



—Via Electronic Filing—

April 30, 2009

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

Re: May 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 May 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 May 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 March 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:

May 2009	Fuel Cost Charge (\$/kWh)
Residential	0.02477
C & I Non-Demand	0.02587
C & I Demand	0.02526
C & I Demand Time of Day On-Peak	0.03069
C & I Demand Time of Day Off-Peak	0.02061
Outdoor Lighting	0.01942

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 May FCC, the net MISO Day 2 costs for March 2009 as recorded in Account 555. The MISO Day 2 cost recovery included in this May FCC is \$8,784,142, 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 May FCC, the net MISO ASM costs for March 2009 as recorded in Account 555. The MISO ASM cost recovery included in this May FCC is \$378,801, 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 March 2009 Asset Based Margin amount of \$-5,213 has been included in the May 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 May 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', written in a cursive style.

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 May-2009

May-2009 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02532	-\$0.00050	\$0.00003	\$0.02485
Residential	\$0.02524	-\$0.00050	\$0.00003	\$0.02477
C & I Non-Demand	\$0.02636	-\$0.00052	\$0.00003	\$0.02587
C & I Demand Non-TOD	\$0.02574	-\$0.00051	\$0.00003	\$0.02526
C & I Demand TOD On-Peak	\$0.03127	-\$0.00062	\$0.00004	\$0.03069
C & I Demand TOD Off-Peak	\$0.02100	-\$0.00042	\$0.00003	\$0.02061
Outdoor Lighting	\$0.01979	-\$0.00039	\$0.00002	\$0.01942
Residential				
Residential Service	\$ 0.02524	\$ (0.00050)	\$ 0.00003	\$ 0.02477
Residential TOD	\$ 0.02524	\$ (0.00050)	\$ 0.00003	\$ 0.02477
Residential - Underground	\$ 0.02524	\$ (0.00050)	\$ 0.00003	\$ 0.02477
Residential TOD - Underground	\$ 0.02524	\$ (0.00050)	\$ 0.00003	\$ 0.02477
Energy Control - (Non-Demand)	\$ 0.02524	\$ (0.00050)	\$ 0.00003	\$ 0.02477
Limit Off Peak	\$ 0.02524	\$ (0.00050)	\$ 0.00003	\$ 0.02477
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02636	\$ (0.00052)	\$ 0.00003	\$ 0.02587
Limit Off Peak	\$ 0.02636	\$ (0.00052)	\$ 0.00003	\$ 0.02587
Small General Service	\$ 0.02636	\$ (0.00052)	\$ 0.00003	\$ 0.02587
Small General TOD - Metered	\$ 0.02636	\$ (0.00052)	\$ 0.00003	\$ 0.02587
Small General TOD - Unmetered	\$ 0.02636	\$ (0.00052)	\$ 0.00003	\$ 0.02587
Fire and Civil Defense Siren	\$ 0.02636	\$ (0.00052)	\$ 0.00003	\$ 0.02587
Direct Current (Closed)	\$ 0.02636	\$ (0.00052)	\$ 0.00003	\$ 0.02587
C & I Demand				
General Service	\$ 0.02574	\$ (0.00051)	\$ 0.00003	\$ 0.02526
General TOD - On Peak	\$ 0.03127	\$ (0.00062)	\$ 0.00004	\$ 0.03069
General TOD - Off Peak	\$ 0.02100	\$ (0.00042)	\$ 0.00003	\$ 0.02061
Peak Controlled (Closed)	\$ 0.02574	\$ (0.00051)	\$ 0.00003	\$ 0.02526
Peak Controlled TOD (Closed) - On Peak	\$ 0.03127	\$ (0.00062)	\$ 0.00004	\$ 0.03069
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02100	\$ (0.00042)	\$ 0.00003	\$ 0.02061
Peak Controlled Tiered	\$ 0.02574	\$ (0.00051)	\$ 0.00003	\$ 0.02526
Peak Controlled Tiered TOD - On Peak	\$ 0.03127	\$ (0.00062)	\$ 0.00004	\$ 0.03069
Peak Controlled Tiered TOD - Off Peak	\$ 0.02100	\$ (0.00042)	\$ 0.00003	\$ 0.02061
Energy Controlled (Closed)	\$ 0.02574	\$ (0.00051)	\$ 0.00003	\$ 0.02526
Tier 1 Energy Controlled Rider	\$ 0.02574	\$ (0.00051)	\$ 0.00003	\$ 0.02526
Real Time Pricing - Firm - On Peak	\$ 0.03127	\$ (0.00062)	\$ 0.00004	\$ 0.03069
Real Time Pricing - Firm - Off Peak	\$ 0.02100	\$ (0.00042)	\$ 0.00003	\$ 0.02061
Real Time Pricing - Controllable - On Peak	\$ 0.03127	\$ (0.00062)	\$ 0.00004	\$ 0.03069
Real Time Pricing - Controllable - Off Peak	\$ 0.02100	\$ (0.00042)	\$ 0.00003	\$ 0.02061
Small Municipal Pumping	\$ 0.02574	\$ (0.00051)	\$ 0.00003	\$ 0.02526
Municipal Pumping	\$ 0.02574	\$ (0.00051)	\$ 0.00003	\$ 0.02526
Excess Energy - St. Anthony Falls	\$ 0.02574	\$ (0.00051)	\$ 0.00003	\$ 0.02526
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01979	\$ (0.00039)	\$ 0.00002	\$ 0.01942
Street Lighting System	\$ 0.01979	\$ (0.00039)	\$ 0.00002	\$ 0.01942
Street Lighting Energy	\$ 0.01979	\$ (0.00039)	\$ 0.00002	\$ 0.01942
Street Lighting Energy - Metered	\$ 0.01979	\$ (0.00039)	\$ 0.00002	\$ 0.01942
Street Lighting Energy (Closed)	\$ 0.01979	\$ (0.00039)	\$ 0.00002	\$ 0.01942
Street Lighting - City of St. Paul	\$ 0.01979	\$ (0.00039)	\$ 0.00002	\$ 0.01942

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 May-2009

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Dec-08	Jan-09	Feb-09	Mar-09	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$49,160,776	\$47,129,747	\$40,519,694	\$44,289,260	\$181,099,477
Account 518 - Nuclear Fuel	\$7,964,041	\$7,798,706	\$7,173,261	\$6,562,615	\$29,498,623
Account 555 - Purchased Power ¹	\$48,506,144	\$40,860,947	\$33,961,134	\$39,969,637	\$163,297,861
Account 555 - MISO Day 2 Charges	\$16,032,432	\$19,476,624	\$10,449,675	\$8,880,133	\$54,838,864
Account 555 MISO Day 2 - Schedule 24	\$0	(\$102,992)	(\$93,039)	(\$95,992)	(\$292,022)
Account 555 MISO - ASM Charges	\$0	(\$928,519)	(\$1,111,922)	\$378,801	(\$1,661,640)
Total MISO Charges	\$16,032,432	\$18,445,114	\$9,244,713	\$9,162,943	\$52,885,202
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$121,663,393	\$114,234,514	\$90,898,802	\$99,984,454	\$426,781,163
Less Fuel Cost of InterSystem Sales	(\$19,948,985)	(\$9,244,507)	(\$9,812,213)	(\$9,290,280)	(\$48,295,985)
Net System Costs	\$101,714,408	\$104,990,007	\$81,086,589	\$90,694,174	\$378,485,178
System MWh Sales					
Total NSP System Retail	3,715,105	3,869,018	3,373,718	3,504,517	14,462,358
Non-Gen Muni's/Load Pattern	122,434	137,915	116,434	106,377	483,160
Total NSP System MWh Sales	3,837,539	4,006,933	3,490,152	3,610,894	14,945,518
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.651¢	2.620¢	2.323¢	2.512¢	2.532¢
Base Fuel Cost Included in Rates	1.092¢	0.000¢	0.000¢	0.000¢	0.273¢
Class Ratio/TOD Ratio					
(i) Residential	1.0000	0.9956	0.9956	0.9956	0.9967
(ii) C & I Non-Demand	1.0000	1.0548	1.0548	1.0548	1.0411
(iii) C & I Demand Non-TOD	1.0000	1.0219	1.0219	1.0219	1.0164
(iv) C & I Demand TOD On-Peak	1.0000	1.3135	1.3135	1.3135	1.2351
(v) C & I Demand TOD Off-Peak	1.0000	0.7726	0.7726	0.7726	0.8295
(vi) Outdoor Lighting	1.0000	0.7088	0.7088	0.7088	0.7816
North Dakota Fuel Cost Factor (FCF)					
				FCF Ratio	4 Month Average
(i) Residential				0.9967	2.524¢
(ii) C & I Non-Demand				1.0411	2.636¢
(iii) C & I Demand Non-TOD				1.0164	2.574¢
(iv) C & I Demand TOD On-Peak				1.2351	3.127¢
(v) C & I Demand TOD Off-Peak				0.8295	2.100¢
(vi) Outdoor Lighting				0.7816	1.979¢

¹ Excludes demand-related expenses

Electric Operations - State of North Dakota

Derivation of Adjustment for Fuel Clause Rider

Current Period Cost of Energy for May-2009

North Dakota Retail MWh Sales				
(i) Residential	-	101,992	84,551	81,182
(ii) C & I Non-Demand	-	17,159	13,462	13,734
(iii) C & I Demand Non-TOD	-	63,019	56,351	64,180
(iv) C & I Demand TOD On-Peak	-	16,065	22,074	18,857
(v) C & I Demand TOD Off-Peak	-	29,158	36,055	29,201
(vi) Outdoor Lighting	-	1,939	2,089	1,609
(vii) Total		220,312	229,332	214,582
				208,763
				872,989

May-2009 Recovery Provision (True-up Factor) Calculation

Prior Unrecovered Expenses (Jan-09 Balance of Unrecovered Expenses)	Total
	Jan-09
	(\$132,845)

Prior Expenses Recovered in Mar-2009

	FCF Ratio	True-Up Factor per kWh	Actual ND MWh Sales	Prior Recovered Expenses in
(i) Residential				
(ii) C & I Non-Demand	0.9989	-0.018¢	81,182	(\$14,274)
(iii) C & I Demand Non-TOD	1.0137	-0.018¢	13,734	(\$2,451)
(iv) C & I Demand TOD On-Peak	1.0055	-0.018¢	64,180	(\$11,359)
(v) C & I Demand TOD Off-Peak	1.0784	-0.019¢	18,857	(\$3,579)
(vi) Outdoor Lighting	0.9432	-0.017¢	29,201	(\$4,848)
(vii) Total	0.9272	-0.016¢	1,609	(\$263)
			208,763	(\$36,774)

Actual Cost Should Have Been Recovered in Mar-09

	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.512¢	0.000¢	208,763	\$5,244,127

Cost Recovered in Mar-09

	FCF Ratio	Fuel Cost Recovered	Actual ND MWh Sales	Actual Recovery
(i) Residential	0.9989	2.671¢	81,182	\$2,168,419
(ii) C & I Non-Demand	1.0137	2.711¢	13,734	\$372,278
(iii) C & I Demand Non-TOD	1.0055	2.689¢	64,180	\$1,725,612
(iv) C & I Demand TOD On-Peak	1.0784	2.884¢	18,857	\$543,768
(v) C & I Demand TOD Off-Peak	0.9432	2.522¢	29,201	\$736,483
(vi) Outdoor Lighting	0.9272	2.479¢	1,609	\$39,892
(vii) Total			208,763	\$5,586,454

Total Balance of Unrecovered Expenses (May-09 Balance of Unrecovered Expenses)

May-2009 Recovery Provision	(\$438,398)
4 Month ND Retail Total MWh Sales	872,989
May-2009 Recovery Provision per KWH	-0.050¢

May-2009 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9967	-0.050¢	-0.050¢
(ii) C & I Non-Demand	1.0411	-0.050¢	-0.052¢
(iii) C & I Demand Non-TOD	1.0164	-0.050¢	-0.051¢
(iv) C & I Demand TOD On-Peak	1.2351	-0.050¢	-0.062¢
(v) C & I Demand TOD Off-Peak	0.8295	-0.050¢	-0.042¢
(vi) Outdoor Lighting	0.7816	-0.050¢	-0.039¢

May-2009 Margin Sharing Refunds		
	Asset Based Margin Sharing Refund	Total
Refund/Special Charge Amount	\$5,213	\$5,213
(i) Residential	0.003¢	0.003¢
(ii) C & I Non-Demand	0.003¢	0.003¢
(iii) C & I Demand Non-TOD	0.003¢	0.003¢
(iv) C & I Demand TOD On-Peak	0.004¢	0.004¢
(v) C & I Demand TOD Off-Peak	0.003¢	0.003¢
(vi) Outdoor Lighting	0.002¢	0.002¢

May-2009 Factors	
	Total
(i) Residential	2.477¢
(ii) C & I Non-Demand	2.587¢
(iii) C & I Demand Non-TOD	2.526¢
(iv) C & I Demand TOD On-Peak	3.069¢
(v) C & I Demand TOD Off-Peak	2.061¢
(vi) Outdoor Lighting	1.942¢

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		
	Apr-09	May-09	Differ- ence	Percent Change	FCA Application Apr-09	May-09	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$170.0	\$181.1	\$11.1	6.5%	39.8%	42.4%	2.6%
2 Nuclear	\$30.3	\$29.5	(\$0.8)	-2.6%	7.1%	6.9%	-0.2%
3 Purchases	\$164.4	\$163.3	(\$1.1)	-0.7%	38.5%	38.3%	-0.2%
MISO related Purchases	\$62.3	\$52.9	(\$9.4)	-15.1%	14.6%	12.4%	-2.2%
4 Total System Costs	427.0	426.8	(\$0.2)	-0.1%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$52.5	\$48.3	(\$4.2)	-8.0%	12.3%	11.3%	-1.0%
6 Net System Costs	\$374.6	\$378.5	\$3.9	1.1%	87.7%	88.7%	1.0%
7							
** GWH OUTPUT **							
9 Fossil	6,888	6,934	46	0.7%	39.4%	39.5%	0.1%
10 Nuclear	4,720	4,541	(179)	-3.8%	27.0%	25.9%	-1.1%
11 Purchases	4,745	4,789	44	0.9%	27.1%	27.3%	0.2%
12 Hydro & Other	232	423	191	82.3%	1.3%	2.4%	1.1%
13 Net Interchange	901	849	(52)	-5.8%	5.2%	4.8%	-0.4%
14 Total Output	17,486	17,536	50	0.3%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,886	1,839	(48)	-2.5%	10.8%	10.5%	-0.3%
16 Native Requirement	15,600	15,697	98	0.6%	89.2%	89.5%	0.3%
17							
** COST per KWH OUTPUT (\$)							
19 Fossil	2.468	2.612	0.143	5.8%			
20 Nuclear	0.642	0.650	0.008	1.2%			
21 Purchases	3.465	3.410	-0.055	-1.6%			
22 Total System Costs	2.442	2.434	-0.008	-0.3%			
23 Intersystem Sales	2.782	2.627	-0.155	-5.6%			
24 Net System Costs	2.401	2.411	0.010	0.4%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,318	14,946	628	4.4%			
28							
29 COST per KWH SALES (\$)	2.616	2.532	-0.084	-3.2%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.181	-0.050	0.130				
(i) Residential	-0.180	-0.050	0.130				
(ii) C & I Non-Demand	-0.186	-0.052	0.133				
(iii) C & I Demand Non-TOD	-0.183	-0.051	0.132				
(iv) C & I Demand TOD On-Peak	-0.209	-0.062	0.147				
(v) C & I Demand TOD Off-Peak	-0.160	-0.042	0.118				
(vi) Outdoor Lighting	-0.154	-0.039	0.115				
32 REFUND	-0.047	0.003	0.050				
(i) Residential	-0.047	0.003					
(ii) C & I Non-Demand	-0.048	0.003					
(iii) C & I Demand Non-TOD	-0.048	0.003					
(iv) C & I Demand TOD On-Peak	-0.055	0.004					
(v) C & I Demand TOD Off-Peak	-0.042	0.003					
(vi) Outdoor Lighting	-0.040	0.002					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.388	2.485	0.096	4.0%			
(i) Residential	2.383	2.477	0.094				
(ii) C & I Non-Demand	2.454	2.587					
(iii) C & I Demand Non-TOD	2.414	2.526					
(iv) C & I Demand TOD On-Peak	2.763	3.069					
(v) C & I Demand TOD Off-Peak	2.117	2.061					
(vi) Outdoor Lighting	2.040	1.942					

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	\$0.09
250	\$0.23
500	\$0.47
750	\$0.70
1,000	\$0.94

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	
	Apr-09	May-09
** GWH OUTPUT **		
Thermal	24,337	187,560
Wind plus disper gen	(103)	(92)
Hydro	208,089	235,397
Hydro and Other	232,323	422,865
Rounded to nearest thousand:	232	423
Sales		
Non Gen Munic Total	494,563,000	483,160,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,886,491,000	1,838,713,000
Rounded to nearest million:	1886.491	1838.713

Northern States Power Company, A Minnesota Corporation
MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

Attachment 2

Page 1

		System	Intersystem	Retail
March 2009 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 14,017,976.64	\$ 2,436,071.61	\$ 16,454,048.25
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,498,002.44	\$ -	\$ 2,498,002.44
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 3,729.35	\$ -	\$ 3,729.35
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (10,159,751.34)	\$ -	\$ (10,159,751.34)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,099,395.94	\$ -	\$ 1,099,395.94
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)	\$ 1,526,626.57	\$ 699,917.90	\$ 2,226,544.47
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (1,028.69)	\$ -	\$ (1,028.69)
14	Real-Time Distribution of Losses Amount	\$ (914,821.01)	\$ -	\$ (914,821.01)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (295,755.74)	\$ -	\$ (295,755.74)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 57,543.91	\$ -	\$ 57,543.91
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (1,356.25)	\$ -	\$ (1,356.25)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ (461,186.14)	\$ -	\$ (461,186.14)
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ (136.24)	\$ -	\$ (136.24)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 853,515.58	\$ -	\$ 853,515.58
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)	\$ 188,414.23	\$ -	\$ 188,414.23
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)	\$ (10,470.62)	\$ -	\$ (10,470.62)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (90,403.64)	\$ -	\$ (90,403.64)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (46,865.07)	\$ -	\$ (46,865.07)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (35,107.25)	\$ -	\$ (35,107.25)
37	Financial Transmission Guarantee Uplift Amount	\$ 42,353.07	\$ -	\$ 42,353.07
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ (3,362,593.04)	\$ -	\$ (3,362,593.04)
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 159,155.78	\$ -	\$ 159,155.78
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (78,356.75)	\$ -	\$ (78,356.75)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 1,469,188.21	\$ -	\$ 1,469,188.21
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (454,293.85)	\$ 5,423.01	\$ (448,870.84)
42	Real-Time Price Volatility Make Whole Payment Amount	\$ (200,340.12)	\$ 46,261.53	\$ (154,078.59)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 781,084.82	\$ (13,143.12)	\$ 767,941.70
19	Real-Time Market Administration Amount	\$ 76,296.06	\$ (5,878.71)	\$ 70,417.35
29	Financial Transmission Rights Market Administration Amount	\$ 74,111.98	\$ -	\$ 74,111.98
33	Day-Ahead Schedule 24 Allocation Amount	\$ 89,444.75	\$ (1,446.65)	\$ 87,998.10
34	Real-Time Schedule 24 Allocation Amount	\$ 8,655.37	\$ (661.91)	\$ 7,993.46
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	\$ (590,145.66)	\$ -	\$ (590,145.66)
26	Real-Time Uninstructed Deviation Amount	\$ 104.32	\$ (651.48)	\$ (547.16)
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 1,225,053.54	\$ -	\$ 1,225,053.54
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (1,223,639.77)	\$ -	\$ (1,223,639.77)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (530,160.21)	\$ -	\$ (530,160.21)
TOTAL MISO CHARGES		\$ 5,714,241.17	\$ 3,165,892.18	\$ 8,880,133.35

SCHEDULE 24 (FOR RETAIL)	\$ 95,991.56
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TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)	\$ 8,784,141.79
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MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
March 2009 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (496,020.40)	\$ (243,291.45)	\$ (739,311.85)
2	Day-Ahead Spinning Reserve Amount	\$ (70,777.85)	\$ (27,375.40)	\$ (98,153.25)
3	Day-Ahead Supplemental Reserve	\$ (24,405.30)	\$ (19,154.25)	\$ (43,559.55)
4	Real-Time Regulation Amount	\$ 184,580.97	\$ 135,580.51	\$ 320,161.48
5	Real-Time Spinning Reserve Amount	\$ (19,842.30)	\$ 31,389.24	\$ 11,546.94
6	Real-Time Supplemental Reserve Amount.	\$ 1,539.99	\$ 16,467.05	\$ 18,007.04
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ 7,576.06		\$ 7,576.06
7b	Real Time Excessive Energy Congestion	\$ -		\$ -
7c	Real Time Excessive Energy Loss	\$ -		\$ -
8a	Real Time Non Excessive Energy Amount	\$ (289,138.86)		\$ (289,138.86)
8b	Real Time Non Excessive Energy Congestion	\$ 240,415.38		\$ 240,415.38
8c	Real Time Non Excessive Energy Loss	\$ 177,533.48		\$ 177,533.48
9	Real Time Net Regulation Adjustment Amount	\$ 7,666.21	\$ 3,265.24	\$ 10,931.45
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 346,584.21	\$ 176,378.67	\$ 522,962.88
11	Real Time Spinning Reserve Cost Distribution	\$ 124,815.49	\$ 26,204.98	\$ 151,020.47
12	Real Time Supplemental Reserve Cost Distribution	\$ 15,511.13	\$ 11,293.89	\$ 26,805.02
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 66,530.40	\$ (4,526.23)	\$ 62,004.17
14	Real Time Contignecy Reserve Deployment Failure	\$ -	\$ -	\$ -
TOTAL MISO ASM CHARGES		\$ 272,568.61	\$ 106,232.25	\$ 378,800.86

