



414 Nicollet Mall
Minneapolis, Minnesota 55401

— Via Electronic Filing —

May 31, 2016

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

Re: June 2016 Fuel Cost Charge

Dear Mr. Nitschke:

Northern States Power Company, doing business as Xcel Energy and operating in North Dakota, hereby submits its electric fuel cost charge (FCC) for June 2016.

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

June 2016	Fuel Cost Charge (\$/kWh)
Residential	0.02332
C & I Non-Demand	0.02414
C & I Demand	0.02383
C & I Demand Time of Day On-Peak	0.02994
C & I Demand Time of Day Off-Peak	0.01861
Outdoor Lighting	0.01717

MISO CHARGES IMPLEMENTATION

MISO Day 2 Charges

This filing includes our reporting of the Midcontinent Independent System Operator, Inc. (MISO) charges under the Day 2 Market. Pursuant to the Commission's April 6, 2005 Order in Case No. PU-05-147 and the Order in Case No. PU-07-776, Xcel Energy is authorized to recover MISO Day 2 costs. The current FCC also reflected the MISO Day 2 charge types including three Auction Revenue Rights (ARR) and three Financial Transmission Rights (FTR) charge types.¹ Consistent with this Order and the required "net" accounting of MISO Day 2 costs and revenues, we have included in the June 2016 FCC the net MISO Day 2 costs for April 2016 as recorded in Account 555. The MISO Day 2 cost recovery included in this June 2016 FCC is \$1,557,301, 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 ASM charge types are included in the Fuel Cost Rider, 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 include in the June 2016 FCC the net MISO ASM costs for April 2016 as recorded in Account 555. The MISO ASM cost recovery included in the FCC is \$1,860,918, which is the net of many items. The detailed records are contained in Attachment 2, page 2.

REFUNDS

Asset and Non-Asset Based Margins Sharing Refund

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 100 percent of wholesale asset based margins to North Dakota customers. The Asset Based Margin credit of \$20,202 has been included as a credit to the June 2016 Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. Starting from February 2011, the prior year retail share of the Non-Asset Based Margins has been 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 the 2015 Non-Asset Based Margin credit is \$50,462 and this credit amount has been fully

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

credited to customers Attachment 3, page 2 contains the derivation of this refund amount.

Sales of Renewable Energy Credits

Pursuant to the Commission Order dated September 9, 2010 in Case No. PU-10-19, the Company is authorized to sell excess Renewable Energy Credits (RECs) allocable to our North Dakota jurisdiction and credit 90 percent of the net proceeds back to customers through the Fuel Cost Rider (FCR). Under the February 26, 2014 Settlement, instead of 90 percent, 100 percent of the North Dakota state jurisdictional share of revenue generated by the sale of RECs is credited to customers. (See Attachment 3, page 3). There were no REC sales during the current reporting period.

PURCHASED POWER AGREEMENT (PPA) COST RECOVERY REVIEW

Pursuant to the Commission's February 26, 2014 Order Adopting Settlement (Case No. PU-12-813) the following procedural changes reflected in 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 the Fuel Cost Charges. 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 the June 2016 FCR reporting month 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

Pursuant to the Commission's March 9, 2016 Order Accepting Settlement (Case Nos. PU-12-813, *et. al.*) the costs and volumes of fifteen Community-Based Energy Development (C-BED) and two small solar PPAs are to be excluded from the calculation of the Company's monthly FCR charge. This t monthly report reflects the adjustments addressed in the Commission's Order. Please see Attachment 1, Page 5 for the details. The excluded C-BED and solar PPAs are as follows:

Community Based Energy Development (CBED) 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 is the calculation of the June 2016 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 at 701-241-8632.

Sincerely,

/ s /

Amy S. Fredregill
RESOURCE PLANNING AND STRATEGY MANAGER

Enclosures
CC: David H. Sederquist

Northern States Power Company
 Electric Operations - State of North Dakota
 Derivation of Adjustment for Fuel Clause Rider
 Current Period Cost of Energy for Jun-2016

Jun-2016 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02333	\$0.00018	-\$0.00012	\$0.02340
Residential	\$0.02326	\$0.00018	-\$0.00012	\$0.02332
C & I Non-Demand	\$0.02407	\$0.00019	-\$0.00012	\$0.02414
C & I Demand Non-TOD	\$0.02376	\$0.00019	-\$0.00012	\$0.02383
C & I Demand TOD On-Peak	\$0.02986	\$0.00023	-\$0.00015	\$0.02994
C & I Demand TOD Off-Peak	\$0.01856	\$0.00014	-\$0.00009	\$0.01861
Outdoor Lighting	\$0.01713	\$0.00013	-\$0.00009	\$0.01717
Residential				
Residential Service	\$ 0.02326	\$ 0.00018	\$ (0.00012)	\$ 0.02332
Residential TOD	\$ 0.02326	\$ 0.00018	\$ (0.00012)	\$ 0.02332
Residential - Underground	\$ 0.02326	\$ 0.00018	\$ (0.00012)	\$ 0.02332
Residential TOD - Underground	\$ 0.02326	\$ 0.00018	\$ (0.00012)	\$ 0.02332
Energy Control - (Non-Demand)	\$ 0.02326	\$ 0.00018	\$ (0.00012)	\$ 0.02332
Limit Off Peak	\$ 0.02326	\$ 0.00018	\$ (0.00012)	\$ 0.02332
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02407	\$ 0.00019	\$ (0.00012)	\$ 0.02414
Limit Off Peak	\$ 0.02407	\$ 0.00019	\$ (0.00012)	\$ 0.02414
Small General Service	\$ 0.02407	\$ 0.00019	\$ (0.00012)	\$ 0.02414
Small General TOD - Metered	\$ 0.02407	\$ 0.00019	\$ (0.00012)	\$ 0.02414
Small General TOD - Unmetered	\$ 0.02407	\$ 0.00019	\$ (0.00012)	\$ 0.02414
Fire and Civil Defense Siren	\$ 0.02407	\$ 0.00019	\$ (0.00012)	\$ 0.02414
Direct Current (Closed)	\$ 0.02407	\$ 0.00019	\$ (0.00012)	\$ 0.02414
C & I Demand				
General Service	\$ 0.02376	\$ 0.00019	\$ (0.00012)	\$ 0.02383
General TOD - On Peak	\$ 0.02986	\$ 0.00023	\$ (0.00015)	\$ 0.02994
General TOD - Off Peak	\$ 0.01856	\$ 0.00014	\$ (0.00009)	\$ 0.01861
Peak Controlled (Closed)	\$ 0.02376	\$ 0.00019	\$ (0.00012)	\$ 0.02383
Peak Controlled TOD (Closed) - On Peak	\$ 0.02986	\$ 0.00023	\$ (0.00015)	\$ 0.02994
Peak Controlled TOD (Closed) - Off Peak	\$ 0.01856	\$ 0.00014	\$ (0.00009)	\$ 0.01861
Peak Controlled Tiered	\$ 0.02376	\$ 0.00019	\$ (0.00012)	\$ 0.02383
Peak Controlled Tiered TOD - On Peak	\$ 0.02986	\$ 0.00023	\$ (0.00015)	\$ 0.02994
Peak Controlled Tiered TOD - Off Peak	\$ 0.01856	\$ 0.00014	\$ (0.00009)	\$ 0.01861
Energy Controlled (Closed)	\$ 0.02376	\$ 0.00019	\$ (0.00012)	\$ 0.02383
Tier 1 Energy Controlled Rider	\$ 0.02376	\$ 0.00019	\$ (0.00012)	\$ 0.02383
Real Time Pricing - Firm - On Peak	\$ 0.02986	\$ 0.00023	\$ (0.00015)	\$ 0.02994
Real Time Pricing - Firm - Off Peak	\$ 0.01856	\$ 0.00014	\$ (0.00009)	\$ 0.01861
Real Time Pricing - Controllable - On Peak	\$ 0.02986	\$ 0.00023	\$ (0.00015)	\$ 0.02994
Real Time Pricing - Controllable - Off Peak	\$ 0.01856	\$ 0.00014	\$ (0.00009)	\$ 0.01861
Small Municipal Pumping	\$ 0.02376	\$ 0.00019	\$ (0.00012)	\$ 0.02383
Municipal Pumping	\$ 0.02376	\$ 0.00019	\$ (0.00012)	\$ 0.02383
Excess Energy - St. Anthony Falls	\$ 0.02376	\$ 0.00019	\$ (0.00012)	\$ 0.02383
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01713	\$ 0.00013	\$ (0.00009)	\$ 0.01717
Street Lighting System	\$ 0.01713	\$ 0.00013	\$ (0.00009)	\$ 0.01717
Street Lighting Energy	\$ 0.01713	\$ 0.00013	\$ (0.00009)	\$ 0.01717
Street Lighting Energy - Metered	\$ 0.01713	\$ 0.00013	\$ (0.00009)	\$ 0.01717
Street Lighting Energy (Closed)	\$ 0.01713	\$ 0.00013	\$ (0.00009)	\$ 0.01717
Street Lighting - City of St. Paul	\$ 0.01713	\$ 0.00013	\$ (0.00009)	\$ 0.01717

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Jan-16	Feb-16	Mar-16	Apr-16	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$45,029,964	\$34,725,752	\$27,324,375	\$23,358,395	\$130,438,486
Account 518 - Nuclear Fuel	\$7,094,043	\$7,279,561	\$10,696,586	\$10,504,918	\$35,575,108
Account 555 - Purchased Power ¹	\$38,195,938	\$38,089,568	\$38,591,082	\$42,633,423	\$157,510,011
C-BED Wind & Solar PPA Costs	\$0	\$0	(\$4,778,197)	(\$5,632,183)	(\$10,410,380)
C-BED Wind PPA Curtailment Payment	\$0	\$0	(\$221,503)	(\$203,950)	(\$425,453)
Replacement Energy Costs	\$0	\$0	\$2,038,451	\$2,275,487	\$4,313,938
Account 555 - With PPAs Adjustment ²	\$0	\$0	(\$2,961,249)	(\$3,560,646)	(\$6,521,895)
MISO Day 2 Charges	\$5,071,466	\$6,341,748	\$4,691,629	\$1,644,428	\$17,749,271
MISO Day 2 - Schedule 24	(\$79,278)	(\$97,706)	(\$82,385)	(\$87,127)	(\$346,495)
MISO - ASM Charges	\$2,751,558	\$1,132,280	\$797,506	\$1,860,918	\$6,542,261
Account 555 - Total MISO Charges	\$7,743,746	\$7,376,322	\$5,406,751	\$3,418,219	\$23,945,038
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$98,063,692	\$87,471,203	\$79,057,544	\$76,354,309	\$340,946,748
Less Fuel Cost of InterSystem Sales	(\$7,335,842)	(\$6,168,145)	(\$6,558,736)	(\$9,933,338)	(\$29,996,060)
Net System Costs	\$90,727,850	\$81,303,058	\$72,498,808	\$66,420,971	\$310,950,688
System MWh Sales					
Total NSP System Retail	3,530,598	3,376,930	3,486,859	2,932,612	13,326,999
Non-Gen Muni's/Load Pattern	-	-	-	-	-
Total NSP System MWh Sales	3,530,598	3,376,930	3,486,859	2,932,612	13,326,999
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System					
System (Including All PPAs)	2.570¢	2.408¢	2.164¢	2.386¢	2.382¢
System (Adjusted for 17 PPAs Exclusion)	2.570¢	2.408¢	2.079¢	2.265¢	2.333¢
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			2.333¢	0.9969	2.326¢
(ii) C & I Non-Demand			2.333¢	1.0318	2.407¢
(iii) C & I Demand Non-TOD			2.333¢	1.0184	2.376¢
(iv) C & I Demand TOD On-Peak			2.333¢	1.2798	2.986¢
(v) C & I Demand TOD Off-Peak			2.333¢	0.7954	1.856¢
(vi) Outdoor Lighting			2.333¢	0.7341	1.713¢
North Dakota Retail MWh Sales					
(i) Residential	87,368	79,199	73,616	56,587	296,770
(ii) C & I Non-Demand	11,753	11,058	11,328	8,714	42,853
(iii) C & I Demand Non-TOD	66,866	64,747	73,347	55,348	260,308
(iv) C & I Demand TOD On-Peak	15,332	17,746	18,502	14,566	66,146
(v) C & I Demand TOD Off-Peak	29,416	28,781	28,824	23,540	110,561
(vi) Outdoor Lighting	2,093	1,956	1,703	1,497	7,249
(vii) Total	212,828	203,487	207,320	160,252	783,887
Jun-2016 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Feb-16 Balance of Unrecovered Expenses)					Total
					Feb-16
					(\$230,880)

¹ Excludes demand-related expenses

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

Prior Expenses Recovered in Apr-2016 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	56,587	(\$52,599)
(ii) C & I Non-Demand	8,714	(\$8,553)
(iii) C & I Demand Non-TOD	55,348	(\$52,776)
(iv) C & I Demand TOD On-Peak	14,566	(\$17,614)
(v) C & I Demand TOD Off-Peak	23,540	(\$17,825)
(vi) Outdoor Lighting	1,497	(\$1,331)
(vii) Total	160,252	(\$150,698)

Actual Cost Should Have Been Recovered in Apr-16				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.265¢	0.000¢	160,252	\$3,629,708

Cost Recovered in Apr-16 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	56,587	\$1,198,395
(ii) C & I Non-Demand	8,714	\$192,476
(iii) C & I Demand Non-TOD	55,348	\$1,203,280
(iv) C & I Demand TOD On-Peak	14,566	\$415,232
(v) C & I Demand TOD Off-Peak	23,540	\$375,797
(vi) Outdoor Lighting	1,497	\$21,552
(vii) Total	160,252	\$3,406,732

Total Balance of Unrecovered Expenses (Jun-16 Balance of Unrecovered Expenses)	
Jun-2016 Recovery Provision	\$142,794
4 Month ND Retail Total MWh Sales	783,887
Jun-2016 Recovery Provision per KWH	0.018¢

Jun-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	0.018¢	0.018¢
(ii) C & I Non-Demand	1.0318	0.018¢	0.019¢
(iii) C & I Demand Non-TOD	1.0184	0.018¢	0.019¢
(iv) C & I Demand TOD On-Peak	1.2798	0.018¢	0.023¢
(v) C & I Demand TOD Off-Peak	0.7954	0.018¢	0.014¢
(vi) Outdoor Lighting	0.7341	0.018¢	0.013¢

Refunds/Additional Charges				
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Refund	Total
Refund/Special Charge Amount	(\$20,202)	\$0	\$0	(\$20,202)
(i) Residential	-0.012¢	0.000¢	0.000¢	-0.012¢
(ii) C & I Non-Demand	-0.012¢	0.000¢	0.000¢	-0.012¢
(iii) C & I Demand Non-TOD	-0.012¢	0.000¢	0.000¢	-0.012¢
(iv) C & I Demand TOD On-Peak	-0.015¢	0.000¢	0.000¢	-0.015¢
(v) C & I Demand TOD Off-Peak	-0.009¢	0.000¢	0.000¢	-0.009¢
(vi) Outdoor Lighting	-0.009¢	0.000¢	0.000¢	-0.009¢

Jun-2016 Factors	
	Total
(i) Residential	2.332¢
(ii) C & I Non-Demand	2.414¢
(iii) C & I Demand Non-TOD	2.383¢
(iv) C & I Demand TOD On-Peak	2.994¢
(v) C & I Demand TOD Off-Peak	1.861¢
(vi) Outdoor Lighting	1.717¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	May-16	Jun-16	Differ- ence	Percent Change	FCA Application May-16	Jun-16	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$144.8	\$130.4	(\$14.4)	-9.9%	40.7%	38.3%	-2.4%
2 Nuclear	\$33.0	\$35.6	\$2.6	7.7%	9.3%	10.4%	1.1%
3 Purchases	\$150.4	\$151.0	\$0.6	0.4%	42.3%	44.3%	2.0%
MISO related Purchases	\$27.2	\$23.9	(\$3.3)	-12.0%	7.7%	7.0%	-0.7%
4 Total System Costs	355.4	340.9	(\$14.5)	-4.1%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$29.7	\$30.0	\$0.3	1.0%	8.4%	8.8%	0.4%
6 Net System Costs	\$325.7	\$311.0	(\$14.7)	-4.5%	91.6%	91.2%	-0.4%
7							
** GWH OUTPUT **							
9 Fossil	4,275	3,730	(545)	-12.7%	35.7%	39.2%	3.5%
10 Nuclear	4,057	4,344	287	7.1%	33.9%	45.6%	11.7%
11 Purchases	3,815	3,822	7	0.2%	31.9%	40.1%	8.2%
12 Hydro & Other	3,431	3,349	(82)	-2.4%	28.7%	35.2%	6.5%
13 Net Interchange	(3,603)	(5,721)	(2,118)	-58.8%	-30.1%	-60.1%	-30.0%
14 Total Output	11,975	9,524	(2,451)	-20.5%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,792	1,798	5	0.3%	15.0%	18.9%	3.9%
16 Native Requirement	10,183	7,726	(2,456)	-24.1%	85.0%	81.1%	-3.9%
17							
** COST per KWH OUTPUT (¢) **							
19 Fossil	3.387	3.497	0.110	3.2%			
20 Nuclear	0.814	0.819	0.005	0.6%			
21 Purchases	3.941	3.951	0.009	0.2%			
22 Total System Costs	2.968	3.580	0.612	20.6%			
23 Intersystem Sales	1.658	1.669	0.011	0.7%			
24 Net System Costs	3.199	4.024	0.826	25.8%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,842	13,327	(515)	-3.7%			
28							
29 COST per KWH SALES (¢)	2.353	2.333	-0.020	-0.8%			
30							
31 RECOVERY PROV (¢ / KWH) - SYS	-0.248	0.018	0.266				
(i) Residential	-0.247	0.018	0.265				
(ii) C & I Non-Demand	-0.255	0.019	0.274				
(iii) C & I Demand Non-TOD	-0.252	0.019	0.271				
(iv) C & I Demand TOD On-Peak	-0.317	0.023	0.340				
(v) C & I Demand TOD Off-Peak	-0.197	0.014	0.211				
(vi) Outdoor Lighting	-0.182	0.013	0.195				
32 REFUND	-0.652	-0.652	0.000				
(i) Residential	-0.654	-0.012					
(ii) C & I Non-Demand	-0.670	-0.012					
(iii) C & I Demand Non-TOD	-0.663	-0.012					
(iv) C & I Demand TOD On-Peak	-0.840	-0.015					
(v) C & I Demand TOD Off-Peak	-0.514	-0.009					
(vi) Outdoor Lighting	-0.485	-0.009					
33 SYSTEM FCC IMPACT (¢ / KWH)	1.453	1.699	0.246	16.9%			
(i) Residential	1.450	2.332	0.882				
(ii) C & I Non-Demand	1.501	2.414					
(iii) C & I Demand Non-TOD	1.481	2.383					
(iv) C & I Demand TOD On-Peak	1.861	2.994					
(v) C & I Demand TOD Off-Peak	1.157	1.861					
(vi) Outdoor Lighting	1.068	1.717					

Residential BILL IMPACT (\$'s)

Calculations:

		Change from kWh Previous Month
[4] = [1]+[2]+[3]	[21] = [3] / [11]	
[6] = [4] - [5]	[22] = [4] / [14]	100 \$0.88
[14] = [9]+..+[13]	[23] = [5] / [15]	250 \$2.21
[16] = [14] - [15]	[24] = [6] / [16]	500 \$4.41
[19] = [1] / [9]	[29] = [6] / [27]	750 \$6.62
[20] = [2] / [10]	[33] = [29]+[31]	1,000 \$8.82

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>	
	May-16	Jun-16
** GWH OUTPUT **		
Thermal	2,358,842	2,234,344
Disper gen	(55)	(48)
<u>Hydro plus Wind</u>	1,072,662	1,114,242
Hydro and Other	3,431,449	3,348,538
Rounded to nearest thousand:	3,431	3,349
<u>Sales</u>		
Non Gen Munic Total	0	0
Load Pattern Power	0	0
<u>Resale & Interchange (Intersystem)</u>	1,792,390,000	1,797,540,000
Rounded to nearest million:	1792.39	1797.54

Northern States Power Company
Electric Operations - State of North Dakota

Derivation of Replacement Cost for the Designated Purchased Power Agreements
 For Actual Month of April 2016 (June FCC)

	Without PPAs Exclusion	With PPAs Exclusion	Difference	Adjustment to ND Fuel Cost
PPAs Replacement Cost				
System Fuel Costs	\$69,981,617	\$69,981,617		
Less: PPAs Exclusion				
15 C-BED Wind PPAs	\$0	(\$5,597,248)		
2 Solar PPAs	\$0	(\$34,935)		
Wind Curtailment Payments	\$0	(\$203,950)		
Total Exclusion	\$0	(\$5,836,133)		
Net System Costs	\$69,981,617	\$64,145,484		
Billing Month System Sales	2932612	2932612		
Billing Month North Dakota Sales	160252	160252		
North Dakota Percentage	5.4645%	5.4645%		
Affected PPAs Volume (System)	100463	100463		
Affected PPAs Volume (North Dakota's Share)	5490	5490		
Billing Month System Sales	2932612	2932612		
Less: Affected PPAs Volume	2932612	-100463		
Net System Billing Month Sales	2932612	2832149		
Billing Month North Dakota Sales	160252	160252		
Less: Affected PPAs Volume	160252	-5490		
Net North Dakota Billing Month Sales	160252	154762		
System Fuel Costs	\$69,981,617	\$64,145,484		
North Dakota Percentage	5.4645%	5.4645%		
North Dakota Fuel Cost	\$3,824,145	\$3,505,230	(\$318,915)	
Affected PPAs Volume (System)		100463		
North Dakota Average System Cost (\$/MWh)		\$23.53		
North Dakota Replacement Cost	\$0	\$2,363,894		
Affected PPAs Volume (North Dakota's Share)		5490		
North Dakota Average System Cost (\$/MWh)		\$23.53		
North Dakota Replacement Cost	\$0	\$129,180	\$129,180	
Adjusted PPA Cost Added to ND FCA Calculation				(\$189,735)
Fuel Cost Impact Due to PPA Exclusion				(\$0.00123)
Residential Fuel Cost Charge Impact (750 kWh Use)				(\$0.92)

		System	Intersystem	Retail
April 2016 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ (6,107,897.64)	\$ 7,549,986.95	\$ 1,442,089.31
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,282,266.73	\$ -	\$ 2,282,266.73
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 19.85	\$ -	\$ 19.85
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (5,938,923.06)	\$ -	\$ (5,938,923.06)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 692,322.88	\$ -	\$ 692,322.88
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	\$ (19.85)	\$ -	\$ (19.85)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 a	Real-Time Asset Energy Amount - Energy Component (1)	\$ 570,194.83	\$ 930,664.85	\$ 1,500,859.68
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 3,187.59	\$ -	\$ 3,187.59
14	Real-Time Distribution of Losses Amount	\$ (276,111.47)	\$ -	\$ (276,111.47)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ 31,431.11	\$ -	\$ 31,431.11
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 4,284.51	\$ -	\$ 4,284.51
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (542.05)	\$ -	\$ (542.05)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 1,493,424.76	\$ -	\$ 1,493,424.76
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ (2,538.97)	\$ -	\$ (2,538.97)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 1,085,521.37	\$ -	\$ 1,085,521.37
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	\$ 2,538.97	\$ -	\$ 2,538.97
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	\$ 4,894.87	\$ -	\$ 4,894.87
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)	\$ (1,058.49)	\$ -	\$ (1,058.49)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (894,440.50)	\$ -	\$ (894,440.50)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (66,083.22)	\$ -	\$ (66,083.22)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ (395,567.97)	\$ -	\$ (395,567.97)
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ 356,580.37	\$ -	\$ 356,580.37
37	Financial Transmission Guarantee Uplift Amount	\$ (322,802.23)	\$ -	\$ (322,802.23)
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 44,806.03	\$ -	\$ 44,806.03
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 56,175.16	\$ -	\$ 56,175.16
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (62,704.14)	\$ 17,637.38	\$ (45,066.76)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 173,613.59	\$ -	\$ 173,613.59
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ (33,083.25)	\$ 9,842.50	\$ (23,240.75)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (169,044.68)	\$ 19,777.25	\$ (149,267.43)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 530,857.26	\$ (32,739.33)	\$ 498,117.93
19	Real-Time Market Administration Amount	\$ 36,952.62	\$ (4,878.26)	\$ 32,074.36
29	Financial Transmission Rights Market Administration Amount	\$ 36,000.00	\$ -	\$ 36,000.00
33	Day-Ahead Schedule 24 Allocation Amount	\$ 89,915.02	\$ (5,662.59)	\$ 84,252.43
34	Real-Time Schedule 24 Allocation Amount	\$ (97,618.09)	\$ 100,492.27	\$ 2,874.18
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	\$ 59,612.31	\$ 9,393.60	\$ 69,005.91
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 2,985,759.86	\$ -	\$ 2,985,759.86
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (2,988,827.34)	\$ 38,172.66	\$ (2,950,654.68)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (202,532.65)	\$ -	\$ (202,532.65)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 31,176.35	\$ -	\$ 31,176.35
TOTAL MISO CHARGES		\$ (6,988,259.56)	\$ 8,632,687.28	\$ 1,644,427.72
SCHEDULE 24 (FOR RETAIL)				\$ 87,126.61
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 1,557,301.11

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
April 2016 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (141,162.16)		\$ (141,162.16)
2	Day-Ahead Spinning Reserve Amount	\$ (122,627.01)		\$ (122,627.01)
3	Day-Ahead Supplemental Reserve	\$ (29,752.02)		\$ (29,752.02)
4	Real-Time Regulation Amount	\$ (87,555.60)	\$ 111,207.73	\$ 23,652.13
5	Real-Time Spinning Reserve Amount	\$ (17,828.20)	\$ 72,585.08	\$ 54,756.88
6	Real-Time Supplemental Reserve Amount.	\$ 1,511.51	\$ 139.98	\$ 1,651.49
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ 20,399.46		\$ 20,399.46
7b	Real Time Excessive Energy Congestion			\$ -
7c	Real Time Excessive Energy Loss			\$ -
8a	Real Time Non Excessive Energy Amount	\$ 1,903,327.60		\$ 1,903,327.60
8b	Real Time Non Excessive Energy Congestion	\$ (145,978.81)		\$ (145,978.81)
8c	Real Time Non Excessive Energy Loss	\$ (10,923.96)		\$ (10,923.96)
9	Real Time Net Regulation Adjustment Amount	\$ 20,357.45	\$ (6,606.51)	\$ 13,750.94
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 82,757.89		\$ 82,757.89
11	Real Time Spinning Reserve Cost Distribution	\$ 114,522.54		\$ 114,522.54
12	Real Time Supplemental Reserve Cost Distribution	\$ 35,121.00		\$ 35,121.00
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 89,089.13	\$ (27,667.13)	\$ 61,422.00
14	Real Time Contignecy Reserve Deployment Failure	\$ -	\$ -	\$ -
TOTAL MISO ASM CHARGES		\$ 1,711,258.82	\$ 149,659.15	\$ 1,860,917.97

Northern States Power Company
 Electric Operations - State of North Dakota
 Derivation of Adjustment for Fuel Clause Rider
 Asset Based Margin Sharing

1 Forecast Month	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-16	Feb-16
2 True-up Month	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
3												
4 Monthly Refund	(71,432)	(99,484)	(68,297)	(20,202)								
5												
6 Forecast North Dakota Sales	223,782	182,660	163,931	173,060	173,060	173,060	-	-	-	-	-	-
7												
8 Current Month Refund Factor	(0.032)	(0.054)	(0.042)	(0.012)	-	-	-	-	-	-	-	-
9												
14 Expected Refund	(269,298)	210,125	(288,922)	164,765	(336,923)	(20,202)	-	-	-	-	-	-
15 Actual Refunded	(51,808)	(54,124)	(20,295)	(40,578)								
16 Deviation	(217,490)	264,249	(268,627)		(336,923)	(20,202)	-	-	-	-	-	-
17												
18 True-up Factor	(0.097)	0.145	(0.164)	-	-	-	-	-	-	-	-	-
19												
20 Realized Margin	(0.129)	0.090	(0.206)	(0.012)	-	-	-	-	-	-	-	-
21												
22 Class Ratios												
23 Residential	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969
24 C&I Non-Demand	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318
25 C&I Demand Non-TOD	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184
26 C&I Demand TOD On-Peak	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798
27 C&I Demand TOD Off-Peak	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954
28 Outdoor Lighting	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341
29												
30 Realized Margin Adj for Class Ratios												
31 Residential	(0.129)	0.090	(0.205)	(0.012)	-	-	-	-	-	-	-	-
32 C&I Non-Demand	(0.133)	0.093	(0.212)	(0.012)	-	-	-	-	-	-	-	-
33 C&I Demand Non-TOD	(0.131)	0.092	(0.209)	(0.012)	-	-	-	-	-	-	-	-
34 C&I Demand TOD On-Peak	(0.165)	0.115	(0.263)	(0.015)	-	-	-	-	-	-	-	-
35 C&I Demand TOD Off-Peak	(0.103)	0.072	(0.163)	(0.009)	-	-	-	-	-	-	-	-
36 Outdoor Lighting	(0.095)	0.066	(0.151)	(0.009)	-	-	-	-	-	-	-	-

205,343.17 Beginning with June FCA prior month deviation will be trued up in the Recovery Provision computation.

Northern States Power Company
 Electric Operations - State of North Dakota
 Derivation of Adjustment for Fuel Clause Rider
 Non-Asset Based Margin Sharing

1 Forecast Month	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17
2 True-up Month	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16
3												
4 Monthly Refund	(4,205)	(50,462)	4,205	0	-							
5												
6 Forecast North Dakota Sales	212,098	223,782	182,660	163,931	173,060							
7												
8 Current Month Refund Factor	(0.002)	(0.023)	0.002	-	-	-	-	-	-	-	-	-
13												
14 Expected Refund	(21,268)	(12,776)	(9,259)	(46,243)	5,555	-	-	-	-	-	-	-
15 Actual Refund	(16,214)	(16,995)	(10,609)	(24,084)	(15,401)							
16 Deviation	(5,054)	4,219	1,350	(22,159)		-	-	-	-	-	-	-
17												
18 True-up Factor	(0.002)	0.002	0.001	(0.014)	-	-	-	-	-	-	-	-
19												
20 Realized Margin	(0.004)	(0.021)	0.003	(0.014)	-	-	-	-	-	-	-	-
21												
22 Class Ratios												
23 Residential	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969
24 C&I Non-Demand	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318
25 C&I Demand Non-TOD	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184
26 C&I Demand TOD On-Peak	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798
27 C&I Demand TOD Off-Peak	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954
28 Outdoor Lighting	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341
29												
30 Realized Margin Adj for Class Ratios												
31 Residential	(0.004)	(0.021)	0.003	(0.013)	-	-	-	-	-	-	-	-
32 C&I Non-Demand	(0.005)	(0.021)	0.003	(0.014)	-	-	-	-	-	-	-	-
33 C&I Demand Non-TOD	(0.004)	(0.021)	0.003	(0.014)	-	-	-	-	-	-	-	-
34 C&I Demand TOD On-Peak	(0.006)	(0.026)	0.004	(0.017)	-	-	-	-	-	-	-	-
35 C&I Demand TOD Off-Peak	(0.003)	(0.016)	0.002	(0.011)	-	-	-	-	-	-	-	-
36 Outdoor Lighting	(0.003)	(0.015)	0.002	(0.010)	-	-	-	-	-	-	-	-

20,956

Beginning with June FCA prior month deviation will be trued up in the Recovery Provision computation.

Northern States Power Company
 Electric Operations - State of North Dakota
 Derivation of Adjustment for Fuel Clause Rider
 Sales of Renewable Energy Credits

1 Forecast Month	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-16	Feb-16
2 True-up Month	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
3												
4 Monthly Refund	-	(13,210)	(157,823)									
5												
6 Forecast North Dakota Sales	223,782	182,660	163,931	173,060								
7												
8 Current Month Refund Factor	-	(0.007)	(0.096)	-	-	-	-	-	-	-	-	-
9												
14 Expected Refund	(487,641)	558,449	(478,452)	571,551	-	-	-	-	-	-	-	-
15 Actual Refund	(9,189)	(26,312)	72,004	55,059								
16 Deviation	(478,452)	584,761	(550,456)		-	-	-	-	-	-	-	-
17												
18 True-up Factor	(0.214)	0.320	(0.336)	-	-	-	-	-	-	-	-	-
19												
20 Realized Refund	(0.214)	0.313	(0.432)	-	-	-	-	-	-	-	-	-
21												
22 Class Ratios												
23 Residential	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969
24 C&I Non-Demand	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318
25 C&I Demand Non-TOD	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184
26 C&I Demand TOD On-Peak	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798
27 C&I Demand TOD Off-Peak	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954
28 Outdoor Lighting	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341
29												
30 Realized Margin Adj for Class Ratios												
31 Residential	(0.213)	0.312	(0.431)	-	-	-	-	-	-	-	-	-
32 C&I Non-Demand	(0.221)	0.323	(0.446)	-	-	-	-	-	-	-	-	-
33 C&I Demand Non-TOD	(0.218)	0.319	(0.440)	-	-	-	-	-	-	-	-	-
34 C&I Demand TOD On-Peak	(0.274)	0.400	(0.553)	-	-	-	-	-	-	-	-	-
35 C&I Demand TOD Off-Peak	(0.170)	0.249	(0.344)	-	-	-	-	-	-	-	-	-
36 Outdoor Lighting	(0.157)	0.230	(0.317)	-	-	-	-	-	-	-	-	-

516,492 Beginning with June FCA prior month deviation will be trued up in the Recovery Provision computation.