



—Via Electronic Filing—

February 27, 2009

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

Re: March 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 March 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 March 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 January 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 1 to 3).

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

March 2009	Fuel Cost Charge (\$/kWh)
Residential	0.02461
C & I Non-Demand	0.02499
C & I Demand	0.02478
C & I Demand Time of Day On-Peak	0.02665
C & I Demand Time of Day Off-Peak	0.02318
Outdoor Lighting	0.02277

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 March FCC, the net MISO Day 2 costs for January 2009 as recorded in Account 555. The MISO Day 2 cost recovery included in this March FCC is \$19,373,633, 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.

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

¹ Previously embedded in other FTR charge types.

Cost Rider. Consistent with the MISO order and the required “net” accounting of ASM costs and revenues, we include in the March FCC, the net MISO ASM costs for January 2009 as recorded in Account 555. The MISO ASM cost recovery included in this March FCC is \$-928,519, which is the net of many items. The detailed records are contained in Attachment 2, page 2.

REFUNDS

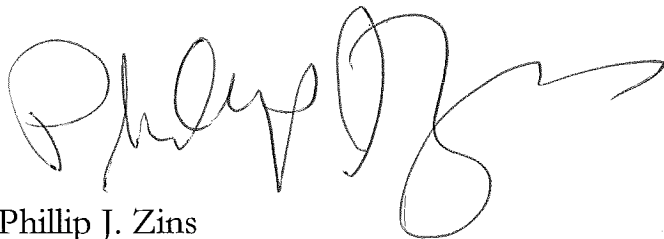
Pursuant to the above referenced Order Adopting Settlement, the January 2009 Asset Based Margin amount of \$173,372 has been included in the March Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. The 2009 North Dakota retail share of the Non-Asset Based Margins will be determined after the close of the calendar year and will be credited to the FCC during 2010. Also included as a one-time refund is the deferred Auction Revenue Rights (ARR) credit of \$196,369 that covered the period of June 2008 to December 2008 (See Attachment 3, page 2).

OTHER REPORTING ITEM

Attachment is the calculation of the March 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". The signature is fluid and cursive, with a long horizontal stroke extending to the right.

Phillip J. Zins
Manager, Pricing and Planning

Enclosures (2)
CC: David H. Sederquist

Electric Operations - State of North Dakota

Derivation of Adjustment for Fuel Clause Rider

Current Period Cost of Energy for Mar-2009

Mar-2009 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02674	-\$0.00018	-\$0.00090	\$0.02566
Residential	\$0.02671	-\$0.00018	-\$0.00192	\$0.02461
C & I Non-Demand	\$0.02711	-\$0.00018	-\$0.00194	\$0.02499
C & I Demand Non-TOD	\$0.02689	-\$0.00018	-\$0.00193	\$0.02478
C & I Demand TOD On-Peak	\$0.02884	-\$0.00019	-\$0.00199	\$0.02665
C & I Demand TOD Off-Peak	\$0.02522	-\$0.00017	-\$0.00187	\$0.02318
Outdoor Lighting	\$0.02479	-\$0.00016	-\$0.00186	\$0.02277
Residential				
Residential Service	\$ 0.02671	\$ (0.00018)	\$ (0.00192)	\$ 0.02461
Residential TOD	\$ 0.02671	\$ (0.00018)	\$ (0.00192)	\$ 0.02461
Residential - Underground	\$ 0.02671	\$ (0.00018)	\$ (0.00192)	\$ 0.02461
Residential TOD - Underground	\$ 0.02671	\$ (0.00018)	\$ (0.00192)	\$ 0.02461
Energy Control - (Non-Demand)	\$ 0.02671	\$ (0.00018)	\$ (0.00192)	\$ 0.02461
Limit Off Peak	\$ 0.02671	\$ (0.00018)	\$ (0.00192)	\$ 0.02461
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02711	\$ (0.00018)	\$ (0.00194)	\$ 0.02499
Limit Off Peak	\$ 0.02711	\$ (0.00018)	\$ (0.00194)	\$ 0.02499
Small General Service	\$ 0.02711	\$ (0.00018)	\$ (0.00194)	\$ 0.02499
Small General TOD - Metered	\$ 0.02711	\$ (0.00018)	\$ (0.00194)	\$ 0.02499
Small General TOD - Unmetered	\$ 0.02711	\$ (0.00018)	\$ (0.00194)	\$ 0.02499
Fire and Civil Defense Siren	\$ 0.02711	\$ (0.00018)	\$ (0.00194)	\$ 0.02499
Direct Current (Closed)	\$ 0.02711	\$ (0.00018)	\$ (0.00194)	\$ 0.02499
C & I Demand				
General Service	\$ 0.02689	\$ (0.00018)	\$ (0.00193)	\$ 0.02478
General TOD - On Peak	\$ 0.02884	\$ (0.00019)	\$ (0.00199)	\$ 0.02665
General TOD - Off Peak	\$ 0.02522	\$ (0.00017)	\$ (0.00187)	\$ 0.02318
Peak Controlled (Closed)	\$ 0.02689	\$ (0.00018)	\$ (0.00193)	\$ 0.02478
Peak Controlled TOD (Closed) - On Peak	\$ 0.02884	\$ (0.00019)	\$ (0.00199)	\$ 0.02665
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02522	\$ (0.00017)	\$ (0.00187)	\$ 0.02318
Peak Controlled Tiered	\$ 0.02689	\$ (0.00018)	\$ (0.00193)	\$ 0.02478
Peak Controlled Tiered TOD - On Peak	\$ 0.02884	\$ (0.00019)	\$ (0.00199)	\$ 0.02665
Peak Controlled Tiered TOD - Off Peak	\$ 0.02522	\$ (0.00017)	\$ (0.00187)	\$ 0.02318
Energy Controlled (Closed)	\$ 0.02689	\$ (0.00018)	\$ (0.00193)	\$ 0.02478
Tier 1 Energy Controlled Rider	\$ 0.02689	\$ (0.00018)	\$ (0.00193)	\$ 0.02478
Real Time Pricing - Firm - On Peak	\$ 0.02884	\$ (0.00019)	\$ (0.00199)	\$ 0.02665
Real Time Pricing - Firm - Off Peak	\$ 0.02522	\$ (0.00017)	\$ (0.00187)	\$ 0.02318
Real Time Pricing - Controllable - On Peak	\$ 0.02884	\$ (0.00019)	\$ (0.00199)	\$ 0.02665
Real Time Pricing - Controllable - Off Peak	\$ 0.02522	\$ (0.00017)	\$ (0.00187)	\$ 0.02318
Small Municipal Pumping	\$ 0.02689	\$ (0.00018)	\$ (0.00193)	\$ 0.02478
Municipal Pumping	\$ 0.02689	\$ (0.00018)	\$ (0.00193)	\$ 0.02478
Excess Energy - St. Anthony Falls	\$ 0.02689	\$ (0.00018)	\$ (0.00193)	\$ 0.02478
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.02479	\$ (0.00016)	\$ (0.00186)	\$ 0.02277
Street Lighting System	\$ 0.02479	\$ (0.00016)	\$ (0.00186)	\$ 0.02277
Street Lighting Energy	\$ 0.02479	\$ (0.00016)	\$ (0.00186)	\$ 0.02277
Street Lighting Energy - Metered	\$ 0.02479	\$ (0.00016)	\$ (0.00186)	\$ 0.02277
Street Lighting Energy (Closed)	\$ 0.02479	\$ (0.00016)	\$ (0.00186)	\$ 0.02277
Street Lighting - City of St. Paul	\$ 0.02479	\$ (0.00016)	\$ (0.00186)	\$ 0.02277

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 Mar-2009

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Oct-08	Nov-08	Dec-08	Jan-09	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$24,644,851	\$33,208,997	\$49,160,776	\$47,129,747	\$154,144,371
Account 518 - Nuclear Fuel	\$4,964,190	\$7,360,886	\$7,964,041	\$7,798,706	\$28,087,823
Account 555 - Purchased Power ¹	\$36,792,004	\$41,092,713	\$48,506,144	\$40,860,947	\$167,251,808
Account 555 - MISO Day 2 Charges	\$30,481,109	\$18,566,013	\$16,032,432	\$19,476,624	\$84,556,178
Account 555 MISO Day 2 - Schedule 24	\$0	\$0	\$0	(\$102,992)	(\$102,992)
Account 555 MISO - ASM Charges	\$0	\$0	\$0	(\$928,519)	(\$928,519)
Total MISO Charges	\$30,481,109	\$18,566,013	\$16,032,432	\$18,445,114	\$83,524,668
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$96,882,155	\$100,228,608	\$121,663,393	\$114,234,514	\$433,008,670
Less Fuel Cost of InterSystem Sales	(\$4,220,821)	(\$13,467,554)	(\$19,948,985)	(\$9,244,507)	(\$46,881,867)
Net System Costs	\$92,661,334	\$86,761,054	\$101,714,408	\$104,990,007	\$386,126,803
System MWH Sales					
Total NSP System Retail	3,493,004	2,865,421	3,715,105	3,869,018	13,942,548
Non-Gen Muni's/Load Pattern	119,170	117,780	122,434	137,915	497,299
Total NSP System MWh Sales	3,612,174	2,983,201	3,837,539	4,006,933	14,439,847
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.565¢	2.908¢	2.651¢	2.620¢	2.674¢
Base Fuel Cost Included in Rates	1.092¢	1.092¢	1.092¢	0.000¢	0.819¢
Class Ratio/TOD Ratio					
(i) Residential	1.0000	1.0000	1.0000	0.9956	0.9989
(ii) C & I Non-Demand	1.0000	1.0000	1.0000	1.0548	1.0137
(iii) C & I Demand Non-TOD	1.0000	1.0000	1.0000	1.0219	1.0055
(iv) C & I Demand TOD On-Peak	1.0000	1.0000	1.0000	1.3135	1.0784
(v) C & I Demand TOD Off-Peak	1.0000	1.0000	1.0000	0.7726	0.9432
(vi) Outdoor Lighting	1.0000	1.0000	1.0000	0.7088	0.9272
North Dakota Fuel Cost Factor (FCF)					
				FCF Ratio	4 Month Average
(i) Residential				0.9989	2.671¢
(ii) C & I Non-Demand				1.0137	2.711¢
(iii) C & I Demand Non-TOD				1.0055	2.689¢
(iv) C & I Demand TOD On-Peak				1.0784	2.884¢
(v) C & I Demand TOD Off-Peak				0.9432	2.522¢
(vi) Outdoor Lighting				0.9272	2.479¢

¹ Excludes demand-related expenses

North Dakota Retail MWh Sales					
(i) Residential				101,992	
(ii) C & I Non-Demand				17,159	
(iii) C & I Demand Non-TOD				63,019	
(iv) C & I Demand TOD On-Peak				16,065	
(v) C & I Demand TOD Off-Peak				29,158	
(vi) Outdoor Lighting				1,939	
(vii) Total	168,428	136,652	220,312	229,332	754,724

Mar-2009 Recovery Provision (True-up Factor) Calculation	
Prior Unrecovered Expenses (Nov-08 Balance of Unrecovered Expenses)	Total
	Nov-08
	\$240,966

Prior Expenses Recovered in Jan-2009				
	FCF Ratio	True-Up Factor per kWh	Actual ND MWh Sales	Prior Received Expenses in
(i) Residential				
(ii) C & I Non-Demand	1.0000	0.036¢	101,992	\$36,717
(iii) C & I Demand Non-TOD	1.0000	0.036¢	17,159	\$6,177
(iv) C & I Demand TOD On-Peak	1.0000	0.036¢	63,019	\$22,687
(v) C & I Demand TOD Off-Peak	1.0000	0.036¢	16,065	\$5,783
(vi) Outdoor Lighting	1.0000	0.036¢	29,158	\$10,497
(vii) Total	1.0000	0.036¢	1,939	\$698
			229,332	\$82,559

Actual Cost Should Have Been Recovered in Jan-09				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.620¢	1.092¢	229,332	\$3,504,193

Cost Recovered in Jan-09				
	FCF Ratio	Fuel Cost Recovered	Actual ND MWh Sales	Actual Recovery
(i) Residential	1.0000	1.655¢	101,992	\$1,687,968
(ii) C & I Non-Demand	1.0000	1.655¢	17,159	\$283,981
(iii) C & I Demand Non-TOD	1.0000	1.655¢	63,019	\$1,042,964
(iv) C & I Demand TOD On-Peak	1.0000	1.655¢	16,065	\$265,876
(v) C & I Demand TOD Off-Peak	1.0000	1.655¢	29,158	\$482,565
(vi) Outdoor Lighting	1.0000	1.655¢	1,939	\$32,090
(vii) Total			229,332	\$3,795,445

Total Balance of Unrecovered Expenses (Mar-09 Balance of Unrecovered Expenses)	
Mar-2009 Recovery Provision	(\$132,845)
4 Month ND Retail Total MWh Sales	754,724
Mar-2009 Recovery Provision per KWH	-0.018¢

Mar-2009 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9989	-0.018¢	-0.018¢
(ii) C & I Non-Demand	1.0137	-0.018¢	-0.018¢
(iii) C & I Demand Non-TOD	1.0055	-0.018¢	-0.018¢
(iv) C & I Demand TOD On-Peak	1.0784	-0.018¢	-0.019¢
(v) C & I Demand TOD Off-Peak	0.9432	-0.018¢	-0.017¢
(vi) Outdoor Lighting	0.9272	-0.018¢	-0.016¢

Mar-2009 Margin Sharing Refunds			
	Asset Based Margin Sharing Refund	ARR One Time Refund	Total
Refund/Special Charge Amount	(\$173,372)	(\$196,369)	(\$369,741)
(i) Residential	-0.090¢	-0.102¢	-0.192¢
(ii) C & I Non-Demand	-0.092¢	-0.102¢	-0.194¢
(iii) C & I Demand Non-TOD	-0.091¢	-0.102¢	-0.193¢
(iv) C & I Demand TOD On-Peak	-0.097¢	-0.102¢	-0.199¢
(v) C & I Demand TOD Off-Peak	-0.085¢	-0.102¢	-0.187¢
(vi) Outdoor Lighting	-0.084¢	-0.102¢	-0.186¢

Mar-2009 Factors		Total
(i) Residential		2.461¢
(ii) C & I Non-Demand		2.499¢
(iii) C & I Demand Non-TOD		2.478¢
(iv) C & I Demand TOD On-Peak		2.665¢
(v) C & I Demand TOD Off-Peak		2.318¢
(vi) Outdoor Lighting		2.277¢

		System	Intersystem	Retail
January 2009 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 21,876,558.64	\$ 5,125,199.33	\$ 27,001,757.97
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 4,467,353.54	\$ -	\$ 4,467,353.54
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 14,237.52	\$ -	\$ 14,237.52
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (13,385,392.53)	\$ -	\$ (13,385,392.53)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 656,220.52	\$ -	\$ 656,220.52
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)	\$ 3,045,566.69	\$ 714,738.76	\$ 3,760,305.45
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (28,300.92)	\$ -	\$ (28,300.92)
14	Real-Time Distribution of Losses Amount	\$ (2,122,916.70)	\$ -	\$ (2,122,916.70)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (51,800.85)	\$ -	\$ (51,800.85)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 1,059,799.86	\$ -	\$ 1,059,799.86
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (118,093.68)	\$ -	\$ (118,093.68)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 433,218.81	\$ -	\$ 433,218.81
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ 2,116.32	\$ -	\$ 2,116.32
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ (627,499.51)	\$ -	\$ (627,499.51)
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)	\$ (60,897.84)	\$ -	\$ (60,897.84)
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)	\$ (530,468.08)	\$ -	\$ (530,468.08)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (338,364.17)	\$ -	\$ (338,364.17)
30	Financial Transmission Rights Monthly Allocation Amount	\$ 3,544.81	\$ -	\$ 3,544.81
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (86,897.68)	\$ -	\$ (86,897.68)
37	Financial Transmission Guarantee Uplift Amount	\$ 144,434.21	\$ -	\$ 144,434.21
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ (546,801.78)	\$ -	\$ (546,801.78)
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 206,062.21	\$ -	\$ 206,062.21
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (296,193.56)	\$ -	\$ (296,193.56)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 1,223,957.47	\$ -	\$ 1,223,957.47
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (1,730,861.80)	\$ 302,887.80	\$ (1,427,974.00)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 576,385.75	\$ (12,048.89)	\$ 564,336.86
19	Real-Time Market Administration Amount	\$ 46,327.91	\$ (2,549.72)	\$ 43,778.19
29	Financial Transmission Rights Market Administration Amount	\$ 116,207.89	\$ -	\$ 116,207.89
33	Day-Ahead Schedule 24 Allocation Amount	\$ 97,640.83	\$ (2,041.80)	\$ 95,599.03
34	Real-Time Schedule 24 Allocation Amount	\$ 7,824.17	\$ (431.51)	\$ 7,392.66
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	\$ 25,098.44	\$ -	\$ 25,098.44
26	Real-Time Uninstructed Deviation Amount	\$ (6,962.86)	\$ (538.60)	\$ (7,501.46)
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 1,256,381.80	\$ -	\$ 1,256,381.80
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (1,256,383.55)	\$ -	\$ (1,256,383.55)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (719,692.96)	\$ -	\$ (719,692.96)
TOTAL MISO CHARGES		\$ 13,351,408.92	\$ 6,125,215.37	\$ 19,476,624.29
SCHEDULE 24 (FOR RETAIL)				\$ 102,991.69
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 19,373,632.60

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

	System	Intersystem	Retail
January 2009 Actual			
Procurement Charges			
1 Day-Ahead Regulation Amount	\$ (555,962.15)	\$ 278,220.54	\$ (277,741.61)
2 Day-Ahead Spinning Reserve Amount	\$ (92,316.67)	\$ 21,274.46	\$ (71,042.21)
3 Day-Ahead Supplemental Reserve	\$ (25,825.00)	\$ 20,241.25	\$ (5,583.75)
4 Real-Time Regulation Amount	\$ 102,272.23	\$ (21,710.27)	\$ 80,561.96
5 Real-Time Spinning Reserve Amount	\$ (44,208.55)	\$ 20,263.09	\$ (23,945.46)
6 Real-Time Supplemental Reserve Amount	\$ 2,461.12	\$ (995.88)	\$ 1,465.24
Resource Energy Charges			
7 Real Time Excessive Energy Amount	\$ (361,539.12)	\$ -	\$ (361,539.12)
8 Real Time Non Excessive Enrgy Amount	\$ (1,046,432.74)	\$ -	\$ (1,046,432.74)
9 Real Time Net Regulation Adjustment Amount	\$ (2,630.78)	\$ 1,384.26	\$ (1,246.52)
Cost Distribution Charges			
10 Real Time Regulation Reserve Cost Distribution Amount	\$ 504,148.18	\$ (178,721.19)	\$ 325,426.99
11 Real Time Spinning Reserve Cost Distribution	\$ 387,987.85	\$ (29,530.67)	\$ 358,457.18
12 Real Time Supplemental Reserve Cost Distribution	\$ 14,276.35	\$ (11,217.68)	\$ 3,058.67
Penalty Charges			
13 Real Time Excessive/Dificient Energy Deployment	\$ 92,274.27	\$ (5,774.03)	\$ 86,500.24
14 Real Time Contignecy Reserve Deployment Failure	\$ 3,542.56	\$ -	\$ 3,542.56
TOTAL MISO ASM CHARGES	\$ (1,021,952.45)	\$ 93,433.88	\$ (928,518.57)

MISO Day 2 ARR Charges Refund (June 2008 - January 2009)

	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
Total MWH Sales (Cal. Month)								
North Dakota	\$ 159,100	\$ 183,170	\$ 191,026	\$ 162,407	\$ 167,342	\$ 183,076	\$ 216,198	\$ 1,262,319
Total System	\$ 3,504,531	\$ 4,198,881	\$ 4,097,869	\$ 3,552,167	\$ 3,556,834	\$ 3,560,649	\$ 3,764,717	\$ 26,235,648
Gross ARR								
Auction Revenue Rights - FTR Auction Transactions	\$ 4,170,348	\$ 4,170,348	\$ 4,170,348	\$ 1,659,908	\$ 1,659,908	\$ 1,659,908	\$ 1,256,382	\$ 18,747,150
Auction Revenue Rights - Monthly ARR Revenue	\$ (4,170,347)	\$ (4,170,347)	\$ (4,170,347)	\$ (1,749,157)	\$ (1,572,600)	\$ (1,481,377)	\$ (1,256,384)	\$ (18,570,558)
Auction Revenue Rights - ARR Stage 2 Distribution	\$ (600,952)	\$ (672,111)	\$ (636,531)	\$ (529,526)	\$ (545,424)	\$ (546,648)	\$ (719,563)	\$ (4,250,755)
Total ARR	\$ (600,951)	\$ (672,110)	\$ (636,530)	\$ (618,775)	\$ (458,116)	\$ (368,117)	\$ (719,565)	\$ (4,074,164)
Refund Allocations								
North Dakota	\$ (27,282)	\$ (29,320)	\$ (29,672)	\$ (28,291)	\$ (21,553)	\$ (18,927)	\$ (41,323)	\$ (196,369)
Refund to Retail Customers								
					Margin Credited to North Dakota Retail Customers \$ (196,369)			
					Forecasted March North Dakota Sales (Cal. Month) 191,827			
					North Dakota Realized Margin (Cents per kWh) (0.102)			

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>		
	Feb-2009	Mar-2009	Differ- ence	Percent Change	FCA Application Feb-2009	Mar-2009	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$140.4	\$154.1	\$13.8	9.8%	32.6%	35.6%	3.0%
2 Nuclear	\$25.0	\$28.1	\$3.1	12.4%	5.8%	6.5%	0.7%
3 Purchases	\$171.4	\$167.3	(\$4.1)	-2.4%	39.8%	38.6%	-1.2%
MISO 2 related Purchases	\$94.3	\$83.5	(\$10.7)	-11.4%	21.9%	19.3%	-2.6%
4 Total System Costs	431.0	433.0	\$2.0	0.5%	100.0%	100.0%	0.0%
3 Intersystem Sales	\$51.8	\$46.9	(\$4.9)	-9.4%	12.0%	10.8%	-1.2%
6 Net System Costs	\$379.2	\$386.1	\$6.9	1.8%	88.0%	89.2%	1.2%
7							
8 ** GWH OUTPUT **							
9 Fossil	6,094	6,494	400	6.6%	36.0%	37.3%	1.3%
10 Nuclear	4,008	4,436	428	10.7%	23.7%	25.5%	1.8%
11 Purchases	5,688	5,299	(389)	-6.8%	33.6%	30.4%	-3.2%
12 Hydro & Other	205	244	39	19.0%	1.2%	1.4%	0.2%
13 Net Interchange	912	948	36	3.9%	5.4%	5.4%	0.0%
14 Total Output	16,907	17,421	514	3.0%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,646	1,741	96	5.8%	9.7%	10.0%	0.3%
16 Native Requirement	15,261	15,680	418	2.7%	90.3%	90.0%	-0.3%
17							
18 ** COST per KWH OUTPUT (¢) **							
19 Fossil	2.304	2.374	0.070	3.0%			
20 Nuclear	0.624	0.633	0.009	1.5%			
21 Purchases	3.013	3.156	0.143	4.8%			
22 Total System Costs	2.549	2.486	-0.064	-2.5%			
23 Intersystem Sales	3.146	2.692	-0.453	-14.4%			
24 Net System Costs	2.485	2.463	-0.022	-0.9%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,449	14,440	(9)	-0.1%			
28							
29 COST per KWH SALES (¢)	2.625	2.674	0.049	1.9%			
30							
31 RECOVERY PROV (¢ / KWH)	-0.162	-0.018	0.144				
32 REFUND	0.000	-0.192	-0.192				
33 TOTAL FCA IMPACT (¢ / KWH)	2.463	2.464	0.001	0.0%			

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	\$0.00
250	\$0.00
500	\$0.00
750	\$0.01
1,000	\$0.01