414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

August 30, 2010

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

Re: September 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 September 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 September 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 July 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).

17 PU-10-12 Filed 08/30/2010 Pages: 12
September 2010 Fuel Cost adjustment
Northern States Power Company
Phillip J. Zins

The table below shows the new Fuel Cost Charge by customer class category:

September 2010	Fuel Cost Charge ($/kWh)
Residential	0.02961
C & I Non-Demand	0.03137
C & I Demand	0.03039
C & I Demand Time of Day On-Peak	0.03906
C & I Demand Time of Day Off-Peak	0.02298
Outdoor Lighting	0.02108

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 types[1], 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 September FCC, the net MISO Day 2 costs for July 2010 as recorded in Account 555. The MISO Day 2 cost recovery included in this September FCC is $19,625,160, 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.

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[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 September FCC, the net MISO ASM costs for July 2010 as recorded in Account 555. The MISO ASM cost recovery included in this September FCC is -$3,335,760, 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 July 2010 Asset Based Margin amount of $83,589 has been included in the September 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 September FCC is $16,155, or 0.010¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

OTHER REPORTING ITEM

Attachment is the calculation of the September 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 Sep-2010

Sep-2010 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	**$0.02846**	**$0.00187**	**-$0.00059**	**$0.02974**
Residential	**$0.02833**	**$0.00186**	**-$0.00059**	**$0.02961**
C & I Non-Demand	**$0.03002**	**$0.00198**	**-$0.00063**	**$0.03137**
C & I Demand Non-TOD	**$0.02908**	**$0.00191**	**-$0.00061**	**$0.03039**
C & I Demand TOD On-Peak	**$0.03738**	**$0.00246**	**-$0.00078**	**$0.03906**
C & I Demand TOD Off-Peak	**$0.02199**	**$0.00145**	**-$0.00046**	**$0.02298**
Outdoor Lighting	**$0.02017**	**$0.00133**	**-$0.00042**	**$0.02108**
Residential				
Residential Service	$ 0.02833	$ 0.00186	$ (0.00059)	$ 0.02961
Residential TOD	$ 0.02833	$ 0.00186	$ (0.00059)	$ 0.02961
Residential - Underground	$ 0.02833	$ 0.00186	$ (0.00059)	$ 0.02961
Residential TOD - Underground	$ 0.02833	$ 0.00186	$ (0.00059)	$ 0.02961
Energy Control - (Non-Demand)	$ 0.02833	$ 0.00186	$ (0.00059)	$ 0.02961
Limit Off Peak	$ 0.02833	$ 0.00186	$ (0.00059)	$ 0.02961
C & I Non-Demand				
Energy Controlled - (Non-Demand)	$ 0.03002	$ 0.00198	$ (0.00063)	$ 0.03137
Limit Off Peak	$ 0.03002	$ 0.00198	$ (0.00063)	$ 0.03137
Small General Service	$ 0.03002	$ 0.00198	$ (0.00063)	$ 0.03137
Small General TOD - Metered	$ 0.03002	$ 0.00198	$ (0.00063)	$ 0.03137
Small General TOD - Unmetered	$ 0.03002	$ 0.00198	$ (0.00063)	$ 0.03137
Fire and Civil Defense Siren	$ 0.03002	$ 0.00198	$ (0.00063)	$ 0.03137
Direct Current (Closed)	$ 0.03002	$ 0.00198	$ (0.00063)	$ 0.03137
C & I Demand				
General Service	$ 0.02908	$ 0.00191	$ (0.00061)	$ 0.03039
General TOD - On Peak	$ 0.03738	$ 0.00246	$ (0.00078)	$ 0.03906
General TOD - Off Peak	$ 0.02199	$ 0.00145	$ (0.00046)	$ 0.02298
Peak Controlled (Closed)	$ 0.02908	$ 0.00191	$ (0.00061)	$ 0.03039
Peak Controlled TOD (Closed) - On Peak	$ 0.03738	$ 0.00246	$ (0.00078)	$ 0.03906
Peak Controlled TOD (Closed) - Off Peak	$ 0.02199	$ 0.00145	$ (0.00046)	$ 0.02298
Peak Controlled Tiered	$ 0.02908	$ 0.00191	$ (0.00061)	$ 0.03039
Peak Controlled Tiered TOD - On Peak	$ 0.03738	$ 0.00246	$ (0.00078)	$ 0.03906
Peak Controlled Tiered TOD - Off Peak	$ 0.02199	$ 0.00145	$ (0.00046)	$ 0.02298
Energy Controlled (Closed)	$ 0.02908	$ 0.00191	$ (0.00061)	$ 0.03039
Tier 1 Energy Controlled Rider	$ 0.02908	$ 0.00191	$ (0.00061)	$ 0.03039
Real Time Pricing - Firm - On Peak	$ 0.03738	$ 0.00246	$ (0.00078)	$ 0.03906
Real Time Pricing - Firm - Off Peak	$ 0.02199	$ 0.00145	$ (0.00046)	$ 0.02298
Real Time Pricing - Controllable - On Peak	$ 0.03738	$ 0.00246	$ (0.00078)	$ 0.03906
Real Time Pricing - Controllable - Off Peak	$ 0.02199	$ 0.00145	$ (0.00046)	$ 0.02298
Small Municipal Pumping	$ 0.02908	$ 0.00191	$ (0.00061)	$ 0.03039
Municipal Pumping	$ 0.02908	$ 0.00191	$ (0.00061)	$ 0.03039
Excess Energy - St. Anthony Falls	$ 0.02908	$ 0.00191	$ (0.00061)	$ 0.03039
Outdoor Lighting				
Automatic Protective Lighting	$ 0.02017	$ 0.00133	$ (0.00042)	$ 0.02108
Street Lighting System	$ 0.02017	$ 0.00133	$ (0.00042)	$ 0.02108
Street Lighting Energy	$ 0.02017	$ 0.00133	$ (0.00042)	$ 0.02108
Street Lighting Energy - Metered	$ 0.02017	$ 0.00133	$ (0.00042)	$ 0.02108
Street Lighting Energy (Closed)	$ 0.02017	$ 0.00133	$ (0.00042)	$ 0.02108
Street Lighting - City of St. Paul	$ 0.02017	$ 0.00133	$ (0.00042)	$ 0.02108

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 Sep-2010

	Column (A) Apr-10	Column (B) May-10	Column (C) Jun-10	Column (D) Jul-10	Column (E) 4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	$28,892,464	$42,295,040	$39,902,362	$55,067,341	$166,157,207
Account 518 - Nuclear Fuel	$8,045,935	$7,461,565	$10,244,323	$10,499,991	$36,251,813
Account 555 - Purchased Power[1]	$32,827,975	$46,251,093	$40,206,803	$56,703,451	$175,989,322
Account 555 - MISO Day 2 Charges	$18,780,094	$16,331,544	$15,104,838	$19,722,045	$69,938,521
Account 555 MISO Day 2 - Schedule 24	($86,104)	($97,339)	($84,899)	($96,885)	($365,227)
Account 555 MISO - ASM Charges	$186,146	$3,111,926	($1,078,074)	($3,335,760)	($1,115,762)
Total MISO Charges	$18,880,137	$19,346,131	$13,941,865	$16,289,400	$68,457,533
Financial Instruments	$0	$0	$0	$0	$0
Total System Costs	$88,646,511	$115,353,828	$104,295,353	$138,560,182	$446,855,874
Less Fuel Cost of InterSystem Sales	($7,335,161)	($14,193,013)	($9,145,253)	($23,721,609)	($54,395,036)
Net System Costs	$81,311,350	$101,160,815	$95,150,100	$114,838,573	$392,460,838
System MWH Sales					
Total NSP System Retail	3,129,808	2,907,623	3,649,319	3,841,078	13,527,828
Non-Gen Muni's/Load Pattern	67,601	60,608	65,001	67,976	261,186
Total NSP System MWh Sales	3,197,409	2,968,231	3,714,320	3,909,054	13,789,014
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	**2.543¢**	**3.408¢**	**2.562¢**	**2.938¢**	**2.846¢**
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	**2.833¢**
(ii) C & I Non-Demand	1.0548	**3.002¢**
(iii) C & I Demand Non-TOD	1.0219	**2.908¢**
(iv) C & I Demand TOD On-Peak	1.3135	**3.738¢**
(v) C & I Demand TOD Off-Peak	0.7726	**2.199¢**
(vi) Outdoor Lighting	0.7088	**2.017¢**

[1] Excludes demand-related expenses

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 Sep-2010

North Dakota Retail MWh Sales

(i) Residential	55,786	45,211	51,563	59,551	212,111
(ii) C & I Non-Demand	10,380	8,456	9,830	10,009	38,675
(iii) C & I Demand Non-TOD	54,120	48,522	60,218	60,762	223,622
(iv) C & I Demand TOD On-Peak	17,650	15,394	21,149	18,832	73,025
(v) C & I Demand TOD Off-Peak	27,666	23,067	34,834	29,571	115,138
(vi) Outdoor Lighting	1,569	1,263	1,210	1,129	5,171
(vii) Total	167,171	141,913	178,804	179,854	667,742

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

Prior Unrecovered Expenses (May-10 Balance of Unrecovered Expenses)

	Total May-10
	$937,757

Prior Expenses Recovered in Jul-2010

	FCF Ratio	True-Up Factor per kWh	Actual ND MWh Sales	Prior Reccovered Expenses in
(i) Residential				
(ii) C & I Non-Demand	0.9956	0.128¢	59,551	$76,349
(iii) C & I Demand Non-TOD	1.0548	0.136¢	10,009	$13,595
(iv) C & I Demand TOD On-Peak	1.0219	0.132¢	60,762	$79,960
(v) C & I Demand TOD Off-Peak	1.3135	0.169¢	18,832	$31,854
(vi) Outdoor Lighting	0.7726	0.099¢	29,571	$29,421
(vii) Total	0.7088	0.091¢	1,129	$1,031
			179,854	$232,210

Actual Cost Should Have Been Recovered in Jul-10

	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.938¢	0.000¢	179,854	$5,284,111

Cost Recovered in Jul-10

	FCF Ratio	Fuel Cost Recovered	Actual ND MWH Sales	Actual Recovery
(i) Residential	0.9956	2.616¢	59,551	$1,558,114
(ii) C & I Non-Demand	1.0548	2.772¢	10,009	$277,451
(iii) C & I Demand Non-TOD	1.0219	2.686¢	60,762	$1,631,796
(iv) C & I Demand TOD On-Peak	1.3135	3.452¢	18,832	$650,058
(v) C & I Demand TOD Off-Peak	0.7726	2.030¢	29,571	$600,408
(vi) Outdoor Lighting	0.7088	1.863¢	1,129	$21,030
(vii) Total			179,854	$4,738,856

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

Sep-2010 Recovery Provision	$1,250,802
4 Month ND Retail Total MWh Sales	667,742
Sep-2010 Recovery Provision per KWH	**0.187¢**

Sep-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	0.187¢	**0.186¢**
(ii) C & I Non-Demand	1.0548	0.187¢	**0.198¢**
(iii) C & I Demand Non-TOD	1.0219	0.187¢	**0.191¢**
(iv) C & I Demand TOD On-Peak	1.3135	0.187¢	**0.246¢**
(v) C & I Demand TOD Off-Peak	0.7726	0.187¢	**0.145¢**
(vi) Outdoor Lighting	0.7088	0.187¢	**0.133¢**

Sep-2010 Margin Sharing Refunds

	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
Refund/Special Charge Amount	($83,589)	($16,155)	**($99,744)**
(i) Residential	-0.050¢	-0.010¢	**-0.059¢**
(ii) C & I Non-Demand	-0.052¢	-0.010¢	**-0.063¢**
(iii) C & I Demand Non-TOD	-0.051¢	-0.010¢	**-0.061¢**
(iv) C & I Demand TOD On-Peak	-0.065¢	-0.013¢	**-0.078¢**
(v) C & I Demand TOD Off-Peak	-0.038¢	-0.007¢	**-0.046¢**
(vi) Outdoor Lighting	-0.035¢	-0.007¢	**-0.042¢**

Sep-2010 Factors

	Total
(i) Residential	**2.961¢**
(ii) C & I Non-Demand	**3.137¢**
(iii) C & I Demand Non-TOD	**3.039¢**
(iv) C & I Demand TOD On-Peak	**3.906¢**
(v) C & I Demand TOD Off-Peak	**2.298¢**
(vi) Outdoor Lighting	**2.108¢**

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		
			Differ-	Percent	FCA Application		Differ-
	Aug-10	Sep-10	ence	Change	Aug-10	Sep-10	ence
** COSTS (Millions) **							
1 Fossil	$138.6	$166.2	$27.6	19.9%	34.8%	37.2%	2.4%
2 Nuclear	$35.5	$36.3	$0.7	2.0%	8.9%	8.1%	-0.8%
3 Purchases	$153.3	$176.0	$22.7	14.8%	38.5%	39.4%	0.9%
MISO related Purchases	$70.7	$68.5	($2.2)	-3.2%	17.8%	15.3%	-2.5%
4 Total System Costs	398.1	446.9	$48.8	12.3%	100.0%	100.0%	0.0%
5 Intersystem Sales	$38.4	$54.4	$16.0	41.8%	9.6%	12.2%	2.6%
6 Net System Costs	$359.7	$392.5	$32.7	9.1%	90.4%	87.8%	-2.6%
7							
8 ** GWH OUTPUT **							
9 Fossil	5,159	5,717	558	10.8%	15.6%	16.2%	0.6%
10 Nuclear	4,235	4,181	(54)	-1.3%	12.8%	11.8%	-1.0%
11 Purchases	5,285	5,435	150	2.8%	16.0%	15.4%	-0.6%
12 Hydro & Other	880	1,279	399	45.3%	2.7%	3.6%	0.9%
13 Net Interchange	17,541	18,723	1,182	6.7%	53.0%	53.0%	0.0%
14 Total Output	33,100	35,335	2,235	6.8%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,612	1,708	96	6.0%	4.9%	4.8%	-0.1%
16 Native Requirement	31,488	33,627	2,139	6.8%	95.1%	95.2%	0.1%
17							
18 ** COST per KWH OUTPUT (¢) **							
19 Fossil	2.686	2.906	0.221	8.2%			
20 Nuclear	0.839	0.867	0.028	3.4%			
21 Purchases	2.901	3.238	0.337	11.6%			
22 Total System Costs	1.203	1.265	0.062	5.2%			
23 Intersystem Sales	2.380	3.185	0.805	33.8%			
24 Net System Costs	1.142	1.167	0.025	2.2%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,505	13,789	284	2.1%			
28							
29 COST per KWH SALES (¢)	2.664	2.846	0.182	6.8%			
30							
31 RECOVERY PROV (¢ / KWH) - SYS	0.020	0.187	0.168				
(i) Residential	0.020	0.186	0.167				
(ii) C & I Non-Demand	0.021	0.198	0.177				
(iii) C & I Demand Non-TOD	0.020	0.191	0.171				
(iv) C & I Demand TOD On-Peak	0.026	0.246	0.220				
(v) C & I Demand TOD Off-Peak	0.015	0.145	0.129				
(vi) Outdoor Lighting	0.014	0.133	0.119				
32 REFUND	0.000	0.000	0.000				
(i) Residential	0.000	-0.059					
(ii) C & I Non-Demand	0.000	-0.063					
(iii) C & I Demand Non-TOD	0.000	-0.061					
(iv) C & I Demand TOD On-Peak	0.000	-0.078					
(v) C & I Demand TOD Off-Peak	0.000	-0.046					
(vi) Outdoor Lighting	0.000	-0.042					
33 SYSTEM FCC IMPACT (¢ / KWH)	2.684	3.033	0.350	13.0%			
(i) Residential	2.588	2.961	0.373				
(ii) C & I Non-Demand	2.742	3.137					
(iii) C & I Demand Non-TOD	2.657	3.039					
(iv) C & I Demand TOD On-Peak	3.415	3.906					
(v) C & I Demand TOD Off-Peak	2.009	2.298					
(vi) Outdoor Lighting	1.843	2.108					

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]

Residential BILL IMPACT ($'s)

kWh	Change from Previous Month
100	$0.37
250	$0.93
500	$1.86
750	$2.80
1,000	$3.73

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	
	Aug-10	Sep-10
** GWH OUTPUT **		
Thermal	602,288	984,163
Wind plus disper gen	(45)	(45)
Hydro	277,964	294,566
Hydro and Other	880,207	1,278,684
Rounded to nearest thousand:	880	1,279
Sales		
Non Gen Munic Total	264,463,000	261,186,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,611,786,000	1,708,115,000
Rounded to nearest million:	1611.786	1708.115

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System		Intersystem		Retail
July 2010 Actual						
Energy and Loss Charges						
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	$ 28,535,373.18	$	3,764,418.25	$	32,299,791.43
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	$ 3,113,300.62	$	-	$	3,113,300.62
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 17,327.55	$	-	$	17,327.55
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	$ (25,660,014.60)	$	-	$	(25,660,014.60)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	$ 3,969,471.37	$	-	$	3,969,471.37
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)	$ 3,482,049.65	$	2,594,898.58	$	6,076,948.23
13 c	Real-Time Asset Energy Amount - Loss Component (1)	$ (45,763.22)	$	-	$	(45,763.22)
14	Real-Time Distribution of Losses Amount	$ (2,420,178.01)	$	-	$	(2,420,178.01)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$	-	$	-
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$	-	$	-
21	Real-time Net inadvertent Distribution	$ 44,901.79	$	-	$	44,901.79
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	$ 78,561.56	$	-	$	78,561.56
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	$ (5,527.54)	$	-	$	(5,527.54)
Congestion Related Charges						
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	$ 3,481,211.15	$	-	$	3,481,211.15
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 1,510.25	$	-	$	1,510.25
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	$ 3,563,172.02	$	-	$	3,563,172.02
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)	$ (35,679.97)	$	-	$	(35,679.97)
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)	$ (3,923.82)	$	-	$	(3,923.82)
FTR Related Charges						
28	Financial Transmission Rights Hourly Allocation Amount	$ (4,806,323.38)	$	-	$	(4,806,323.38)
30	Financial Transmission Rights Monthly Allocation Amount	$ (184,494.81)	$	-	$	(184,494.81)
31	Financial Transmission Rights Transaction Amount	$ -	$	-	$	-
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$	-	$	-
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (159,912.22)	$	-	$	(159,912.22)
37	Financial Transmission Guarantee Uplift Amount	$ 173,825.15	$	-	$	173,825.15
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$	-	$	-
Uplift Charges						
23	Real-Time Revenue Neutrality Uplift Amount	$ 600,689.49	$	-	$	600,689.49
Revenue Sufficiency Guarantee (RSG) Charges						
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 306,849.50	$	-	$	306,849.50
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (762,018.74)	$	129,169.20	$	(632,849.54)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 536,769.43	$	-	$	536,769.43
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (1,019,155.55)	$	305,887.10	$	(713,268.45)
43	Real-Time Price Volatility Make Whole Payment Amount	$ (562,463.14)	$	22,159.94	$	(540,303.20)
Market Adminstration Charges						
4	Day-Ahead Market Administration Amount	$ 807,965.56	$	(8,482.77)	$	799,482.79
19	Real-Time Market Administration Amount	$ 56,828.46	$	(7,335.81)	$	49,492.65
29	Financial Transmission Rights Market Administration Amount	$ 85,419.60	$	-	$	85,419.60
33	Day-Ahead Schedule 24 Allocation Amount	$ 92,213.07	$	(971.20)	$	91,241.87
34	Real -Time Schedule 24 Allocation Amount	$ 6,486.44	$	(843.69)	$	5,642.75
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	$ (7,109.53)	$	-	$	(7,109.53)
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	$ (850,770.85)	$	-	$	(850,770.85)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (409,572.73)	$	-	$	(409,572.73)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 53,987.30	$	-	$	53,987.30
	TOTAL MISO CHARGES	$ 12,923,145.12	$	6,798,899.60	$	19,722,044.72
	SCHEDULE 24 (FOR RETAIL)				$	96,884.62
	TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				$	19,625,160.10

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System		Intersystem		Retail
July 2010 Actual						
Procurement Charges						
1	Day-Ahead Regulation Amount	$	(797,211.31)	$ -	$	(797,211.31)
2	Day-Ahead Spinning Reserve Amount	$	(140,783.92)	$ -	$	(140,783.92)
3	Day-Ahead Supplemental Reserve	$	(118,149.45)	$ -	$	(118,149.45)
4	Real-Time Regulation Amount	$	81,169.78	$ 458,087.46	$	539,257.24
5	Real-Time Spinning Reserve Amount	$	(34,202.68)	$ 56,530.05	$	22,327.37
6	Real-Time Supplemental Reserve Amount.	$	99,701.23	$ 22,908.52	$	122,609.75
Resource Energy Charges						
7a	Real Time Excessive Energy Amount	$	(27,030.72)		$	(27,030.72)
7b	Real Time Excessive Energy Congestion	$	-		$	-
7c	Real Time Excessive Energy Loss	$	-		$	-
8a	Real Time Non Excessive Energy Amount	$	(3,822,724.47)		$	(3,822,724.47)
8b	Real Time Non Excessive Energy Congestion	$	65,810.00		$	65,810.00
8c	Real Time Non Excessive Energy Loss	$	121,353.00		$	121,353.00
9	Real Time Net Regulation Adjustment Amount	$	58,789.48	$ (20,333.42)	$	38,456.06
Cost Distribution Charges						
10	Real Time Regulation Reserve Cost Distribution Amount	$	344,458.49	$ -	$	344,458.49
11	Real Time Spinnng Reserve Cost Distribution	$	223,736.59	$ -	$	223,736.59
12	Real Time Supplemental Reserve Cost Distribution	$	66,099.99	$ -	$	66,099.99
Penalty Charges						
13	Real Time Excessive/Dificient Energy Deployment	$	27,581.28	$ (3,309.84)	$	24,271.44
14	Real Time Contignecy Reserve Deployment Failure	$	2,257.89	$ (498.26)	$	1,759.63
	TOTAL MISO ASM CHARGES	**$**	**(3,849,144.82)**	**$ 513,384.51**	**$**	**(3,335,760.31)**

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

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
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
Monthly Refund	(161,371)	10,622	(54,285)	(21,836)	(155,670)	(141,793)	(89,740)					
Forecast North Dakota Sales	194,554	163,606	164,425	165,070	188,515	188,034	168,026	179,415	187,205	-	-	-
Current Month Refund Factor	(0.083)	0.006	(0.033)	(0.013)	(0.083)	(0.075)	(0.053)	-	-	-	-	-
Forecasted North Dakota Sales	215,527	196,388	194,554	163,606	164,425	165,070	188,515	188,034	168,026	-	-	-
Actual North Dakota Sales (Cal. Mo.)	222,254	189,946	190,655	151,863	160,154	167,487	195,892	-	-	-	-	-
Deviation	(6,727)	6,442	3,899	11,743	4,271	(2,417)	(7,377)	188,034	168,026	-	-	-
Expected Refund	(13,480)	(81,774)	(160,951)	7,940	(57,511)	(21,266)	(157,164)	(141,482)	(83,589)	-	-	-
Actual Refund	(13,900)	(79,092)	(157,725)	7,370	(56,017)	(21,577)	(163,315)	-	-	-	-	-
Deviation	420	(2,682)	(3,226)	570	(1,494)	311	6,151	(141,482)	(83,589)	-	-	-
True-up Factor	0.000	(0.002)	(0.002)	0.000	(0.001)	0.000	0.004	-	-	-	-	-
Realized Margin	(0.083)	0.005	(0.035)	(0.013)	(0.083)	(0.075)	**(0.050)**	-	-	-	-	-
Class Ratios												
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
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
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
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
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
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
Realized Margin Adj for Class Ratios												
Residential	(0.082)	0.005	(0.035)	(0.013)	(0.083)	(0.075)	(0.050)	-	-	-	-	-
C&I Non-Demand	(0.087)	0.005	(0.037)	(0.014)	(0.088)	(0.079)	(0.052)	-	-	-	-	-
C&I Demand Non-TOD	(0.085)	0.005	(0.036)	(0.013)	(0.085)	(0.077)	(0.051)	-	-	-	-	-
C&I Demand TOD On-Peak	(0.109)	0.006	(0.046)	(0.017)	(0.110)	(0.099)	(0.065)	-	-	-	-	-
C&I Demand TOD Off-Peak	(0.064)	0.004	(0.027)	(0.010)	(0.064)	(0.058)	(0.038)	-	-	-	-	-
Outdoor Lighting	(0.059)	0.003	(0.025)	(0.009)	(0.059)	(0.053)	(0.035)	-	-	-	-	-

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	-	-	-	-
7													
8	**Current Month Refund Factor**	(0.009)	(0.009)	(0.010)	(0.010)	(0.010)	(0.009)	(0.009)	(0.010)	-	-	-	-
9													
10	Forecasted North Dakota Sales			196,388	194,554	163,606	164,425	165,070	188,515	-	-	-	-
11	Actual North Dakota Sales (Cal. Mo.)			189,946	190,655	151,863	160,154	167,487	195,892	-	-	-	-
12	Deviation			6,442	3,899	11,743	4,271	(2,417)	(7,377)	-	-	-	-
13													
14	Expected Refund			(16,831)	(16,831)	(17,384)	(17,168)	(18,078)	(17,278)	-	-	-	-
15	Actual Refund			(16,278)	(16,494)	(16,137)	(16,722)	(18,342)	(17,954)	-	-	-	-
16	Deviation			(553)	(337)	(1,247)	(447)	264	676	-	-	-	-
17													
18	**True-up Factor**	-	-	(0.000)	(0.000)	(0.001)	(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)**	-	-	-	-
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)	-	-	-	-
32	C&I Non-Demand	(0.009)	(0.009)	(0.011)	(0.011)	(0.012)	(0.010)	(0.009)	(0.010)	-	-	-	-
33	C&I Demand Non-TOD	(0.009)	(0.009)	(0.011)	(0.011)	(0.011)	(0.009)	(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)	-	-	-	-
35	C&I Demand TOD Off-Peak	(0.007)	(0.007)	(0.008)	(0.008)	(0.008)	(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)	-	-	-	-