



— Via Electronic Filing —

January 31, 2017

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

**Re: February 2017 Fuel Cost Rider Rates
Case No. PU-17-12**

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 February 2017.

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

| February 2017 | FCR rate/kWh |
|-------------------------------------|--------------|
| Residential | \$0.02517 |
| C & I Non-Demand | \$0.02605 |
| C & I Demand | \$0.02571 |
| C & I Demand Time of Day (On-Peak) | \$0.03231 |
| C & I Demand Time of Day (Off-Peak) | \$0.02008 |
| Outdoor Lighting | \$0.01853 |

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 February 2017 FCR the net MISO Day 2 costs for December 2016 as recorded in Account 555. The MISO Day 2 cost recovery included in this month’s FCR is \$9,601,016, which is the net of many items. Pursuant to the above mentioned Orders, the Company also provides more detailed information in Attachment C 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 February 2017 FCR rates the net MISO ASM costs for December 2016 as recorded in Account 555. The MISO ASM cost recovery included in this month’s FCR is -\$135,967 which is the net of many items. The detailed records are contained in Attachment C.

INCLUDED 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. December margins of \$480,376 have been included as an off-setting credit in this month’s FCR. Additional information is found in Attachments E and F.

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 evenly over the following 12-month period. The North Dakota retail share of the 2015 Non-Asset Based Margin credit is \$50,462 and \$4,206 is being fully credited to customers each month. See Attachments E and F.

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 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 E and F.

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

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 made 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;
- The Company will file an annual summary listing the new resources that have been included in the FCR during the previous calendar year;
- If, within 6 months of the filing of the annual summary, the Commission does not initiate a review of the new PPA(s) listed, the Company will be allowed to recover the related costs for the duration of the contract(s); and
- Renewable energy resources or purchases with FCR-qualifying costs that are 50 MW or larger in size (nameplate capacity) will not be included in the FCR unless and until the Commission has granted an Advance Determination of Prudence (ADP) for the resource.

It should be noted that MISO market energy purchases are not subject to the above requirements.

This month's FCR filing has a new renewable purchase, North Star Solar PV, included in the FCR for the first time. However the Commission has not approved an ADP for this PPA; therefore the purchased power cost of this PPA is excluded from the calculation of FCR rates. The following PPAs have been excluded from the FCR as a result of Commission review and disapproval:

1. School Sisters of Notre Dame (0.8 MW)³
2. Marshall Solar LLC (62.25 MW)⁴
3. North Star Solar PV (100 MW)⁵

NEGOTIATED AGREEMENT PURCHASED POWER 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 2 small solar PPAs (see table below) 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 (i.e., the system average) used to effectuate the impact of disallowing these PPAs.

³ Case No. PU-16-458, "ORDER REGARDING 2015 POWER PURCHASE AGREEMENT COSTS", October 5, 2016.

⁴ The 62.25 MW Marshall Solar project is one of the three projects in the Company's proposed 187 MW solar energy portfolio that was not approved by the Commission (Case No, PU-14-810).

⁵ The 100 MW North Star Solar project is one of the three projects in the Company's proposed 187 MW solar energy portfolio that was not approved by the Commission (Case No, PU-14-810).

| | |
|--|--|
| 1. Jeffers Wind 20, LLC (50 MW) | 10. North Wind Turbines (15 MW) |
| 2. Big Blue (36 MW) | 11. Valley View Transmission (10 MW) |
| 3. Community Wind South (Zephyr) (30 MW) | 12. Uilk Wind Farm (4.5 MW) |
| 4. Ridgewind Power Partners LLC (25 MW) | 13. Hilltop Power (2 MW) |
| 5. Adams Wind Generations (20 MW) | 14. Winona County Wind (1.5 MW) |
| 6. Danielson Wind Farms (20 MW) | 15. Woodstock Municipal Wind, LLC (0.8 MW) |
| 7. Ewington Energy Systems LLC (20 MW) | 16. Outland Solar (2 MW) |
| 8. Grant County Wind, LLC (20 MW) | 17. Best Power (St. Johns Solar) (0.4 MW) |
| 9. North Community Turbines (15 MW) | |

MONTHLY FCR RATE CALCULATION AND SUPPORTING DOCUMENTS

This filing includes the following supporting documents:

- Attachment A – Summary of calculation of the January 2017 FCR rates
- Attachment B – Four Month Fuel Cost Rider Costs
- Attachment C – Detail of MISO Day 2 and ASM Settlement Charges
- Attachment D – Derivation of Replacement Costs for Disallowed PPAs
- Attachment E – Deviation of FCR True-Up Adjustment
- Attachment F – Summary of Credits Included in the FCR by Month
- Attachment G – Historical Trend of FCR Charges (Residential)

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

Summary of Fuel Cost Rider Rates - February 2017

System Fuel and Purchased Energy Costs

4 Month Total

| | | |
|---|----------------------|----------------------|
| 1 NSP System Fuel/Energy Costs (Retail) | \$306,369,322 | Att B, p. 1, line 6 |
| 2 MISO Charges | \$32,429,499 | Att B, p. 1, line 10 |
| 3 Disallowed Purchased Power Costs ¹ | (\$10,837,142) | Att B, p. 1, line 14 |
| 4 Net NSP System Costs | <u>\$327,961,679</u> | |

ND Fuel and Purchased Energy Costs

4 Month Total

| | | |
|-----------------------------------|---------------------|----------------------|
| 5 NSP System MWh Sales (Retail) | 13,155,921 | Att B, p. 1, line 16 |
| 6 Average NSP System Cost per kWh | 2.493¢ | line 4 / line 5/10 |
| 7 ND MWh Sales (Retail) | 687,531 | Att B, p. 1, line 18 |
| 8 ND Fuel & Purch Energy Costs | <u>\$17,140,148</u> | line 6 x line 7 |

Credits and Other Adjustments Applicable to ND

December 2016

| | | |
|--|--------------------|-------------------------|
| 9 Wholesale Margins | (\$480,376) | Att B, p. 1, line 20,21 |
| 10 REC Sales Proceeds | (\$62,313) | Att B, p. 1, line 22 |
| 11 Method Transition Adjustment ² | \$0 | Att B, p. 1, line 23 |
| 12 Net Credits and Other | <u>(\$542,689)</u> | |

Over/Under Recovered Costs

Amount

| | | |
|-----------------------------------|-----------|---------------------|
| 13 True-Up Amount for August 2016 | \$761,274 | Att E, p.1, line 19 |
|-----------------------------------|-----------|---------------------|

ND Net FCR Costs

4 Month Total.

| | | |
|-------------------------|--------------|------------------------|
| 14 Net FCR Costs | \$17,358,733 | line 8+line 12+line 13 |
| 15 Net FCR Cost per kWh | 2.525¢ | line 14 / line 7/10 |

Fuel Cost Rider Rate By Class

| | Customer Class | ND Cost of Fuel/kWh | Cust. Class Ratio ³ | FCR Rate |
|----|---------------------------|---------------------|--------------------------------|---------------|
| 16 | Residential | 2.525¢ | 0.99690 | 2.517¢ |
| 17 | C & I Non-Demand | 2.525¢ | 1.03180 | 2.605¢ |
| 18 | C & I Demand Non-TOD | 2.525¢ | 1.01840 | 2.571¢ |
| 19 | C & I Demand TOD On-Peak | 2.525¢ | 1.27980 | 3.231¢ |
| 20 | C & I Demand TOD Off-Peak | 2.525¢ | 0.79540 | 2.008¢ |
| 21 | Outdoor Lighting | 2.525¢ | 0.73410 | 1.853¢ |

¹ Excludes 17 wind and solar PPAs pursuant to March 9, 2016 Order Approving Settlement

² Temporary recovery adjustment to transition to new method for including offsetting proceeds in the FCR

³ See Fuel Cost Rider Tariff

4 Month Fuel Cost Rider Costs - February 2017

| | (A) | (B) | (C) | (D) | (E) |
|--|----------------|----------------|---------------|----------------|----------------|
| Fuel & Purchased Energy Costs | Sep-16 | Oct-16 | Nov-16 | Dec-16 | 4 Month Total |
| 1 Account 151 - Fossil Fuel | \$36,100,627 | \$35,332,713 | \$36,193,504 | \$35,706,944 | \$143,333,788 |
| 2 Account 518 - Nuclear Fuel | \$9,450,980 | \$8,295,048 | \$8,024,265 | \$10,508,444 | \$36,278,737 |
| 3 Account 555 - Purchased Power ¹ | \$45,754,735 | \$42,648,046 | \$40,654,857 | \$45,902,680 | \$174,960,318 |
| 4 Sub-Total NSP Sys Energy Costs | \$91,306,342 | \$86,275,807 | \$84,872,626 | \$92,118,068 | \$354,572,843 |
| 5 Exclude Costs of InterSystem Sales | (\$11,951,402) | (\$11,216,673) | (\$9,004,808) | (\$16,030,637) | (\$48,203,521) |
| 6 Total Sys Fuel & Purch Energy | \$79,354,940 | \$75,059,134 | \$75,867,818 | \$76,087,430 | \$306,369,322 |

MISO Charges

| | | | | | |
|-----------------------------|-------------|-------------|---------------|-------------|--------------|
| 7 Day 2 Market | \$7,672,664 | \$7,615,807 | \$7,941,842 | \$9,601,016 | \$32,831,329 |
| 8 Exclude Schedule 24 | (\$108,274) | (\$137,208) | (\$85,007) | (\$79,986) | (\$410,476) |
| 9 Ancillary Services Market | \$1,626,774 | (\$36,147) | (\$1,446,013) | (\$135,967) | \$8,647 |
| 10 Total MISO Charges | \$9,191,164 | \$7,442,451 | \$6,410,821 | \$9,385,063 | \$32,429,499 |

Disallowed PPAs²

| | | | | | |
|--------------------------------------|---------------|---------------|---------------|---------------|----------------|
| 11 Exclude Costs of Disallowed PPAs | (\$3,982,490) | (\$4,433,387) | (\$4,507,984) | (\$5,659,750) | (\$18,583,611) |
| 12 Exclude Related Curtailment Costs | (\$68,078) | (\$248) | (\$75,012) | (\$11,710) | (\$155,048) |
| 13 Replacement Energy Costs | \$1,539,629 | \$1,813,720 | \$2,052,064 | \$2,496,104 | \$7,901,517 |
| 14 Net Disallowance | (\$2,510,939) | (\$2,619,915) | (\$2,530,932) | (\$3,175,356) | (\$10,837,142) |

| | | | | | |
|-------------------------|--------------|--------------|--------------|--------------|---------------|
| 15 Net NSP System Costs | \$86,035,165 | \$79,881,670 | \$79,747,707 | \$82,297,137 | \$327,961,679 |
|-------------------------|--------------|--------------|--------------|--------------|---------------|

ND Fuel and Purchased Energy Costs

| | Sep-16 | Oct-16 | Nov-16 | Dec-16 | 4 Month Total |
|---------------------------------|-------------|-------------|-------------|-------------|---------------|
| 16 NSP System Sales (Retail) | 3,685,099 | 3,181,464 | 2,950,455 | 3,338,903 | 13,155,921 |
| 17 Avg. NSP System Cost per kWh | 2.335¢ | 2.511¢ | 2.703¢ | 2.465¢ | 2.493¢ |
| 18 ND Sales (Retail) | 180,258 | 161,208 | 157,023 | 189,042 | 687,531 |
| 19 ND Fuel & Purch Energy Costs | \$4,209,024 | \$4,047,933 | \$4,244,332 | \$4,659,885 | \$17,140,148 |

Credits and True-Up

| | | | | | |
|--|-------------|-------------|-------------|-------------|---------------|
| 20 Asset-Based Margins | (\$113,728) | (\$154,423) | (\$294,178) | (\$480,376) | (\$1,042,705) |
| 21 Non-Asset-Based Margins | \$0 | \$0 | \$13,522 | \$0 | \$13,522 |
| 22 REC Sales Proceeds (100%) | \$0 | \$0 | \$241,815 | (\$62,313) | \$179,502 |
| 23 Method Transition Adjustment ³ | \$0 | \$0 | \$0 | \$0 | \$0 |
| 24 Net Credits and Other | (\$113,728) | (\$154,423) | (\$38,841) | (\$542,689) | (\$849,681) |

¹ Excludes demand-related expenses, MN Windsource energy costs, and MN Solar Gardens energy costs

² Excludes 17 wind and solar PPAs pursuant to March 9, 2016 Order Approving Settlement (PU-12-813)

³ Temporary adjustment needed to transition to new method for including Credits in the FCR

MISO Day 2 Settlement Charges - February 2017

| Energy and Losses | <u>FERC Account</u> | <u>Retail Expense (Rev)</u> |
|---|---------------------|---------------------------------|
| 1 Day Ahead Asset Energy - Energy | 555 | \$9,430,454 |
| 2 Day Ahead Asset Energy - Losses | 555 | \$4,426,568 |
| 3 Day Ahead Financial Bilateral Transaction Loss | 555 | \$275 |
| 4 Day Ahead Non-Asset Energy - Energy | 555 | (\$8,738,191) |
| 5 Day Ahead Non-Asset Energy - Losses | 555 | \$820,238 |
| 6 Day Ahead Losses Rebate on Carve-out Grandfathered Agreements | 555 | (\$275) |
| 7 Day Ahead Losses Rebate on Option B Grandfathered Agreements | 555 | \$0 |
| 8 Real Time Asset Energy - Energy | 555 | \$3,844,017 |
| 9 Real Time Asset Energy - Losses | 555 | \$1,709 |
| 10 Real Time Distribution of Losses | 555 | (\$1,384,209) |
| 11 Real Time Financial Bilateral Transaction - Losses | 555 | \$0 |
| 12 Real Time Losses Rebate on Carve-out Grandfathered Agreements | 555 | \$0 |
| 13 Real Time Net Inadvertent Distribution | 555 | \$42,339 |
| 14 Real Time Non-Asset Energy - Energy | 555 | \$345 |
| 15 Real Time Non-Asset Energy - Losses | 555 | (\$7) |
| 16 Total Energy and Losses | | \$8,443,263 |
| Congestion | | |
| 17 Day Ahead Asset Energy - Congestion | 555 | \$3,445,808 |
| 18 Day Ahead Financial Bilateral Transaction - Congestion | 555 | (\$13,752) |
| 19 Day Ahead Non-Asset Energy - Congestion | 555 | \$1,628,179 |
| 20 Day Ahead Congestion Rebate - Carve-out Grandfather Agreements | 555 | \$13,752 |
| 21 Day Ahead Congestion Rebate - Option B Grandfather Agreements | 555 | \$0 |
| 22 Real Time Asset Energy - Congestion | 555 | \$41,770 |
| 23 Real Time Financial Bilateral Transaction - Congestion | 555 | \$0 |
| 24 Real Time Congestion Rebate - Carve-out Grandfather Agreements | 555 | \$0 |
| 25 Real Time Non-Asset Energy - Congestion | 555 | (\$36) |
| 26 Total Congestion-Related | | \$5,115,721 |
| Financial Transmission Rights (FTR) | | |
| 27 FTR Hourly Allocation | 555 | (\$4,664,786) |
| 28 FTR Monthly Allocation | 555 | (\$338,255) |
| 29 FTR Transaction | 555 | \$0 |
| 30 FTR Yearly Allocation | 555 | \$0 |
| 31 FTR Full Funding Guarantee | 555 | (\$48,608) |
| 32 FTR Guarantee Uplift | 555 | \$53,665 |
| 33 FTR Monthly Transaction | 555 | \$0 |
| 34 Total Financial Transmission Rights Charges | | (\$4,997,984) |

MISO Day 2 Settlement Charges - February 2017

| | <u>FERC Account</u> | <u>Retail Expense (Rev)</u> |
|--|---------------------|---------------------------------|
| Uplift | | |
| 35 Real-Time Revenue Neutrality Uplift | 555 | \$299,374 |
| 36 Total Uplift | | <u>\$299,374</u> |
| Revenue Sufficiency Guarantee (RSG) | | |
| 37 Day Ahead RSG Distribution | 555 | \$149,114 |
| 38 Day Ahead RSG Make Whole Payment | 555 | (\$18,692) |
| 39 Real time RSG First Pass Distribution | 555 | \$242,111 |
| 40 Real Time RSG Make Whole Payment | 555 | (\$61,886) |
| 41 Real Time Price Volatility Make Whole Payment | 555 | (\$224,389) |
| 42 Total Revenue Sufficiency Guarantee | 555 | <u>\$86,257</u> |
| Market Administration¹ | | |
| 43 Day Ahead Market Administration | 575.7 | \$581,914 |
| 44 Real Time Market Administration | 575.7 | \$35,752 |
| 45 FTR Market Administration | 575.7 | \$29,508 |
| 46 Total Market Administration | | <u>\$647,174</u> |
| Virtual Energy | | |
| 47 Day Ahead Virtual Energy | 555 | \$0 |
| 48 Real Time Virtual Energy | 555 | \$0 |
| 49 Total Virtual Energy | 555 | <u>\$0</u> |
| Auction Revenue Rights (ARR) | | |
| 50 ARR FTR Auction Transactions | 555 | \$2,119,952 |
| 51 ARR Monthly Revenue | 555 | (\$2,094,025) |
| 52 ARR Stage 2 Distribution | 555 | (\$145,480) |
| 53 ARR Monthly Infeasible Revenue | 555 | \$76,245 |
| 54 Total Auction Revenue Rights | | <u>(\$43,308)</u> |
| Other Miscellaneous | | |
| 55 Real Time Miscellaneous | 555 | (\$29,468) |
| 56 Real Time Uninstructed Deviation | 555 | \$0 |
| 57 Total Other Miscellaneous | | <u>(\$29,468)</u> |
| 58 Grand Total MISO Day 2 Charges | | <u><u>\$9,521,030</u></u> |

¹ Excludes Schedule 24 costs, which are recovered in base rates.

MISO Ancillary Services Markets (ASM) Charges - February 2017

| | <u>FERC Account</u> | <u>Retail Expense (Rev)</u> |
|---|---------------------|---------------------------------|
| Procurement | | |
| 1 Day Ahead Regulation | 555 | (\$260,028) |
| 2 Day Ahead Spinning Reserve | 555 | (\$184,205) |
| 3 Day Ahead Supplemental Reserve | 555 | (\$52,166) |
| 4 Real Time Regulation | 555 | \$154,210 |
| 5 Real Time Spinning Reserve | 555 | \$89,670 |
| 6 Real Time Supplemental Reserve | 555 | \$2,645 |
| 7 Total Procurement | | <u>(\$249,874)</u> |
| Resource Energy | | |
| 8 Real Time Excessive Energy | 555 | \$298,146 |
| 9 Real Time Excessive Energy - Congestion | 555 | \$0 |
| 10 Real Time Excessive Energy - Losses | 555 | \$0 |
| 11 Real Time Non-Excessive Energy | 555 | (\$356,627) |
| 12 Real Time Non-Excessive Energy - Congestion | 555 | (\$198,936) |
| 13 Real Time Non-Excessive Energy - Losses | 555 | \$5,158 |
| 14 Real Time Net Regulation Adjustment | 555 | \$1,074 |
| 15 Total Resource Energy | | <u>(\$251,186)</u> |
| Cost Distribution | | |
| 16 Real Time Regulation Reserve Cost Distribution | 555 | \$130,721 |
| 17 Real Time Spinning Reserve Cost Distribution | 555 | \$123,760 |
| 18 Real Time Supplemental Reserve Cost Distribution | 555 | \$67,034 |
| 19 Total Cost Distribution | | <u>\$321,515</u> |
| Penalties | | |
| 20 Real Time Excessive/Deficient Energy Deployment | 555 | \$43,537 |
| 21 Real Time Contingency Reserve Deployment Failure | 555 | \$42 |
| 22 Total Penalties | | <u>\$43,579</u> |
| 23 Grand Total ASM Charges | | <u>(\$135,967)</u> |

Derivation of December 2016 Replacement Costs for Disallowed PPAs

| | <u>NSP System</u> | <u>ND Allocation¹</u> | <u>ND Jurisdiction</u> | |
|--|----------------------|----------------------------------|------------------------|-------------------------|
| Fuel & Purchased Energy Costs | | | | |
| 1 Fuel & Purch Energy Costs (Retail) ² | \$85,472,493 | 5.6618% | \$4,839,281 | Att B, Col D, line 6+10 |
| Disallowed PPA Costs | | | | |
| 2 15 C-BED Wind PPAs | (\$5,308,948) | 5.6618% | (\$300,582) | |
| 3 4 Solar PPAs | (\$350,802) | 5.6618% | (\$19,862) | |
| 4 Wind Curtailment Payments | (\$11,710) | 5.6618% | (\$663) | |
| 5 Total Exclusion | <u>(\$5,671,460)</u> | | <u>(\$321,107)</u> | |
| 6 Adjusted Fuel & Purch Energy Costs | <u>\$79,801,033</u> | 5.6618% | <u>\$4,518,175</u> | Line 1 - line 5 |
| Energy Sales (Billing Mo.) | | | | |
| 7 MWh Energy Sales | [a] 3,338,903 | [b] 5.6618% | [c] 189,042 | [b]=[c]/[a] |
| 8 Disallowed PPA MWh Energy Sales | (101,262) | 5.6618% | (5,733) | |
| 9 Adjusted MWh Sales (Billing Mo.) | <u>3,237,641</u> | | <u>183,309</u> | |
| Replacement Costs | | | | |
| 10 Avg. Cost (\$/MWh) w/o Disallowed PPAs | \$24.65 | | \$24.65 | Line 6 / line 9 |
| 11 Replacement Cost for Disallowed PPAs ³ | \$2,496,108 | | \$141,318 | Line 8 x line 10 |
| Impact of Disallowance | | | | |
| 12 Net Impact of Disallowance | (\$3,175,352) | | (\$179,788) | Line 5 + line 11 |
| 13 FCR Rate Impact of Disallowance /kWh | | | -0.095¢ | Line 12 / line 7 |
| 14 Residential Monthly Bill Impact (750 kWh) | | | (\$0.71) | Line 13 x 750 |

¹ Based on ratio of ND billed energy sales to NSP System billed sales as shown in line 7

² Including MISO charges

³ Reflects the average system fuel and purchased energy cost per kWh (excluding the disallowed PPA costs and volumes) applied to the energy volumes of the disallowed PPAs.

Derivation of FCR True-Up Adjustment - December 2016

Cost to Recover in December 2016

| | [a] Dec Sys Fuel Cost/kWh ¹ | [b] Dec ND MWh Sales ² | Amount | |
|-----------------------------------|--|---|--------------------|-----------------|
| 1 Fuel & Purchased Energy Costs | 2.465¢ | 189,042 | \$4,659,885 | [a] x [b] |
| 2 True Up Amount for October 2016 | | | \$621,935 | |
| 3 Net Costs | | | <u>\$5,281,820</u> | Line 1 + Line 2 |

Cost Recovered in December 2016

| | Sales | Amount |
|---------------------------------|----------------|--------------------|
| 4 (i) Residential | 67,897 | \$1,650,923 |
| 5 (ii) C & I Non-Demand | 9,903 | \$249,140 |
| 6 (iii) C & I Demand Non-TOD | 64,615 | \$1,604,599 |
| 7 (iv) C & I Demand TOD On-Peak | 16,795 | \$524,063 |
| 8 (v) C & I Demand TOD Off-Peak | 28,020 | \$543,325 |
| 9 (vi) Outdoor Lighting | 1,812 | \$32,386 |
| 10 Total | <u>189,042</u> | <u>\$4,604,436</u> |

True-Up Obligation

| | | |
|----------------------------------|----------------|-------------------|
| 11 (i) Residential | 67,897 | (\$30,006) |
| 12 (ii) C & I Non-Demand | 9,903 | (\$4,562) |
| 13 (iii) C & I Demand Non-TOD | 64,615 | (\$28,600) |
| 14 (iv) C & I Demand TOD On-Peak | 16,795 | (\$9,825) |
| 15 (v) C & I Demand TOD Off-Peak | 28,020 | (\$9,879) |
| 16 (vi) Outdoor Lighting | 1,812 | (\$1,018) |
| 17 Total | <u>189,042</u> | <u>(\$83,890)</u> |

| | | |
|-----------------|--------------------|-------------------|
| 18 Net Recovery | <u>\$4,520,546</u> | Line 10 + Line 17 |
|-----------------|--------------------|-------------------|

Over/Under Recovered Costs

| | | |
|-------------------------------------|------------------|------------------|
| 19 True-Up Amount for December 2016 | <u>\$761,274</u> | Line 3 - Line 18 |
|-------------------------------------|------------------|------------------|

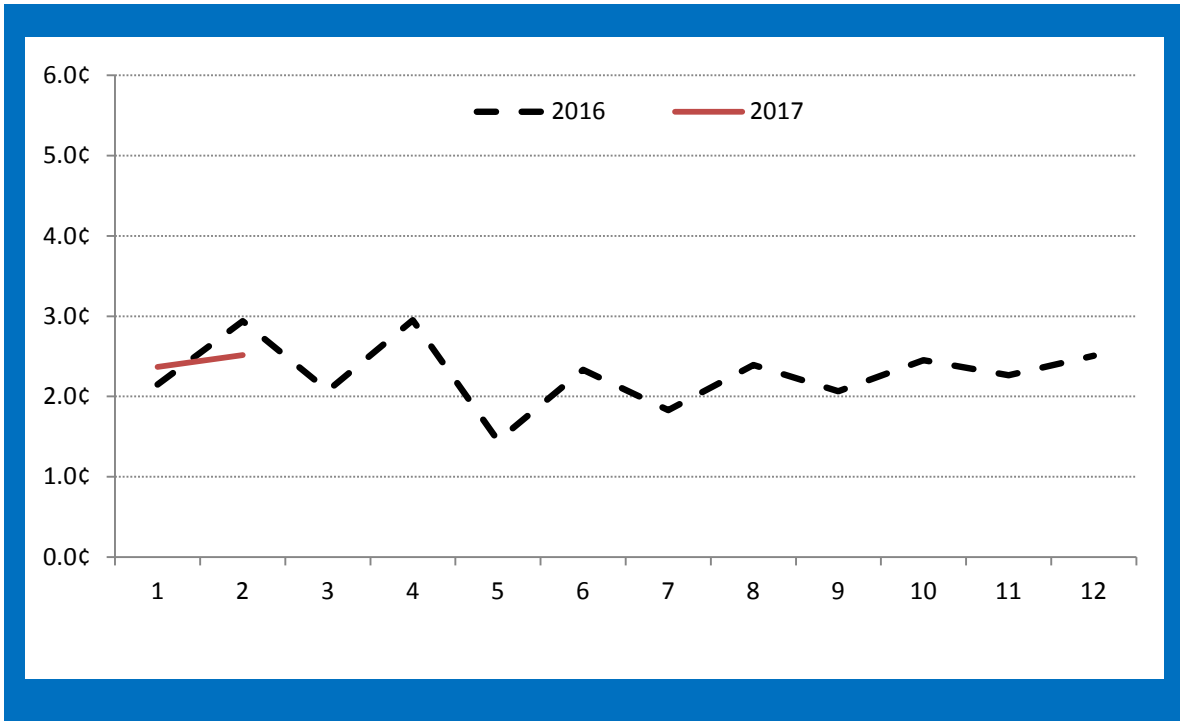
¹ Reflects the average for the month of December 2016.

² Actual ND sales in month of December 2016.

Summary of Credits Included in the FCR by Month

| Month | Asset Based Margins | Non-Asset Based Margins | Renewable Energy Credits | Total |
|----------------------|---------------------|-------------------------|--------------------------|--------------------|
| 1 January | (\$71,432) | (\$50,462) | \$0 | (\$121,894) |
| 2 February | (\$99,484) | \$0 | (\$13,210) | (\$112,694) |
| 3 March | (\$68,297) | \$0 | (\$157,823) | (\$226,120) |
| 4 April | (\$20,202) | \$0 | \$0 | (\$20,202) |
| 5 May | (\$57,701) | \$0 | \$0 | (\$57,701) |
| 6 June | (\$11,125) | \$0 | \$0 | (\$11,125) |
| 7 July | (\$80,350) | \$0 | \$0 | (\$80,350) |
| 8 August | (\$64,619) | \$0 | \$0 | (\$64,619) |
| 9 September | (\$113,728) | \$0 | \$0 | (\$113,728) |
| 10 October | (\$154,423) | \$0 | \$0 | (\$154,423) |
| 11 November | (\$294,178) | \$13,522 | \$241,815 | (\$38,841) |
| 12 December | (\$480,376) | \$0 | (\$62,313) | (\$542,689) |
| 13 Cumulative | (1,515,915) | (36,940) | 8,469 | (1,544,386) |

Historical Trend of FCR Charges (Residential)



| | | Residential Fuel Cost Charges | | | |
|----|-----------|-------------------------------|---|-------------|---|
| | | <u>2016</u> | Typical <u>Bill Impact¹</u> | <u>2017</u> | Typical <u>Bill Impact¹</u> |
| 1 | January | 2.148¢ | \$16.11 | 2.370¢ | \$17.78 |
| 2 | February | 2.939¢ | \$22.04 | 2.517¢ | \$18.88 |
| 3 | March | 2.073¢ | \$15.55 | | |
| 4 | April | 2.950¢ | \$22.13 | | |
| 5 | May | 1.450¢ | \$10.88 | | |
| 6 | June | 2.332¢ | \$17.49 | | |
| 7 | July | 1.829¢ | \$13.72 | | |
| 8 | August | 2.394¢ | \$17.96 | | |
| 9 | September | 2.067¢ | \$15.50 | | |
| 10 | October | 2.454¢ | \$18.41 | | |
| 11 | November | 2.266¢ | \$17.00 | | |
| 12 | December | 2.510¢ | \$18.83 | | |
| 13 | Average | 2.284¢ | \$17.13 | 2.444¢ | \$18.33 |

¹ For non-electric heating residential customers using 750 kWh