	(0.088)	(0.079)	-	-	-
33 C&I Demand Non-TOD	(0.085)	0.005	(0.036)	(0.013)	(0.085)	(0.077)	-	-	-
34 C&I Demand TOD On-Peak	(0.109)	0.006	(0.046)	(0.017)	(0.110)	(0.099)	-	-	-
35 C&I Demand TOD Off-Peak	(0.064)	0.004	(0.027)	(0.010)	(0.064)	(0.058)	-	-	-
36 Outdoor Lighting	(0.059)	0.003	(0.025)	(0.009)	(0.059)	(0.053)	-	-	-

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
2 True-up Month			Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10
3									
4 Monthly Refund	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)
5									
6 Forecast North Dakota Sales	196,388	194,554	163,606	164,425	165,070	188,515	188,034	-	-
7									
8 Current Month Refund Factor	(0.009)	(0.009)	(0.010)	(0.010)	(0.010)	(0.009)	(0.009)	-	-
9									
10 Forecasted North Dakota Sales			196,388	194,554	163,606	164,425	165,070	-	-
11 Actual North Dakota Sales (Cal. Mo.)			189,946	190,655	151,863	160,154	167,487	-	-
12 Deviation			6,442	3,899	11,743	4,271	(2,417)	-	-
13									
14 Expected Refund			(16,831)	(16,831)	(17,384)	(17,168)	(18,078)	-	-
15 Actual Refund			(16,278)	(16,494)	(16,137)	(16,722)	(18,342)	-	-
16 Deviation			(553)	(337)	(1,247)	(447)	264	-	-
17									
18 True-up Factor	-	-	(0.000)	(0.000)	(0.001)	(0.000)	0.000	-	-
19									
20 Realized Margin	(0.009)	(0.009)	(0.011)	(0.010)	(0.011)	(0.009)	(0.009)	-	-
21									
22 Class Ratios									
23 Residential	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
25 C&I Demand Non-TOD	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
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
28 Outdoor Lighting	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)	-	-
32 C&I Non-Demand	(0.009)	(0.009)	(0.011)	(0.011)	(0.012)	(0.010)	(0.009)	-	-
33 C&I Demand Non-TOD	(0.009)	(0.009)	(0.011)	(0.011)	(0.011)	(0.009)	(0.009)	-	-
34 C&I Demand TOD On-Peak	(0.011)	(0.011)	(0.014)	(0.014)	(0.014)	(0.012)	(0.012)	-	-
35 C&I Demand TOD Off-Peak	(0.007)	(0.007)	(0.008)	(0.008)	(0.008)	(0.007)	(0.007)	-	-
36 Outdoor Lighting	(0.006)	(0.006)	(0.008)	(0.007)	(0.008)	(0.006)	(0.006)	-	-

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

POWER PLANT AND GENERATING UNIT DATA REPORT: 2009

ALLOWABLE CODES

Call Heading	Code	Code Definition	Call Heading	Code	Code Definition
** Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
				WI	Wind
				OTHER	Other - provide description
*** Energy Source & Fuel Type	BIT	Bituminous Coal	*** Unit of Measure	GAL	Gallons
	COAL	Coal (general)		MCF	Thousand cubic feet
	DIESEL	Diesel		MMCF	Million cubic feet
	FO2	Fuel Oil #2 (Mid Distillate)		TONS	Tons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		BBL	Barrels
	LIG	Lignite		THERMS	Therms
	LPG	Liquefied Propane Gas			
	NG	Natural Gas			
	NUC	Nuclear			
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = $\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$ (percentage)

Operating Availability = $100 - \text{Maintenance percentage} - \text{Forced Outage percentage}$ (percentage)

Capacity Factor = $\frac{\text{Total Annual MWh of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8,760}$ (percentage)

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.