



414 Nicollet Mall
Minneapolis, Minnesota 55401

— Via Electronic Filing —

August 31, 2016

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

**Re: September 2016 Fuel Cost Rider Rates
Case No. PU-16-12**

Dear Mr. Nitschke:

Northern States Power Company, doing business as Xcel Energy and operating in North Dakota, hereby submits its electric Fuel Cost Rider (FCR) rates for September 2016.

The table below shows the September FCR rates by customer class:

September 2016	FCR Rate/kWh
Residential	\$0.02067
C & I Non-Demand	\$0.02140
C & I Demand	\$0.02112
C & I Demand Time of Day (On-Peak)	\$0.02654
C & I Demand Time of Day (Off-Peak)	\$0.01650
Outdoor Lighting	\$0.01522

See Attachment A for the supporting calculations of these rates.

MID-CONTINENT INDEPENDENT SYSTEM OPERATOR (MISO) CHARGES

Day 2 Market

Pursuant to the Commission's Orders in Case No. PU-05-147 and Case No. PU-07-776, Xcel Energy is authorized to recover MISO Day 2 costs in the FCR. The current FCR rates reflect MISO Day 2 charge types including three Auction Revenue Rights (ARR) and three Financial Transmission Rights (FTR) charge types.¹ Consistent with these Orders and the required "net" accounting of MISO Day 2 costs and revenues, we have included in the September 2016 FCR the net MISO Day 2 costs for July 2016 as recorded in Account 555. The MISO Day 2 cost recovery included in this month's FCR is \$12,315,804 which is the net of many items. Pursuant to the above-mentioned Orders, the Company also provides more detailed information in Attachment B of this filing to support the calculation of the MISO Day 2 costs.

Ancillary Services Market (ASM)

With the implementation of the MISO ASM on January 6, 2009, the net costs or revenues of 14 ASM charge types are included in the FCR, pursuant to Commission guidance in Case No. PU-09-016. Consistent with the MISO Order and the required "net" accounting of ASM costs and revenues, we reflect in the September 2016 FCR rates the net MISO ASM costs for July 2016 as recorded in Account 555. The MISO ASM cost recovery included in this month's FCR is \$2,238,393 which is the net of many items. The detailed records are contained in Attachment B.

REFUNDS

Asset Based Margins

Under the terms of the Revised Second Amended Settlement adopted by the Commission² on February 26, 2014 (retroactive to January 1, 2014), the Company began passing through to North Dakota customers 100 percent of wholesale asset based margins. Margins of \$371,823 have been included as an off-setting credit in this month's FCR. Additional information is found in Attachment C.

Non-Asset Based Margins

Beginning in February 2011, the prior year retail share of Non-Asset Based Margins is credited to North Dakota customers via the FCR over the following 12-month period. The North Dakota retail share of the 2015 Non-Asset Based Margin credit is \$50,462 and this amount is being fully credited to customers this year. See Attachment C.

Sales of Renewable Energy Credits (RECs)

Pursuant to the Commission Order in Case No. PU-10-19, the Company was authorized to sell excess Renewable Energy Credits (RECs) allocable to our North Dakota

¹ Previously embedded in other FTR charge types.

² Case Nos. PU-12-813, PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743, PU-13-194, PU-13-195

jurisdiction and credit 90 percent of the North Dakota jurisdictional share of net proceeds generated by the sale back to customers through the FCR. Under the Commission's February 26, 2014 Order adopting Settlement, the share of the net proceeds to customers was increased to 100 percent. There were no REC sales during the current reporting period. See Attachment C.

PURCHASED POWER AGREEMENT (PPA) COST RECOVERY REVIEW

Pursuant to the Commission's February 26, 2014 Order Adopting Settlement the following procedural changes reflected in the Revised Second Amended Settlement were intended to provide additional transparency regarding cost recovery of renewable energy projects or purchases:

- The Company will notify the Commission in its monthly FCR filings of any new renewable projects, qualifying in part or whole for FCR cost recovery, whose costs are included in the calculation of FCR rates. In addition, the Company will file an annual summary listing the new resources that have been included in the FCR during the previous calendar year;
- Future renewable energy resources or purchases with FCR-qualifying costs that are 50 MW or larger in size (nameplate capacity) will require approval of an Advance Determination of Prudence before included for recovery in the FCR; and
- MISO market energy purchases are not subject to the above requirements.

For this month's FCR filing there are no new renewable projects or purchases that require the above-referenced reporting obligation. The Company will monitor and comply with these obligations under the Settlement going forward.

NEGOTIATED AGREEMENT EXCLUSIONS

Pursuant to the Commission's March 9, 2016 Order Accepting the Negotiated Agreement (Case Nos. PU-12-813, *et. al.*), the costs and volumes of 15 Community-Based Energy Development (C-BED) and two small solar PPAs are to be excluded from the calculation of the Company's monthly FCR rates. See Attachment D for more details concerning the calculation of the replacement energy costs (system average) used to effectuate the exclusion of these disallowed PPAs.

The excluded C-BED and solar PPAs are listed below:

Community Based Energy Development Wind

1. Jeffers Wind 20, LLC (50 MW)
2. Big Blue (36 MW)
3. Community Wind South (Zephyr) (30 MW)
4. Ridgewind Power Partners LLC (25 MW)
5. Adams Wind Generations (20 MW)

6. Danielson Wind Farms (20 MW)
7. Ewington Energy Systems LLC (20 MW)
8. Grant County Wind, LLC (20 MW)
9. North Community Turbines (15 MW)
10. North Wind Turbines (15 MW)
11. Valley View Transmission (10 MW)
12. Ulk Wind Farm (4.5 MW)
13. Hilltop Power (2 MW)
14. Winona County Wind (1.5 MW)
15. Woodstock Municipal Wind, LLC (0.8 MW)

Solar Contracts

1. Outland Solar (2 MW)
2. Best Power (St. Johns) (0.4 MW)

MONTHLY CALCULATIONS AND COMPARISONS

Attached are the following supporting workpapers:

- Attachment A – Calculation of the September 2016 FCR rates
- Attachment B – Detail of MISO Day 2 and ASM net costs
- Attachment C – Summary of wholesale margins and REC credits
- Attachment D – Derivation of replacement energy costs for disallowed PPAs
- Attachment E – Comparison of energy and costs to the previous month

If you have any questions regarding the information contained in this filing, please contact Dave Sederquist at 701-241-8632 or dave.sederquist@xcelenergy.com.

Sincerely,

/ s /

Amy S. Fredregill
RESOURCE PLANNING AND STRATEGY MANAGER

CC: David H. Sederquist

Enclosures

Calculation of the FCR Rates for Sep-2016

Sep-2016 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Base & FCA Factor
System	\$0.02407	-\$0.00333	\$0.02074
Residential	\$0.02400	-\$0.00332	\$0.02067
C & I Non-Demand	\$0.02484	-\$0.00344	\$0.02140
C & I Demand Non-TOD	\$0.02451	-\$0.00339	\$0.02112
C & I Demand TOD On-Peak	\$0.03080	-\$0.00426	\$0.02654
C & I Demand TOD Off-Peak	\$0.01915	-\$0.00265	\$0.01650
Outdoor Lighting	\$0.01767	-\$0.00245	\$0.01522
Residential			
Residential Service	\$ 0.02400	\$ (0.00332)	\$ 0.02067
Residential TOD	\$ 0.02400	\$ (0.00332)	\$ 0.02067
Residential - Underground	\$ 0.02400	\$ (0.00332)	\$ 0.02067
Residential TOD - Underground	\$ 0.02400	\$ (0.00332)	\$ 0.02067
Energy Control - (Non-Demand)	\$ 0.02400	\$ (0.00332)	\$ 0.02067
Limit Off Peak	\$ 0.02400	\$ (0.00332)	\$ 0.02067
C & I Non-Demand			
Energy Controlled - (Non-Demand)	\$ 0.02484	\$ (0.00344)	\$ 0.02140
Limit Off Peak	\$ 0.02484	\$ (0.00344)	\$ 0.02140
Small General Service	\$ 0.02484	\$ (0.00344)	\$ 0.02140
Small General TOD - Metered	\$ 0.02484	\$ (0.00344)	\$ 0.02140
Small General TOD - Unmetered	\$ 0.02484	\$ (0.00344)	\$ 0.02140
Fire and Civil Defense Siren	\$ 0.02484	\$ (0.00344)	\$ 0.02140
Direct Current (Closed)	\$ 0.02484	\$ (0.00344)	\$ 0.02140
C & I Demand			
General Service	\$ 0.02451	\$ (0.00339)	\$ 0.02112
General TOD - On Peak	\$ 0.03080	\$ (0.00426)	\$ 0.02654
General TOD - Off Peak	\$ 0.01915	\$ (0.00265)	\$ 0.01650
Peak Controlled (Closed)	\$ 0.02451	\$ (0.00339)	\$ 0.02112
Peak Controlled TOD (Closed) - On Peak	\$ 0.03080	\$ (0.00426)	\$ 0.02654
Peak Controlled TOD (Closed) - Off Peak	\$ 0.01915	\$ (0.00265)	\$ 0.01650
Peak Controlled Tiered	\$ 0.02451	\$ (0.00339)	\$ 0.02112
Peak Controlled Tiered TOD - On Peak	\$ 0.03080	\$ (0.00426)	\$ 0.02654
Peak Controlled Tiered TOD - Off Peak	\$ 0.01915	\$ (0.00265)	\$ 0.01650
Energy Controlled (Closed)	\$ 0.02451	\$ (0.00339)	\$ 0.02112
Tier 1 Energy Controlled Rider	\$ 0.02451	\$ (0.00339)	\$ 0.02112
Real Time Pricing - Firm - On Peak	\$ 0.03080	\$ (0.00426)	\$ 0.02654
Real Time Pricing - Firm - Off Peak	\$ 0.01915	\$ (0.00265)	\$ 0.01650
Real Time Pricing - Controllable - On Peak	\$ 0.03080	\$ (0.00426)	\$ 0.02654
Real Time Pricing - Controllable - Off Peak	\$ 0.01915	\$ (0.00265)	\$ 0.01650
Small Municipal Pumping	\$ 0.02451	\$ (0.00339)	\$ 0.02112
Municipal Pumping	\$ 0.02451	\$ (0.00339)	\$ 0.02112
Excess Energy - St. Anthony Falls	\$ 0.02451	\$ (0.00339)	\$ 0.02112
Outdoor Lighting			
Automatic Protective Lighting	\$ 0.01767	\$ (0.00245)	\$ 0.01522
Street Lighting System	\$ 0.01767	\$ (0.00245)	\$ 0.01522
Street Lighting Energy	\$ 0.01767	\$ (0.00245)	\$ 0.01522
Street Lighting Energy - Metered	\$ 0.01767	\$ (0.00245)	\$ 0.01522
Street Lighting Energy (Closed)	\$ 0.01767	\$ (0.00245)	\$ 0.01522
Street Lighting - City of St. Paul	\$ 0.01767	\$ (0.00245)	\$ 0.01522

Calculation of the FCR Rates for Sep-2016

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Apr-16	May-16	Jun-16	Jul-16	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$23,358,395	\$26,821,520	\$34,691,290	\$44,734,478	\$129,605,683
Account 518 - Nuclear Fuel	\$10,504,918	\$10,864,217	\$10,468,675	\$10,538,374	\$42,376,184
Account 555 - Purchased Power ¹	\$42,633,423	\$37,639,621	\$35,952,045	\$38,696,166	\$154,921,255
C-BED Wind & Solar PPA Costs	(\$5,632,183)	(\$3,826,145)	(\$3,598,502)	(\$2,885,868)	(\$15,942,697)
C-BED Wind PPA Curtailment Payment	(\$203,950)	(\$175,684)	(\$138,118)	\$15,322	(\$502,430)
Replacement Energy Costs	\$2,275,487	\$1,455,875	\$1,391,290	\$1,245,578	\$6,368,230
Account 555 - With PPAs Adjustment ²	(\$3,560,646)	(\$2,545,953)	(\$2,345,330)	(\$1,624,968)	(\$10,076,897)
MISO Day 2 Charges	\$1,644,428	\$1,245,289	\$6,076,958	\$12,432,051	\$21,398,726
MISO Day 2 - Schedule 24	(\$87,127)	(\$95,620)	(\$71,709)	(\$116,247)	(\$370,703)
MISO - ASM Charges	\$1,860,918	\$1,857,686	\$2,614,958	\$2,238,393	\$8,571,956
Account 555 - Total MISO Charges	\$3,418,219	\$3,007,355	\$8,620,207	\$14,554,197	\$29,599,979
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$76,354,309	\$75,786,760	\$87,386,887	\$106,898,247	\$346,426,204
Less Fuel Cost of InterSystem Sales	(\$9,933,338)	(\$4,502,564)	(\$4,709,292)	(\$10,411,870)	(\$29,557,064)
Net System Costs	\$66,420,971	\$71,284,196	\$82,677,596	\$96,486,377	\$316,869,139
System MWh Sales					
Total NSP System Retail	2,932,612	3,094,585	3,454,370	3,681,052	13,162,619
Non-Gen Muni's/Load Pattern	-	-	-	-	-
Total NSP System MWh Sales	2,932,612	3,094,585	3,454,370	3,681,052	13,162,619
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System					
System (Including All PPAs)	2.386¢	2.386¢	2.461¢	2.665¢	2.484¢
System (Adjusted for 17 PPAs Exclusion)	2.265¢	2.304¢	2.393¢	2.621¢	2.407¢
Class Ratio/TOD Ratio					
(i) Residential	0.9969	0.9969	0.9969	0.9969	0.9969
(ii) C & I Non-Demand	1.0318	1.0318	1.0318	1.0318	1.0318
(iii) C & I Demand Non-TOD	1.0184	1.0184	1.0184	1.0184	1.0184
(iv) C & I Demand TOD On-Peak	1.2798	1.2798	1.2798	1.2798	1.2798
(v) C & I Demand TOD Off-Peak	0.7954	0.7954	0.7954	0.7954	0.7954
(vi) Outdoor Lighting	0.7341	0.7341	0.7341	0.7341	0.7341
North Dakota Fuel Cost Factor (FCF)					
			Avg Unit Cost	FCF Ratio	4 Month Average
(i) Residential			2.407¢	0.9969	2.400¢
(ii) C & I Non-Demand			2.407¢	1.0318	2.484¢
(iii) C & I Demand Non-TOD			2.407¢	1.0184	2.451¢
(iv) C & I Demand TOD On-Peak			2.407¢	1.2798	3.080¢
(v) C & I Demand TOD Off-Peak			2.407¢	0.7954	1.915¢
(vi) Outdoor Lighting			2.407¢	0.7341	1.767¢
North Dakota Retail MWh Sales					
(i) Residential	56,587	47,829	52,879	56,285	213,580
(ii) C & I Non-Demand	8,714	7,835	8,039	8,086	32,674
(iii) C & I Demand Non-TOD	55,348	61,128	62,771	63,052	242,299
(iv) C & I Demand TOD On-Peak	14,566	19,206	19,558	19,250	72,580
(v) C & I Demand TOD Off-Peak	23,540	29,090	31,752	31,439	115,821
(vi) Outdoor Lighting	1,497	1,257	1,143	1,024	4,921
(vii) Total	160,252	166,345	176,142	179,136	681,875
Sep-2016 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (May-16 Balance of Unrecovered Expenses)					Total
					May-16
					(\$2,196,001)

¹ Excludes demand-related expenses

² Excludes 17 PPAs pursuant to March 9, 2016 Order Approving Settlement

Calculation of the FCR Rates for Sep-2016

Prior Expenses Recovered in Jul-2016 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	56,285	(\$100,918)
(ii) C & I Non-Demand	8,086	(\$14,450)
(iii) C & I Demand Non-TOD	63,052	(\$111,782)
(iv) C & I Demand TOD On-Peak	19,250	(\$44,313)
(v) C & I Demand TOD Off-Peak	31,439	(\$45,197)
(vi) Outdoor Lighting	1,024	(\$1,032)
(vii) Total	179,136	(\$317,692)

Actual Cost Should Have Been Recovered in Jul-16				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.621¢	0.000¢	179,136	\$4,695,155

Cost Recovered in Jul-16 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	56,285	\$1,612,016
(ii) C & I Non-Demand	8,086	\$238,388
(iii) C & I Demand Non-TOD	63,052	\$1,840,066
(iv) C & I Demand TOD On-Peak	19,250	\$676,866
(v) C & I Demand TOD Off-Peak	31,439	\$755,120
(vi) Outdoor Lighting	1,024	\$23,257
(vii) Total	179,136	\$5,145,713

Total Balance of Unrecovered Expenses (Sep-16 Balance of Unrecovered Expenses)	
Sep-2016 Recovery Provision	(\$2,271,166)
4 Month ND Retail Total MWh Sales	681,875
Sep-2016 Recovery Provision per KWH	-0.333¢

Sep-2016 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9969	-0.333¢	-0.332¢
(ii) C & I Non-Demand	1.0318	-0.333¢	-0.344¢
(iii) C & I Demand Non-TOD	1.0184	-0.333¢	-0.339¢
(iv) C & I Demand TOD On-Peak	1.2798	-0.333¢	-0.426¢
(v) C & I Demand TOD Off-Peak	0.7954	-0.333¢	-0.265¢
(vi) Outdoor Lighting	0.7341	-0.333¢	-0.245¢

Sep-2016 Factors		Total
(i) Residential		2.067¢
(ii) C & I Non-Demand		2.140¢
(iii) C & I Demand Non-TOD		2.112¢
(iv) C & I Demand TOD On-Peak		2.654¢
(v) C & I Demand TOD Off-Peak		1.650¢
(vi) Outdoor Lighting		1.522¢

		System	Intersystem	Retail
July 2016 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 14,751,852.20	\$ 7,641,678.27	\$ 22,393,530.47
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,637,572.44	\$ -	\$ 2,637,572.44
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ (4,115.25)	\$ -	\$ (4,115.25)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (13,021,473.40)	\$ -	\$ (13,021,473.40)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,802,574.91	\$ -	\$ 1,802,574.91
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	\$ 4,115.25	\$ -	\$ 4,115.25
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 a	Real-Time Asset Energy Amount - Energy Component (1)	\$ 213,728.78	\$ 1,789,068.86	\$ 2,002,797.64
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 56,601.47	\$ -	\$ 56,601.47
14	Real-Time Distribution of Losses Amount	\$ (2,855,796.74)	\$ -	\$ (2,855,796.74)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (905,844.50)	\$ -	\$ (905,844.50)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ (87,310.49)	\$ -	\$ (87,310.49)
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ 16,457.34	\$ -	\$ 16,457.34
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 6,693,773.94	\$ -	\$ 6,693,773.94
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ (12,653.88)	\$ -	\$ (12,653.88)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 1,681,442.69	\$ -	\$ 1,681,442.69
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	\$ 12,653.88	\$ -	\$ 12,653.88
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	\$ 30,079.22	\$ -	\$ 30,079.22
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)	\$ 40,600.70	\$ -	\$ 40,600.70
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (10,118,461.00)	\$ -	\$ (10,118,461.00)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (144,058.98)	\$ -	\$ (144,058.98)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (516,778.16)	\$ -	\$ (516,778.16)
37	Financial Transmission Guarantee Uplift Amount	\$ 535,488.44	\$ -	\$ 535,488.44
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 1,335,881.88	\$ -	\$ 1,335,881.88
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 88,413.54	\$ -	\$ 88,413.54
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (26,345.38)	\$ 10,205.57	\$ (16,139.81)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 315,992.23	\$ -	\$ 315,992.23
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ (364,259.72)	\$ 218,481.50	\$ (145,778.22)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (225,785.91)	\$ 6,073.15	\$ (219,712.76)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 580,690.42	\$ (23,136.95)	\$ 557,553.47
19	Real-Time Market Administration Amount	\$ 45,672.58	\$ (4,832.27)	\$ 40,840.31
29	Financial Transmission Rights Market Administration Amount	\$ 40,601.76	\$ -	\$ 40,601.76
33	Day-Ahead Schedule 24 Allocation Amount	\$ 91,294.75	\$ (3,630.43)	\$ 87,664.32
34	Real-Time Schedule 24 Allocation Amount	\$ (117,571.26)	\$ 146,154.36	\$ 28,583.10
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	\$ 81,280.91	\$ 56,150.21	\$ 137,431.12
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 2,398,660.25	\$ -	\$ 2,398,660.25
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (2,416,523.31)	\$ (48,887.37)	\$ (2,465,410.68)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (72,008.18)	\$ -	\$ (72,008.18)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 78,282.87	\$ -	\$ 78,282.87
TOTAL MISO CHARGES		\$ 2,644,726.29	\$ 9,787,324.90	\$ 12,432,051.19
SCHEDULE 24 (FOR RETAIL)				\$ 116,247.42
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 12,315,803.77

Summary of Wholesale Margins and REC Credits for September 2016 Fuel Cost Charge

North Dakota True-up Detail for September 2016 FCC					
	Fuel Recovery True Up	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Sharing Refund	Total
April Unrecovered Expenses	-\$2,138,302				-\$2,138,302
Less: May Recovery of April Unrecovered	\$317,692				\$317,692
Actual July Recovery	-\$4,119,972				-\$4,119,972
Less: Expected June Recovery	\$4,695,155				\$4,695,155
Asset Based Margin Sharing		-\$371,823			-\$371,823
Non Asset Based Margin Sharing			-\$14,610		-\$14,610
REC Sharing				-\$639,306	-\$639,306
Miscellaneous Adjustment					\$0
Total Under/(Over) Recovered Expenses	-\$1,245,427	-\$371,823	-\$14,610	-\$639,306	-\$2,271,166
August Four Month Average MWh Sales	681,875	681,875	681,875	681,875	681,875
True-up Factor per KWH (cents/kWh)	(0.183)	(0.055)	(0.002)	(0.094)	(0.333)
Percent of Total	55%	16%	1%	28%	100%

Northern States Power Company
Electric Operations - State of North Dakota

Derivation of Replacement Cost for the Disallowed Purchased Power Agreements (PPAs)
 For Actual Month of July 2016 (September FCC)

	PPAs Included	PPAs Excluded	Difference	Adjustment to ND Fuel Cost
PPAs Replacement Cost				
System Fuel Costs	\$98,111,345	\$98,111,345		
Less: PPAs Exclusion				
15 C-BED Wind PPAs	\$0	(\$2,835,766)		
2 Solar PPAs	\$0	(\$50,103)		
Wind Curtailment Payments	\$0	\$15,322		
Total Exclusion	<u>\$0</u>	<u>(\$2,870,547)</u>		
Net System Costs	\$98,111,345	\$95,240,798		
Billing Month System Sales	3681052	3681052		
Billing Month North Dakota Sales	179136	179136		
North Dakota Percentage	4.8664%	4.8664%		
Affected PPAs Volume (System)	47523	47523		
Affected PPAs Volume (North Dakota's Share)	2313	2313		
Billing Month System Sales	3681052	3681052		
Less: Affected PPAs Volume		<u>-47523</u>		
Net System Billing Month Sales	<u>3681052</u>	<u>3633529</u>		
Billing Month North Dakota Sales	179136	179136		
Less: Affected PPAs Volume		<u>-2313</u>		
Net North Dakota Billing Month Sales	<u>179136</u>	<u>176823</u>		
System Fuel Costs	\$98,111,345	\$95,240,798		
North Dakota Percentage	4.8664%	4.8664%		
North Dakota Fuel Cost	\$4,774,490	\$4,634,798	(\$139,692)	
Affected PPAs Volume (System)		47523		
North Dakota Average System Cost (\$/MWh)		\$26.21		
North Dakota Replacement Cost	\$0	\$1,245,656		
Affected PPAs Volume (North Dakota's Share)		2313		
North Dakota Average System Cost (\$/MWh)		\$26.21		
North Dakota Replacement Cost	\$0	\$60,628	\$60,628	
Adjusted PPA Cost Added to ND FCA Calculation				(\$79,064)
Fuel Cost Impact Due to PPA Exclusion				(\$0.00045)
Residential Fuel Cost Charge Impact (750 kWh Use)				(\$0.34)

COMPARISON OF ENERGY AND COSTS TO THE PREVIOUS MONTH
 Prior Month Compared to Current Month FCA

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Aug-16	Sep-16	Difference	Percent Change	FCA Application Aug-16	Sep-16	Difference
** COSTS (Millions) **							
1 Fossil	\$112.2	\$129.6	\$17.4	15.5%	35.2%	37.4%	2.2%
2 Nuclear	\$42.5	\$42.4	(\$0.2)	-0.4%	13.4%	12.2%	-1.2%
3 Purchases	\$143.4	\$144.8	\$1.4	1.0%	45.0%	41.8%	-3.2%
MISO related Purchases	\$20.5	\$29.6	\$9.1	44.7%	6.4%	8.5%	2.1%
4 Total System Costs	318.6	346.4	\$27.8	8.7%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$25.7	\$29.6	\$3.9	15.0%	8.1%	8.5%	0.4%
6 Net System Costs	\$292.9	\$316.9	\$24.0	8.2%	91.9%	91.5%	-0.4%
7							
8 ** GWH OUTPUT **							
9 Fossil	3,104	3,549	445	14.3%	32.0%	32.7%	0.7%
10 Nuclear	5,039	5,009	(30)	-0.6%	52.0%	46.2%	-5.8%
11 Purchases	3,879	4,169	290	7.5%	40.1%	38.5%	-1.6%
12 Hydro & Other	3,329	3,406	77	2.3%	34.4%	31.4%	-3.0%
13 Net Interchange	(5,666)	(5,296)	370	6.5%	-58.5%	-48.9%	9.6%
14 Total Output	9,685	10,837	1,152	11.9%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,559	1,547	(12)	-0.7%	16.1%	14.3%	-1.8%
16 Native Requirement	8,126	9,290	1,163	14.3%	83.9%	85.7%	1.8%
17							
18 ** COST per KWH OUTPUT (¢) **							
19 Fossil	3.615	3.652	0.037	1.0%			
20 Nuclear	0.844	0.846	0.002	0.2%			
21 Purchases	3.697	3.474	-0.223	-6.0%			
22 Total System Costs	3.289	3.197	-0.093	-2.8%			
23 Intersystem Sales	1.649	1.910	0.261	15.8%			
24 Net System Costs	3.604	3.411	-0.193	-5.4%			
25							
26							
27 TOTAL SYSTEM GWH SALES	12,968	13,163	195	1.5%			
28							
29 COST per KWH SALES (¢)	2.258	2.407	0.149	6.6%			
30							
31 RECOVERY PROV (¢ / KWH) - SYS	0.143	-0.333	-0.476				
(i) Residential	0.143	-0.332	-0.475				
(ii) C & I Non-Demand	0.148	-0.344	-0.492				
(iii) C & I Demand Non-TOD	0.146	-0.339	-0.485				
(iv) C & I Demand TOD On-Peak	0.183	-0.426	-0.610				
(v) C & I Demand TOD Off-Peak	0.114	-0.265	-0.379				
(vi) Outdoor Lighting	0.105	-0.245	-0.350				
32 REFUND	0.000	0.000	0.000				
(i) Residential	0.000	0.000					
(ii) C & I Non-Demand	0.000	0.000					
(iii) C & I Demand Non-TOD	0.000	0.000					
(iv) C & I Demand TOD On-Peak	0.000	0.000					
(v) C & I Demand TOD Off-Peak	0.000	0.000					
(vi) Outdoor Lighting	0.000	0.000					
33 SYSTEM FCC IMPACT (¢ / KWH)	2.401	2.074	-0.327	-13.6%			
(i) Residential	2.394	2.067	-0.327				
(ii) C & I Non-Demand	2.478	2.140					
(iii) C & I Demand Non-TOD	2.446	2.112					
(iv) C & I Demand TOD On-Peak	3.073	2.654					
(v) C & I Demand TOD Off-Peak	1.910	1.650					
(vi) Outdoor Lighting	1.763	1.522					

Residential BILL IMPACT (\$'s)

Calculations:

[4] = [1]+[2]+[3]
 [6] = [4] - [5]
 [14] = [9]+..+[13]
 [16] = [14] - [15]
 [19] = [1] / [9]
 [20] = [2] / [10]

[21] = [3] / [11]
 [22] = [4] / [14]
 [23] = [5] / [15]
 [24] = [6] / [16]
 [29] = [6] / [27]
 [33] = [29]+[31]

kWh	Change from Previous Month
100	(\$0.33)
250	(\$0.82)
500	(\$1.63)
750	(\$2.45)
1,000	(\$3.27)

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>	
	Aug-16	Sep-16
** GWH OUTPUT **		
Thermal	2,174,167	2,352,813
Disper gen	(59)	(75)
<u>Hydro plus Wind</u>	1,155,138	1,053,094
Hydro and Other	3,329,246	3,405,832
Rounded to nearest thousand:	3,329	3,406
<u>Sales</u>		
Non Gen Munic Total	0	0
Load Pattern Power	0	0
<u>Resale & Interchange (Intersystem)</u>	1,558,550,000	1,547,262,000
Rounded to nearest million:	1558.55	1547.262