



—Via Electronic Filing—

September 29, 2009

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

Re: October 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 October 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 October 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 August 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:

October 2009	Fuel Cost Charge (\$/kWh)
Residential	0.02313
C & I Non-Demand	0.02450
C & I Demand	0.02374
C & I Demand Time of Day On-Peak	0.03051
C & I Demand Time of Day Off-Peak	0.01795
Outdoor Lighting	0.01646

MISO CHARGES IMPLEMENTATION

MISO Day 2 Charges

This filing includes our reporting of the Midwest Independent System Operator (“MISO”) charges under the Day 2 Market. Pursuant to the Commission’s Order (Docket No. PU-05-147) dated April 6, 2005, Xcel Energy is authorized to recover on an interim basis, subject to refund, the MISO Day 2 costs. The March FCC reflected the new MISO Day 2 charge types: 3 Auction Revenue Rights (ARR) and 3 new Financial Transmission Rights (FTR) charge types¹, to be reflected in Fuel Cost Rider. Consistent with this Order and the required “net” accounting of Day 2 costs and revenues, we have included in the October FCC, the net MISO Day 2 costs for August 2009 as recorded in Account 555. The MISO Day 2 cost recovery included in this October FCC is \$11,130,087, 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 August 31, 2009 the Commission issued Order on the 2007 AAA (Docket No. E-999/AA-07-1130), indicating effective July 1, 2009, Xcel Energy shall allocate the cost of MISO congestion and losses to retail and wholesale on a megawatt-hour basis. The

¹ Previously embedded in other FTR charge types.

Company is in the process of setting up accounting changes to this order and will reflect this adjustment in the subsequent FCA.

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 October FCC, the net MISO ASM costs for August 2009 as recorded in Account 555. The MISO ASM cost recovery included in this October FCC is \$2,374,116, which is the net of many items. The detailed records are contained in Attachment 2, page 2.

REFUNDS

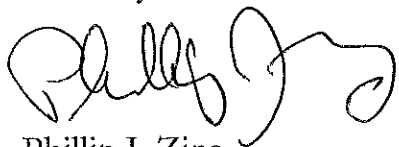
Pursuant to the above referenced Order Adopting Settlement, the August 2009 Asset Based Margin amount of \$23,790 has been included in the October Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. The 2009 North Dakota retail share of the Non-Asset Based Margins will be determined 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 October FCC, as well as a statistical summary of energy sources and costs, compared to the previous month.

If you have any questions regarding the information contained in this filing, please contact Dave Sederquist in Fargo at 701-241-8632.

Sincerely,



Phillip J. Zins
Manager, Pricing and Planning
Enclosures (2)
CC: David H. Sederquist

Northern States Power Company, A Minnesota Corporation & Wholly Owned Subsidiary of Xcel Energy Inc.
 Electric Operations - State of North Dakota
 Derivation of Adjustment for Fuel Clause Rider
 Current Period Cost of Energy for Oct-2009

Oct-2009 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02455	-\$0.00118	-\$0.00014	\$0.02323
Residential	\$0.02444	-\$0.00118	-\$0.00014	\$0.02313
C & I Non-Demand	\$0.02590	-\$0.00125	-\$0.00015	\$0.02450
C & I Demand Non-TOD	\$0.02509	-\$0.00121	-\$0.00014	\$0.02374
C & I Demand TOD On-Peak	\$0.03225	-\$0.00155	-\$0.00018	\$0.03051
C & I Demand TOD Off-Peak	\$0.01897	-\$0.00091	-\$0.00011	\$0.01795
Outdoor Lighting	\$0.01740	-\$0.00084	-\$0.00010	\$0.01646
Residential				
Residential Service	\$ 0.02444	\$ (0.00118)	\$ (0.00014)	\$ 0.02313
Residential TOD	\$ 0.02444	\$ (0.00118)	\$ (0.00014)	\$ 0.02313
Residential - Underground	\$ 0.02444	\$ (0.00118)	\$ (0.00014)	\$ 0.02313
Residential TOD - Underground	\$ 0.02444	\$ (0.00118)	\$ (0.00014)	\$ 0.02313
Energy Control - (Non-Demand)	\$ 0.02444	\$ (0.00118)	\$ (0.00014)	\$ 0.02313
Limit Off Peak	\$ 0.02444	\$ (0.00118)	\$ (0.00014)	\$ 0.02313
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02590	\$ (0.00125)	\$ (0.00015)	\$ 0.02450
Limit Off Peak	\$ 0.02590	\$ (0.00125)	\$ (0.00015)	\$ 0.02450
Small General Service	\$ 0.02590	\$ (0.00125)	\$ (0.00015)	\$ 0.02450
Small General TOD - Metered	\$ 0.02590	\$ (0.00125)	\$ (0.00015)	\$ 0.02450
Small General TOD - Unmetered	\$ 0.02590	\$ (0.00125)	\$ (0.00015)	\$ 0.02450
Fire and Civil Defense Siren	\$ 0.02590	\$ (0.00125)	\$ (0.00015)	\$ 0.02450
Direct Current (Closed)	\$ 0.02590	\$ (0.00125)	\$ (0.00015)	\$ 0.02450
C & I Demand				
General Service	\$ 0.02509	\$ (0.00121)	\$ (0.00014)	\$ 0.02374
General TOD - On Peak	\$ 0.03225	\$ (0.00155)	\$ (0.00018)	\$ 0.03051
General TOD - Off Peak	\$ 0.01897	\$ (0.00091)	\$ (0.00011)	\$ 0.01795
Peak Controlled (Closed)	\$ 0.02509	\$ (0.00121)	\$ (0.00014)	\$ 0.02374
Peak Controlled TOD (Closed) - On Peak	\$ 0.03225	\$ (0.00155)	\$ (0.00018)	\$ 0.03051
Peak Controlled TOD (Closed) - Off Peak	\$ 0.01897	\$ (0.00091)	\$ (0.00011)	\$ 0.01795
Peak Controlled Tiered	\$ 0.02509	\$ (0.00121)	\$ (0.00014)	\$ 0.02374
Peak Controlled Tiered TOD - On Peak	\$ 0.03225	\$ (0.00155)	\$ (0.00018)	\$ 0.03051
Peak Controlled Tiered TOD - Off Peak	\$ 0.01897	\$ (0.00091)	\$ (0.00011)	\$ 0.01795
Energy Controlled (Closed)	\$ 0.02509	\$ (0.00121)	\$ (0.00014)	\$ 0.02374
Tier 1 Energy Controlled Rider	\$ 0.02509	\$ (0.00121)	\$ (0.00014)	\$ 0.02374
Real Time Pricing - Firm - On Peak	\$ 0.03225	\$ (0.00155)	\$ (0.00018)	\$ 0.03051
Real Time Pricing - Firm - Off Peak	\$ 0.01897	\$ (0.00091)	\$ (0.00011)	\$ 0.01795
Real Time Pricing - Controllable - On Peak	\$ 0.03225	\$ (0.00155)	\$ (0.00018)	\$ 0.03051
Real Time Pricing - Controllable - Off Peak	\$ 0.01897	\$ (0.00091)	\$ (0.00011)	\$ 0.01795
Small Municipal Pumping	\$ 0.02509	\$ (0.00121)	\$ (0.00014)	\$ 0.02374
Municipal Pumping	\$ 0.02509	\$ (0.00121)	\$ (0.00014)	\$ 0.02374
Excess Energy - St. Anthony Falls	\$ 0.02509	\$ (0.00121)	\$ (0.00014)	\$ 0.02374
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01740	\$ (0.00084)	\$ (0.00010)	\$ 0.01646
Street Lighting System	\$ 0.01740	\$ (0.00084)	\$ (0.00010)	\$ 0.01646
Street Lighting Energy	\$ 0.01740	\$ (0.00084)	\$ (0.00010)	\$ 0.01646
Street Lighting Energy - Metered	\$ 0.01740	\$ (0.00084)	\$ (0.00010)	\$ 0.01646
Street Lighting Energy (Closed)	\$ 0.01740	\$ (0.00084)	\$ (0.00010)	\$ 0.01646
Street Lighting - City of St. Paul	\$ 0.01740	\$ (0.00084)	\$ (0.00010)	\$ 0.01646

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 Oct-2009

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	May-09	Jun-09	Jul-09	Aug-09	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$31,165,671	\$31,916,856	\$34,884,806	\$37,083,990	\$135,051,323
Account 518 - Nuclear Fuel	\$6,882,519	\$8,461,886	\$8,758,100	\$8,753,879	\$32,856,384
Account 555 - Purchased Power ¹	\$37,336,051	\$36,014,699	\$41,316,745	\$48,107,021	\$162,774,516
Account 555 - MISO Day 2 Charges	\$10,327,685	\$12,818,639	\$14,757,076	\$11,227,373	\$49,130,773
Account 555 MISO Day 2 - Schedule 24	(\$88,464)	(\$83,255)	(\$95,225)	(\$97,286)	(\$364,230)
Account 555 MISO - ASM Charges	(\$213,104)	\$246,543	\$135,795	\$2,374,116	\$2,543,349
Total MISO Charges	\$10,026,117	\$12,981,926	\$14,797,647	\$13,504,203	\$51,309,893
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$85,410,358	\$89,375,367	\$99,757,298	\$107,449,093	\$381,992,116
Less Fuel Cost of InterSystem Sales	(\$10,380,755)	(\$5,091,111)	(\$10,952,672)	(\$14,341,684)	(\$40,766,222)
Net System Costs	\$75,029,603	\$84,284,256	\$88,804,626	\$93,107,409	\$341,225,894
System MWh Sales					
Total NSP System Retail	2,929,354	3,327,015	3,719,953	3,521,273	13,497,595
Non-Gen Muni's/Load Pattern	99,454	96,266	101,974	102,634	400,328
Total NSP System MWh Sales	3,028,808	3,423,281	3,821,927	3,623,907	13,897,923
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.477¢	2.462¢	2.324¢	2.569¢	2.455¢
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	2.444¢
(ii) C & I Non-Demand				1.0548	2.590¢
(iii) C & I Demand Non-TOD				1.0219	2.509¢
(iv) C & I Demand TOD On-Peak				1.3135	3.225¢
(v) C & I Demand TOD Off-Peak				0.7726	1.897¢
(vi) Outdoor Lighting				0.7088	1.740¢

¹ Excludes demand-related expenses

North Dakota Retail MWh Sales					
(i) Residential	49,122	47,922	55,045	50,529	202,618
(ii) C & I Non-Demand	9,216	9,005	9,741	9,225	37,187
(iii) C & I Demand Non-TOD	53,507	53,421	57,975	56,576	221,479
(iv) C & I Demand TOD On-Peak	15,235	21,720	21,107	18,500	76,562
(v) C & I Demand TOD Off-Peak	23,091	35,077	33,092	28,364	119,624
(vi) Outdoor Lighting	1,297	1,158	1,107	1,173	4,735
(vii) Total	151,468	168,303	178,067	164,367	662,205

Oct-2009 Recovery Provision (True-up Factor) Calculation	
Prior Unrecovered Expenses (Jun-09 Balance of Unrecovered Expenses)	Total
	Jun-09
	(\$1,244,418)

Prior Expenses Recovered in Aug-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	-0.176¢	50,529	(\$88,837)
(iii) C & I Demand Non-TOD	1.0548	-0.186¢	9,225	(\$17,183)
(iv) C & I Demand TOD On-Peak	1.0219	-0.180¢	56,576	(\$102,096)
(v) C & I Demand TOD Off-Peak	1.3135	-0.232¢	18,500	(\$42,911)
(vi) Outdoor Lighting	0.7726	-0.136¢	28,364	(\$38,698)
(vii) Total	0.7088	-0.125¢	1,173	(\$1,468)
			164,367	(\$291,193)

Actual Cost Should Have Been Recovered in Aug-09				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.569¢	0.000¢	164,367	\$4,222,588

Cost Recovered in Aug-09				
	FCF Ratio	Fuel Cost Recovered	Actual ND MWh Sales	Actual Recovery
(i) Residential	0.9956	2.446¢	50,529	\$1,236,035
(ii) C & I Non-Demand	1.0548	2.592¢	9,225	\$239,079
(iii) C & I Demand Non-TOD	1.0219	2.511¢	56,576	\$1,420,515
(iv) C & I Demand TOD On-Peak	1.3135	3.227¢	18,500	\$597,045
(v) C & I Demand TOD Off-Peak	0.7726	1.898¢	28,364	\$538,428
(vi) Outdoor Lighting	0.7088	1.742¢	1,173	\$20,428
(vii) Total			164,367	\$4,051,529

Total Balance of Unrecovered Expenses (Oct-09 Balance of Unrecovered Expenses)	
Oct-2009 Recovery Provision	(\$782,166)
4 Month ND Retail Total MWh Sales	662,205
Oct-2009 Recovery Provision per KWH	-0.118¢

Oct-2009 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9956	-0.118¢	-0.118¢
(ii) C & I Non-Demand	1.0548	-0.118¢	-0.125¢
(iii) C & I Demand Non-TOD	1.0219	-0.118¢	-0.121¢
(iv) C & I Demand TOD On-Peak	1.3135	-0.118¢	-0.155¢
(v) C & I Demand TOD Off-Peak	0.7726	-0.118¢	-0.091¢
(vi) Outdoor Lighting	0.7088	-0.118¢	-0.084¢

Oct-2009 Margin Sharing Refunds		
	Asset Based Margin Sharing Refund	Total
Refund/Special Charge Amount	(\$23,790)	(\$23,790)
(i) Residential	-0.014¢	-0.014¢
(ii) C & I Non-Demand	-0.015¢	-0.015¢
(iii) C & I Demand Non-TOD	-0.014¢	-0.014¢
(iv) C & I Demand TOD On-Peak	-0.018¢	-0.018¢
(v) C & I Demand TOD Off-Peak	-0.011¢	-0.011¢
(vi) Outdoor Lighting	-0.010¢	-0.010¢

Oct-2009 Factors	
	Total
(i) Residential	2.313¢
(ii) C & I Non-Demand	2.450¢
(iii) C & I Demand Non-TOD	2.374¢
(iv) C & I Demand TOD On-Peak	3.051¢
(v) C & I Demand TOD Off-Peak	1.795¢
(vi) Outdoor Lighting	1.646¢

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>		
	Sep-09	Oct-09	Differ- ence	Percent Change	FCA Application Sep-09	Oct-09	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$136.4	\$135.1	(\$1.4)	-1.0%	38.1%	35.4%	-2.7%
2 Nuclear	\$29.5	\$32.9	\$3.3	11.2%	8.3%	8.6%	0.3%
3 Purchases	\$147.1	\$162.8	\$15.7	10.7%	41.1%	42.6%	1.5%
MISO related Purchases	\$45.0	\$51.3	\$6.3	14.0%	12.6%	13.4%	0.8%
4 Total System Costs	358.1	362.0	\$23.9	6.7%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$32.1	\$40.8	\$8.7	27.1%	9.0%	10.7%	1.7%
6 Net System Costs	\$326.0	\$341.2	\$15.2	4.7%	91.0%	89.3%	-1.7%
7							
8 ** GWH OUTPUT **							
9 Fossil	5,638	5,823	185	3.3%	33.6%	26.5%	-7.1%
10 Nuclear	4,049	4,484	435	10.7%	24.1%	20.4%	-3.7%
11 Purchases	5,862	6,402	540	9.2%	34.9%	29.1%	-5.8%
12 Hydro & Other	667	577	(90)	-13.5%	4.0%	2.6%	-1.4%
13 Net Interchange	558	4,706	4,148	743.4%	3.3%	21.4%	18.1%
14 Total Output	16,774	21,992	5,218	31.1%	100.0%	100.0%	0.0%
15 Intersystem Sales	2,347	2,815	468	19.9%	14.0%	12.8%	-1.2%
16 Native Requirement	14,427	19,177	4,750	32.9%	86.0%	87.2%	1.2%
17							
18 ** COST per KWH OUTPUT (\$)							
19 Fossil	2.420	2.319	-0.101	-4.2%			
20 Nuclear	0.730	0.733	0.003	0.4%			
21 Purchases	2.509	2.543	0.033	1.3%			
22 Total System Costs	2.135	1.737	-0.398	-18.6%			
23 Intersystem Sales	1.366	1.448	0.082	6.0%			
24 Net System Costs	2.260	1.779	-0.480	-21.3%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,558	13,898	340	2.5%			
28							
29 COST per KWH SALES (\$)	2.404	2.455	0.051	2.1%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.079	-0.118	-0.040				
(i) Residential	-0.078	-0.118	-0.039				
(ii) C & I Non-Demand	-0.083	-0.125	-0.042				
(iii) C & I Demand Non-TOD	-0.080	-0.121	-0.040				
(iv) C & I Demand TOD On-Peak	-0.103	-0.155	-0.052				
(v) C & I Demand TOD Off-Peak	-0.061	-0.091	-0.031				
(vi) Outdoor Lighting	-0.056	-0.084	-0.028				
32 REFUND	-0.027	-0.014	0.013				
(i) Residential	-0.027	-0.014					
(ii) C & I Non-Demand	-0.028	-0.015					
(iii) C & I Demand Non-TOD	-0.028	-0.014					
(iv) C & I Demand TOD On-Peak	-0.035	-0.018					
(v) C & I Demand TOD Off-Peak	-0.021	-0.011					
(vi) Outdoor Lighting	-0.019	-0.010					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.298	2.323	0.024	1.1%			
(i) Residential	2.288	2.313	0.025				
(ii) C & I Non-Demand	2.424	2.450					
(iii) C & I Demand Non-TOD	2.349	2.374					
(iv) C & I Demand TOD On-Peak	3.019	3.051					
(v) C & I Demand TOD Off-Peak	1.776	1.795					
(vi) Outdoor Lighting	1.629	1.646					

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	\$0.02
250	\$0.06
500	\$0.12
750	\$0.18
1,000	\$0.25

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>	
	Sep-09	Oct-09
** GWH OUTPUT **		
Thermal	452,122	408,698
Wind plus disper gen	(81)	(79)
Hydro	214,680	168,393
Hydro and Other	666,721	577,012
Rounded to nearest thousand:	667	577
Sales		
Non Gen Munic Total	404,724,000	400,328,000
Load Pattern Power	0	0
<u>Resale & Interchange (Intersystem)</u>	2,347,393,000	2,815,231,000
Rounded to nearest million:	2347.393	2815.231

		System	Intersystem	Retail
August 2009 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 17,581,553.10	\$ 7,029,434.22	\$ 24,610,987.32
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,244,789.74	\$ -	\$ 2,244,789.74
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 5,623.56	\$ -	\$ 5,623.56
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (18,747,503.53)	\$ -	\$ (18,747,503.53)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,076,462.06	\$ -	\$ 1,076,462.06
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)	\$ (505,860.18)	\$ 556,234.85	\$ 50,374.67
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 80,486.17	\$ -	\$ 80,486.17
14	Real-Time Distribution of Losses Amount	\$ (1,401,628.26)	\$ -	\$ (1,401,628.26)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (19,457.36)	\$ -	\$ (19,457.36)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 946,142.92	\$ -	\$ 946,142.92
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (1,615.27)	\$ -	\$ (1,615.27)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 255,341.86	\$ -	\$ 255,341.86
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ 669.43	\$ -	\$ 669.43
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 655,673.38	\$ -	\$ 655,673.38
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)	\$ 137,010.76	\$ -	\$ 137,010.76
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)	\$ (79,154.56)	\$ -	\$ (79,154.56)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (640,282.21)	\$ -	\$ (640,282.21)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (27,521.20)	\$ -	\$ (27,521.20)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (78,164.82)	\$ -	\$ (78,164.82)
37	Financial Transmission Guarantee Uplift Amount	\$ 77,287.56	\$ -	\$ 77,287.56
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 517,188.75	\$ -	\$ 517,188.75
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 99,976.84	\$ -	\$ 99,976.84
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (143,712.57)	\$ 12,577.72	\$ (131,134.85)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 1,253,416.48	\$ -	\$ 1,253,416.48
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (76,596.70)	\$ 23,186.61	\$ (53,410.09)
42	Real-Time Price Volatility Make Whole Payment Amount	\$ (251,996.66)	\$ 23,483.69	\$ (228,512.97)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 749,903.29	\$ (44,354.78)	\$ 705,548.51
19	Real-Time Market Administration Amount	\$ 57,740.79	\$ (5,165.16)	\$ 52,575.63
29	Financial Transmission Rights Market Administration Amount	\$ 99,485.28	\$ -	\$ 99,485.28
33	Day-Ahead Schedule 24 Allocation Amount	\$ 96,098.63	\$ (5,557.84)	\$ 90,540.79
34	Real-Time Schedule 24 Allocation Amount	\$ 7,392.00	\$ (647.15)	\$ 6,744.85
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	\$ 95,373.13	\$ -	\$ 95,373.13
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
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)
TOTAL MISO CHARGES		\$ 3,638,180.67	\$ 7,589,192.16	\$ 11,227,372.83

SCHEDULE 24 (FOR RETAIL)	\$ 97,285.64
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TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)	\$ 11,130,087.19
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MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
August 2009 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (412,561.73)	\$ -	\$ (412,561.73)
2	Day-Ahead Spinning Reserve Amount	\$ (48,814.65)	\$ -	\$ (48,814.65)
3	Day-Ahead Supplemental Reserve	\$ (26,964.00)	\$ -	\$ (26,964.00)
4	Real-Time Regulation Amount	\$ 120,774.41	\$ 163,317.35	\$ 284,091.76
5	Real-Time Spinning Reserve Amount	\$ (3,098.72)	\$ 19,647.07	\$ 16,548.35
6	Real-Time Supplemental Reserve Amount.	\$ 1,698.84	\$ 13,881.14	\$ 15,579.98
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (48,791.35)	\$ -	\$ (48,791.35)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 1,847,615.84	\$ -	\$ 1,847,615.84
8b	Real Time Non Excessive Energy Congestion	\$ 482,216.27	\$ -	\$ 482,216.27
8c	Real Time Non Excessive Energy Loss	\$ (201,915.98)	\$ -	\$ (201,915.98)
9	Real Time Net Regulation Adjustment Amount	\$ 13,390.52	\$ (15,969.52)	\$ (2,579.00)
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 281,362.59	\$ -	\$ 281,362.59
11	Real Time Spinning Reserve Cost Distribution	\$ 146,078.46	\$ -	\$ 146,078.46
12	Real Time Supplemental Reserve Cost Distribution	\$ 16,863.74	\$ -	\$ 16,863.74
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 29,330.55	\$ (4,449.42)	\$ 24,881.13
14	Real Time Contignecy Reserve Deployment Failure	\$ 504.25	\$ -	\$ 504.25
TOTAL MISO ASM CHARGES		\$ 2,197,689.04	\$ 176,426.62	\$ 2,374,115.66

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	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10
2 True-up Month	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10
3 Monthly Refund	(173,372)	(82,316)	(64,153)	(156)	(45,284)	7,115	(47,027)	(24,155)				
4 Forecast North Dakota Sales	191,827	174,423	167,216	169,094	182,677	182,651	177,780	169,550	162,133	207,797	-	-
5 Current Month Refund Factor	(0.090)	(0.047)	(0.038)	(0.000)	(0.025)	0.004	(0.026)	(0.014)	-	-	-	-
6 Forecasted North Dakota Sales	191,827	174,423	167,216	169,094	182,677	182,651	177,780	169,550	162,133	207,797	-	-
7 Actual North Dakota Sales (Cal. Mo.)	268,578	165,328	160,677	156,178	176,480	172,835	177,780	169,550	162,133	207,797	-	-
8 Deviation	(76,751)	9,095	6,539	12,916	6,197	9,816	177,780	169,550	162,133	207,797	-	-
9 Expected Refund	(173,372)	(82,316)	(64,153)	(156)	(45,284)	7,115	(47,027)	(24,155)				
10 Actual Refund	(242,738)	(78,023)	(41,009)	(4,109)	(43,552)	6,410	(48,556)	(23,790)				
11 Deviation	69,366	(4,293)	(340)	(340)	(340)	6,410	(48,556)	(23,790)				
12 True-up Factor	-	-	0.041	(0.003)	0.000	(0.000)	(0.001)	0.000	-	-	-	-
13 Realized Margin	(0.090)	(0.047)	0.003	(0.003)	(0.025)	0.004	(0.027)	(0.014)	-	-	-	-
14 Class Ratios												
15 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
16 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
17 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
18 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
19 C&I Demand TOD Off-Peak	0.9432	0.8663	0.8295	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726
20 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
21 Realized Margin Adj for Class Ratios												
22 Residential	(0.090)	(0.047)	0.003	(0.003)	(0.025)	0.004	(0.027)	(0.014)	-	-	-	-
23 C&I Non-Demand	(0.092)	(0.048)	0.003	(0.003)	(0.026)	0.004	(0.028)	(0.015)	-	-	-	-
24 C&I Demand Non-TOD	(0.091)	(0.048)	0.003	(0.003)	(0.025)	0.004	(0.028)	(0.014)	-	-	-	-
25 C&I Demand TOD On-Peak	(0.097)	(0.055)	0.004	(0.003)	(0.032)	0.005	(0.036)	(0.018)	-	-	-	-
26 C&I Demand TOD Off-Peak	(0.085)	(0.042)	0.003	(0.002)	(0.019)	0.003	(0.021)	(0.011)	-	-	-	-
27 Outdoor Lighting	(0.084)	(0.040)	0.002	(0.002)	(0.017)	0.003	(0.019)	(0.010)	-	-	-	-