



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

October 28, 2010

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

Re: November 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 November 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 November 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 September 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:

November 2010	Fuel Cost Charge (\$/kWh)
Residential	0.02505
C & I Non-Demand	0.02654
C & I Demand	0.02571
C & I Demand Time of Day On-Peak	0.03305
C & I Demand Time of Day Off-Peak	0.01944
Outdoor Lighting	0.01783

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 November FCC, the net MISO Day 2 costs for September 2010 as recorded in Account 555. The MISO Day 2 cost recovery included in this November FCC is \$10,127,840, 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 November FCC, the net MISO ASM costs for September 2010 as recorded in Account 555. The MISO ASM cost recovery included in this November FCC is -\$465,255, 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 September 2010 Asset Based Margin amount of \$49,824 has been included in the November 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 November FCC is \$17,407, 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 November 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

Nov-2010 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02609	-\$0.00057	-\$0.00036	\$0.02516
Residential	\$0.02598	-\$0.00057	-\$0.00036	\$0.02505
C & I Non-Demand	\$0.02752	-\$0.00060	-\$0.00038	\$0.02654
C & I Demand Non-TOD	\$0.02666	-\$0.00058	-\$0.00037	\$0.02571
C & I Demand TOD On-Peak	\$0.03427	-\$0.00075	-\$0.00047	\$0.03305
C & I Demand TOD Off-Peak	\$0.02016	-\$0.00044	-\$0.00028	\$0.01944
Outdoor Lighting	\$0.01849	-\$0.00040	-\$0.00025	\$0.01783
Residential				
Residential Service	\$ 0.02598	\$ (0.00057)	\$ (0.00036)	\$ 0.02505
Residential TOD	\$ 0.02598	\$ (0.00057)	\$ (0.00036)	\$ 0.02505
Residential - Underground	\$ 0.02598	\$ (0.00057)	\$ (0.00036)	\$ 0.02505
Residential TOD - Underground	\$ 0.02598	\$ (0.00057)	\$ (0.00036)	\$ 0.02505
Energy Control - (Non-Demand)	\$ 0.02598	\$ (0.00057)	\$ (0.00036)	\$ 0.02505
Limit Off Peak	\$ 0.02598	\$ (0.00057)	\$ (0.00036)	\$ 0.02505
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02752	\$ (0.00060)	\$ (0.00038)	\$ 0.02654
Limit Off Peak	\$ 0.02752	\$ (0.00060)	\$ (0.00038)	\$ 0.02654
Small General Service	\$ 0.02752	\$ (0.00060)	\$ (0.00038)	\$ 0.02654
Small General TOD - Metered	\$ 0.02752	\$ (0.00060)	\$ (0.00038)	\$ 0.02654
Small General TOD - Unmetered	\$ 0.02752	\$ (0.00060)	\$ (0.00038)	\$ 0.02654
Fire and Civil Defense Siren	\$ 0.02752	\$ (0.00060)	\$ (0.00038)	\$ 0.02654
Direct Current (Closed)	\$ 0.02752	\$ (0.00060)	\$ (0.00038)	\$ 0.02654
C & I Demand				
General Service	\$ 0.02666	\$ (0.00058)	\$ (0.00037)	\$ 0.02571
General TOD - On Peak	\$ 0.03427	\$ (0.00075)	\$ (0.00047)	\$ 0.03305
General TOD - Off Peak	\$ 0.02016	\$ (0.00044)	\$ (0.00028)	\$ 0.01944
Peak Controlled (Closed)	\$ 0.02666	\$ (0.00058)	\$ (0.00037)	\$ 0.02571
Peak Controlled TOD (Closed) - On Peak	\$ 0.03427	\$ (0.00075)	\$ (0.00047)	\$ 0.03305
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02016	\$ (0.00044)	\$ (0.00028)	\$ 0.01944
Peak Controlled Tiered	\$ 0.02666	\$ (0.00058)	\$ (0.00037)	\$ 0.02571
Peak Controlled Tiered TOD - On Peak	\$ 0.03427	\$ (0.00075)	\$ (0.00047)	\$ 0.03305
Peak Controlled Tiered TOD - Off Peak	\$ 0.02016	\$ (0.00044)	\$ (0.00028)	\$ 0.01944
Energy Controlled (Closed)	\$ 0.02666	\$ (0.00058)	\$ (0.00037)	\$ 0.02571
Tier 1 Energy Controlled Rider	\$ 0.02666	\$ (0.00058)	\$ (0.00037)	\$ 0.02571
Real Time Pricing - Firm - On Peak	\$ 0.03427	\$ (0.00075)	\$ (0.00047)	\$ 0.03305
Real Time Pricing - Firm - Off Peak	\$ 0.02016	\$ (0.00044)	\$ (0.00028)	\$ 0.01944
Real Time Pricing - Controllable - On Peak	\$ 0.03427	\$ (0.00075)	\$ (0.00047)	\$ 0.03305
Real Time Pricing - Controllable - Off Peak	\$ 0.02016	\$ (0.00044)	\$ (0.00028)	\$ 0.01944
Small Municipal Pumping	\$ 0.02666	\$ (0.00058)	\$ (0.00037)	\$ 0.02571
Municipal Pumping	\$ 0.02666	\$ (0.00058)	\$ (0.00037)	\$ 0.02571
Excess Energy - St. Anthony Falls	\$ 0.02666	\$ (0.00058)	\$ (0.00037)	\$ 0.02571
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01849	\$ (0.00040)	\$ (0.00025)	\$ 0.01783
Street Lighting System	\$ 0.01849	\$ (0.00040)	\$ (0.00025)	\$ 0.01783
Street Lighting Energy	\$ 0.01849	\$ (0.00040)	\$ (0.00025)	\$ 0.01783
Street Lighting Energy - Metered	\$ 0.01849	\$ (0.00040)	\$ (0.00025)	\$ 0.01783
Street Lighting Energy (Closed)	\$ 0.01849	\$ (0.00040)	\$ (0.00025)	\$ 0.01783
Street Lighting - City of St. Paul	\$ 0.01849	\$ (0.00040)	\$ (0.00025)	\$ 0.01783

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 Nov-2010

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Jun-10	Jul-10	Aug-10	Sep-10	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$39,902,362	\$55,067,341	\$58,449,676	\$32,483,786	\$185,903,165
Account 518 - Nuclear Fuel	\$10,244,323	\$10,499,991	\$10,436,900	\$10,120,300	\$41,301,512
Account 555 - Purchased Power ¹	\$40,206,803	\$56,703,451	\$51,892,571	\$42,858,688	\$191,661,513
Account 555 - MISO Day 2 Charges	\$15,104,838	\$19,722,045	\$19,796,437	\$10,215,984	\$64,839,304
Account 555 MISO Day 2 - Schedule 24	(\$84,899)	(\$96,885)	(\$102,950)	(\$88,143)	(\$372,878)
Account 555 MISO - ASM Charges	(\$1,078,074)	(\$3,335,760)	(\$1,843,516)	(\$465,255)	(\$6,722,605)
Total MISO Charges	\$13,941,865	\$16,289,400	\$17,849,971	\$9,662,585	\$57,743,821
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$104,295,353	\$138,560,182	\$138,629,117	\$95,125,359	\$476,610,012
Less Fuel Cost of InterSystem Sales	(\$9,145,253)	(\$23,721,609)	(\$16,801,461)	(\$15,484,547)	(\$65,152,870)
Net System Costs	\$95,150,100	\$114,838,573	\$121,827,656	\$79,640,812	\$411,457,142
System MWh Sales					
Total NSP System Retail	3,649,319	3,841,078	4,249,406	3,737,306	15,477,109
Non-Gen Muni's/Load Pattern	65,001	67,976	77,837	80,260	291,074
Total NSP System MWh Sales	3,714,320	3,909,054	4,327,243	3,817,566	15,768,183
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.562¢	2.938¢	2.815¢	2.086¢	2.609¢
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	2.598¢
(ii) C & I Non-Demand				1.0548	2.752¢
(iii) C & I Demand Non-TOD				1.0219	2.666¢
(iv) C & I Demand TOD On-Peak				1.3135	3.427¢
(v) C & I Demand TOD Off-Peak				0.7726	2.016¢
(vi) Outdoor Lighting				0.7088	1.849¢

¹ Excludes demand-related expenses

North Dakota Retail MWh Sales					
(i) Residential	51,563	59,551	66,473	53,979	231,566
(ii) C & I Non-Demand	9,830	10,009	10,272	9,169	39,280
(iii) C & I Demand Non-TOD	60,218	60,762	63,143	60,097	244,220
(iv) C & I Demand TOD On-Peak	21,149	18,832	20,271	19,488	79,740
(v) C & I Demand TOD Off-Peak	34,834	29,571	31,083	30,560	126,048
(vi) Outdoor Lighting	1,210	1,129	1,195	1,405	4,939
(vii) Total	178,804	179,854	192,437	174,698	725,793

Nov-2010 Recovery Provision (True-up Factor) Calculation	
Prior Unrecovered Expenses (Jul-10 Balance of Unrecovered Expenses)	Total Jul-10
	\$1,250,802

Prior Expenses Recovered in Sep-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	0.186¢	53,979	\$100,668
(iii) C & I Demand Non-TOD	1.0548	0.198¢	9,169	\$18,116
(iv) C & I Demand TOD On-Peak	1.0219	0.191¢	60,097	\$115,038
(v) C & I Demand TOD Off-Peak	1.3135	0.246¢	19,488	\$47,949
(vi) Outdoor Lighting	0.7726	0.145¢	30,560	\$44,227
(vii) Total	0.7088	0.133¢	1,405	\$1,865
			174,698	\$327,863

Actual Cost Should Have Been Recovered in Sep-10				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.086¢	0.000¢	174,698	\$3,644,200

Cost Recovered in Sep-10				
	FCF Ratio	Fuel Cost Recovered	Actual ND MWh Sales	Actual Recovery
(i) Residential	0.9956	2.833¢	53,979	\$1,529,483
(ii) C & I Non-Demand	1.0548	3.002¢	9,169	\$275,250
(iii) C & I Demand Non-TOD	1.0219	2.908¢	60,097	\$1,747,817
(iv) C & I Demand TOD On-Peak	1.3135	3.738¢	19,488	\$728,505
(v) C & I Demand TOD Off-Peak	0.7726	2.199¢	30,560	\$671,959
(vi) Outdoor Lighting	0.7088	2.017¢	1,405	\$28,342
(vii) Total			174,698	\$4,981,356

Total Balance of Unrecovered Expenses (Nov-10 Balance of Unrecovered Expenses)	
Nov-2010 Recovery Provision	(\$414,217)
4 Month ND Retail Total MWh Sales	725,793
Nov-2010 Recovery Provision per KWH	-0.057¢

Nov-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	-0.057¢	-0.057¢
(ii) C & I Non-Demand	1.0548	-0.057¢	-0.060¢
(iii) C & I Demand Non-TOD	1.0219	-0.057¢	-0.058¢
(iv) C & I Demand TOD On-Peak	1.3135	-0.057¢	-0.075¢
(v) C & I Demand TOD Off-Peak	0.7726	-0.057¢	-0.044¢
(vi) Outdoor Lighting	0.7088	-0.057¢	-0.040¢
Nov-2010 Margin Sharing Refunds			
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
Refund/Special Charge Amount	(\$49,824)	(\$17,407)	(\$67,231)
(i) Residential	-0.026¢	-0.009¢	-0.036¢
(ii) C & I Non-Demand	-0.028¢	-0.010¢	-0.038¢
(iii) C & I Demand Non-TOD	-0.027¢	-0.010¢	-0.037¢
(iv) C & I Demand TOD On-Peak	-0.035¢	-0.012¢	-0.047¢
(v) C & I Demand TOD Off-Peak	-0.021¢	-0.007¢	-0.028¢
(vi) Outdoor Lighting	-0.019¢	-0.007¢	-0.025¢
Nov-2010 Factors			
	Total		
(i) Residential	2.505¢		
(ii) C & I Non-Demand	2.654¢		
(iii) C & I Demand Non-TOD	2.571¢		
(iv) C & I Demand TOD On-Peak	3.305¢		
(v) C & I Demand TOD Off-Peak	1.944¢		
(vi) Outdoor Lighting	1.783¢		

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>		
	Oct-10	Nov-10	Differ- ence	Percent Change	FCA Application Oct-10	Nov-10	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$195.7	\$185.9	(\$9.8)	-5.0%	39.4%	39.0%	-0.4%
2 Nuclear	\$38.6	\$41.3	\$2.7	6.9%	7.8%	8.7%	0.9%
3 Purchases	\$195.1	\$191.7	(\$3.4)	-1.7%	39.3%	40.2%	0.9%
MISO related Purchases	\$67.4	\$57.7	(\$9.7)	-14.4%	13.6%	12.1%	-1.5%
4 Total System Costs	496.8	476.6	(\$20.2)	-4.1%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$63.9	\$65.2	\$1.3	2.0%	12.9%	13.7%	0.8%
6 Net System Costs	\$433.0	\$411.5	(\$21.5)	-5.0%	87.1%	86.3%	-0.8%
7							
** GWH OUTPUT **							
9 Fossil	6,300	6,096	(204)	-3.2%	15.3%	16.2%	0.9%
10 Nuclear	4,361	4,648	287	6.6%	10.6%	12.4%	1.8%
11 Purchases	5,625	5,488	(137)	-2.4%	13.6%	14.6%	1.0%
12 Hydro & Other	1,764	1,666	(98)	-5.6%	4.3%	4.4%	0.1%
13 Net Interchange	23,233	19,686	(3,547)	-15.3%	56.3%	52.4%	-3.9%
14 Total Output	41,283	37,584	(3,699)	-9.0%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,862	1,914	52	2.8%	4.5%	5.1%	0.6%
16 Native Requirement	39,421	35,670	(3,751)	-9.5%	95.5%	94.9%	-0.6%
17							
** COST per KWH OUTPUT (¢) **							
19 Fossil	3.107	3.050	-0.057	-1.8%			
20 Nuclear	0.886	0.889	0.002	0.3%			
21 Purchases	3.468	3.492	0.025	0.7%			
22 Total System Costs	1.203	1.268	0.065	5.4%			
23 Intersystem Sales	3.430	3.403	-0.027	-0.8%			
24 Net System Costs	1.098	1.154	0.055	5.0%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,919	15,768	849	5.7%			
28							
29 COST per KWH SALES (¢)	2.902	2.609	-0.293	-10.1%			
30							
31 RECOVERY PROV (¢ / KWH) - SYS	0.054	-0.057	-0.111				
(i) Residential	0.054	-0.057	-0.111				
(ii) C & I Non-Demand	0.057	-0.060	-0.117				
(iii) C & I Demand Non-TOD	0.055	-0.058	-0.114				
(iv) C & I Demand TOD On-Peak	0.071	-0.075	-0.146				
(v) C & I Demand TOD Off-Peak	0.042	-0.044	-0.086				
(vi) Outdoor Lighting	0.038	-0.040	-0.079				
32 REFUND	-0.059	-0.036	0.023				
(i) Residential	-0.059	-0.036	0.023				
(ii) C & I Non-Demand	-0.062	-0.038	0.024				
(iii) C & I Demand Non-TOD	-0.060	-0.037	0.023				
(iv) C & I Demand TOD On-Peak	-0.077	-0.047	0.030				
(v) C & I Demand TOD Off-Peak	-0.046	-0.028	0.018				
(vi) Outdoor Lighting	-0.042	-0.025	0.017				
33 SYSTEM FCC IMPACT (¢ / KWH)	2.897	2.516	-0.381	-13.2%			
(i) Residential	2.885	2.505	-0.380				
(ii) C & I Non-Demand	3.056	2.654	-0.402				
(iii) C & I Demand Non-TOD	2.961	2.571	-0.390				
(iv) C & I Demand TOD On-Peak	3.806	3.305	-0.501				
(v) C & I Demand TOD Off-Peak	2.239	1.944	-0.295				
(vi) Outdoor Lighting	2.054	1.783	-0.271				

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	(\$0.38)
250	(\$0.95)
500	(\$1.90)
750	(\$2.85)
1,000	(\$3.80)

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>	
	Oct-10	Nov-10
** GWH OUTPUT **		
Thermal	1,398,087	1,239,485
Wind plus disper gen	(62)	(61)
Hydro	365,959	426,872
Hydro and Other	1,763,984	1,666,296
Rounded to nearest thousand:	1,764	1,666
<u>Sales</u>		
Non Gen Munic Total	271,422,000	291,074,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,861,868,000	1,914,319,000
Rounded to nearest million:	1861.868	1914.319

		System	Intersystem	Retail
September 2010 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 14,843,101.05	\$ 2,699,318.36	\$ 17,542,419.41
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 1,649,108.90	\$ -	\$ 1,649,108.90
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 3,623.50	\$ -	\$ 3,623.50
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (15,768,359.05)	\$ -	\$ (15,768,359.05)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 2,318,631.81	\$ -	\$ 2,318,631.81
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)	\$ 1,172,277.34	\$ 1,271,048.84	\$ 2,443,326.18
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (7,339.26)	\$ -	\$ (7,339.26)
14	Real-Time Distribution of Losses Amount	\$ (556,480.82)	\$ -	\$ (556,480.82)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ 349,233.62	\$ -	\$ 349,233.62
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ (77,885.03)	\$ -	\$ (77,885.03)
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ 17,642.76	\$ -	\$ 17,642.76
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ (381,480.84)	\$ -	\$ (381,480.84)
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ (817.06)	\$ -	\$ (817.06)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 3,036,345.03	\$ -	\$ 3,036,345.03
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)	\$ (69,743.67)	\$ -	\$ (69,743.67)
15	Real-Time Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component (1)	\$ 4,221.30	\$ -	\$ 4,221.30
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (997,828.97)	\$ -	\$ (997,828.97)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (88,103.18)	\$ -	\$ (88,103.18)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ 44,870.85	\$ -	\$ 44,870.85
37	Financial Transmission Rights Guarantee Uplift Amount	\$ (44,904.31)	\$ -	\$ (44,904.31)
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 310,743.76	\$ -	\$ 310,743.76
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 148,384.27	\$ -	\$ 148,384.27
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (126,443.76)	\$ 42,295.63	\$ (84,148.13)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 559,993.90	\$ -	\$ 559,993.90
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (389,172.74)	\$ 197,998.49	\$ (191,174.25)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (314,306.86)	\$ 7,031.52	\$ (307,275.34)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 560,808.34	\$ (8,368.84)	\$ 552,439.50
19	Real-Time Market Administration Amount	\$ 38,849.92	\$ (5,265.27)	\$ 33,584.65
29	Financial Transmission Rights Market Administration Amount	\$ 44,856.96	\$ -	\$ 44,856.96
33	Day-Ahead Schedule 24 Allocation Amount	\$ 84,362.96	\$ (1,251.25)	\$ 83,111.71
34	Real-Time Schedule 24 Allocation Amount	\$ 5,821.92	\$ (790.21)	\$ 5,031.71
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	\$ (10,150.99)	\$ -	\$ (10,150.99)
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	\$ (445,675.85)	\$ -	\$ (445,675.85)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 125,803.96	\$ -	\$ 125,803.96
TOTAL MISO CHARGES		\$ 6,013,966.54	\$ 4,202,017.27	\$ 10,215,983.81
SCHEDULE 24 (FOR RETAIL)				\$ 88,143.42
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 10,127,840.39

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
September 2010 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (314,909.96)	\$ -	\$ (314,909.96)
2	Day-Ahead Spinning Reserve Amount	\$ (108,022.34)	\$ -	\$ (108,022.34)
3	Day-Ahead Supplemental Reserve	\$ (92,990.85)	\$ -	\$ (92,990.85)
4	Real-Time Regulation Amount	\$ (35,540.04)	\$ 97,079.16	\$ 61,539.12
5	Real-Time Spinning Reserve Amount	\$ (23,558.77)	\$ 57,575.61	\$ 34,016.84
6	Real-Time Supplemental Reserve Amount	\$ 11,329.28	\$ 31,318.86	\$ 42,648.14
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (13,060.56)	\$ -	\$ (13,060.56)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ (349,783.66)	\$ -	\$ (349,783.66)
8b	Real Time Non Excessive Energy Congestion	\$ (140,349.32)	\$ -	\$ (140,349.32)
8c	Real Time Non Excessive Energy Loss	\$ 2,440.54	\$ -	\$ 2,440.54
9	Real Time Net Regulation Adjustment Amount	\$ (7,243.64)	\$ (216.89)	\$ (7,460.53)
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 235,709.26	\$ -	\$ 235,709.26
11	Real Time Spinning Reserve Cost Distribution	\$ 118,991.70	\$ -	\$ 118,991.70
12	Real Time Supplemental Reserve Cost Distribution	\$ 61,936.42	\$ -	\$ 61,936.42
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 6,743.62	\$ (2,703.50)	\$ 4,040.12
14	Real Time Contignecy Reserve Deployment Failure	\$ -	\$ -	\$ -
TOTAL MISO ASM CHARGES		\$ (648,308.32)	\$ 183,053.24	\$ (465,255.08)

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	Dec-10	Jan-11	Feb-11
2 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
3												
4 Monthly Refund	(161,371)	10,622	(54,285)	(21,836)	(155,670)	(141,793)	(89,740)	(93,985)	(46,840)			
5												
6 Forecast North Dakota Sales	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	(0.083)	0.006	(0.033)	(0.013)	(0.083)	(0.075)	(0.053)	(0.052)	(0.025)	-	-	-
9												
10 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	-
11 Actual North Dakota Sales (Cal. Mo.)	222,254	189,946	190,655	151,863	160,154	167,487	195,892	194,367	162,030	-	-	-
12 Deviation	(6,727)	6,442	3,899	11,743	4,271	(2,417)	(7,377)	(6,333)	5,996	179,415	187,205	-
13												
14 Expected Refund	(13,480)	(81,774)	(160,951)	7,940	(57,511)	(21,266)	(157,164)	(141,482)	(83,589)	(89,219)	(49,824)	-
15 Actual Refund	(13,900)	(79,092)	(157,725)	7,370	(56,017)	(21,577)	(163,315)	(146,248)	(80,605)	-	-	-
16 Deviation	420	(2,682)	(3,226)	570	(1,494)	311	6,151	4,766	(2,984)	(89,219)	(49,824)	-
17												
18 True-up Factor	0.000	(0.002)	(0.002)	0.000	(0.001)	0.000	0.004	0.003	(0.002)	-	-	-
19												
20 Realized Margin	(0.083)	0.005	(0.035)	(0.013)	(0.083)	(0.075)	(0.050)	(0.050)	(0.027)	-	-	-
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	(0.082)	0.005	(0.035)	(0.013)	(0.083)	(0.075)	(0.050)	(0.050)	(0.026)	-	-	-
32 C&I Non-Demand	(0.087)	0.005	(0.037)	(0.014)	(0.088)	(0.079)	(0.052)	(0.052)	(0.028)	-	-	-
33 C&I Demand Non-TOD	(0.085)	0.005	(0.036)	(0.013)	(0.085)	(0.077)	(0.051)	(0.051)	(0.027)	-	-	-
34 C&I Demand TOD On-Peak	(0.109)	0.006	(0.046)	(0.017)	(0.110)	(0.099)	(0.065)	(0.065)	(0.035)	-	-	-
35 C&I Demand TOD Off-Peak	(0.064)	0.004	(0.027)	(0.010)	(0.064)	(0.058)	(0.038)	(0.038)	(0.021)	-	-	-
36 Outdoor Lighting	(0.059)	0.003	(0.025)	(0.009)	(0.059)	(0.053)	(0.035)	(0.035)	(0.019)	-	-	-

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	-	-
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)	-	-
9												
10 Forecasted North Dakota Sales			196,388	194,554	163,606	164,425	165,070	188,515	188,034	168,026	-	-
11 Actual North Dakota Sales (Cal. Mo.)			189,946	190,655	151,863	160,154	167,487	195,892	194,367	162,030	-	-
12 Deviation			6,442	3,899	11,743	4,271	(2,417)	(7,377)	(6,333)	5,996	-	-
13												
14 Expected Refund			(16,831)	(16,831)	(17,384)	(17,168)	(18,078)	(17,278)	(16,567)	(16,155)	-	-
15 Actual Refund			(16,278)	(16,494)	(16,137)	(16,722)	(18,342)	(17,954)	(17,126)	(15,579)	-	-
16 Deviation			(553)	(337)	(1,247)	(447)	264	676	559	(576)	-	-
17												
18 True-up Factor	-	-	(0.000)	(0.000)	(0.001)	(0.000)	0.000	0.000	0.000	(0.000)	-	-
19												
20 Realized Margin	(0.009)	(0.009)	(0.011)	(0.010)	(0.011)	(0.009)	(0.009)	(0.010)	(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	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)	-	-
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)	-	-
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)	-	-
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)	-	-
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)	-	-
36 Outdoor Lighting	(0.006)	(0.006)	(0.008)	(0.007)	(0.008)	(0.006)	(0.006)	(0.007)	(0.006)	(0.007)	-	-