



—Via Electronic Filing—

July 30, 2009

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

**Re: August 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 August 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 August 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 June 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:

August 2009	Fuel Cost Charge (\$/kWh)
Residential	0.02274
C & I Non-Demand	0.02409
C & I Demand	0.02334
C & I Demand Time of Day On-Peak	0.03000
C & I Demand Time of Day Off-Peak	0.01765
Outdoor Lighting	0.01619

## 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 types<sup>1</sup>, 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 2009 as recorded in Account 555. The MISO Day 2 cost recovery included in this August FCC is \$12,735,383, 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.

<sup>1</sup> 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. 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 2009 as recorded in Account 555. The MISO ASM cost recovery included in this August FCC is \$246,543, 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 2009 Asset Based Margin amount of \$-6,775 has been included in the August 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 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,

A handwritten signature in black ink, appearing to read "Phillip J. Zins", with a long horizontal flourish extending to the right.

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-2009

Aug-2009 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
<b>System</b>	\$0.02457	-\$0.00177	\$0.00004	\$0.02284
<b>Residential</b>	\$0.02446	-\$0.00176	\$0.00004	\$0.02274
C & I Non-Demand	\$0.02592	-\$0.00186	\$0.00004	\$0.02409
C & I Demand Non-TOD	\$0.02511	-\$0.00180	\$0.00004	\$0.02334
C & I Demand TOD On-Peak	\$0.03227	-\$0.00232	\$0.00005	\$0.03000
C & I Demand TOD Off-Peak	\$0.01898	-\$0.00136	\$0.00003	\$0.01765
Outdoor Lighting	\$0.01742	-\$0.00125	\$0.00003	\$0.01619
<b>Residential</b>				
Residential Service	\$ 0.02446	\$ (0.00176)	\$ 0.00004	\$ 0.02274
Residential TOD	\$ 0.02446	\$ (0.00176)	\$ 0.00004	\$ 0.02274
Residential - Underground	\$ 0.02446	\$ (0.00176)	\$ 0.00004	\$ 0.02274
Residential TOD - Underground	\$ 0.02446	\$ (0.00176)	\$ 0.00004	\$ 0.02274
Energy Control - (Non-Demand)	\$ 0.02446	\$ (0.00176)	\$ 0.00004	\$ 0.02274
Limit Off Peak	\$ 0.02446	\$ (0.00176)	\$ 0.00004	\$ 0.02274
<b>C &amp; I Non-Demand</b>				
Energy Controlled - (Non-Demand)	\$ 0.02592	\$ (0.00186)	\$ 0.00004	\$ 0.02409
Limit Off Peak	\$ 0.02592	\$ (0.00186)	\$ 0.00004	\$ 0.02409
Small General Service	\$ 0.02592	\$ (0.00186)	\$ 0.00004	\$ 0.02409
Small General TOD - Metered	\$ 0.02592	\$ (0.00186)	\$ 0.00004	\$ 0.02409
Small General TOD - Unmetered	\$ 0.02592	\$ (0.00186)	\$ 0.00004	\$ 0.02409
Fire and Civil Defense Siren	\$ 0.02592	\$ (0.00186)	\$ 0.00004	\$ 0.02409
Direct Current (Closed)	\$ 0.02592	\$ (0.00186)	\$ 0.00004	\$ 0.02409
<b>C &amp; I Demand</b>				
General Service	\$ 0.02511	\$ (0.00180)	\$ 0.00004	\$ 0.02334
General TOD - On Peak	\$ 0.03227	\$ (0.00232)	\$ 0.00005	\$ 0.03000
General TOD - Off Peak	\$ 0.01898	\$ (0.00136)	\$ 0.00003	\$ 0.01765
Peak Controlled (Closed)	\$ 0.02511	\$ (0.00180)	\$ 0.00004	\$ 0.02334
Peak Controlled TOD (Closed) - On Peak	\$ 0.03227	\$ (0.00232)	\$ 0.00005	\$ 0.03000
Peak Controlled TOD (Closed) - Off Peak	\$ 0.01898	\$ (0.00136)	\$ 0.00003	\$ 0.01765
Peak Controlled Tiered	\$ 0.02511	\$ (0.00180)	\$ 0.00004	\$ 0.02334
Peak Controlled Tiered TOD - On Peak	\$ 0.03227	\$ (0.00232)	\$ 0.00005	\$ 0.03000
Peak Controlled Tiered TOD - Off Peak	\$ 0.01898	\$ (0.00136)	\$ 0.00003	\$ 0.01765
Energy Controlled (Closed)	\$ 0.02511	\$ (0.00180)	\$ 0.00004	\$ 0.02334
Tier 1 Energy Controlled Rider	\$ 0.02511	\$ (0.00180)	\$ 0.00004	\$ 0.02334
Real Time Pricing - Firm - On Peak	\$ 0.03227	\$ (0.00232)	\$ 0.00005	\$ 0.03000
Real Time Pricing - Firm - Off Peak	\$ 0.01898	\$ (0.00136)	\$ 0.00003	\$ 0.01765
Real Time Pricing - Controllable - On Peak	\$ 0.03227	\$ (0.00232)	\$ 0.00005	\$ 0.03000
Real Time Pricing - Controllable - Off Peak	\$ 0.01898	\$ (0.00136)	\$ 0.00003	\$ 0.01765
Small Municipal Pumping	\$ 0.02511	\$ (0.00180)	\$ 0.00004	\$ 0.02334
Municipal Pumping	\$ 0.02511	\$ (0.00180)	\$ 0.00004	\$ 0.02334
Excess Energy - St. Anthony Falls	\$ 0.02511	\$ (0.00180)	\$ 0.00004	\$ 0.02334
<b>Outdoor Lighting</b>				
Automatic Protective Lighting	\$ 0.01742	\$ (0.00125)	\$ 0.00003	\$ 0.01619
Street Lighting System	\$ 0.01742	\$ (0.00125)	\$ 0.00003	\$ 0.01619
Street Lighting Energy	\$ 0.01742	\$ (0.00125)	\$ 0.00003	\$ 0.01619
Street Lighting Energy - Metered	\$ 0.01742	\$ (0.00125)	\$ 0.00003	\$ 0.01619
Street Lighting Energy (Closed)	\$ 0.01742	\$ (0.00125)	\$ 0.00003	\$ 0.01619
Street Lighting - City of St. Paul	\$ 0.01742	\$ (0.00125)	\$ 0.00003	\$ 0.01619

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-2009

	Column (A) Mar-09	Column (B) Apr-09	Column (C) May-09	Column (D) Jun-09	Column (E) 4 Month Total
<b>Fuel and Purchased Power Costs</b>					
Account 151 - Fossil Fuel	\$44,289,260	\$38,470,249	\$31,165,671	\$31,916,856	\$145,842,036
Account 518 - Nuclear Fuel	\$6,562,615	\$5,445,252	\$6,882,519	\$8,461,886	\$27,352,273
Account 555 - Purchased Power <sup>1</sup>	\$39,969,637	\$32,424,378	\$37,336,051	\$36,014,699	\$145,744,765
Account 555 - MISO Day 2 Charges	\$8,880,133	\$9,567,159	\$10,327,685	\$12,818,639	\$41,593,616
Account 555 MISO Day 2 - Schedule 24	(\$95,992)	(\$88,819)	(\$88,464)	(\$83,255)	(\$356,530)
Account 555 MISO - ASM Charges	<u>\$378,801</u>	<u>(\$2,293,179)</u>	<u>(\$213,104)</u>	<u>\$246,543</u>	<u>(\$1,880,940)</u>
Total MISO Charges	\$9,162,943	\$7,185,161	\$10,026,117	\$12,981,926	\$39,356,147
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	<u>\$99,984,454</u>	<u>\$83,525,040</u>	<u>\$85,410,358</u>	<u>\$89,375,367</u>	<u>\$358,295,220</u>
Less Fuel Cost of InterSystem Sales	(\$9,290,280)	(\$5,646,290)	(\$10,380,755)	(\$5,091,111)	(\$30,408,436)
Net System Costs	<u>\$90,694,174</u>	<u>\$77,878,750</u>	<u>\$75,029,603</u>	<u>\$84,284,256</u>	<u>\$327,886,784</u>
<b>System MWh Sales</b>					
Total NSP System Retail	3,504,517	3,177,135	2,929,354	3,327,015	12,938,021
Non-Gen Muni's/Load Pattern	106,377	107,030	99,454	96,266	409,127
Total NSP System MWh Sales	<u>3,610,894</u>	<u>3,284,165</u>	<u>3,028,808</u>	<u>3,423,281</u>	<u>13,347,148</u>
<b>Average Unit Cost of Fuel and Purchased Power</b>					
Fuel Cost per kWh for NSP System	2.512¢	2.371¢	2.477¢	2.462¢	2.457¢
Base Fuel Cost Included in Rates	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢
<b>Class Ratio/TOD Ratio</b>					
(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
<b>North Dakota Fuel Cost Factor (FCF)</b>					
				FCF Ratio	4 Month Average
(i) Residential				0.9956	2.446¢
(ii) C & I Non-Demand				1.0548	2.592¢
(iii) C & I Demand Non-TOD				1.0219	2.511¢
(iv) C & I Demand TOD On-Peak				1.3135	3.227¢
(v) C & I Demand TOD Off-Peak				0.7726	1.898¢
(vi) Outdoor Lighting				0.7088	1.742¢

<sup>1</sup> Excludes demand-related expenses

North Dakota Retail MWh Sales					
(i) Residential	81,182	64,544	49,122	47,922	242,770
(ii) C & I Non-Demand	13,734	11,046	9,216	9,005	43,001
(iii) C & I Demand Non-TOD	64,180	51,340	53,507	53,421	222,448
(iv) C & I Demand TOD On-Peak	18,857	17,941	15,235	21,720	73,753
(v) C & I Demand TOD Off-Peak	29,201	29,717	23,091	35,077	117,086
(vi) Outdoor Lighting	1,609	1,568	1,297	1,158	5,632
(vii) Total	208,763	176,156	151,468	168,303	704,690

Aug-2009 Recovery Provision (True-up Factor) Calculation	
<b>Prior Unrecovered Expenses (Apr-09 Balance of Unrecovered Expenses)</b>	<b>Total</b>
	Apr-09
	(\$1,558,757)

Prior Expenses Recovered in Jun-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	-0.187¢	47,922	(\$89,729)
(iii) C & I Demand Non-TOD	1.0548	-0.198¢	9,005	(\$17,863)
(iv) C & I Demand TOD On-Peak	1.0219	-0.192¢	53,421	(\$102,668)
(v) C & I Demand TOD Off-Peak	1.3135	-0.247¢	21,720	(\$53,654)
(vi) Outdoor Lighting	0.7726	-0.145¢	35,077	(\$50,967)
(vii) Total	0.7088	-0.133¢	1,158	(\$1,544)
			168,303	(\$316,425)

Actual Cost Should Have Been Recovered in Jun-09				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.462¢	0.000¢	168,303	\$4,143,620

Cost Recovered in Jun-09				
	FCF Ratio	Fuel Cost Recovered	Actual ND MWh Sales	Actual Recovery
(i) Residential	0.9956	2.453¢	47,922	\$1,175,602
(ii) C & I Non-Demand	1.0548	2.599¢	9,005	\$234,042
(iii) C & I Demand Non-TOD	1.0219	2.518¢	53,421	\$1,345,120
(iv) C & I Demand TOD On-Peak	1.3135	3.236¢	21,720	\$702,960
(v) C & I Demand TOD Off-Peak	0.7726	1.904¢	35,077	\$667,756
(vi) Outdoor Lighting	0.7088	1.746¢	1,158	\$20,224
(vii) Total			168,303	\$4,145,705

Total Balance of Unrecovered Expenses (Aug-09 Balance of Unrecovered Expenses)	
Aug-2009 Recovery Provision	(\$1,244,418)
4 Month ND Retail Total MWh Sales	704,690
Aug-2009 Recovery Provision per KWH	-0.177¢

<b>Aug-2009 Recovery Provision (True-up Factor) per kWh by Customer Category</b>			
	<b>FAF Ratio</b>	<b>Recovery Provision Adjustment</b>	<b>Recovery Provision Adj by Class</b>
(i) Residential	0.9956	-0.177¢	-0.176¢
(ii) C & I Non-Demand	1.0548	-0.177¢	-0.186¢
(iii) C & I Demand Non-TOD	1.0219	-0.177¢	-0.180¢
(iv) C & I Demand TOD On-Peak	1.3135	-0.177¢	-0.232¢
(v) C & I Demand TOD Off-Peak	0.7726	-0.177¢	-0.136¢
(vi) Outdoor Lighting	0.7088	-0.177¢	-0.125¢

  

<b>Aug-2009 Margin Sharing Refunds</b>		
	<b>Asset Based Margin Sharing Refund</b>	<b>Total</b>
<b>Refund/Special Charge Amount</b>	\$6,775	\$6,775
(i) Residential	0.004¢	0.004¢
(ii) C & I Non-Demand	0.004¢	0.004¢
(iii) C & I Demand Non-TOD	0.004¢	0.004¢
(iv) C & I Demand TOD On-Peak	0.005¢	0.005¢
(v) C & I Demand TOD Off-Peak	0.003¢	0.003¢
(vi) Outdoor Lighting	0.003¢	0.003¢

  

<b>Aug-2009 Factors</b>	
	<b>Total</b>
(i) Residential	2.274¢
(ii) C & I Non-Demand	2.409¢
(iii) C & I Demand Non-TOD	2.334¢
(iv) C & I Demand TOD On-Peak	3.000¢
(v) C & I Demand TOD Off-Peak	1.765¢
(vi) Outdoor Lighting	1.619¢

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		
	Jul-09	Aug-09	Differ- ence	Percent Change	FCA Application Jul-09	Aug-09	Differ- ence
<b>** COSTS (Millions) **</b>							
1 Fossil	\$154.4	\$145.8	(\$8.6)	-5.6%	42.9%	40.7%	-2.2%
2 Nuclear	\$26.1	\$27.4	\$1.3	4.9%	7.2%	7.6%	0.4%
3 Purchases	\$143.7	\$145.7	\$2.1	1.4%	39.9%	40.7%	0.8%
MISO related Purchases	\$35.6	\$39.4	\$3.7	10.5%	9.9%	11.0%	1.1%
4 Total System Costs	359.8	358.3	(\$1.5)	-0.4%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$35.1	\$30.4	(\$4.7)	-13.4%	9.8%	8.5%	-1.3%
6 Net System Costs	\$324.7	\$327.9	\$3.2	1.0%	90.2%	91.5%	1.3%
7							
8 <b>** GWH OUTPUT **</b>							
9 Fossil	5,960	5,551	(409)	-6.9%	37.3%	34.0%	-3.3%
10 Nuclear	3,779	3,822	43	1.1%	23.6%	23.4%	-0.2%
11 Purchases	5,017	5,537	520	10.4%	31.4%	34.0%	2.6%
12 Hydro & Other	654	812	158	24.2%	4.1%	5.0%	0.9%
13 Net Interchange	587	586	(1)	-0.2%	3.7%	3.6%	-0.1%
14 Total Output	15,997	16,308	311	1.9%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,909	2,022	113	5.9%	11.9%	12.4%	0.5%
16 Native Requirement	14,088	14,286	198	1.4%	88.1%	87.6%	-0.5%
17							
18 <b>** COST per KWH OUTPUT (\$) **</b>							
19 Fossil	2.591	2.627	0.036	1.4%			
20 Nuclear	0.690	0.716	0.026	3.8%			
21 Purchases	2.864	2.632	-0.232	-8.1%			
22 Total System Costs	2.249	2.197	-0.052	-2.3%			
23 Intersystem Sales	1.840	1.504	-0.336	-18.3%			
24 Net System Costs	2.305	2.295	-0.010	-0.4%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,414	13,347	(67)	-0.5%			
28							
29 COST per KWH SALES (\$)	2.421	2.457	0.036	1.5%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.061	-0.177	-0.116				
(i) Residential	-0.061	-0.176	-0.115				
(ii) C & I Non-Demand	-0.064	-0.186	-0.122				
(iii) C & I Demand Non-TOD	-0.062	-0.180	-0.118				
(iv) C & I Demand TOD On-Peak	-0.080	-0.232	-0.152				
(v) C & I Demand TOD Off-Peak	-0.047	-0.136	-0.089				
(vi) Outdoor Lighting	-0.043	-0.125	-0.082				
32 REFUND	-0.025	0.004	0.029				
(i) Residential	-0.025	0.004					
(ii) C & I Non-Demand	-0.026	0.004					
(iii) C & I Demand Non-TOD	-0.026	0.004					
(iv) C & I Demand TOD On-Peak	-0.033	0.005					
(v) C & I Demand TOD Off-Peak	-0.019	0.003					
(vi) Outdoor Lighting	-0.018	0.003					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.335	2.284	-0.051	-2.2%			
(i) Residential	2.325	2.274	-0.051				
(ii) C & I Non-Demand	2.463	2.409					
(iii) C & I Demand Non-TOD	2.387	2.334					
(iv) C & I Demand TOD On-Peak	3.068	3.000					
(v) C & I Demand TOD Off-Peak	1.804	1.765					
(vi) Outdoor Lighting	1.655	1.619					

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	(\$0.05)
250	(\$0.13)
500	(\$0.25)
750	(\$0.38)
1,000	(\$0.51)

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	
	Jul-09	Aug-09
<b>** GWH OUTPUT **</b>		
Thermal	399,128	551,261
Wind plus disper gen	(74)	(75)
Hydro	255,135	260,388
Hydro and Other	654,189	811,574
Rounded to nearest thousand:	654	812
<b>Sales</b>		
Non Gen Munic Total	429,295,000	409,127,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,908,885,000	2,021,790,000
Rounded to nearest million:	1908.885	2021.79

		System	Intersystem	Retail
<b>June 2009 Actual</b>				
<b>Energy and Loss Charges</b>				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 19,413,692.54	\$ 4,077,547.52	\$ 23,491,240.06
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 1,298,544.56	\$ -	\$ 1,298,544.56
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 2,781.08	\$ -	\$ 2,781.08
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (20,982,424.06)	\$ -	\$ (20,982,424.06)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 2,930,330.99	\$ -	\$ 2,930,330.99
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)	\$ 1,569,811.71	\$ 405,640.34	\$ 1,975,452.05
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (28,754.09)	\$ -	\$ (28,754.09)
14	Real-Time Distribution of Losses Amount	\$ (839,611.50)	\$ -	\$ (839,611.50)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (1,022,132.09)	\$ -	\$ (1,022,132.09)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ (180,866.53)	\$ -	\$ (180,866.53)
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ 52,201.05	\$ -	\$ 52,201.05
<b>Congestion Related Charges</b>				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ (1,628,966.90)	\$ -	\$ (1,628,966.90)
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ 689.19	\$ -	\$ 689.19
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 4,617,049.25	\$ -	\$ 4,617,049.25
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)	\$ (131,742.39)	\$ -	\$ (131,742.39)
15	Real-Time Financial Bilateral Transaction Congestion Amount	\$ -	\$ -	\$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component (1)	\$ 97,629.79	\$ -	\$ 97,629.79
<b>FTR Related Charges</b>				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (1,395,212.58)	\$ -	\$ (1,395,212.58)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (290,863.88)	\$ -	\$ (290,863.88)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ 1,129,681.11	\$ -	\$ 1,129,681.11
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (59,030.12)	\$ -	\$ (59,030.12)
37	Financial Transmission Guarantee Uplift Amount	\$ 58,459.67	\$ -	\$ 58,459.67
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
<b>Uplift Charges</b>				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 1,643,940.49	\$ -	\$ 1,643,940.49
<b>Revenue Sufficiency Guarantee (RSG) Charges</b>				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 131,010.60	\$ -	\$ 131,010.60
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (35,992.73)	\$ 90,766.75	\$ 54,774.02
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 1,867,481.41	\$ -	\$ 1,867,481.41
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ (94,005.98)	\$ (247,420.14)	\$ (341,426.12)
42	Real-Time Price Volatility Make Whole Payment Amount	\$ (166,986.70)	\$ (120,636.64)	\$ (287,623.34)
<b>Market Administration Charges</b>				
4	Day-Ahead Market Administration Amount	\$ 778,567.81	\$ (29,426.21)	\$ 749,141.60
19	Real-Time Market Administration Amount	\$ 53,447.69	\$ (3,707.54)	\$ 49,740.15
29	Financial Transmission Rights Market Administration Amount	\$ 77,918.88	\$ -	\$ 77,918.88
33	Day-Ahead Schedule 24 Allocation Amount	\$ 81,184.16	\$ (2,971.58)	\$ 78,212.58
34	Real-Time Schedule 24 Allocation Amount	\$ 5,418.23	\$ (375.59)	\$ 5,042.64
35	Schedule 24 Admin Allocation	\$ -	\$ -	\$ -
<b>Virtual Energy Charges</b>				
12	Day-Ahead Virtual Energy Amount	\$ -	\$ -	\$ -
27	Real-Time Virtual Energy Amount	\$ -	\$ -	\$ -
<b>Other MISO Charges</b>				
20	Real-Time Miscellaneous Amount	\$ 121,912.87	\$ -	\$ 121,912.87
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
<b>Auction Revenue Rights (ARR)</b>				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 1,334,027.52	\$ -	\$ 1,334,027.52
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (1,217,213.47)	\$ -	\$ (1,217,213.47)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (542,755.79)	\$ -	\$ (542,755.79)
<b>TOTAL MISO CHARGES</b>		<b>\$ 8,649,221.79</b>	<b>\$ 4,169,416.91</b>	<b>\$ 12,818,638.70</b>
<b>SCHEDULE 24 (FOR RETAIL)</b>				<b>\$ 83,255.22</b>
<b>TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)</b>				<b>\$ 12,735,383.48</b>

## MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
<b>June 2009 Actual</b>				
<b>Procurement Charges</b>				
1	Day-Ahead Regulation Amount	\$ (515,112.53)	\$ -	\$ (515,112.53)
2	Day-Ahead Spinning Reserve Amount	\$ (122,248.21)	\$ -	\$ (122,248.21)
3	Day-Ahead Supplemental Reserve	\$ (26,132.10)	\$ -	\$ (26,132.10)
4	Real-Time Regulation Amount	\$ 159,817.98	\$ 109,023.96	\$ 268,841.94
5	Real-Time Spinning Reserve Amount	\$ (13,120.21)	\$ 30,226.88	\$ 17,106.67
6	Real-Time Supplemental Reserve Amount	\$ 3,379.10	\$ 10,647.39	\$ 14,026.49
<b>Resource Energy Charges</b>				
7a	Real Time Excessive Energy Amount	\$ (106,549.22)		\$ (106,549.22)
7b	Real Time Excessive Energy Congestion	\$ -		\$ -
7c	Real Time Excessive Energy Loss	\$ -		\$ -
8a	Real Time Non Excessive Energy Amount	\$ (445,749.29)		\$ (445,749.29)
8b	Real Time Non Excessive Energy Congestion	\$ 380,917.44		\$ 380,917.44
8c	Real Time Non Excessive Energy Loss	\$ 221,244.31		\$ 221,244.31
9	Real Time Net Regulation Adjustment Amount	\$ 18,383.87	\$ (7,020.76)	\$ 11,363.11
<b>Cost Distribution Charges</b>				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 291,798.18	\$ -	\$ 291,798.18
11	Real Time Spinning Reserve Cost Distribution	\$ 178,372.44	\$ -	\$ 178,372.44
12	Real Time Supplemental Reserve Cost Distribution	\$ 15,637.59	\$ -	\$ 15,637.59
<b>Penalty Charges</b>				
13	Real Time Excessive/Dificient Energy Deployment	\$ 73,087.45	\$ (10,061.67)	\$ 63,025.78
14	Real Time Contingency Reserve Deployment Failure	\$ -	\$ 0.06	\$ 0.06
<b>TOTAL MISO ASM CHARGES</b>		<b>\$ 113,726.80</b>	<b>\$ 132,815.86</b>	<b>\$ 246,542.66</b>

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						
5												
6 Forecast North Dakota Sales	191,827	174,423	167,216	169,094	182,677	182,651	177,780	169,550				
7												
8 Current Month Refund Factor	(0.090)	(0.047)	(0.038)	(0.000)	(0.025)	0.004						
9												
10 Forecasted North Dakota Sales			191,827	174,423	167,216	169,094	182,677	182,651				
11 Actual North Dakota Sales (Cal. Mo.)			268,578	165,328	160,677	156,178	-	-				
12 Deviation			(76,751)	9,095	6,539	12,916	182,677	182,651				
13												
14 Expected Refund			(173,372)	(82,316)	5,213	(4,449)	(45,081)	6,775				
15 Actual Refund			(242,738)	(78,023)	5,010	(4,109)	-	-				
16 Deviation			69,366	(4,293)	203	(340)	(45,081)	6,775				
17												
18 True-up Factor			0.041	(0.003)	0.000	(0.000)						
19												
20 Realized Margin	(0.090)	(0.047)	0.003	(0.003)	(0.025)	0.004						
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						
32 C&I Non-Demand	(0.092)	(0.048)	0.003	(0.003)	(0.026)	0.004						
33 C&I Demand Non-TOD	(0.091)	(0.048)	0.003	(0.003)	(0.025)	0.004						
34 C&I Demand TOD On-Peak	(0.097)	(0.055)	0.004	(0.003)	(0.032)	0.005						
35 C&I Demand TOD Off-Peak	(0.085)	(0.042)	0.003	(0.002)	(0.019)	0.003						
36 Outdoor Lighting	(0.084)	(0.040)	0.002	(0.002)	(0.017)	0.003						