April 26, 2019 **PUBLIC DOCUMENT**

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **PUBLIC Review of the 2017-2018 Annual Automatic Adjustment Reports**
Docket No. E999/AA-18-373

Dear Mr. Wolf:

Minnesota Rules 7825.2800 through 7825.2830 requires natural gas and electric utilities implementing automatic adjustments in the recovery of fuel purchases to file annual automatic adjustment reports. To provide further context to these reports, the Minnesota Department of Commerce, Division of Energy Resources (Department) provides excerpts from the Statement of Need and Reasonableness (SONAR) that the Minnesota Public Utilities Commission (Commission) issued when it adopted these rules.

These rules were put in place in 1984 in Docket No. G,E-999/R-83-467. In its April 18, 1984 SONAR (1984 SONAR) at pages 10-11, the Commission stated the following regarding the purpose of the annual filings by the utilities:

> There currently is no provision in the rules to require the [C]ommission to annually review the entire effect of automatic adjustments upon customer rates, consumption patterns, utility revenues and distribution of supplier refunds; nor is there any provision to review projected fuel and gas costs. Therefore, the intent of the proposed additions is to make information about automatic adjustment of charges available for annual review by the [C]ommission, intervenors and the public, to provide a means by which the [C]ommission may determine the appropriateness and reasonableness of the separate charge and refund transactions during a prior year.
>
> Currently utilities submit periodic automatic adjustment reports to the Minnesota Department of Public Service (DPS) [a predecessor to the Department of Commerce]. These reports are reviewed by the DPS to determine that the rates are in compliance with [C]ommission rules and approved rates. An annual report filed directly with the Commission will

> enable the Commission to more effectively discharge its duties to review and monitor rates pursuant to Minn. Stat. § Ch. 216B (1982).
>
> The materials required to be submitted will allow the Commission to make an independent, accurate evaluation of the automatic adjustment charges for each utility.
>
> The information required by the Commission for the annual report of automatic adjustment of charges is needed to fully evaluate the impact these charges have had upon the ratepayers of each utility during the reporting period.

The Commission stated the following on page 13 regarding how the information in the reports is to be used at the Commission's annual meeting ("The commission shall annually conduct a separate meeting to review the automatic adjustment of charges reported herein"):

> This addition to the rule will allow the Commission an opportunity to review and evaluate all utilities' automatic adjustments at one time, giving the Commission a broad perspective for its analysis of the application and impact of automatic adjustments. This meeting will also give the Commission an opportunity to review any cost changes in gas or electric utility fuel purchases and will allow the public and utilities to address to [sic] the appropriateness of changes in automatic adjustments during the reporting period.

Attached is the Department's *Review of the 2017-2018 Annual Automatic Adjustment Reports* for rate-regulated electric utilities in Minnesota (FYE18 AAA Report). Each electric utility discussed in this report is being sent a public version. A trade secret version specific to each utility is being sent via electronic mail to the respective utilities.

The Department is available should the Commission have any questions about the FYE18 AAA Report herein provided.

Sincerely,

/s/ MARK A. JOHNSON
Public Utilities Analyst Coordinator

MAJ/ja
Attachments

PUBLIC REVIEW OF 2017-2018 (FYE18) ANNUAL AUTOMATIC ADJUSTMENT REPORTS

FOR ELECTRIC UTILITIES

SUBMITTED TO THE
MINNESOTA PUBLIC UTILITIES COMMISSION

COMMERCE DEPARTMENT

DOCKET NO. E999/AA-18-373

APRIL 26, 2019

TABLE OF CONTENTS

I. OVERVIEW

This document provides the Division of Energy Resources of the Minnesota Department of Commerce's (Department) summary and partial review of the automatic adjustment charges for the July 2017 - June 2018 (FYE18) reporting period, which were filed by four Minnesota electric utilities in compliance with Minnesota Rule 7825.2810.

The Department offers recommendations to the Minnesota Public Utilities Commission (Commission), and requests that the Commission review this information and determine whether the rates charged by electric utilities during this period were reasonable.

The utilities included in this report are:

- Dakota Electric Association (Dakota or DEA);
- Minnesota Power (Minnesota Power or MP);
- Otter Tail Power Company (Otter Tail or OTP); and
- Northern States Power Company d/b/a Xcel Energy, Incorporated – Electric Utility (NSP or Xcel Electric).

The four rate-regulated electric utilities required to provide information per Minnesota Rules filed the information necessary to meet their filing requirements.[1]

The Department's review focused on whether the electric utilities had, during the period of July 1, 2017 to June 30, 2018, accurately adjusted their energy rates to reflect changes in fuel costs according to Commission rules and Commission-approved rule variances.

II. FILING REQUIREMENTS

A. MINNESOTA RULES

Pursuant to Minnesota Rule 7825.2810, subpart 1, the filing requirements for electric utilities include the following:

- Paragraph A – the base cost of fuel approved by the Commission in the utility's most recent rate case;
- Paragraph B – billing adjustment amounts charged to customers for each type of energy cost, such as nuclear, coal, or purchased power;
- Paragraph D – total cost of fuel delivered to customers;
- Paragraph E – revenues collected from customers for energy delivered; and
- Paragraph G – amount of refunds credited to customers.[2]

[1] The Commission granted Northwestern Wisconsin Electric Company (NWEC) a variance from the annual reporting requirements in Minnesota Rules 7825.2800 through 7825.2840 in its Order dated December 18, 2001 in Docket No. G,E999/AA-00-1027. Since the Commission granted this variance with no expiration date, it continues until revoked by the Commission.

[2] Paragraphs C and F pertain to natural gas utilities.

Each reporting utility computed billing adjustments and total fuel costs on a system-wide basis.[3] This approach is consistent with the methods used in the monthly fuel clause adjustment (FCA) filings, and the Commission approved this approach in previous proceedings. Therefore, the Department concludes that the Annual Automatic Adjustment Reports (AAA Reports) from all four reporting electric utilities comply with the Commission's filing requirements, as described in Minnesota Rule 7825.2810, subpart 1.

Further, Minnesota Rule 7825.2820 requires the following:

> By September 1 of each year, all gas and electric utilities shall submit to the commission an independent auditor's report evaluating accounting for automatic adjustments for the prior year commencing July 1 and ending June 30 or any other year if requested by the utility and approved by the commission.

In its 1984 SONAR, the Commission stated the following at page 12 regarding the purpose of this requirement:

> This addition to existing rules is necessary and reasonable because the existing rules provide that certain accounts included in the uniform system of accounts will be used in the calculation of automatic adjustments. An independent auditor's report will provide, in addition to the checks on the computation of automatic adjustment charges done by the DPS [a predecessor to the Department of Commerce] and the Commission, a further check that the charges and credits used in the computation are in compliance with the uniform system of accounts as required by these rules.

All electric utilities submitted auditors' reports in compliance with Minnesota Rule 7825.2820.
The Commission's July 21, 2017 Order in Docket No. E999/AA-15-611, regarding the review of the 2014-2015 Annual Automatic Adjustment Reports for all Electric Utilities, required the following in Ordering Paragraph 7:

> 7. In future AAA filings, Xcel, Minnesota Power, and Otter Tail must include in their independent auditors' reports the following:
>   a. comparison of the documentation in support of payments and invoices received from energy suppliers;
>   b. comparison of the base costs of power approved by the Commission to the bases used by the utility;

[3] In the discussion of allocations throughout this report, the Department notes that the two categories to which total system costs and revenues are allocated are 1) retail customers and 2) wholesale transactions. Allocations to retail customers are reflected directly in FCA rates, whereas allocations to the wholesale sector may or may not be reflected in rates charged to wholesale customers. For purposes of the ratemaking elements of this report, it is helpful to think of "wholesale transactions" as being similar to shareholders or another non-jurisdictional entity.

c. recalculation of the billing adjustment charge (credit) per kWh charged to customers for purchased power for the entire applicable period by customer class;
d. comparison of the accounting records for the revenues billed to customers for energy delivered for the relevant period to the total sales of electric energy;
e. on a test basis, an examination of individual billings in each customer class by recalculating the automatic adjustment of charges and credits and tracing to individual customers' subsidiary records to ensure that the calculated credit or charge was correctly recorded;
f. an examination of any corrections to FCA charges or other billing errors;
g. a reconciliation of total revenue and cost of power in the utility's general ledger; and
h. a recalculation of any true-up, and tracing of the related revenue and expense amounts to the utility's accounting records.

Based on our review, Xcel Electric and OTP provided the above information in their Auditor Reports for FYE18. As a result, the Department recommends that the Commission accept Xcel Electric's and OTP's Auditor Reports for FYE18.

As explained in the Department's October 19, 2018 Comments in Docket E999/AA-17-492 (Docket 17-492), MP did not address ordering paragraph 7 in their Auditor's Report. As a result, the Department recommended that MP address this in their reply comments in Docket 17-492. In its reply comments, MP indicated that its internal and independent auditors confirmed that their "scope of work covered all relevant areas from Order Point 7." Based on this additional information, the Department recommended that the Commission accept MP's Auditor Report for FYE17.

The Department notes that MP's FYE18 filing was made on September 1, 2018, before the Department's October 19, 2018 Comments in Docket 17-492. As with the previous Auditor Report, MP's FYE18 Auditor Report does not explicitly indicate that it contains all the information required to comply with Ordering Paragraph 7. The Department requests that MP provide this information in reply comments, or confirm that the auditor's scope of work included all of the information in Ordering Paragraph 7. The Department will make its recommendation regarding MP's FYE18 Auditor Report after it reviews MP's reply comments.

Minnesota Rule 7825.2830 requires all electric utilities to "submit to the commission a five-year projection of fuel costs by energy source by month for the first two years and on an annual basis thereafter." All utilities complied with this requirement.

Minnesota Rule 7825.2840 requires all electric utilities to "provide notice of the availability of the reports defined in parts 7825.2800 to 7825.2830 to all interveners in the previous two general rate cases." All utilities complied with this requirement.

In the next section, the Department summarizes the fuel cost projections submitted by each of the electric utilities that made annual fuel cost filings.

B. SUMMARY OF FUEL COST PROJECTIONS

Minnesota Rule 7825.2830 requires all electric utilities to "submit to the commission a five-year projection of fuel costs by energy source by month for the first two years and on an annual basis thereafter." All utilities complied with this requirement. In its 1984 SONAR, the Commission stated the following at page 12 regarding the purpose of this requirement:

> The overall purpose of a five-year projection of fuel and gas costs is to aid the Commission in anticipating potential rate impacts upon Minnesota ratepayers. These projections will provide the Commission with a state-wide perspective on future energy requirements and costs which may affect customer consumption, the level of rates, facility expansion requirements, and rate design proposals.

The following summarizes the information provided by the utilities.

Dakota does not own generation and transmission resources, and instead purchases its power from Great River Energy, its wholesale generation and transmission provider; thus, the figures for Dakota are not directly comparable to the projections for other utilities, and were excluded from Graph 1 below.

The utilities' energy cost projections are summarized below:[4]

Graph 1: Utilities' Forecast of Annual Energy Costs ($/MWh)

[TRADE SECRET DATA HAS BEEN EXCISED]

Table 1.1: Utilities' Forecast of Annual Energy Costs

[TRADE SECRET DATA HAS BEEN EXCISED]

(1) Page 47 of 50, Dakota's August 28, 2018 AAA report in Docket No. E999/AA-18-373.
(2) Page 21 of 193, MP's August 31, 2018 AAA report in Docket No. E999/AA-18-373.
(3) Pages 159-163 of 232, OTP's August 31, 2018 AAA report in Docket No. E999/AA-18-373.
(4) Pages 69-73 of 375, Xcel Electric's August 31, 2018 AAA report in Docket No. E999/AA-18-373.

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[4] Dakota and MP provided their forecasted data based on a fiscal year while OTP and Xcel Electric used a calendar year.

Table 1.2 Annual and Cumulative Percent Change in Forecasted Energy Costs

[TRADE SECRET DATA HAS BEEN EXCISED]

During the Commission's deliberation in Docket Nos. E999/AA-12-757, 13-599 and 14-579, the Commission indicated an interest in understanding the reliability of the investor-owned utilities' (IOUs) annual energy forecasts (as provided in their AAA reports). The Department provides below for informational purposes Graph 2, Table 2.1 and Table 2.2, which compare the IOUs' forecasts of 2018 energy costs to actual 2018 energy costs.[5]

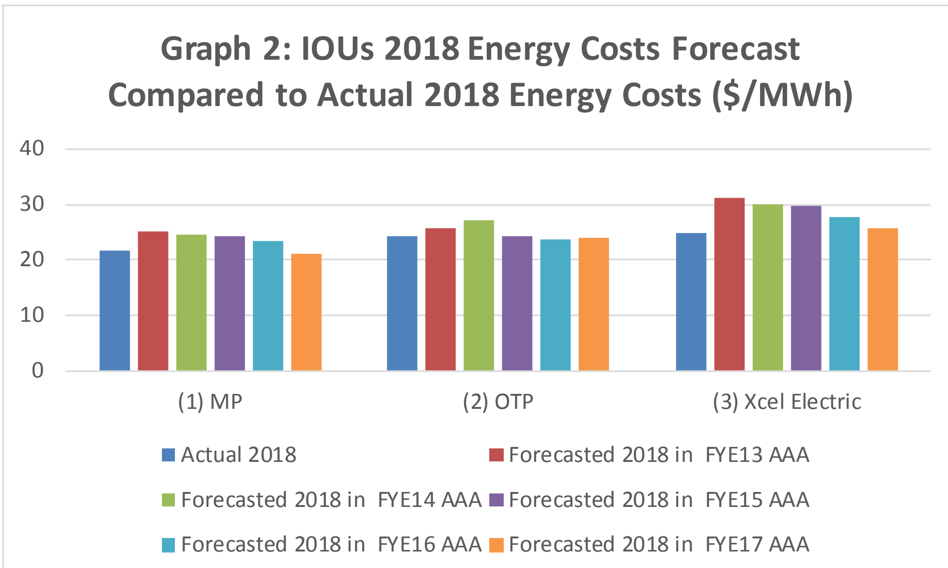

Table 2.1: IOUs' 2018 Energy Cost Forecast Compared to Actual 2018 Energy Costs ($/MWh)

$/MWh	Actual 2018	Forecasted 2018 in FYE13 AAA	Forecasted 2018 in FYE14 AAA	Forecasted 2018 in FYE15 AAA	Forecasted 2018 in FYE16 AAA	Forecasted 2018 in FYE17 AAA
(1) MP	21.75	25.08	24.45	24.33	23.37	21.23
(2) OTP	24.14	25.79	27.05	24.33	23.80	23.94
(3) Xcel Electric	24.86	31.21	29.91	29.64	27.87	25.64

(1) Attachment 4, page 3 of 3, MP's FYE13-FYE17 AAA reports.
(2) OTP's FYE13-FYE17 AAA reports.
(3) Part G, Section 1, pages 1-5 of 5, Xcel Electric's FYE13-FYE17 AAA reports.

As would be expected, the Department notes that the forecasts generally became closer to 2018 actual annual costs, the closer to 2018 the forecasts were made. OTP had a more reliable forecast than the other two IOUs over the last five years, as shown in Table 2.2 below.

[5] OTP and Xcel Electric's FYE13-FYE17 forecasts for 2018 are calendar year forecasts, while MP's forecast for 2018 is a fiscal year forecast.

Table 2.2 Annual Percent Deviation from Actual 2018 Energy Costs

	Actual 2018 $/MWh	Forecasted 2018 in FYE13 AAA	Forecasted 2018 in FYE14 AAA	Forecasted 2018 in FYE15 AAA	Forecasted 2018 in FYE16 AAA	Forecasted 2018 in FYE17 AAA
MP	21.75	15.3%	12.41%	11.86%	7.45%	-2.39%
OTP	24.14	6.8%	12.05%	0.79%	-1.41%	-0.83%
Xcel Electric	24.86	25.5%	20.31%	19.23%	12.11%	3.14%

III. COMPLIANCES

The Department addresses the following reports in this section.[6]

A. *In the Matter of a Request for Investigation of Northern States Power Company's Practices Regarding Energy Marketing and the Fuel Clause*, Docket No. E002/CI-00-415.

B. *In the Matter of a Request by Northern States Power Company, d/b/a Xcel Energy for Commission Approval of Gas Financial Instruments Natural Gas Financial Instruments for Wholesale Electric Transactions,* Docket No. E002/M-01-1953.

C. Xcel's Wind Curtailment Report *In the Matter of Northern States Power Company d/b/a Xcel Energy's Annual Automatic Adjustment of Charges Reports for Its Electric and Gas Utility Operations and Purchased Gas Adjustment True-up Filing,* Docket No. E,G999/AA-04-1279, and *In the Matter of a Request by Northern States Power Company, d/b/a Xcel Energy for Approval of a Power Purchase Agreement with Navitas Energy, LLC,* Docket No. E002/M-02-51.

D. *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Utility Service in Minnesota,* FCA Settlement Agreement (Xcel Electric's compliance filing), Docket No. E002/GR-05-1428.

E. History of Nuclear Fuel Sinking Fund, Docket No. E002/M-81-306.

F. Offsetting Revenues and/or Compensation Received by Investor-Owned Utilities (IOUs) (*In the Matter of Northern States Power Company d/b/a Xcel Energy's Petition for Approval of a Renewable Energy Purchase Agreement with KODA Energy, LLC*, Docket No. E002/M-08-1098, *In the Matter of Xcel Energy's Petition for Approval of a Power Purchase Agreement with Diamond K Dairy, Inc.,* Docket No. E002/M-10-486, and *In the Matter of the Review of the 2009-2010 Annual Automatic Adjustment Reports for All Electric Utilities*, E999/AA-10-884).

G. Maintenance Expenses of Generation Plants (*In the Matter of the Review of the 2005 Annual Automatic Adjustment of Charges for All Electric and Gas Utilities,* Docket No. E999/AA-06-1208).

[6] The Department notes that the analysis of compliances related to the MISO Day 1 market is discussed in Section V of this report, *Effects of the MISO Day 1 Market on Minnesota Ratepayers.* The discussion of the effects of the MISO Day 2 market is discussed in Section VIII of this report, *Effects of the MISO Day 2 Market on Minnesota Ratepayers.*

H. Plant Outages Contingency Plans (*In the Matter of the Review of the 2008 Annual Automatic Adjustment Reports for All Electric Utilities,* Docket No. E999/AA-08-995).

I. Sharing Lessons Learned Regarding Forced Outages (*In the Matter of the Review of the 2009-2010 Annual Automatic Adjustment Reports for All Electric Utilities,* Docket No. E999/AA-10-884).

J. *In the Matter of Otter Tail Power Company's Petition for Approval of a Monthly Fuel Clause Adjustment True-Up Provision:* OTP's FCA True Up, Docket No. E017/M-03-30.

K. *In the Matter of Xcel Energy's Petition for Approval of Replacement Power Purchase Agreement with WM Renewable Energy. LLC,* Xcel's Curtailment of WM Renewable Energy, Docket No. E002/M-10-161.

L. *In the Matter of a Petition by Minnesota Power for Approval of a Power Purchase Agreement with Manitoba Hydro,* Report on Purchased Power Agreement (PPA) with Manitoba Hydro, Docket No. E015/M-10-961.

M. *In the Matter of Xcel Energy's Request for Approval of a Community Solar Garden Program*, Docket No. E002/M-13-867.

N. Transformer Reporting for Xcel, MP and OTP as required by the Commission's August 16, 2013 Order in Docket No. E999/AA-11-792, Ordering Point no. 23.

O. *In the Matter of Xcel Energy's Petition for Approval of an Amendment to the Hennepin Energy Recovery Center Power Purchase Agreement,* Docket No. E002/M-17-532.

P. *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of a Renewable*Connect Pilot Programs,* Docket No. E002/M-15-985.

Q. *In the Matter of the Petition of Northern States Power Company for Approval to Sell Land and Tanks to Flint Hills Resources Pine Bend, LLC,* Docket No. E002/PA-17-529.

R. *In the Matter of the Petition of Northern States Power Company for Approval to Sell 365 Acres of Sherco Land,* Docket No. E002/PA-17-528.

The Department discusses each of these items below.

A. IN THE MATTER OF A REQUEST FOR INVESTIGATION OF NORTHERN STATES POWER COMPANY'S PRACTICES REGARDING ENERGY MARKETING AND THE FUEL CLAUSE, DOCKET NO. E002/CI-00-415

On April 3, 2000, the Residential and Small Business Utilities Division of the Office of Attorney General (OAG) requested that the Commission initiate a summary investigation under Minn. Stat. §216B.21 into whether Xcel's cost allocations between retail ratepayers and wholesale electric sales was just and reasonable as to retail rates. On April 20, 2001, the OAG stated that a formal investigation was no longer warranted so long as Xcel complies with certain reporting requirements.

In its Order dated June 15, 2001, in Docket No. E002/CI-00-415, Ordering Paragraph No. 2, the Commission required Xcel Electric to provide a monthly comparison of generation costs allocated to retail and wholesale customers for the months of June, July, and August with its AAA report to ensure that the Company is reasonably allocating generation costs between retail and wholesale customers. Xcel Electric included this data for the first time in its annual reporting filings on September 4, 2001 in Schedule 2 of Attachment G. Xcel Electric has since provided this data in its annual reporting filings for all years to date.

In its filing for FYE18, the monthly generation costs allocated to retail and wholesale customers was provided for 2018.[7] Xcel illustrated its monthly comparison of generation cost allocation between retail and wholesale classes for the months of June, July and August of 2018.

The Department reviewed Xcel's monthly comparisons of generation costs allocated to retail customers and the wholesale sector, and noted that the information filed by the Company appears to comply with the requirements of the Commission's Order. Xcel's data indicated that for all three months in 2018, the average generation costs allocated to retail customers were less than the average generation costs allocated only to the wholesale sector.

The Department notes that a high-level check of the allocations between retail and wholesale customers remains helpful to ensure that lowest cost resources continue to be assigned to retail customers. Based on our review of the 2018 data, the Department recommends that the Commission accept Xcel Electric's compliance filing, including the high-level cost allocation test between wholesale and retail customers for June, July, and August of 2018. The Department recommends that the Commission continue to require Xcel Electric to report this generation cost allocation data in its next AAA filing under the current FCA process, as required by Docket No. E002/CI-00-415, Ordering Paragraph No. 2.

B. IN THE MATTER OF A REQUEST BY NORTHERN STATES POWER COMPANY, D/B/A XCEL ENERGY FOR COMMISSION APPROVAL OF GAS FINANCIAL INSTRUMENTS FOR WHOLESALE ELECTRIC TRANSACTIONS: XCEL ELECTRIC'S COMPLIANCE FILING, DOCKET NO. E002/M-01-1953

On March 20, 2002 in Docket No. E002/M-01-1953, the Commission approved a request by Xcel Electric for accounting treatment and related processes necessary to separate the cost accounting for natural gas financial instruments purchased to meet the needs of jurisdictional retail electric and natural gas customers from the natural gas financial instruments purchased to support Xcel Electric's non-jurisdictional wholesale electric sales activities. With Commission approval, Xcel Electric proposed to submit a written request that their external auditors specifically examine these transactions in preparation of the auditor's report to be submitted with Xcel Electric's FYE02 electric and natural gas

[7] This information was provided in part as Part H, Section 2, Schedule 1 in the initial filing of Docket No. E999/AA-18-373 on September 1, 2018, and was subsequently provided in full in a supplemental filing in the same Docket on October 15, 2018.

AAA reports and purchased gas adjustment true-up to be filed September 1, 2002, to ensure that the accounting separation is implemented appropriately.

Xcel Electric's FYE18 AAA report includes a copy of the prescribed letter by Xcel Electric to its external auditors[8] and a copy of the Deloitte & Touche, LLP Independent Auditors' Report,[9] which concluded:

We have performed the procedures enumerated below, which were agreed to by Northern States Power Company, a Minnesota Corporation (the "Company") and the Minnesota Public Utilities Commission (the "Commission") (the specified parties), solely to assist you with the compliance of Rules 7825.2700 to 7825.2820 governing automatic adjustment of energy charges, and with the Fuel Clause Riders and Dockets as defined on Sheet Nos. 5-91, 5-91.1, 5-91.2, and 5-91.3 of the electric rates filed by the Company with the Commission, as well as with Docket No. E002/MR-15-827….

j. Through inspection of a sample of eleven accounting records, we identified no exceptions with the accounting separation of retail and wholesale financial instruments.

k. On a sample basis, we inspected vendor invoices and traced gains and losses to the accounting records for one selection. We did not identify any wholesale electric financial instrument gains or losses recorded in Account 555 or Account 804.

The Department concludes that Xcel Electric's Natural Gas Financial Instruments compliance filing complies with the Commission's Order in Docket No. E002/M-01-1953. The Department intends to review Xcel Electric's continued compliance with this requirement in future AAA filings.

C. XCEL ELECTRIC'S WIND CURTAILMENT REPORT, IN THE MATTER OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY'S ANNUAL AUTOMATIC ADJUSTMENT OF CHARGES REPORTS FOR ITS ELECTRIC AND GAS UTILITY OPERATIONS AND PURCHASED GAS ADJUSTMENT TRUE-UP FILING, DOCKET NO. E,G999/AA-04-1279, AND IN THE MATTER OF A REQUEST BY NORTHERN STATES POWER COMPANY, D/B/A XCEL ENERGY FOR APPROVAL OF A POWER PURCHASE AGREEMENT WITH NAVITAS ENERGY. LLC, DOCKET NO. E002/M-02-51.

In the past, various Commission Orders emphasized reporting and regulatory review of the curtailment practices used by Xcel Electric in connection with its wind Purchased Power Agreements (PPAs).

The Department notes that our May 10, 2005 extensive review of Xcel Electric's wind curtailments in Docket No. E999/AA-04-1279 provides a thorough background on the issue of wind curtailment payments. In its April 4, 2006 Order in that docket, the Commission required in Ordering Paragraph 5 that "Xcel shall continue to track all curtailments and curtailment payments and report on them in its monthly and AAA filings."

In addition, Ordering Paragraph 7 of that Order required Xcel Electric to "provide an annual assessment of wind commitments and available or planned transmission capacity" and to "include projected

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[8] See Part F, Schedule 1 of Xcel Electric's FYE18 AAA report.
[9] See REVISED Part F, Schedule 2 of the Xcel Electric's FYE18 AAA report, as supplemented on March 7, 2019.

curtailment payments related to wind for a five-year time period in light of planned and existing projects and commitments to update the system."

For this FYE18 AAA Report, the Department concludes that Xcel Electric is in compliance with the Commission's April 4, 2006 Order *Adopting Treatment of Curtailment Payments to Wind Developers through FCA and Requiring Compliance Filings* in Docket No. E999/AA-04-1279. In particular, Xcel Electric included in its FYE18 AAA filing a report on its projected wind curtailment payments over the 2018-2022 period for planned and existing projects and any commitments made to update the system.[10]

The Department reviewed Xcel Electric's wind curtailment data. Curtailment costs have been substantially reduced from their peak during FYE05 from 16.50 percent of the total cost of wind, including curtailments, to 8.3 percent in FYE08 and 1.8 percent in FYE13. While curtailment costs increased substantially to 9.4 percent in FYE14, they were down again at 4.4 percent in FYE15 and are at their lowest level in the last thirteen years in FYE18, 0.27 percent.[11]

The Department notes that Xcel Electric's FYE18 wind curtailment report (Wind Report) indicates that, similar to previous wind reports, most of the curtailment payments are related to MISO directives (curtailment reason code 3).[12]

The Department recommends that the Commission accept Xcel Electric's FYE18 Wind Curtailment compliance filing.

D. IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC UTILITY SERVICE IN MINNESOTA, FCA SETTLEMENT AGREEMENT (XCEL ELECTRIC'S COMPLIANCE FILING IN DOCKET NO. E002/GR-05-1428)

During Xcel Electric's 2005 rate case (Docket No. E002/GR-05-1428), the Minnesota Chamber of Commerce and the Large Industrial Group entered into an FCA Settlement Agreement with Xcel Electric. The settlement included several commitments by Xcel Electric intended to provide customers with more information and analysis to enhance the ability of customers to plan for and manage volatility in fuel costs. Xcel Electric's FYE18 AAA filing included more discussion on Xcel Electric's plans for hedging fuel or energy purchases and more analysis of Xcel Electric's attempts to mitigate volatility, cover risks associated with planned outages and optimize hedging of congestion costs. The additional information also included a dollar-per-megawatt-hour ($/MWh) price to show the rolling 12-month average cost quarterly based on expected market conditions.

The Department was not a party to this settlement, and thus invites comments on this information from those who were parties, regarding whether there are any concerns that need to be addressed.

[10] Part H, Section 5, Schedule 2 of Xcel Electric's FYE18 AAA report.
[11] Source: Attachment D1 to this report.
[12] Part H, Section 5, Schedule 1 of Xcel Electric's FYE18 AAA report.

E. HISTORY OF NUCLEAR FUEL SINKING FUND, DOCKET NO. E002/M-81-306

In the Commission's March 16, 2018 Order Accepting Reports and Setting Additional Requirements in Docket No. E999/AA-16-523, Ordering Paragraph 4 stated:

> The Commission hereby discontinues Xcel's Nuclear Fuel Sinking Fund reporting requirement established by Commission order dated July 14, 1981, in Docket No. E-002/M-81-306. The reporting requirement shall restart if Xcel becomes responsible for nuclear fuel interim storage and disposal expenses to the U.S. Department of Energy in the future.

In accordance with the Commission's March 16, 2018 Order, Xcel did not include a Nuclear Fuel Sinking Fund Compliance in its FYE18 AAA filing.

F. OFFSETTING REVENUES AND/OR COMPENSATION RECEIVED BY IOUS (IN THE MATTER OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY'S PETITION FOR APPROVAL OF A RENEWABLE ENERGY PURCHASE AGREEMENT WITH KODA ENERGY, LLC, DOCKET NO. E002/M-08-1098, IN THE MATTER OF XCEL ENERGY'S PETITION FOR APPROVAL OF A POWER PURCHASE AGREEMENT WITH DIAMOND K DAIRY, INC., E002/M-10-486 AND IN THE MATTER OF THE REVIEW OF THE 2009-2010 ANNUAL AUTOMATIC ADJUSTMENT REPORTS FOR ALL ELECTRIC UTILITIES E999/AA-10-884)

In its January 29, 2009 Order in Docket No. E002/M-08-1098 (2009 Order), the Commission required Xcel Electric to report in future AAA filings all revenue from any source as a result of a Renewable Energy Purchase Agreement with KODA Energy, and to itemize any such revenue by source and amount.

Xcel Electric stated that "the Company has not received any new revenue as described in this Order."[13] Therefore, the Department concludes that Xcel Electric complied with the 2009 Order.

In its August 26, 2010 Order in Docket No. E002/M-10-486 (2010 Order), the Commission required Xcel Electric to offset its recovery of costs by all revenues the Company receives from any and all sources as a result of Xcel Electric's power purchase agreement with Diamond K Dairy, and to report and itemize any such revenues by source and amount in its annual automatic adjustment reports.

Xcel Electric stated that "the Company has not received any new revenue as described in this Order."[14] Therefore, the Department concludes that Xcel Electric complied with the 2010 Order.

In its April 6, 2012 Order in Docket No. E999/AA-10-884 (2012 Order), the Commission required the IOUs to report in future AAA filings any offsetting revenues or compensation recovered by the utilities as a result of contracts, investments, or expenditures paid for by their ratepayers. If any offsetting revenues and/or compensation are not credited back to a utility's ratepayers through the fuel clause,

[13] Source: Part H, Sections 1-10, page 4 of 6 of Xcel Electric's FYE18 AAA report.
[14] Source: Part H, Sections 1-10, pages 4-5 of 6 of Xcel Electric's FYE18 AAA report.

the IOUs should clearly identify such revenues or compensation by source and amount and fully justify their action in the relevant AAA filings.

The IOUs indicated that they passed any such offsetting revenues or compensation through the fuel clause. Therefore, the Department concludes that the IOUs complied with the April 6, 2012 Order in Docket No. E999/AA-10-884 (Ordering Point 8).

The Department will continue to monitor the treatment of offsetting revenues and compensation recovered by the utilities in future filings.

G. MAINTENANCE EXPENSES OF GENERATION PLANTS (IN THE MATTER OF THE REVIEW OF THE 2005 ANNUAL AUTOMATIC ADJUSTMENT OF CHARGES FOR ALL ELECTRIC AND GAS UTILITIES, DOCKET NO. E999/AA-06-1208)

In its February 6, 2008 Order in Docket No. E999/AA-06-1208 (the 06-1208 Order), the Commission required all electric utilities subject to automatic adjustment filing requirements, with the exception of Dakota Electric, to include in future annual automatic adjustment filings the actual expenses pertaining to maintenance of generation plants, with a comparison to the generation maintenance budget from the utility's most recent rate case.

This requirement stems from the drastic increase in IOUs' outage costs during FYE06 and FYE07.[15] When a plant experiences a forced outage, the utility must replace the megawatt hours that plant would have produced if it had been operating, usually through wholesale market purchases. The cost of those purchases flows through the FCA directly to ratepayers. The high level of outage costs in FYE06 and FYE07 raised the issues of whether plants were being maintained appropriately to prevent forced outages, and whether IOUs were spending as much on plant maintenance as they were charging to their customers in base rates. The Commission agreed with the Department and the Large Power Interveners that "utilities have a duty to minimize unplanned facility outages through adequate maintenance and to minimize the costs of scheduled outages through careful planning, prudent timing, and efficient completion of scheduled work." 06-1208 Order at 5.

Due to delays to the filing of the Department's FYE17 analysis, the Department updated that report with actual data for 2017. At the time the utilities filed their annual AAA filings, 2018 actuals were not yet available, and thus there is no additional data included in the FYE18 filings. The Department summarizes the maintenance spending of Xcel, OTP, and MP below. As stated in the Department's FYE17 analysis, Xcel, OTP, and MP are all spending less on maintenance of their generation facilities than was budgeted in their most recent rate cases. The Department also notes that, as shown in Attachment D2 to this Report, outage costs have decreased as a share of net energy costs since FYE07 and FYE08.

[15] Department Attachment D2 shows that outage costs have decreased as a share of energy costs since FYE07.

Table 3
Comparison of Generation Maintenance Expense[16]
($ Millions)

	Test Year	Rate Case Budgeted	Actual 2016-2017 Average	Difference
Xcel	2016	184.7	174.2	-5.7%
OTP	2016	15.1	13.1	-13.5%
MP*	2017	42.5	38.6	-9.3%

*MP's average is limited to its 2017 actuals.

Due to the link between the level of maintenance expense and forced outages, and due to the different ratemaking incentives that have existed for maintenance expenses versus replacement fuel costs (incentive to minimize operations and maintenance expense between rate cases with little to no incentive to minimize replacement power costs), the Department intends to continue to monitor the IOUs' actual expenses pertaining to maintenance of generation plants, with a comparison to the generation maintenance budget from the IOUs' recent rate cases in future AAA filings. The Commission's recent decision[17] to amend the FCA mechanism is expected to more closely align utilities' incentives regarding operations and maintenance costs and fuel costs. However, the Department will also continue to monitor outage costs on a going-forward basis.

The Department requests that Xcel, OTP, and MP provide the actual versus budgeted data for generation maintenance expense for 2018 in reply comments.

H. PLANT OUTAGES CONTINGENCY PLANS (IN THE MATTER OF THE REVIEW OF THE 2008 ANNUAL AUTOMATIC ADJUSTMENT REPORTS FOR ALL ELECTRIC UTILITIES, DOCKET NO. E999/AA-08-995)

In its March 15, 2010 Order, the Commission required the following in Ordering Paragraph 12:

> All electric utilities required to file annual automatic adjustment reports shall work with their contractors to identify and develop reasonable contingency plans to mitigate against the risk of delays or lack of performance when contractors perform poorly and increase costs during plant outages. The Commission asks the OES [Department] to continue monitoring this issue and to include a report on the electric utilities' plans in its next review.

[16] Source: Attachment D3.

[17] See the Commission's December 19, 2017 *Order Approving New Annual Fuel Clause Adjustment Requirements and Setting Filing Requirements* in Docket No. E999/CI-03-802.

This requirement first stemmed from the drastic increase in OTP's energy costs due to replacement power costs in November ($39/MWh) and December 2007 ($51.20/MWh) caused by a contractor's failure to perform the contracted work for a planned outage of the Big Stone plant.

In its FYE07 AAA report, the Department requested suggestions from the utilities regarding improving outage-related contracts to better protect ratepayers. In response, the utilities appeared to jointly state that "while we attempt to include contract terms or performance bonds to indemnify us for delays or lack of performance, requiring a contractor to indemnify us for replacement energy cost is cost prohibitive." (MP's September 29, 2009 reply comments at 9). However, utilities did not provide evidence to support that position, nor did they suggest other methods to protect ratepayers from paying for high replacement power costs during forced (unforeseen) outages.

The Department continued to attempt to generate a useful discussion to identify ways to ensure that ratepayers were better protected from delays or lack of performance through the lessons learned by the utilities.

While MP stated that "[d]uring this period, there were no delays or lack of performance by contractors,"[18] OTP[19] and Xcel[20] shared a useful summary of their processes and procedures to address poor contractor performance.

I. SHARING LESSONS LEARNED REGARDING FORCED OUTAGES (IN THE MATTER OF THE REVIEW OF THE 2009-2010 ANNUAL AUTOMATIC ADJUSTMENT REPORTS FOR ALL ELECTRIC UTILITIES, DOCKET NO. E999/AA-10-884)

In its April 6, 2012 Order in Docket Nos. E999/AA-09-961 and E999/AA-10-884, the Commission required the IOUs to provide in supplemental filings to their FYE11 AAA reports (in Docket No. E-999/AA-11-792) and in future AAA reports, a simple annual identification of forced outages and a short discussion of how such outages could have been avoided or alleviated.

In their FYE18 AAA filings, the IOUs provided the required information. Therefore, the Department concludes that the IOUs complied with the reporting requirement of Order Point 22 of the April 6, 2012 Order in Docket No. E999/AA-10-884.

J. IN THE MATTER OF OTTER TAIL POWER COMPANY'S PETITION FOR APPROVAL OF A MONTHLY FUEL CLAUSE ADJUSTMENT TRUE-UP PROVISION: FCA TRUE-UP REPORT IN DOCKET NO. E017/M-03-30

In its Order dated December 27, 2006, the Commission provided specific true-up procedures applicable to the Otter Tail's annual true-up filings.

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[18] Source: Attachment 19 of MP's FYE18 AAA report.
[19] Source: Part H, Section 5 of OTP's FYE18 AAA report.
[20] Source: Part K, Section 3, pages 1-2 of 2 of Xcel Electric's FYE18 AAA report.

On July 31, 2018, Otter Tail submitted a compliance report and proposal to implement a true-up credit (decrease in rates) of $0.0004 per kWh. In comments filed on August 29, 2018, the Department recommended that the Commission approve Otter Tail's compliance report and the true-up credit. The Commission's October 9, 2018 Order approved Otter Tail's true-up decrease in rates beginning September 1, 2018.

K. IN THE MATTER OF XCEL ENERGY'S PETITION FOR APPROVAL OF REPLACEMENT POWER PURCHASE AGREEMENT WITH WM RENEWABLE ENERGY. LLC, CURTAILMENT OF WM RENEWABLE ENERGY, DOCKET NO. E002/M-10-161

In its April 30, 2010 Order (2010 Order) in Docket No. E002/M-10-161, the Commission required Xcel Electric to report on any curtailment of wind energy from WM Renewable Energy, including the reasons for any such curtailments and the amounts paid, in Xcel Electric's monthly fuel clause adjustment filings.

Xcel Electric stated that "the Company is not aware of any curtailments or curtailment payments during the current reporting period."[21] Therefore, the Department concludes that Xcel Electric complied with the 2010 Order in Docket No. E002/M-10-161 regarding WM Renewable Energy.

L. IN THE MATTER OF A PETITION BY MINNESOTA POWER FOR APPROVAL OF A POWER PURCHASE AGREEMENT WITH MANITOBA HYDRO, REPORT ON MP'S PPA WITH MANITOBA HYDRO (DOCKET NO. E015/M-10-961)

The Commission's March 11, 2011 Order in Docket No. E015/M-10-961 required MP to provide in its annual AAA report information regarding the number of times certain energy products were offered by Manitoba Hydro to MP, the number of times such offers were accepted, and various energy price comparisons.

MP provided the required reporting information in compliance with the Commission's Order in Docket No. E015/M-10-961 regarding Manitoba Hydro PPA.[22]

M. IN THE MATTER OF XCEL ENERGY'S REQUEST FOR APPROVAL OF A COMMUNITY SOLAR GARDEN PROGRAM, DOCKET NO. E002/M-13-867.

In its September 17, 2014 Order in Docket No. E002/M-13-867,[23] the Commission approved Xcel Electric's proposal to recover Community Solar Garden (CSG) program costs, including customer bill credits, additional Renewable Energy Credits (RECs), and unsubscribed energy, through the FCA mechanism. The first solar garden in Xcel Electric's program came online in September 2015. As noted by Xcel in Part E, Section 2, Page 4 of 4, of its FYE18 AAA Report, as of June 2017, the Company has

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[21] Source: Page 109 of 375 of Xcel Electric's FYE18 AAA report.
[22] Source: Attachment No. 14 of MP's FYE18 AAA report.
[23] *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of its Proposed Community Solar Garden program*, ORDER APPROVING SOLAR GARDEN PLAN WITH MODIFICATIONS, September 17, 2014, Docket No. E002/M-13-867.

been recovering monthly fuel costs from 111 community solar gardens.[24] Xcel's total Community Solar Garden cost recovery in the FYE18 AAA period was $40,464,368 as shown on Part H, Section 9, Schedule 2, Page 1 of 1.

The Department reviewed Xcel Electric's Community Solar Garden program costs and was able to tie the solar costs to Xcel Electric's monthly FCA filings. Xcel stated that it allocates CSG costs to its various jurisdictions by dividing the costs into market and above-market categories by reviewing solar garden production by hour and the corresponding Locational Marginal Price (LMP)[25] at that hour. Market costs are allocated to each jurisdiction based on sales, while costs above market are directly assigned to the Minnesota fuel clause.[26] Based on our review, the Department concludes that the Community Solar Garden Program costs included in Xcel Electric's FCA appear reasonable.

N. TRANSFORMER REPORTING

In its August 31, 2009 Order in Docket Nos. E999/AA-07-1130, E999/M-07-1028, and E999/M-09-602, the Commission required all utilities (except Dakota Electric Association) to provide the following information regarding transformers in their 2009 AAA filings:[27]

a. the number of transformers exceeding 100 kilovolts on their system and the size of each transformer;
b. an analysis as to whether they are maintaining in inventory or otherwise have reasonable access to a reasonable number of spare transformers in different sizes so as to avoid excessive replacement power costs during outages.

In its August 16, 2013 Order in Docket No. E999/AA-11-792, the Commission required all utilities (except Dakota Electric Association) to include the following information regarding transformers in future AAA filings:[28]

a. use Xcel's reporting format for the table found in Part H, Sections 1 – 8, page 3 of 6, but with the incorporation of all transformers on a utility's system, and with status of each transformer identified as one of these four categories: in-service standalone, in-service duplicate, on-order, or storage.
b. provide information regarding policy on backup strategies for transformers like MP did in their Attachment 13.
c. provide their policy for transformer maintenance.

[24] See Part H, Section 9, Schedule 1, Page 1 of 1 of Xcel Electric's FYE18 AAA report for more information on the 111 solar gardens.
[25] The Locational Marginal Price is the cost of providing the next megawatt of electrical energy at a specific location on the grid.
[26] Part H, Sections 1-10, page 6, of Xcel Electric's FYE17 AAA report in Docket No. E999/AA-17-492.
[27] See the Commission's August 31, 2009 Order in Docket No. E999/AA-07-1130, Ordering Point No. 16.
[28] See the Commission's August 16, 2013 Order in Docket No. E999/AA-11-792, Ordering Point No. 23.

Xcel Electric provided its transformer reporting in Part H, Section 4, page 2 of 6 of its FYE18 AAA Report. In addition, Xcel Electric provided a schedule showing the status of each transformer that exceeds 100 kilovolts in Part H, Schedule 1 of its FYE18 AAA Report.

As explained in the Department's October 19, 2018 comments in Docket 17-492, Xcel Electric did not provide information in its initial filing in Docket 17-492 regarding its backup strategies for transformers or their policy for transformer maintenance. As a result, the Department recommended that Xcel Electric provide this information in reply comments. Xcel Electric provided this information in reply comments, which the Department reviewed and concluded that Xcel Electric provided the relevant information in accordance with the Commission's August 16, 2013 Order in Docket No. E999/AA-11-792 and recommended that the Commission accept Xcel Electric's transformer reporting for FYE17.

As in Docket 17-492, Xcel Electric failed to provide in its FYE18 AAA filing the required information regarding Xcel Electric's backup strategies or transformer maintenance policies. The Department recommends that Xcel Electric provide this information in reply comments. The Department will make its overall recommendation regarding Xcel Electric's FYE18 transformer reporting after it reviews Xcel Electric's reply comments.

MP provided its transformer reporting in Attachment 13 of its FYE18 AAA Report. Similar to Xcel Electric, the Department noted in its October 19, 2018 Comments in 17-492 that MP did not provide their policy for transformer maintenance. Similarly, MP's FYE18 filing does not include information regarding MP's transformer maintenance policy. The Department recommends that MP provide this information in reply comments. The Department will provide its recommendation regarding MP's FYE18 transformer reporting after it has reviewed MP's reply comments.

OTP provided its transformer reporting in Attachment H, Section 8 of its FYE18 AAA Report. The Department reviewed OTP's transformer reporting and concludes that the required information was provided in accordance with the Commission's August 16, 2013 Order. As a result, the Department recommends that the Commission accept OTP's transformer reporting for FYE18.

O. HENNEPIN ENERGY RECOVERY CENTER

The Commission's December 28, 2017 *Order Rejecting Proposed Amendment to Power Purchase Agreement* in Docket No. E002/M-17-532 rejected Xcel Electric's proposed amendment to a power purchase agreement (PPA) with the Hennepin Energy Recovery Center (HERC), which was to define pricing terms during a seven-year extension period. Subsequently, Xcel Electric's February 1, 2018 *Response to Reconsideration Request* clarified that "[t]he Second Amendment provides for interim market based pricing for energy sold to the Company after December 31, 2017, at the day-ahead MISO locational marginal price (LMP), adjusted for any applicable MISO market charges and real-time settlement differences."

The Department reviewed the costs Xcel Electric attributed to the HERC power purchase agreement. Specifically, the Department attempted to match the hourly, day-ahead locational marginal pricing data (DALMP)—used by Xcel Electric to calculate the monthly billing as provided by Xcel Electric in the Company's October 15, 2018 filing—to the historical DALMP data available on the Midcontinent

Independent System Operator, Inc. (MISO) website.[29] During the comparison the Department determined that data used by Xcel Electric to calculate the monthly billing is offset by one hour when compared to the data on MISO's website. For example, MISO's data shows a DALMP of $30.76 for January 1, 2018 hour ending (HE) 2 and $30.90 for HE 3; however, Xcel Electric's bills use $30.76 for HE 1 and $30.90 for HE 2. However, Xcel Electric explained that MISO data is shown in the eastern time zone while Xcel Electric's Minnesota bills are based on central time, hence the one hour difference.

In summary, the Department concludes that Xcel Electric has correctly calculated the interim costs of the HERC power purchase agreement.

*P. RENEWABLE*CONNECT COSTS*

The Commission's February 27, 2017 *Order Approving Pilot Programs and Requiring Filings* in Docket No. E002/M-15-985 approved Xcel Electric's proposals for implementing the Renewable*Connect and Renewable*Connect Government programs (Green Pricing), on a pilot basis. The Commission's approval was contingent upon Xcel Electric adjusting its MISO-accredited wind- and solar-capacity assumptions to reflect MISO's updated values for 2016/2017 planning year.

Regarding the Green Pricing programs, the Department reviewed the wind and solar energy mix, the costs of the associated energy mix, the cost exclusion attributable to the neutrality charge, and how the various amounts flowed through the fuel clause adjustment calculations.

The Department did not identify any issues in Xcel Electric's inputs, calculations, or outputs. Therefore, the Department concludes that Xcel Electric has correctly calculated the costs of the Green Pricing programs that appear in the fuel clause adjustment.

Q. INVER HILLS TANK SALE REFUND

On February 16, 2018, the Commission issued its *Order Approving Petition with Conditions, Approving Cost Recovery Proposal, and Granting Variances* (February 16 Order) in Docket No. E002/PA-17-529 approving Xcel Electric's request to keep a portion of the gain on the sale of land and oil tanks to Flint Hills Resources Pine Bend (Flint Hills). The Order also required Xcel Electric to update 1) its fuel oil loss calculation for fuel prices at the closing of the transaction and 2) file a letter within 10 days of closing on the transaction illustrating Xcel Electric's final calculations.

The Commission's June 18, 2018 *Order Approving Compliance Filing With Modification* (June 18 Order) in Docket No. E002/PA-17-529 approved Xcel Electric's compliance filing, but substituted Commission staff's transaction gain calculation of $0.941 million in place of Xcel Electric's proposed gain calculation; the $0.253 million difference was to be added to the customer's gain portion in the Flint Hills transaction.

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[29] The data is available at: DALMP Data

Xcel Electric's monthly FCA filing in Docket No. E002/AA-18-525 added a credit of $253,000 to the credit provided through the FCA to its ratepayers in Docket No. E002/AA-18-24 of $1,929,053, for a total of $2,282,053 for the Flint Hills transaction. These credits were made to comply with the February 16 Order and June 18 Order in Docket No. E002/PA-17-529.

The Department reviewed Xcel Electric's information and concludes that the total credit of $2,282,053 for the Flint Hills transaction complies with the Commission's February 16 Order and June 18 Order.

R. SHERCO LAND SALE REFUND

On February 6, 2018 in Docket No. E002/PA-17-528, the Commission issued an order (February 6 Order) approving Xcel Electric's proposed options for the potential sales of 50 acres of land at the Sherburne County Generating Station (Sherco) to Northern Metals LLC and 315.2 acres of Sherco land to Jet Stream LLC. The February 6 Order also approved Xcel Electric's proposal to refund the transactions' net gains through the FCA.

Xcel Electric's monthly FCA filing in Docket No. E002/AA-18-525 included a credit of $1,275,903 to be flown through the FCA to comply with the Commission's February 6 Order in Docket No. E002/PA-17-528. This amount is slightly above the net gain of $1,222,631 for the Northern Metals LLC transaction by Xcel Electric in its petition in Docket No. E002/PA-17-528.

The Department reviewed Xcel Electric's information and concludes that the total credit of $1,275,903 complies with the Commission's February 6 Order.

IV. TOTAL FUEL COST REVIEW

A. OVERVIEW

Minn. Rules 7825.2390 to 7825.2920 allow IOUs to use the cost per kWh from the most recent two-month moving average of energy costs (current period cost of energy) as an estimate or forecast of the energy cost per kWh for the current period. Minn. R. 7825.2400, subpart 13. This estimate of energy costs in the next month is a simple forecast based on the average cost of energy from the most recent two months. The Rules allow the utility to recover its current period cost of energy in both its base rates (where the base cost of energy is set) and its FCA (where changes to energy costs, as defined in the Commission's rules are recovered), which totals the current period cost of energy. This is the calculation the utility must use to calculate the FCA, unless the utility has received a variance from the Commission allowing the utility to use a different method.

The Department notes that there are differences among the electric IOUs in how the fuel cost adjustment is calculated. Xcel Electric was granted a variance to charge FCA rates based on Xcel Electric's forecast of fuel costs in the upcoming month, rather than the two-month average cost per kWh required by Minnesota Rules. Further, Xcel Electric adjusts its rates to refund or recover previous over- and under-recoveries of its energy costs through a monthly true-up. DEA and OTP both have an annual true-ups to refund or recover previous over- and under-recoveries of their energy costs. MP did not receive a variance to use a different method and, as a result, MP recovers its current period cost of energy on a monthly basis as provided by the Rules, and does not have a true-up mechanism.

B. DAKOTA ELECTRIC ASSOCIATION

Dakota serves about 105,000 Minnesota electric customers in the southern metropolitan area, in Dakota, Goodhue, Scott and Rice counties. Department Attachment D4 shows that DEA's resource adjustment includes $150,144,028 or $82.12/MWh in fuel costs, which includes generation capacity and transmission costs from its suppliers, during the reporting period.[30] This amount is approximately .17 percent lower than the $82.26/MWh cost in FYE17.

DEA recovered $147,951,133 in fuel costs and thus under-recovered fuel costs in FYE18 by $2,192,895, or 1.46 percent.

Regulated utilities normally recover through their automatic adjustments only changes from the amounts set in a rate case for costs of fuel and cost of energy obtained through purchased power agreements (PPAs); changes in capacity costs are typically not reflected in fuel adjustment clauses. As an electric cooperative providing only distribution service, however, Dakota requires special consideration because it recovers variations in purchased capacity costs as well as energy costs through the fuel adjustment clause. Ordinarily, the inclusion of these costs makes Dakota's monthly over- and under-recoveries potentially greater than those experienced by utilities that only include fuel and PPA costs in their fuel clause. Changes in sales can result in a significant gap between the utility's actual purchased capacity costs per kWh and the purchased capacity costs per kWh built into its base rates. To account for potential discrepancies between its actual and recovered costs through its automatic adjustment, Dakota calculates and applies an annual fuel-cost true-up factor based on these discrepancies.

C. MINNESOTA POWER

Minnesota Power serves about 122,000 electric customers in northeastern Minnesota. MP's fuel costs were $184,402,448 for FYE18.[31] MP under-recovered its fuel costs by $4.68 million in FYE18, or approximately 2.54 percent of its actual costs. Compared to FYE17 fuel costs of $20.84/MWh, MP's costs in FYE18 of $21.75/MWh were 4.4 percent higher.[32]

The Department notes that MP's level of under-/over-recovery varies from month to month. In FYE18, MP's monthly under-/over-recoveries ranged from a $2.2 million under-recovery (July 2017), to a $1.1 million over-recovery (September 2017).

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[30] Subject to Commission approval, Minnesota Rule 7825.2600 allows a utility that purchases at least 75 percent of its annual energy requirements to include capacity costs in its energy adjustment. Dakota does not have its own generation. Dakota purchased all its FYE18 energy needs from power suppliers, Great River Energy (GRE) and Energy Alternatives (EA).

[31] See Department Attachment D5.

[32] See Department Attachment D8.

D. *OTTER TAIL POWER COMPANY*

Otter Tail serves more than 61,000 Minnesota electric customers, primarily in western Minnesota. During the reporting period, OTP's total fuel costs were $59,865,677 or $23.75/MWh for OTP's Minnesota operations in FYE18.[33] This level is 1.2 percent lower than the $24.04/MWh cost in FYE17.[34]

During FYE18, Otter Tail experienced a 1.6 percent over recovery as a whole. As a result, the Commission's October 9, 2018 Order approved Otter Tail's true-up decrease in rates beginning September 1, 2018.[35]

E. *XCEL ELECTRIC*

Xcel Electric, which serves about 1.2 million electric customers in Minnesota, primarily in the metro area, had energy costs of $766,010,118 for FYE18, or $25.60/MWh.[36] This level is 2.1 percent higher than the $25.08/MWh cost in FYE17.[37]

Xcel Electric is the only electric utility to use a forecasted FCA method. Under this method Xcel Electric bases its monthly FCA on its one-month projection of fuel and purchased power costs. Xcel Electric uses this method in lieu of a forecast based on the average of the most recent two months of known costs as specified by Minnesota Rules. The Commission also allowed Xcel Electric to make an additional adjustment to its forecasted FCA to true-up any over- or under-recovery of costs that it experienced two months prior to the month in which it applies a new FCA.

During the Department's review of Xcel Gas' AAA filing in Docket No. G999/AA-18-374, the Department became aware of an issue involving the allocation of natural gas costs between Xcel Gas' retail customers and Xcel Electric's generation facilities. While this issue is discussed in more detail in the Department's April 25, 2019 comments in Docket No. G999/AA-18-374, the Department notes that this issue may result in an adjustment to Xcel Electric's FYE18 fuel costs. In Docket No. G999/AA-18-374, the Department asked Xcel Electric to submit information on the allocation issue in both the electric and natural gas AAA proceedings. The Department will review Xcel's supplemental information and provide supplemental comments should an adjustment to Xcel Electric's FYE18 fuel costs be warranted.

V. EFFECTS OF MISO DAY 1 ON MINNESOTA RATEPAYERS

On March 28, 2002, the Commission approved petitions requesting the transfer of functional control of certain transmission facilities to MISO from the following IOUs:

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[33] See Department Attachment D6.
[34] See Department Attachment D8.
[35] See Docket No. E017/M-03-30.
[36] See Department Attachment D7.
[37] See Department Attachment D8.

- Xcel Electric, Docket No. E002/M-00-257, Order issued May 9, 2002;
- Minnesota Power, Docket No. E015/PA-01-539, Order issued April 26, 2002; and,
- Otter Tail Power, Docket No. E017/PA-01-1391, Order issued May 9, 2002.

These three Minnesota electric investor-owned utility companies were required to provide the information below as part of their AAA reports. The Department summarizes the companies' responses to the seven ordering paragraphs as discussed below.

On July 21, 2017, the Commission in Docket No. E999/AA-15-611 approved excluding the MISO Schedule 10 review in the AAA reports. The Commission noted that because the MISO Schedule 10 information is filed by electric utilities in their general rate cases, which provides parties the opportunity for full record development on these issues, the MISO Schedule 10 review is not necessary in the AAA reports.[38] As a result, the Department has excluded the MISO Schedule 10 review from our MISO Day 1 review below.

The Department also notes that there may no longer be a need for the MISO Day 1 reporting, since the MISO Day 1 has been in operation since 2002 and we have not seen much in the way of concerns that have negatively impacted customers. The Department has discussed the MISO Day 1 reporting requirement with the electric utilities and the consumer advocates in the FCA reform proceeding, and all concluded that this MISO Day 1 reporting is no longer necessary. The Commission is scheduled to address the reporting requirements under the reformed FCA process at its April 25, 2019 Agenda Meeting.

A. ANY AMOUNT OF MISO ADMINISTRATIVE CHARGES DEFFERED BY MISO FOR LATER RECOVERY.

This reporting requirement pertains to MISO administrative charges (Schedule 10 costs) that were deferred as regulatory assets for later recovery. At the Department's request several years ago, the electric utilities provided the following comprehensive answer to describe MISO's deferred Schedule 10 costs:

> "Transmission Start-up Costs" are MISO operating costs incurred prior to initial start-up that were deferred in accordance with a FERC order. These costs are being recovered over a six-year period from MISO's customers through monthly charges under Schedule 10 of the MISO tariff. The "$0.15 per MWh Rate Cap" asset is for ongoing costs incurred but not recovered under Schedule 10 due to the $0.15 per MWh rate cap in place during the first six years of commercial operations. The rate cap ended on February 1, 2008. The "Current Schedule 10" rates based on forecasted billing units and actual costs for the month are included in subsequent months' rate calculations. These costs are classified as deferred regulatory assets, and will be recovered in a subsequent period.

[38] See pages 5 and 6 of the Commission's July 21, 2017 Order in Docket No. E999/AA-15-611.

In a March 26, 2003 compliance filing in response to the FERC's Order accepting a contested partial settlement in Dockets ER02-111 and ER02-652, MISO proposed changes to Schedule 10 to reflect deferral of $25 million of current expenditures that would have been recovered under Schedule 10 in 2003, but that were deferred until February 1, 2008, to be recovered over a five-year period. There are no additional deferrals beyond the $25 million.

During 2003 and 2004, MISO made payments to Grid America, Ameren and Illinois Power. These payments by MISO, net of the exit fees, totaled $40,319,000 and are being amortized over a 10-year period. Amortization of these costs ended as of September 30, 2013.

MISO has deferred costs associated with the integration of the Entergy Operating Companies, Cleco Power LLC, South Mississippi Electric Power Association, Lafayette Utilities Systems and East Texas Electric Cooperative. These deferred integration costs will be recovered over a five-year period, beginning on January 1, 2014, the date of the integration of the first Entergy Operating Company.

In the FYE18 AAA reports, the utilities noted there are no new MISO cost deferrals.

B. EACH INSTANCE WHERE MISO DIRECTED COMPANIES TO CURTAIL THEIR OWN GENERATION, FOR RELIABILITY REASONS, THAT RESULTED IN AN INTERRUPTION OF FIRM RETAIL ELECTRIC SERVICE TO RETAIL CUSTOMERS OF MINNESOTA.

All three utilities indicated that no such instances occurred during the FYE18 reporting period.

C. EACH INSTANCE WHERE MISO DIRECTED THE CURTAILMENT OF DELIVERY OF A FIRM PURCHASED POWER SUPPLY THAT SUBSEQUENTLY RESULTED IN AN INTERRUPTION OF FIRM RETAIL ELECTRIC SERVICE TO THE COMPANIES' RETAIL CUSTOMERS IN MINNESOTA.

All three utilities indicated that no such instances occurred during the FYE18 reporting period.

D. CHANGES TO MISO TARIFFS THAT MAY ULTIMATELY AFFECT THE RATES OF RETAIL CUSTOMERS IN MINNESOTA, AND ON COMPANIES' EFFORTS TO MINIMIZE MISO TRANSMISSION SERVICE COSTS.

The Companies provided various answers in their MISO Day 1 compliance filings on the effect of changes to MISO's tariffs on retail rates in Minnesota. Specifically:

- During the period July 1, 2017 to June 30, 2018, MISO submitted a significant number of filings to FERC, including proposed tariff changes to the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff), compliance filings, generation interconnection agreements subject to the Tariff, answers to complaints, and various other filings. Many of the proposed tariff changes and other filings may ultimately affect rates of retail electric customers in Minnesota in some manner. All MISO filings to FERC during the reporting period are available by month at the MISO web site (www.midwestiso.org) at the "FERC Filings and Orders" tab available under the "Library" tab on the MISO home page.

- The utilities indicated that they have participated in several ongoing efforts to minimize MISO transmission service cost. They stated that their representatives participated in the MISO Transmission Owners Committee and the Transmission Owners Tariff Working Group, which make decisions on certain rate and revenue distribution changes pursuant to the MISO Agreement. They also stated that they have closely monitored the Market Sub-Committee and OATT Business Practices efforts. Finally, they stated that they have been actively involved in the ongoing Regional Expansion and Cost Benefit Task Force (RECB).

- MISO has included Schedules 16 and 17 in its Open Access Transmission, Energy and Operating Reserve Markets Tariff. These schedules are related to MISO's implementation and administrative costs of the MISO energy market. Schedule 16 recovers costs associated with Financial Transmission Rights and Schedule 17 recovers costs associated with the day-ahead and real-time markets. Utilities noted that Schedule 16 and 17 costs have trended downward with expanded MISO membership.

E. AN ANNUAL ANALYSIS OF HOW THE TRANSFER OF OPERATIONAL CONTROL TO THE MISO HAS AFFECTED COMPANIES' OVERALL TRANSMISSION COSTS AND REVENUES AND OVERALL ENERGY COSTS FOR RETAIL CUSTOMERS, INCLUDING:

i. an analysis of how MISO membership has affected Companies' ability to use their own generation sources when they are the least-cost power source; and
ii. Companies' ability to access low-cost power on the wholesale market for their retail customers.

Generally, the utilities agreed that the transfer of operational control of transmission to MISO has not had a significant impact on overall transmission costs. The utilities noted some decreases in transmission revenues; however reduced transmission rates have benefited utilities that need to make energy purchases to serve native load customers. The utilities note that an overall net increase in transmission costs has occurred due to an increase in costs charged under Schedule 10, which pertains to MISO's administrative charges, offset by a decrease in costs due to elimination of transmission rate "pancaking" and elimination of the Mid-Continent Area Power Pool (MAPP) or Mid-America Interconnected Network (MAIN) fee.

The utilities generally agreed to continue to make use of the wholesale power market to provide low-cost energy for their customers. Utilities also indicated there have been times when they have been able to buy power below base load generation costs to the benefit of ratepayers.

In FYE18 and past AAA reports, Xcel Electric provided the following response[39] in regard to how MISO has affected Xcel Electric's ability to use its own generation sources when these are least-cost power sources:

> In summary, NSP makes Company-owned and purchased network resources available to the regional dispatch optimization. NSP uses

[39] Xcel Electric's AAA report in Docket No. E999/AA-18-373 in Part I, Sections 1-7 page 7 of 8.

> proprietary resource trading methods to ensure the least cost resources remain available for native supply, while ensuring that competitive regional supply alternatives have the opportunity to clear when they can provide energy at lower costs.
>
> In general, operation of the Day 2 market and ASM market has not negatively affected the Company's ability to use its own resources (Company-owned generation or bilateral purchased power) when those native resources are the least cost power resource. In particular, the Day 2 market has facilitated the integration of wind energy resources in the regional dispatch much more efficiently than would be the case if NSP system operations had continued on a stand-alone basis.
>
> The Company continues to experience the benefits and efficiencies of the MISO Day 2 and Day 3 Markets, which enhanced NSP's ability to access low-cost power. On a qualitative basis, NSP's experience with the regional generation dispatch market operated by MISO shows benefits related to integration of wind generation resources in the regional economic dispatch. Absent of the MISO provided access to generation on a large regional basis, NSP would experience more disruptive local dispatch requirements, thereby increasing costs for our customers.

F. CONCLUSIONS REGARDING MISO DAY 1

Overall the Department concludes that the Companies' responses have complied generally with all of the AAA MISO Day 1 compliance reporting requirements. The Department expects utilities to continue to work hard to mitigate costs or the effects of changes by MISO or FERC that could negatively impact Minnesota retail customers. Utilities are required to continue to show benefits of MISO Day 1 in the context of their rate cases before receiving further cost recovery of Schedule 10 costs.

VI. EFFECTS OF MISO DAY 2 ON MINNESOTA RATEPAYERS

A. BACKGROUND ON MISO DAY 2

This AAA report is based on twelve full years of data under the MISO Day 2 energy market. Due to the significance of the MISO Day 2 markets on Minnesota ratepayers, the Department dedicates this section to discussing the effects of this market on the way utilities procure energy and the way these costs are reflected in rates.

MISO's Day 2 energy market[40] both did and did not change the way utilities provide service to customers. On one hand, as noted by the Commission in its December 20, 2006 Order *Establishing Accounting Treatment for MISO Day 2 Costs* (Docket Nos. E002/M-04-1970, E015/M-05-277, E017/M-

[40] See the Open Access Transmission and Energy Markets Tariff (TEMT) in *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 101,163 (2004).

05-284, and E001/M-05-406), MISO's Tariff re-characterized the way utilities provide electricity for the customers they are obligated to serve (native load customers[41]), including retail customers. Traditionally the utilities generated most of the electricity needed to serve their customers, and bought or sold any surplus or deficit from or to neighboring utilities. In contrast, under MISO's Tariff, utilities sell all power from their electric generation and other resources into the wholesale market, and purchase power back from the market to provide electric service for their ratepayers.

On the other hand, the Commission required utilities to continue to use the lowest cost resources to serve retail customers, and this fundamental aspect of service did not change, due to MISO's order of dispatching resources into the wholesale market. Moreover, the Commission required a significant amount of oversight of the activity of utilities in the MISO Day 2 market. This oversight has included investigations, reports and various efforts to ascertain whether the utilities are, in practice, acting in the best interests of their customers in the Day 2 market. The following discusses more of the development of MISO Day 2.

On April 1, 2005, MISO began operation of the Day 2 Energy Market, pursuant to its Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff). In technical terms, MISO initiated regional security-constrained economic dispatch with day-ahead and real-time energy markets (described below). The goal is to dispatch generation resources in the most efficient manner in the region, given transmission constraints. Under the Day 2 tariffs, all MISO participants that own or operate generation are required to submit offers of their generation resources (either owned generation or purchases) that are "Network Resources" of the market participant. At the same time, each MISO load-serving entity (LSE) participant must bid their load requirements into the market. (Since utilities are market participants with generation and are also LSEs, utilities participate with both bids and offers.) After receiving the generation offers and load bids, MISO determines the optimal supply of resources that reflects delivery constraints on the transmission grid. MISO "clears" both the day-ahead and real-time markets over its entire footprint, based on participants' bids and offers and the limitations of the transmission system, with the optimized cost of supply.

The Commission issued the following three Orders addressing the utilities' petitions for cost recovery of MISO Day 2 costs.

First, because the Commission had not yet had sufficient opportunity to evaluate the parties' arguments, on April 7, 2005, the Commission provided temporary relief by permitting the parties to recover Day 2 costs through the fuel clause adjustment (FCA) on an interim basis subject to refund.[42]

Second, in its December 21, 2005 Order, after further analysis, the Commission concluded that only certain costs should be recovered through the FCA. In particular, the Commission concluded that the costs of administering the MISO Day 2 Market, listed in Schedules 16 and 17, were insufficiently related

[41] MISO Tariff § 1.208 (issued May 27, 2005).
[42] *Order Authorizing Interim Accounting for MISO Day 2 Costs, Subject to Refund with Interest* (April 7, 2005) in Docket Nos. E002/M-04-1970, E015/M-05-277, E017/M-05-284, and E001/M-05-406.

to energy or the types of costs previously recovered through the FCA to warrant FCA recovery. The Commission ordered the utilities to refund the balance to ratepayers.[43]

In addition, the Commission established reporting requirements and accounting procedures to address the new regulatory dynamics created by MISO's Day 2 Market. In an effort to bring clarity to traditional utility operations, for example, the Commission directed the petitioning utilities to use "net accounting" for Day 2 costs, whereby both the proceeds of the "sale" and the costs of the "purchase" would be recorded in the same account. Because these two conceptual transactions tend to cancel each other, the utility's records reflect the net, or actual, cost or revenue from the operations. Finally, the Commission proposed an investigation into the best method for assuring low-cost electricity in Minnesota.[44] These basic principles are still in place.

Third, on reconsideration, the Commission granted all parties additional time to address the requirement that utilities immediately implement a refund to their customers. By Order dated February 24, 2006, the Commission suspended the immediate refund obligation and restored the utilities' authorization to continue recovering all MISO Day 2 costs through the fuel clause adjustment. While this recovery remained as interim, subject to refund, the Commission also granted the utilities authority to implement deferred accounting for any costs that the Commission would later determine should not be recovered through the FCA. Utilities could continue deferring the MISO Day 2 administrative costs until roughly March 1, 2009, without interest; thereafter the accrual would stop and the accrued balance would be written off gradually without rate recovery (amortized) through roughly March 1, 2012, unless the utility received Commission authority to recover the balance through base rates. The ultimate issue of whether and how MISO Day 2 costs should be recovered on a permanent basis was deferred to allow opportunity for additional analysis.[45]

On June 22, 2006, the parties filed the *Joint Report and Recommendation Regarding MISO Day 2 Cost Recovery* (Joint Report) with the Commission.[46] The Joint Report was supplemented by the comments filed on November 6, 2006. In brief, the Joint Report recommended that the Commission authorize utilities to recover most Day 2 costs via their fuel clause adjustments. In support of the proposal, the utilities agreed to make certain commitments, described further below.

On December 20, 2006, the Commission issued its Order approving MISO Day 2 costs through the FCA, except for Schedule 16 and 17 costs. Schedule 16 and 17 costs were determined to be base rate costs recoverable in the context of a rate case, not energy costs recoverable through the FCA. The Commission's Order addressed conditions for virtual transactions, accounting practices, customer protections, wholesale revenues, and investigation by the Commission to ensure low-cost electricity in Minnesota. Finally, the Commission's Order required utilities to provide several additional informational items in their monthly FCA reports and AAA reports (Ordering Paragraph 7).

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[43] *Order Establishing Second Interim Accounting for MISO Day 2 Costs, Providing for Refunds, and Initiating Investigation* (December 21, 2005 Order) in Docket Nos. E002/M-04-1970, E015/M-05-277, E017/M-05-284, and E001/M-05-406.

[44] December 21, 2005 Order in Docket Nos. E002/M-04-1970, E015/M-05-277, E017/M-05-284, and E001/M-05-406 at Ordering Paragraph 10.

[45] *Order on Reconsideration Suspending Refund, Granting Deferred Accounting and Requiring Filings* at 7-8.

[46] The Joint Report reflected the views of all parties except for what is now known as the Office of the Attorney General-Residential Utilities and Anti-Trust Division.

The Department's analysis below is a limited review of MISO Day 2 overall charges, specific MISO Day 2 charges based on a fluctuation analysis, related allocations to customers, and asset-based margin sharing.

B. OVERALL EFFECTS OF MISO DAY 2 MARKET ON UTILITIES AND THEIR CUSTOMERS

According to MISO's tariff, the Day 2 Market encompasses both the "Day-Ahead Market" and the "Real-Time Market." To participate in the Day-Ahead Market, utilities forecast customers' demand for electricity the next day, including the magnitude and geographical location of the demand. The utilities also designate the generators (network resources) they will make available to meet the total system's needs, and the terms under which each generator would provide electricity to the market if selected (dispatched). MISO uses information from all participants and creates a plan to match supply with demand, consistent with the constraints of the generators and the transmission grid. The following day – the Real-Time Market – MISO implements its plans, adjusted to accommodate changes arising from, for example, unanticipated hot weather or a mechanical failure at a power plant.

In theory, the Day 2 Market enables MISO to dispatch generators with lower operating costs to meet the aggregate demand of all customers without regard to which utility owns a given generator or transmission line, or which utility has an obligation to serve a given customer. This process determines the marginal price of electricity – that is, the price of generating the last unit of power required to meet the combined needs of all customers, when all lower cost sources of power are already in use.

Sometimes MISO will be unable to use the system's lowest-cost generators because doing so would require moving electricity through a transmission line that is already fully in use (constrained). When such transmission constraints arise, MISO selects a substitute generator connected to transmission lines with available capacity, even though the substitute may be more expensive to operate. As a result, the marginal price of electricity is not uniform throughout the grid, but varies by location. This fact gives rise to the term "locational marginal price" (LMP), for electricity at each location on the transmission grid. As noted in AAA filings since at least FYE07, it has become evident that generation outages can have a significant effect on LMPs in the Day 2 market.

The Department discusses our review of MISO Day 2 charges in the next section, including recommendations regarding overall cost and allocation of MISO Day 2 charges between retail and asset-based wholesale customers.

C. OVERALL REVIEW OF MISO DAY 2 CHARGES

This section discusses our overall review of MISO Day 2 charges and allocations between retail customers and the wholesale sector for the following areas:

- Day-Ahead and Real-Time Energy;
- Congestion Costs and Financial Transmission Rights (FTRs);
- Energy Losses;
- Virtual Energy/Non-Asset-Based Transactions;
- Revenue Sufficiency Guarantee (RSG) Costs and Make-Whole Payments;

- Revenue Neutrality Uplift (RNU) Charges;
- Auction Revenue Rights (ARR); and
- Grandfathered Charges.

The Department's audit of MISO Day 2 charges started with the "MISO Day 2 Spreadsheet of Charges" as originally developed in the MISO Day 2 stakeholder process and as ordered by the Commission in its final *Order Establishing Accounting Treatment for MISO Day 2 Costs*, Ordering Paragraph 7, part g. This MISO Day 2 spreadsheet of charges and additional support for MISO Day 2 net cost allocations, especially between retail and wholesale, was updated in the Commission's February 6, 2008 Order for the 2006 AAA, in Ordering Paragraphs 21 to 24. The Department has included all of the information request responses for MISO Day 2, Asset Based Margins and Ancillary Services Market (ASM) as Department Attachment A for Xcel Electric, Department Attachment B for MP, and Department Attachment C for OTP.

1. Review of Xcel Electric's MISO Day 2 Charges

Xcel Electric allocates its MISO Day 2 charges across three categories including retail, asset-based wholesale/intersystem, and non-asset-based wholesale/intersystem. The Company's invoices from MISO combine Xcel Electric's two asset owners: NSPP (generator asset owner) and NSPT (Xcel's trading owner which handles non-asset-based transactions). Since Xcel Electric has two asset owners set up with MISO, the MISO invoices for a given month can be separated between NSPP and NSPT using the MISO daily settlements. A summary of MISO Day 2 charges assigned to the three categories is provided in Part J, Section 5, Schedule 7, page 13 of 13 of Xcel's Electric's FYE18 AAA Report. The Department notes that the amounts and totals reflected on Part J, Section 5, Schedule 7 are at the total-Company level.

A summary of Xcel Electric's total MISO Day 2 charges assigned to retail customers on a total-Company basis for current and prior AAA reporting periods is provided below:

Table 6.1: Total MISO Day 2 Charges Assigned to Retail (in millions)

AAA Reporting Period	FYE11	FYE12	FYE13	FYE14	FYE15	FYE16	FYE17	FYE18
Net Costs	$195.9[47]	$196.6[48]	$200.5[49]	$222.9[50]	$101.7[51]	$54.6[52]	$87.9[53]	$63.1[54]

[47] Source: Xcel Electric's initial filing in Docket No. E999/AA-11-792, Part J, Section 5, Schedule 7, Page 13 of 13.
[48] Source: Xcel Electric's initial filing in Docket No. E999/AA-12-757, Part J, Section 5, Schedule 7, Page 13 of 13.
[49] Source: Xcel Electric's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 7, Page 13 of 13.
[50] Source: Xcel Electric's initial filing in Docket No. E999/AA-14-579, Part J, Section 5, Schedule 7, Page 13 of 13.
[51] Source: Xcel Electric's initial filing in Docket No. E999/AA-15-611, Part J, Section 5, Schedule 7, Page 13 of 13.
[52] Source: Xcel Electric's initial filing in Docket No. E999/AA-16-523, Part J, Section 5, Schedule 7, Page 13 of 13.
[53] Source: Xcel Electric's initial filing in Docket No. E999/AA-17-492, Part J, Section 5, Schedule 7, Page 13 of 13.
[54] Source: Xcel Electric's initial filing in Docket No. E999/AA-18-373, Part J, Section 5, Schedule 7, Page 13 of 13.

The Department notes that the total or net[55] MISO Day 2 costs assigned to Xcel Electric's retail ratepayers have decreased from the FYE17 reporting period and remain quite low compared to previous periods (FYE11 – FYE15).

The Department reviewed Xcel Electric's MISO Day 2 charges for FYE18. The Department performed a limited review of some charge types that appeared to show significant changes between FYE17 and FYE18. In addition, the Department reviewed Xcel Electric's allocation of MISO Day 2 costs.

The Department notes that Xcel Electric's total net MISO Day 2 costs/(revenues) totaled ($84,616,096) for retail and asset-based wholesale/intersystem in FYE18.[56] Of this amount, $63,131,502 in net costs were assigned to retail and ($139,101,700) in net revenues were assigned to asset-based wholesale/intersystem.[57]

The Department reviewed Xcel Electric's allocation of its MISO Day 2 charges across its retail, asset-based wholesale/intersystem, and its non-asset-based wholesale/intersystem. The Department notes that Xcel Electric's allocations between retail and asset-based wholesale/intersystem are complex. The Department described Xcel Electric's allocation methods in detail in the Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports*.[58]

The Department asked Xcel Electric, in Department Information Request No. 12, if Xcel had changed any of the allocation methods used to allocate MISO Day 2 charges between retail and asset-based wholesale from the FYE17 to FYE18 reporting periods. Xcel Electric stated in its response that there have been no changes to the allocation methods for MISO Day 2 charges between retail and asset-based wholesale from the FYE17 to FYE18 reporting periods.

Based on our review, the Department recommends that the Commission accept Xcel Electric's MISO Day 2 reporting and allocations for FYE18.

2. Review of MP's MISO Day 2 Charges

Attachment 9 to Minnesota Power's FYE18 AAA Report contain MP's total MISO charges by month, as well as an estimate of the allocation of those charges across the Company's various customer categories. MP's total MISO charges (MISO Day 2 and ASM) and the amounts allocated to its retail customers in FYE18 increased significantly compared to FYE17 and FYE16, but still remained lower when compared to previous periods (FYE11 – FYE14) as shown in the below table.

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[55] As discussed in section VI A above, the Commission directed the utilities to use "net accounting" for Day 2 costs, whereby both the proceeds of the "sale" and the costs of the "purchase" would be recorded in the same account. Because these two conceptual transactions tend to cancel each other, the utility's records reflect the net, or actual, cost or revenue from the operations.
[56] Source: Xcel Electric's initial filing in Docket No. E999/AA-18-373, Part J, Section 5, Schedule 7, Page 13 of 13.
[57] *Id.*
[58] The Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports* was filed June 1, 2012 in Docket No. E999/AA-11-792.

Table 6.2: Minnesota Power MISO Day 2 & ASM Charges and Amounts Allocated to Retail

	Total MISO Charges		MISO Charges Allocated to Retail	
	Amount ($ millions)	Change from Prior Year	Amount ($ millions)	Change from Prior Year
FYE11	58.1		51.1	
FYE12	56.3	-3.1%	48.2	-5.7%
FYE13	58.3	3.6%	52.9	9.8%
FYE14	61.2	5.0%	58.4	10.4%
FYE15	39.2	-35.9%	40.8	-30.1%
FYE16	30.2	-23.0%	33.3	-18.5%
FYE17	44.6	47.7%	44.8	34.5%
FYE18	55.7	24.9%	47.4	5.8%

Source: Attachment 9 to MP AAA Reports

The Department notes that MP provided, in response to Department Information Request No. 19 parts (a) and (b), the breakout of the "Grand Total" of $55,746,384 (rounded to $55.7 million) as shown on page 77 of 80 of Attachment 9 to MP's FYE18 AAA Report, into MISO Day 2 charges of $55.2 million and ASM charges of $0.5 million. Additionally, as noted in the prior year's Department AAA comments, MP clarified that footnote 1 on MP's Attachment 9 should be corrected to say MISO administrative charges were included in "base rates" and not "base cost of fuel," since administrative costs are not a qualified fuel cost.

As part of our review, the Department asked MP to explain the main drivers that caused the MISO Day 2 and ASM net costs to increase from $44.6 million for FYE17 to $55.7 million on MP's Attachment 9 and as shown in the above table. In response to Department Information Request No. 20 part (a) MP provided the following response:

> Asset Energy increased roughly 12 million dollars from July 2016 – June 2017 to July 2017 – June 2018. All of the increase was in the Day Ahead which was caused by increased Day Ahead LMP prices. DA LMP's at MP.MP averaged $23.76 from July 2016 – June 2017 and escalated to $25.85 from July 2017 – June 2018.

As part of our review, the Department asked MP to provide the MISO bills that support the $5.283 million in MISO Day 2 and ASM charges for March 2018. The Department also requested that MP support its cost allocation of $3.894 million to retail customers "FPE Retail" for March 2018 and to provide plant outages for March 2018. In response to Department Information Request No. 22 parts (a) and (c), MP provided the requested information,[59] which the Department reviewed and considers to be reasonable.

[59] MP's response contained 20 attachments which the Department did not attach, but are available upon request.

The Department asked MP to provide support for some of its monthly financial transmission rights (FTRs) and annual auction revenue rights (ARRs) that sink outside of Minnesota as shown on MP's Attachment 11 of its FYE18 AAA Report. MP provided the following in response to Department Information Request No. 23:

> Please see TRADE SECRET "Table 1 - Monthly FTR Purchases" below, which illustrates the FTR Costs/Benefits associated with the transactions as referenced on Attachment 11 page 3 of 5. Minnesota Power's utilization of the Monthly FTR Auction provides a benefit to customers by managing congestion price volatility exposure on financial bilateral transactions.
>
> Please see TRADE SECRET "Table 2 - Annual FTR Purchases" below, which illustrates the FTR Costs/Benefits associated with the transactions as referenced on Attachment 11 page 4 of 5. Minnesota Power's utilization of the Annual FTR Auction provides a benefit to customers by managing congestion price volatility exposure on financial bilateral transactions.

MP has also noted that MP actively sells any excess energy to the wholesale market and has bilateral transactions that sink outside of Minnesota. The Department notes that the net revenue from excess energy sales are reflected in MP's asset-based margins that are provided to retail customers as discussed in the Asset-Based Margins section below.

The Department reviewed Minnesota Power's MISO Day 2 charges as reported in Attachment 9 to its FYE18 AAA Report and concludes that they are reasonable.

The Department also reviewed Minnesota Power's allocation of its MISO charges across its various customer categories. The Department described Minnesota Power's allocation methods in detail in the Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports*.[60] Because those allocation methods have not changed, the Department will describe them only briefly in this report.[61]

Minnesota Power allocates energy-related charges (including several MISO Day 2 charges) using an algorithm that assigns highest-cost generation or purchases to non-FCA customer categories, theoretically leaving lowest-cost generation or purchases as the responsibility of Minnesota Power's FCA customers (retail and municipal customers). Virtual energy charges are directly assigned to the FCA customer categories. All other non-energy MISO costs are allocated on a per-MWh basis. The Department concludes that these allocation methods are generally reasonable, but cautions that we did not attempt to audit or verify the result of Minnesota Power's algorithm for allocating energy costs.

Based on our review, the Department recommends that the Commission accept Minnesota Power's MISO Day 2 reporting and allocations for FYE18.

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[60] The Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports* was filed June 1, 2012 in Docket No. E999/AA-11-792.

[61] MP's response to Department Information Request No. 17 confirmed that there have been no allocation changes for MISO Day 2 and ASM charges.

3. Review of OTP's MISO Day 2 Charges

OTP allocates its MISO Day 2 charges across three categories including retail, asset-based wholesale, and non-asset-based wholesale. OTP also refers to these categories as its "resource," "marketing" (OTPW) and "dealing" (OTPD) portfolios. OTP's MISO Day 2 charges for retail and asset-based wholesale are billed under OTPW settlement statements. MISO Day 2 charges for non-asset-based wholesale are billed separately under OTPD settlement statements. A summary of MISO Day 2 charges assigned to the three categories is provided in Part H Section 3 Attachment K of OTP's 2017-2018 AAA Report. The Department notes that amounts reflected in Attachment K are at the total-Company level and not the Minnesota jurisdictional level.

A summary of OTP's total MISO Day 2 charges assigned to retail customers for current and prior AAA reporting periods is provided below:

Table 6.3: Total MISO Day 2 Charges Assigned to Retail (in millions)

AAA Reporting Period	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018
Revenues	$173.1	$102.6	$70.8	$94.1	$115.3
Costs	$215.3	$142.7	$111.5	$132.4	$151.8
Net Costs	$42.2	$40.1	$40.1	$38.3	$36.5

The Department reviewed OTP's MISO Day 2 charges as reported in Part H Section 3 Attachment K to OTP's 2017-2018 AAA Report.

In Department Information Request No. 10, the Department asked OTP to explain fluctuations related to MISO Day 2 charges for Day-Ahead Non-Asset Energy Amount and Real-Time Congestion. OTP provided the following response:

> The Day-Ahead Non-Asset Energy Amount (DA_NASSET_EN) is the net charges and credits related to all day-ahead interchange schedules and day-ahead financial schedules settled at commercial pricing nodes where a MISO asset owner does not own an asset. For Otter Tail, this charge type is associated with subsidized federal energy provided by the Western Area Power Administration (WAPA) to serve municipal, tribal, and agency loads located within the Otter Tail service territory where Otter Tail is the supplemental provider. WAPA injects energy into the MISO interface, which is credited to Otter Tail (since Otter Tail does not have an asset at the interface, the energy credit falls in the Day-Ahead Non-Asset Energy Amount charge type). Otter Tail wheels this energy to the WAPA/Otter Tail shared loads where it is withdrawn from the grid and is included as part of the Otter Tail load zone within MISO. The table below illustrates that the Day-Ahead Non-Asset Energy Amount has been quite stable for the 2017/18 reporting period, both in MWhs and revenue. Month to month fluctuations of this charge type are driven by the changing MWh schedule injected by WAPA at the MISO interface and the changing day-ahead LMP price at the MISO interface.

> The Real-Time Congestion charge is not a stand-alone MISO charge type. Congestion is one component of the total Locational Marginal Price (LMP). The total LMP consists of an energy component, loss component, and congestion component. MISO includes all congestion charges within their Day Ahead and Real Time Asset Energy and Non-asset Energy charge types. Otter Tail separately calculates Day Ahead and Real Time Congestion charges and subtracts these values from either the DA Asset Energy or Real Time Asset Energy charge types, as reported by MISO, and lists them as distinct line items in our MISO reports. The Day Ahead Congestion charge is calculated by subtracting the Day Ahead congestion component at an Otter Tail Load generator from the Day Ahead congestion component at the Otter Tail load zone, then multiplying this difference by the total MWs of energy, at that generator, serving Otter Tail load. This is done for each generator serving Otter Tail load. Real time congestion is calculated in a similar manner, but also accounts for deviations from the Day Ahead clearing results. Fluctuations of the Real Time Congestion charge can be impacted by numerous factors including, but not limited to: Over/under forecasting for load, transmission outages, inaccurate wind forecasts, generator de-rates/outages, and changing generation dispatch instructions from MISO.

The Department also reviewed OTP's allocation of its MISO Day 2 charges across its various customer categories. The Department described OTP's allocation methods in detail in the Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports*.[62] In Department Information Request No. 9, the Department requested that OTP explain if any of the Company's allocation methods have changed from the 2010-2011 method for the FYE18 reporting period and if so what the nature of these changes were and the effect these changes have had on the charges assigned to various customer categories. OTP responded that there were no changes to the allocation methods used for FYE18.

The Department recommends that the Commission accept OTP's MISO Day 2 reporting as the Company has provided the required information.

D. ASSET-BASED MARGIN OR WHOLESALE REVENUE REVIEW

1. Xcel Electric

A summary of Xcel Electric's asset-based margins for current and prior AAA reporting periods is provided below:

[62] The Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports* was filed June 1, 2012 in Docket No. E999/AA-11-792.

Table 6.4: Xcel Electric
Minnesota Asset-Based Margins (in millions)

AAA Reporting Period	FYE12	FYE13	FYE14	FYE15	FYE16	FYE17	FYE18
Asset-Based Margins	$4.8[63]	$7.9[64]	$7.2[65]	$4.0[66]	$4.0[67]	$18.3[68]	$21.5[69]

The Department reviewed Xcel Electric's asset-based margins for FYE18 to ensure asset-based margins were returned to ratepayers via the FCA. Similar to last year's review of asset-based margins in Docket No. E999/AA-17-492, the Department selected a monthly asset-based margin amount for testing. Specifically, the Department selected the asset-based margin of $21.4 million for January 2018[70] and tied this back to Xcel Electric's FCA. The Company provided the following in its response to Department Information Request No. 13:

> The $21.475 million reported in the January 2018 AAA filing represents a portion of the total asset based revenues. The question above indicates it is a charge; however; it is a negative net cost and therefore is revenue. Cost of Goods Sold expenses are deducted from the total asset based revenue to calculate the total asset based margin. The Minnesota jurisdictional portion credited to Minnesota ratepayers in the January 2018 fuel clause adjustment was $3,724,985.
>
> Please see below for additional detail:

[63] Per Xcel Electric's Response to Department Information Request No. 35, Attachments A-B in Docket No. E999/AA-16-523; includes monthly true-up amounts.
[64] *Id.*
[65] *Id.*
[66] *Id.*
[67] *Id.*
[68] Per Xcel Electric's Response to Department Information Request No. 24, Attachment A in Docket No. E999/AA-17-492; includes monthly true-up amounts.
[69] Per Xcel Electric's Response to Department Information Request No. 13, Attachment A in Docket No. E999/AA-18-373; includes monthly true-up amounts.
[70] Source: Xcel Electric's initial filing in Docket No. E999/AA-18-373, Part J, Section 5, Schedule 7, Page 7 of 13.

Minnesota Asset Based Margin Sharing	(Jan 2018) $- millions
(1) MISO Day 2 and ASM Intersystem Asset Based	$21.5
(2) Non-MISO Asset Based Revenue	$1.3
(3) Total Asset Based Revenue (1)+(2)	$22.8
(4) Less: Cost of Goods Sold	$16.3
(5) NSP System Asset Based Margins (3)–(4)	$6.5
(6) Less: Ratepayer Sharing (*)	$4.5
(7) Less: Other Jurisdictions Specific Adjustments	$0.9
(8) Other Jurisdictions' Pass-Through/Company Retention	$1.1
* **Ratepayer Sharing Detail**	
Minnesota Jurisdiction	$4,639,978
Less: Other Jurisdictions Specific Adjustments	$914,993
Minnesota Net Portion	**$3,724,985**
Other NSP Jurisdictions	$745,916
Total NSP Ratepayers Sharing	$4,470,901

The Department traced the Minnesota Net Portion amount of $3.7 million to Xcel Electric's March 2018 Fuel Clause Adjustment Report filed on February 28, 2018 in Docket No. E002/AA-18-176.[71] As a result, the Department concludes that Xcel Electric's asset-based margins for FYE18 appear reasonable. The Department will continue to monitor Xcel Electric's asset-based margins in future AAA filings.

2. MP

The table below summarizes MP's actual wholesale asset-based margins over the period 2009 through 2018, and compares those margins to the revenue credit built into MP's base rates each year. As shown, the sum of MP's actual margins over the ten-year period ($337.9 million) is less than its total credits provided in rates to customers of ($365.8 million) over the same period by 3.2 percent. Based on our review, the Department concludes that MP's asset-based margins appear to be reasonable. The Department will continue to monitor MP's wholesale asset-based margins in future AAA filings.

[71] See Attachment 1, Page 4 of Xcel Electric's March 2018 Fuel Clause Adjustment Report in Docket No. E002/AA-18-176.

The Department will continue to monitor MP's wholesale asset-based margins in future AAA filings.

Table 6.5: Minnesota Power Wholesale Asset-Based Margins 2009-2018[72] [73]

Calendar Year	Actual Margin	Revenue Credit Built into Base Rates	Shareholders Benefit/(Loss)	Percent Difference
[a]	[b]	[c]	[d]=[b]-[c]	[e]=[d]/[c]
2009	$53.8	$30.3	$23.5	77.6%
2010	$33.9	$37.7	($3.8)	-10.1%
2011	$31.1	$37.7	($6.6)	-17.5%
2012	$29.5	$37.7	($8.2)	-21.8%
2013	$33.6	$37.7	($4.1)	-11.0%
2014	$34.7	$37.7	($3.0)	-8.1%
2015	$39.8	$37.7	$2.1	5.6%
2016	$47.3	$37.7	$9.6	25.5%
2017	$34.3	$35.8	($1.5)	-4.2%
2018	$39.7	$35.8	$3.9	10.9%
10 Yr. Total	$337.9	$365.8	$11.8	3.2%

3. OTP

A summary of Otter Tail's asset-based margins for current and prior AAA reporting periods is provided below.

Table 6.6: Otter Tail Power's Minnesota Asset-Based Margins

AAA Reporting Period	FYE 14	FYE15	FYE16	FYE17	FYE18[74]
Asset-Based Margins	$5,761,238	$1,545,701	$11,812	$826,096	$915,598

[72] Source for Revenue Credit in Base Rates: 2009 per May 4, 2009 Order in Docket No. E015/GR-08-415; 2010-2016 per November 2, 2010 Order in Docket E015/GR-09-1151; 2017-2018 per J. Pierce Supp. Direct p. 10 & Sch. 5 p. 17 in Docket E015/GR-16-664.

[73] Actual Margin: Department August 25, 2016 *Review of the 2014-2015 Annual Automatic Adjustment Reports* Part II, page 15; 2016 Actual per MP Response to Department Information Request No. 9 in Docket No. E999/AA-16-523; 2017 Actual per MP's response to Department Information Request No. 13 in Docket No.E999/AA-17-492; 2018 Actual per MP's response to Department Information Request No. 18 in Docket No. E999/AA-18-373.

[74] Source: OTP's FYE18 AAA filing, Part H, Section 3, Attachment K, page 26 of 26. Figures for the previous years were provided in the same section of the relevant previous filings, although page numbers may differ.

The Department notes that OTP's asset-based margins have fluctuated significantly from year-to-year as shown in the above table. The fluctuations of asset-based margins appear to be caused largely by the amount of excess energy available for sales, since the MWhs available vary from year to year, and the LMP at the time in which these asset-based margins were made. The Department reviewed OTP's asset-based margins for FYE18 to ensure asset-based margins were returned to ratepayers via the FCA.

Based on our review of OTP's response to Department Information Request No. 11, including Attachments 1, 2, and 3 the Department concludes that OTP has returned its asset-based margins through the monthly FCAs for FYE18. Based on our review, the Department concludes that OTP's asset-based margins appear to be reasonable. The Department will continue to monitor OTP's wholesale asset-based margins in future AAA filings.

E. DEPARTMENT INVOLVEMENT IN MISO PROCESSES

The Department participates in the Organization of MISO States (OMS) workgroups, which correspond with MISO workgroups and subcommittees. This approach has been a useful process for providing joint state filings that are filed with the Federal Energy Regulatory Commission (FERC) on the more significant MISO filings. The OMS has also helped the Department be more proactive in its interaction with MISO. The Department continues to attend or listen to MISO Advisory Committee (AC) Meetings, Annual Stakeholder and Sector Meetings with MISO, Resource Adequacy Workgroup and Supply Adequacy Workgroup (RAWG/SAWG) Meetings, Planning Advisory Committee (PAC) Meetings, Midwest Transmission Expansion Plan (MTEP) Meetings, Demand Response Meetings and other MISO meetings to gain better understanding of MISO proposals prior to implementation.

The Department also participates in MISO issues via our Public Consumer Group Sector for sector voting on issues largely through MISO AC and PAC Meetings, Hot Topic Comments, and various comments to FERC on matters such as: Return on Equity (ROE) Complaint, ROE Incentive Adders, and Prorated Accumulated Deferred Income Tax.

The Department has also found the Minnesota Commission's MISO Quarterly Meetings to be helpful to share information and ask questions of the utilities and MISO experts. The Department greatly appreciates the efforts by the Commission to bring all of the parties together and to facilitate the discussions. The Department also appreciates the participation of all entities in this process. In particular, the Department commends the Commission for focusing the discussions, and thanks the utilities and MISO for their significant efforts, discussions, and willingness to solve problems as they arise.

F. SUMMARY OF CONCLUSIONS REGARDING MISO DAY 2 COSTS AND REVENUES

The Department concludes that the review of MISO Day 2 charges and allocations are complex, due to the volume of information related to these transactions, and the less-than-transparent nature of MISO billings in allocating between retail and asset-based wholesale transactions. Nonetheless, based on our review, the Department recommends that the Commission accept the utilities' MISO Day 2 reporting for FYE18.

VII. ANCILLARY SERVICES MARKET (ASM)

A. BACKGROUND

Utilities must hold enough capacity to meet their load and provide reliable service to comply with North American Electric Reliability Corporation (NERC) reliability standards. The reliability component includes ancillary services. Ancillary services ensure that there is sufficient generation to match loads on the transmission system instantaneously to preserve service reliability.

These ancillary capabilities are as follows:

- Regulation service: having generation operating and able to change their MW output (up or down) to respond to changes in load on a second-by-second basis;
- Spinning Reserve service: having generation on line (spinning) at reduced output, so that it can immediately provide replacement power in the event of an unscheduled outage at another generation unit;
- Supplemental Reserve service: having generation readily available off-line and capable of starting and beginning to generate within ten (10) minutes to respond to an unscheduled outage at another generation unit; and
- Energy Imbalance service: providing energy between entities, such as between a utility and a municipal load-serving entity (which is typically a wholesale customer of the utility), to account for the difference between the amount scheduled during a period (such as an hour) and the amount actually delivered (which may be more or less than the amount scheduled). Energy Imbalance service could be settled either by an "in kind" exchange of energy in a later period, or financially.

MISO's Ancillary Services Market (ASM) began operations on January 6, 2009. The 12 ASM charges are as follows:

Six Procurement charges:	1) Day-Ahead Regulation; 2) Day-Ahead Spinning Reserve Charge; 3) Day-Ahead Supplemental Reserve; 4) Real-Time Regulation; 5) Real-Time Spinning Reserve; 6) Real-Time Supplemental Reserve;
One Resource Energy charge:	1) Net Regulation Adjustment;
Three Cost Distribution charges:	1) Regulation; 2) Spinning Reserve Charge; and 3) Supplemental Reserve; and
Two Penalty charges:	1) Regulation Penalty Amount; and 2) Contingency Reserve Deployment Failure Penalty.

Prior to the start of MISO's ASM, ancillary services were procured in the MISO footprint by each utility through bilateral contracts via Balancing Authorities. On a day-ahead basis, individual Balancing Authorities identified how resources in their Balancing Authority area (formerly referred to as a "control area") would be able to provide the required amounts of ancillary service, which resulted in capacity on native generation resources being held back to provide services of regulation, spinning reserve and supplemental reserve. On a real-time basis, Balancing Authorities dispatched their resources on a second-by-second basis to meet system reliability requirements. If the utility was unable to meet the energy requirements needed to serve their load and provide the necessary ancillary services, they were required by NERC reliability standards to purchase additional energy while they held back capacity to meet reliability needs.

The Commission's Order dated August 23, 2010 in Docket No. E001, 015, 002, 017/M-08-528 (Commission's August 23, 2010 ASM Order) approved Xcel Electric's, MP's, and Interstate Power and Light Company's ASM accounting and recovery via the FCA and required reporting requirements as follows (the Department notes that OTP's ASM was approved via OTP's rate case in Docket No. E017/GR-10-239):

1. The Commission accepts the quarterly reports filed by the three utilities under the March 17, 2009 order in this case.

2. The Commission finds that the record demonstrates overall benefits from the three utilities' participation in the MISO ancillary services market and that the record supports the continued use of the Fuel Clause Adjustment to pass through the costs and revenues associated with that participation. The three utilities are authorized to continue using the Fuel Clause Adjustment to pass through the costs and revenues associated with their participation in the MISO ancillary services market.

3. With the exception of Contingency Reserve Deployment Failure Charges and Excess/Deficient Energy Charges, the Commission removes the "subject to refund" provisions of the March 17, 2009 order for both past and future ancillary services market costs passed through the Fuel Clause Adjustment.

4. All costs and revenues associated with the utilities' participation in the MISO ancillary services market remain subject to the normal review, approval, and recovery procedures that apply to costs and revenues passed through the Fuel Clause Adjustment.

5. The three utilities shall include costs and revenues from their participation in the MISO ancillary services market in future automatic adjustment reports filed under Minn. Rules, parts 7825.2390 *et seq*., including the annual filing required there under. They shall include costs/revenues through June 30, 2010 in the 2011 annual filings,

which are due in September 2010; they shall include costs/revenues beginning July 1, 2010 in the 2012 annual filings, which are due in September 2011.

6. The three utilities shall continue to monitor and report all negative benefits (costs) of participation in the MISO ancillary services market and shall work with MISO to ensure that negative benefits occur, if at all, for limited periods of time and with minimal financial impact.

7. The three utilities shall base the formatting of their reports on costs and revenues associated with participation in the MISO ancillary services market on the format used by Xcel and Minnesota Power in this docket.

8. In their annual summaries on the 12 MISO ancillary services charges the utilities shall use a format similar to that used by Minnesota Power in its Attachment 1 to its February 5, 2010 filing (4th quarter report) and shall work with the [Department] to develop a format that is acceptable.

9. In reporting daily ancillary services market activity and overall net savings created by participation in the ancillary services market, utilities shall use a format similar to that used by Xcel in Attachment A to its February 5, 2010 filing and shall work with the [Department] to develop a format that is acceptable.

10. The utilities' written narratives on the benefits of the ancillary services market and the market's impact on their systems shall be formatted consistent with Xcel's and Minnesota Power's 4th quarter report in this docket.

11. The utilities shall file detailed and specific explanations for all Contingency Reserve Deployment Failure and Excess/Deficient Energy Charges incurred, including an explanation as to why they should be recovered and what actions the utility took to minimize these charges.

12. The utilities shall clearly identify and separately list in their automatic adjustment reports all ancillary services market values included in those reports and/or passed through the Fuel Clause Adjustment.

One focus of the Department's review is on the extent to which a utility incurs penalty charges; thus, the Department begins by describing these penalties. First, the Excessive/Deficient Energy Deployment Charge amount represents the charge to the generator that was not able to maintain actual generator output to within a tolerance band around the set point. During the hours where a generator was unable to meet this requirement, MISO assesses a charge equal to any Day-Ahead or

Real-Time payments to the generator for carrying regulation reserve plus the generator's pro rata share of costs to procure regulation from all resources within MISO.

Second, the Contingency Reserve Deployment Failure Charge represents the charge incurred by generation or demand response resources that fail to deploy contingency reserves at or above the contingency reserve deployment instruction. This charge is assessed if a unit that is selected to provide spinning or supplemental reserves during a specific hour does not perform, and MISO must then deploy another resource.

B. XCEL ELECTRIC

Xcel Electric provided its ASM review in its FYE18 AAA filing in Part J, Section 5, Schedules 8 to 16 and in Part J, Section 6 as required by the Commission's August 23, 2010 ASM Order.

The Department notes that Xcel Electric's total net ASM charges/(revenues) totaled $22,075,817 for retail and asset-based wholesale/intersystem in FYE18.[75] Of this amount, $24,420,064 in net costs were assigned to retail and ($2,344,247) in net revenues were assigned to asset-based wholesale/intersystem.

A summary of Xcel Electric's total MISO ASM charges assigned to retail customers on a total-company basis for current and prior AAA reporting periods is provided below:

Table 7: Xcel Electric
Total MISO ASM Charges Assigned to Retail (in millions)

AAA Reporting Period	FYE12	FYE13	FYE14	FYE15	FYE16	FYE17	FYE18
Net Costs	$13.9[76]	$24.7[77]	$23.5[78]	$24.6[79]	$23.0[80]	$8.3[81]	$24.4[82]

The Department notes that Xcel Electric's retail ASM costs have increased significantly in FYE18 over the FYE17 level, which was unusually low. The Department notes that the vast majority of the FYE18 increase can be attributed to increases in Real Time Non Excessive Energy Charges. This issue is discussed in more detail in the following section.

Xcel Electric also provided a calculation of its net savings related to ASM for FYE18.[83] Xcel Electric indicated net ASM savings of $1.8 million for the total NSP system and $1.3 million for the Minnesota

[75] Source: Xcel Electric's initial filing in Docket No. E999/AA-18-373, Part J, Section 5, Schedule 13, Page 13 of 13.
[76] Source: Xcel Electric's initial filing in Docket No. E999/AA-12-757, Part J, Section 5, Schedule 13, Page 13 of 13.
[77] Source: Xcel Electric's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 13, Page 13 of 13.
[78] Source: Xcel Electric's initial filing in Docket No. E999/AA-14-579, Part J, Section 5, Schedule 13, Page 13 of 13.
[79] Source: Xcel Electric's initial filing in Docket No. E999/AA-15-611, Part J, Section 5, Schedule 13, Page 13 of 13.
[80] Source: Xcel Electric's initial filing in Docket No. E999/AA-16-523, Part J, Section 5, Schedule 13, Page 13 of 13.
[81] Source: Xcel Electric's initial filing in Docket No. E999/AA-17-492, Part J, Section 5, Schedule 13, Page 13 of 13.
[82] Source: Xcel Electric's initial filing in Docket No. E999/AA-18-373, Part J, Section 5, Schedule 13, Page 13 of 13.
[83] Source: Xcel Electric's initial filing in Docket No. E999/AA-18-373, Part J, Section 6, Page 3 of 7.

jurisdiction. Xcel Electric stated that these net savings are associated with optimizing the generation units that are carrying ancillary services across the entire MISO footprint. In addition, Xcel Electric stated that its net savings calculation does not include any additional benefits that have accrued to ratepayers for the reduction in regional regulation reserve requirements.

1) Real Time Non Excessive Energy Amount

The Department notes that Xcel Electric's Real Time Non Excessive Energy Amount charges increased significantly - from $8,041,460[84] in FYE17 to $26,347,229[85] in FYE18. In Department Information Request No. 15, the Department asked Xcel Electric to explain this increase. Xcel Electric replied that:

> The increase in Real Time Non Excessive Energy (NXE) charges is primarily related to:
>
> 1) Higher Locational Marginal Prices on Real-Time balancing purchases. Higher prices contributed $11 million to the increase.
>   a. The period January 2018 through February 2018 had significantly higher prices during a cold weather event (contributing $8 million).
> 2) A 7% increase in Real Time balancing purchases contributed $5.8 million (less impact of the price increase). The increase was spread across several resources.
>
> 3) The impact from an 11% decrease in Real-Time balancing sales was offset by higher prices.
>
> Overall, the NXE charges of $26,347,229 presented in Docket No. E999/AA-18-373 are comprised of purchase and sale transactions where the purchases represent Real-Time balancing adjustments on Day-Ahead Sales of $1.1 billion. See the table below for illustration:

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[84] Source: Xcel Electric's initial filing in Docket No. E999/AA-17-492, Part J, Section 5, Schedule 13, Page 13 of 13.
[85] Source: Xcel Electric's initial filing in Docket No. E999/AA-18-373, Part J, Section 5, Schedule 13, Page 13 of 13.

Real Time Non Excessive Energy Charges (NXE)

FY 2017	Dollars	MWh	$/MWh
Day Ahead Sales	$ 1,006,605,746	44,036,431	$ 22.86
NXE Real Time Sales	$ 74,434,102	3,589,398	$ 20.74
NXE Real Time Purchases	$ (80,882,501)	(3,683,910)	$ 21.96
NXE Real Time Total	$ (6,448,398)	(94,512)	
Congestion & Loss	$ (1,593,062)		
Reported NXE Energy Amount	$ (8,041,460)	(94,512)	
Total Sales	$ 1,000,157,347	43,941,919	$ 22.76

FY 2018	Dollars	MWh	$/MWh
Day Ahead Sales	$ 1,133,799,566	45,771,426	$ 24.77
NXE Real Time Sales	$ 74,767,724	3,193,972	$ 23.41
NXE Real Time Purchases	$ (97,703,916)	(3,949,157)	$ 24.74
NXE Real Time Total	$ (22,936,193)	(755,185)	
Congestion & Loss	$ (3,411,036)		
Reported NXE Energy Amount	$ (26,347,229)	(755,185)	
Total Sales	$ 1,110,863,373	45,016,241	$ 24.68

Change	Dollars	MWh	$/MWh
Day Ahead Sales	$ 127,193,820	1,734,995	$ 1.91
NXE Real Time Sales	$ 333,621	(395,426)	$ 2.67
NXE Real Time Purchases	$ (16,821,415)	(265,247)	$ 2.78
NXE Real Time Total	$ (16,487,794)	(660,673)	
Congestion & Loss	$ (1,817,974)		
Reported NXE Energy Amount	$ (18,305,768)	(660,673)	
Total Sales	$ 110,706,026	1,074,322	

Based on the above, the Department concludes that Xcel Electric's Real Time Non Excessive Energy Charges appear reasonable for FYE18.

2) Excessive/Deficient Energy Deployment Charges (EDEDC)

Xcel Electric discussed and provided its monthly Excessive/Deficient Energy Deployment Charges (EDEDC) in Part J, Section 6 of its filing. EDEDC amounts are charges a utility incurs when a generator is not able to maintain actual generator output within a tolerance band around the set point.

The Department notes that Xcel Electric's total system EDEDC decreased from $1.1 million[86] in FYE17 to $1.0 million[87] in FYE18.

Xcel Electric stated the following in its FYE18 AAA Report regarding EDEDC:

> A certain level of EDEDCs is unavoidable given the current design of the ASM market. Currently for each generator, the Company can only submit a single ramp rate value that represents the average rate at which the generator can increase or decrease output across its entire dispatchable range. For a typical coal unit, the ramp rate varies significantly as the unit moves from minimum load to full load. For example, a coal generator with a minimum capability of 200 MWs and a maximum capability of 400 MWs might be able to operate to 300 MWs with one coal pulverizer in operation, while a generator with a capability between 300 MWs and 400 MWs would require two coal pulverizers to be in operation. The unit might be able to ramp at a rate of 10 MWs/min up to 300 MWs, then slow to 3 MWs/min while the second pulverizer is starting, and then ramp at 5 MWs/min up to 400 MWs. The Company could offer only 3 MWs/min of ramp capability to MISO for dispatch, which would ensure that the unit would be able to follow its dispatch instruction close to 100% of the time, but would drastically under-represent the capability of the unit over most of its dispatchable range.
>
> Offers with low ramp rates mean that the unit will not be able to clear for as much regulation reserve or spinning reserve, and therefore will not be available to fully hedge the Company's cost to procure these services. Low ramp rates also limit the unit's ability to respond to increasing or decreasing LMP prices, which ultimately leads to higher purchase power costs in the market. A more prudent strategy would be to offer 5 or 6 MWs/min of ramp capability for the entire range to strike an appropriate balance between incurring penalties during the limited intervals that the unit would not be able to "keep up," and ensuring the unit can provide sufficient quantities of ancillary and load following services to hedge exposure to market prices.
>
> The ASM benefit calculation is a measure of the extent to which the Company has struck the appropriate balance between too much or too little flexibility being offered to MISO. For the 2017-2018 AAA reporting period, the net benefit for the Company was approximately $1.8 million while the amount incurred in EDEDCs was $1.0 million. The $3.1 million in gross benefits would not have been achievable if the Company had been offering ramp rates for its units that would have all but eliminated the chance of incurring an Excessive Deficient Energy charge.

[86] Source: Xcel Electric's initial filing in Docket No. E999/AA-17-492, Part J, Section 6, Page 5 of 6.
[87] Source: Xcel Electric's initial filing in Docket No. E999/AA-18-373, Part J, Section 6, Page 5 of 7.

> To minimize the incurrence of excessive charges, generation unit performance to MISO setpoints is monitored in real time by the system dispatcher to ensure that plants are keeping up with offered ramp rates. Computer displays show the dispatcher a graphical depiction of actual unit output compared to setpoint along with calculations of the deviation. The system analyst and system dispatcher communicate with the plants on a daily basis to discuss operational issues affecting unit performance and adjust offers to MISO accordingly. This iterative process helps ensure that these charges are, to the extent possible, minimized while still creating opportunities for lower overall costs for ratepayers. For these reasons, a certain level of Excessive Deficient Energy Deployment Charges is expected – and prudent – in light of the overwhelming benefits associated with high unit flexibility that more than offset these charges. [Footnotes omitted]

Based on the above, the Department concludes that Xcel Electric's EDEDC charges for FYE18 appear reasonable.

3) Contingency Reserve Deployment Failure Charges (CRDFC)

Xcel Electric provided its monthly Contingency Reserve Deployment Failure Charges (CRDFC) for FYE18 in Part J, Section 6 of its filing. CRDFC amounts are incurred when generation or demand response resources fail to deploy contingency reserves at or above the contingency reserve deployment instruction. These charges are assessed if a unit that is selected to provide spinning or supplemental reserves during a specific hour does not perform and MISO must then deploy another resource.

The Department notes that Xcel Electric's total system CRDFC increased from $4,629 in FYE17 to $10,176 in FYE18. Regarding its FYE18 CRDFC, Xcel stated that:

> Part J, Section 6, Schedule 3 shows NSP incurred a total of $10,176 in CRDFC during the 2017-2018 AAA reporting period. NSP carries reserves on units with Automatic Generation Control (AGC) and units without AGC. For units without AGC, a phone call to the facility is required to deploy the reserves, adding to the time from receiving the signal and deployment. When deploying a large amount of reserves on many facilities, that action requires many more steps and time becomes critical. Additionally, MISO must meet Disturbance Control Standards within 15 minutes but does not always provide market participants the remaining time between the deployment signal and the end of the 15-minute timeframe to deploy reserves. Instead, MISO holds participants to a 10-minute response regardless of whether MISO has 15 minutes to meet the standard or less than 10 minutes.

> The charges were not the result of any oversight or error by the Company, but simply reflect the fact that generating units are sometimes not able to deliver every requested MW. The Company attempts to minimize these occurrences, as evidenced by the limited charges incurred over the reporting period. Had a similar situation occurred before the start of ASM, the Company would have been required to deploy reserves from another generator in its fleet, and would have incurred increased energy costs that were recovered in the FCA.
>
> The Company tests all resources capable of providing supplemental reserve response every two months to validate capability and readiness if called on by MISO during a contingency. If a resource fails to perform during a test, plant management will address the issue with any required maintenance to return the unit to reliable service. The offer to MISO for the unit to provide reserves will be adjusted accordingly to ensure the capabilities of the unit are not overstated during this time.
>
> In short, CRDFCs are prudently incurred for the same reasons described above regarding Excessive Deficient Energy Deployment charges. Generators are complicated mechanical machines whose performance varies based on many conditions. The benefits of making these units available to provide significant amounts of spinning and supplemental reserves to hedge the Company's cost to procure ancillary services more than offsets the cost of the extremely infrequent circumstances where the unit may not be able to provide 100% of the amount required. Also, Xcel Energy is working to modify the rules which evaluate failure to deploy so that this charge is only applied when a unit fails compared to its offered physical capability.

Based on the above, the Department concludes that Xcel Electric's CRDFC charges for FYE18 appear reasonable.

4) Day Ahead Ramp Capability Amount and Real Time Ramp Capability Amount

As explained in the Department's February 7, 2018 Response Comments in Docket E999/AA-16-523, Xcel Electric included two new MISO charge types (Day Ahead Ramp Capability Amount and Real Time Ramp Capability Amount) in their existing ASM Day Ahead Regulation Amount and Real-Time Regulation Amount. For clarification purposes, the Department recommended that Xcel Electric report these two new charges as separate line items rather than combining them with existing ASM charge types in future AAA Reports. The Commission agreed with the Department's recommendation and required Xcel Electric to report these charges as separate line items in future AAA Reports (see Order Point 6 of the Commission's March 16, 2018 Order in Docket No. E999/AA-16-523).

Xcel Electric complied with the Commission's March 16, 2018 Order in Docket 16-523 by providing a breakout of the two new charge types as shown in Part J, Section 5, Schedule 8, Page 13 of 13 of its FYE18 filing. As shown therein, Xcel Electric's Day Ahead Ramp Capability Amount and Real Time Ramp Capability Amount totaled ($71,013) and ($31,767), respectively, for FYE18.

Based on our review, the Department concludes that Xcel Electric's Day Ahead Ramp Capability Amount and Real Time Ramp Capability Amount for FYE18 appear reasonable. The Department will continue to monitor these charge types in future AAA filings.

5) *ASM Summary*

The Department reviewed Xcel Electric's ASM charges and concludes that, although there is some fluctuation in various amounts, Xcel Electric's ASM charges for FYE18 appear to be reasonable. As a result, the Department recommends that the Commission accept Xcel Electric's ASM reporting for FYE18.

C. MP

1. Overall Review of ASM Costs and Revenues

MP addressed ASM costs and benefits in Attachment 10 to its FYE18 AAA Report. MP reported a net cost of $457,229 for FYE18, compared to $512,428 for FYE17, $82,782 for FYE16, and $161,920 for FYE15, respectively. As noted above, the Department asked MP to explain the main drivers that caused the MISO Day 2 and ASM net costs to increase from $44.6 million for FYE17 to $55.7 million for FYE18, as indicated on MP's Attachment 9 and as shown in the above table. The Department discussed MP's response to Department Information Request No. 20 above in the MISO Day 2 Charges Section and will not repeat the discussion here.

The Department asked MP to explain the main drivers for the $400,342 in Regulation Reserve Cost Distribution Amount and the $400,888 in Spinning Reserve Cost Distribution Amount for FYE18 as shown on MP's Attachment 9 page 77 of 80. In response to Department Information Request No. 20 part (b) MP provided the following response:

> Regulation Reserve Cost Distribution and Spinning Reserve Cost Distribution are Distribution Charges that are MISO procurement costs that are distributed to Asset Owners based on their load.

MP treats ASM charges and credits as non-energy costs and allocates them across customer categories on a per-MWh basis. The Department considers this allocation method to be reasonable.

2. Real-Time Excessive/Deficient Energy Deployment Charges and Real-Time Contingency Reserve Deployment Failure Charges

The Department reviewed MP's real-time Excessive/Deficient Energy Deployment Charge (EDEDC) and the Contingency Reserve Deployment Failure Charges, since these are basically performance penalties.

The Department notes that MP's real time EDEDC amount increased slightly to $91,031 in FYE18, compared to $78,454 in FYE17 and $60,829 in FYE16. According to MP the majority of the EDEDC occurs during start-up, shut downs, set point deviations, or when the unit is having equipment problems and is not considered dispatchable by MISO. Additionally, MP incurred $1,167 in Contingency Reserve Deployment Failure Charges in FYE18, compared to $197 in FYE17, compared to charges of $0 in FYE16, and $288 in FYE15. MP explained that the real time EDEDC for FYE 18 was due to 3 operating days during which MP was short a total of 15.9 MWh at an average cost of $73.37. Overall these charges continue to be minimal.

3. *Day Ahead Ramp Capability Amount and Real Time Ramp Capability Amount*

The Department notes that, beginning in May 2016, MP included two new MISO charge types in its fuel clause: Day Ahead Ramp Capability Amount and Real Time Ramp Capability Amount. MISO developed the Ramp Capability Product to provide additional operational flexibility to better respond to variations in load served by dispatchable resources caused by forecast error, variations in intermittent generation, and generation units not following dispatch signals.

MP's Day Ahead and Real Time Ramp Capability Amounts during May and June of 2016 totaled approximately negative $1,600 (that is, a credit, or reduction, to MP's total MISO charges). In FYE17 and FYE18, the Day Ahead Ramp Capability Amount and Real Time Ramp Capability Amounts totaled a negative $20,780 and $24,018 (that is, a credit, or reduction to MP's total MISO charges).

Prior to the implementation of the Ramp Capability Product, when MISO did not have sufficient ramp capabilities to meet a sudden increase in load served by dispatchable resources, it was forced to call on units providing operating reserves to generate electricity to meet the increased load. At times, this resulted in a shortage of operating reserves and led to a spike in prices for energy or operating reserves, or both. It is cost effective for MISO to dispatch a higher-cost generator in order to have spare capacity at a lower-cost generator with better (i.e. faster) ramp capabilities available to meet fluctuations in demand.

The Day Ahead and Real Time Ramp Capability Amounts represent revenue paid to MISO market participants that provide ramp capabilities. The cost of providing these two ramp capabilities is allocated across all load and exports in the MISO energy market and is billed via the Real-Time Revenue Neutrality Uplift Amount, an existing charge type that is already included in the fuel clause. The Department notes that if the Ramp Capability Products were to be excluded from the fuel clause adjustment, ratepayers would have to pay for the costs of ramp capabilities (via the Real-Time Revenue Neutrality Uplift Amount), but would not receive any of the associated revenues.

4. *Schedule 17, MISO Administrative Costs for ASM*

Attachment 10, Table 10-C on page 5 of 12 of Minnesota Power's FYE18 filing compared MP's MISO Schedule 17 charges prior to the start of the ASM market to its Schedule 17 charges in FYE17. In FYE18, average monthly MISO Schedule 17 charges were $156,587 or $15,664 higher than the average monthly charges prior to the start of the ASM market. This equates to an average monthly increase of

$0.01016 per MWh. This comparison attempts to identify the MISO Schedule 17 charges that are related to ASM.

The Department reviewed MP's FYE18 ASM charges and concludes that they are reasonable. As a result, the Department recommends that the Commission accept Minnesota Power's ASM reporting for FYE18.

D. OTP

In Part H Section 4, Attachment L of its FYE18 AAA Report, OTP provided its ASM information as required by the Commission's August 23, 2010 ASM Order. Specifically, OTP noted that ASM market transition has been smooth from an operational standpoint. OTP noted that there has been a positive economic benefit for OTP, as a result of maximizing capabilities of generating units, which has led to greater operational efficiency. OTP's Schedule 1 shows that OTP is a net seller of ASM products (Regulation, Spinning Reserve, Ramp Capacity and Supplemental Reserve). As a result, ASM provided net benefits of $60,048 to Minnesota ratepayers in 2017-2018. OTP allocates all ASM charges on a per-MWh approach, netting costs and benefits of the various charges. The Company stated, in response to Department Information Request No. 9, that there have been no changes to the allocations of the ASM costs (revenues) during the FYE18 reporting period.

1. *Real-Time Excessive/Deficient Energy Deployment Charges and Real-Time Contingency Reserve Deployment Failure Charges*

According to OTP on page 187 of OTP's FYE18 AAA Report, the Real-Time Excessive/Deficient Energy Deployment Charge amount represents the charge to an Asset Owner owning generation where the Asset Owner's unit fails to follow Setpoint instructions for four consecutive intervals within 1 hour without an exemption. This charge consists of taking back any cleared Day-Ahead Regulation Operating Reserve payment and any cleared Net Real-Time Regulation payment and also assesses a prorated share of the Day-Ahead and Real-Time Regulation Market cost. During the reporting period there was a total of ($9,470) of penalties assessed to Otter Tail units (Schedule 1 of Part H, Section 4, Attachment L, column R, line 17). These are normally mechanical failure situations where the unit fails to follow dispatch for a short time period while small repairs are made.

The Real-Time Contingency Deployment Failure Charge amount represents the charge incurred by resources that fail to deploy contingency reserves at or above the Contingency Reserve Deployment Instruction. Again, these would normally be short intervals where some mechanical failure occurred. For the reporting period, there was a total of ($371) in charges (Schedule 1 of Part H, Section 4, Attachment L, column R, line 16).

The Department notes that OTP's total deployment charges/penalties of $9,841 were relatively minor for the FYE18 reporting period.

2. *Day-Ahead Ramp Capability Amount and Real-Time Ramp Capability Amount*

Beginning in FYE17 OTP began reporting on a new MISO ASM charge for Ramp Capabilities. In Part H, Section 4, Attachment L, page 2 of 4 of their FYE18 AAA Report OTP stated that the MISO Ramp Capability product was designed to increase reliability and decrease the cost of serving load by allowing MISO to be able to better react to changes in power demand. The cost MISO incurs by creating additional ramp capability is offset by the reduced likelihood of insufficient ramp and shortage pricing. OTP received a net benefit of $16,271 for this AAA period (Schedule 1 of Part H Section 4 Attachment L, column R, line 15) from these charges.

The Department reviewed OTP's ASM charges and concludes that, although there is some fluctuation in various amounts, OTP's ASM charges appear to be reasonable and are consistent with historical numbers. As a result the Department recommends that the Commission accept OTP's ASM reporting for FYE18.

VIII. FUEL COSTS AND EFFECTS ON CUSTOMER BILLS

Department Attachment D9 shows various aspects of fuel charges and the effects on customers' bills for informational purposes.

1. *Average Residential Bills for 2017*

The graph on page 1 of 4 of Department Attachment D9 illustrates the monthly average bills for residential customers in calendar year 2017. The information includes customer charges, energy charges, fuel clause adjustments, and Conservation Improvement Program (CIP) surcharges (as described on pp. 3-4 of Attachment D9). Overall, Otter Tail Power had the highest average monthly residential bill of $85.41, followed by Dakota Electric at $85.16, Xcel Electric at $78.92 and Minnesota Power with the lowest average of $66.40 per month.

2. *Energy Charge + FCA (cents per kWh) for Each Utility*

The graph on page 2 of 4 of Department Attachment D9 shows the amounts that residential customers paid during calendar year 2017 in energy charges plus fuel clause adjustments. The ranking from highest to lowest average monthly amounts paid are: Dakota Electric with a 12-month average of 12.33¢/kWh, Xcel Electric with an average of 11.27¢/kWh, Otter Tail with an average of 8.39¢/kWh, and Minnesota Power 7.83¢/kWh. However, the Department notes that, because utilities recover different amounts of fixed costs in the energy charges, this comparison is not as useful as the bill comparison in item 1 above.

IX. RECOMMENDATIONS AND REQUESTS FOR ADDITIONAL INFORMATION

A. SECTION II, FILING REQUIREMENTS

The Department recommends that the Commission accept Xcel Electric's and OTP's Auditor Reports for FYE18.

The Department requests that MP provide all of the information required by Ordering Paragraph 7 of the Commission's Order in Docket No. E999/AA-15-611 in reply comments, or confirm that the auditor's scope of work included all of the required information. The Department will make its overall recommendation regarding MP's FYE18 Auditor Report after it reviews MP's reply comments.

B. SECTION III, COMPLIANCE DOCKETS

The Department recommends that the Commission accept Xcel Electric's compliance filing, including the high-level cost allocation test between wholesale and retail customers for June, July, and August of 2018. The Department recommends that the Commission continue to require Xcel Electric to report this generation cost allocation data in future AAA filings under the current FCA process, as required by Docket No. E002/CI-00-415, Ordering Paragraph No. 2.

The Department concludes that Xcel Electric's Natural Gas Financial Instruments compliance filing complies with the Commission's Order in Docket No. E002/M-01-1953. The Department intends to review Xcel Electric's continued compliance with this requirement in future AAA filings.

The Department recommends that the Commission accept Xcel Electric's Wind Curtailment compliance filing provided in Xcel Electric's FYE18 AAA filing.

The Department notes that Xcel Electric's FYE18 AAA filing included additional information and analysis to address the FCA Settlement Agreement approved by the Commission in Docket No. E002/GR-05-1428. The Department was not a party to this settlement, and thus invites comments on this information from those who were parties, regarding whether there are any concerns that need to be addressed.

The Department will continue to monitor the treatment of offsetting revenues and compensation recovered by the utilities in future filings.

The Department intends to continue to monitor the IOUs' actual expenses pertaining to maintenance of generation plants, with a comparison to the generation maintenance budget from the IOUs' recent rate cases in future AAA filings. The Department will also consider ongoing outage costs on a going forward basis.

The Department requests that Xcel, OTP, and MP provide data for generation maintenance expense for 2018 in reply comments.

The Department concludes that the IOUs complied with the reporting requirement of Order Point 22 of the April 6, 2012 Order in Docket No. E999/AA-10-884.

The Department concludes that Xcel Electric complied with the 2010 Order in Docket No. E002/M-10-161 regarding WM Renewable Energy.

The Department concludes that MP provided the required reporting information in compliance with the Commission's Order in Docket No. E015/M-10-961 regarding the Manitoba Hydro PPA.

The Department concludes that the Community Solar Garden Program costs included in Xcel Electric's FCA appear reasonable.

The Department recommends that Xcel Electric provide information regarding its backup strategies for transformers and its policy for transformer maintenance in reply comments. The Department will provide its recommendation regarding Xcel Electric's transformer reporting for FYE18 after it has reviewed Xcel Electric's reply comments.

The Department recommends that MP provide its policy for transformer maintenance in reply comments. The Department will provide its recommendation regarding MP's transformer reporting for FYE18 after it has reviewed MP's reply comments.

The Department recommends that the Commission accept OTP's transformer reporting for FYE18.

The Department concludes that Xcel Electric has correctly calculated the interim costs of the HERC power purchase agreement.

The Department concludes that Xcel Electric has correctly calculated the costs of the Renewable*Connect Green Pricing programs that appear in the fuel clause adjustment.

The Department concludes that the total credit for the Flint Hills transaction complies with the Commission's Orders in Docket No. E002/PA-17-529.

The Department concludes that the total credit of $1,275,903 for the options for the potential Sherco land sales complies with the Commission's February 6 Order in Docket No. E002/PA-17-528.

C. SECTION IV, FUEL COST REVIEW

During the Department's review of Xcel Gas' AAA filing in Docket No. G999/AA-18-374, the Department became aware of an issue involving the allocation of natural gas costs between Xcel Gas' retail customers and Xcel Electric's generation facilities. While this issue is discussed in more detail in the Department's April 25, 2019 comments in Docket No. G999/AA-18-374, the Department notes that this issue may result in an adjustment to Xcel Electric's FYE18 fuel costs. In Docket No. G999/AA-18-374, the Department asked Xcel Electric to submit information on the allocation issue in both the electric and natural gas AAA proceedings. The Department will review Xcel's supplemental information and provide supplemental comments should an adjustment to Xcel Electric's FYE18 fuel costs be warranted.

D. RECOMMENDATIONS FOR MISO DAY 1

The Department notes that there may no longer be a need for the MISO Day 1 reporting, since the MISO Day 1 has been in operation since 2002 and we have not seen much in the way of concerns that have negatively impacted customers. The Department has discussed the MISO Day 1 reporting requirement with the electric utilities and the consumer advocates in the FCA reform proceeding, and all concluded that this MISO Day 1 reporting is no longer necessary. The Commission is scheduled to address the reporting requirements under the reformed FCA process at its April 25, 2019 Agenda Meeting.

Overall the Department concludes that the Companies' responses have complied generally with all of the AAA MISO Day 1 compliance reporting requirements. The Department expects utilities to continue to work hard to mitigate costs or the effects of changes by MISO or FERC that could negatively impact Minnesota retail customers. Utilities are required to continue to show benefits of MISO Day 1 in the context of their rate cases before receiving further cost recovery of Schedule 10 costs.

E. MISO DAY 2 REPORTING AND ALLOCATIONS

- The Department recommends that the Commission accept Xcel Electric's MISO Day 2 reporting and allocations for FYE18.
- The Department recommends that the Commission accept MP's MISO Day 2 reporting and allocations for FYE18.
- The Department recommends that the Commission accept OTP's MISO Day 2 reporting and allocations for FYE18.

F. RECOMMENDATIONS FOR ASSET BASED MARGINS

- The Department concludes that Xcel Electric's asset-based margins for FYE18 appear reasonable. The Department will continue to monitor Xcel Electric's asset-based margins in future AAA filings.

- The Department concludes that MP's asset-based margins for FYE18 appear to be reasonable. The Department will continue to monitor MP's wholesale asset-based margins in future AAA filings.

- The Department concludes that OTP's asset-based margins for FYE18 appear to be reasonable. The Department will continue to monitor OTP's wholesale asset-based margins in future AAA filings.

G. RECOMMENDATIONS FOR ANCILLARY SERVICES MARKET

- The Department reviewed Xcel Electric's ASM charges and concludes that they are reasonable. As a result, the Department recommends that the Commission accept Xcel Electric's ASM reporting for FYE18.
- The Department reviewed MP's ASM charges and concludes that they are reasonable. As a result, the Department recommends that the Commission accept MP's ASM reporting for FYE18.

The Department reviewed OTP's ASM charges and concludes that they are reasonable. As a result, the Department recommends that the Commission accept OTP's ASM reporting for FYE18.

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Xcel Energy		Information Request No.	12
Docket No.:	E999/AA-18-373		
Response To:	MN Department of Commerce		
Requestor:	Mark Johnson		
Date Received:	December 28, 2018		

Question:

Topic: MISO Day 2 and Ancillary Services Market (ASM) Allocations between Retail and Asset-Based Wholesale

Reference(s): Initial Filing, Part J, Section 5, Schedule 7
Initial Filing, Part J, Section 5, Schedule 13

Please explain if Xcel changed any of the allocation methods used to allocate MISO Day 2 and ASM charges between retail and asset-based wholesale during the FYE18 reporting period when compared to the FYE17 reporting period. If so, please provide the charge type, the change in allocation method, and the impact it had on the dollar amounts allocated between retail and asset-based wholesale for FYE18.

Response:

The allocation method used for MISO Day 2 and ASM charges between retail and asset-based wholesale did not change from FYE17 to FYE18.

Preparer:	Bill Olson
Title:	Manager Market Operations Accounting
Department:	Market Operations Accounting
Telephone:	303-571-7822
Date:	January 7, 2019

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Xcel Energy		Information Request No. 13
Docket No.:	E999/AA-18-373	
Response To:	MN Department of Commerce	
Requestor:	Mark Johnson	
Date Received:	December 28, 2018	

Question:
Topic: Asset-Based Margins
Reference(s): Initial Filing, Part J, Section 5, Schedule 7, Page 7 of 13

Please provide support to show that the ($21,475,170) in MISO Day 2 asset-based charges for January 2018 was included in Xcel's asset-based margin calculation and credited to ratepayers via the fuel clause adjustment.

Response:
The $21.475 million reported in the January 2018 AAA filing represents a portion of the total asset based revenues. The question above indicates it is a charge; however; it is a negative net cost and therefore is revenue. Cost of Goods Sold expenses are deducted from the total asset based revenue to calculate the total asset based margin. The Minnesota jurisdictional portion credited to Minnesota ratepayers in the January 2018 fuel clause adjustment was $3,724,985.

Please see below for additional detail:

Minnesota Asset Based Margin Sharing	(Jan 2018) $- millions
(1) MISO Day 2 and ASM Intersystem Asset Based	$21.5
(2) Non-MISO Asset Based Revenue	$1.3
(3) Total Asset Based Revenue (1)+(2)	$22.8
(4) Less: Cost of Goods Sold	$16.3
(5) NSP System Asset Based Margins (3)–(4)	$6.5
(6) Less: Ratepayer Sharing (*)	$4.5
(7) Less: Other Jurisdictions Specific Adjustments	$0.9
(8) Other Jurisdictions' Pass-Through/Company Retention	$1.1
* **Ratepayer Sharing Detail**	
Minnesota Jurisdiction	$4,639,978
Less: Other Jurisdictions Specific Adjustments	$914,993
Minnesota Net Portion	**$3,724,985**
Other NSP Jurisdictions	$745,916
Total NSP Ratepayers Sharing	$4,470,901

Preparer: Allison Johnson
Title: Principal Financial Consultant
Department: NSP Commercial Accounting
Telephone: 303-571-6967
Date: January 7, 2019

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Xcel Energy Information Request No. 14

Docket No.:	E999/AA-18-373
Response To:	MN Department of Commerce
Requestor:	Mark Johnson
Date Received:	December 28, 2018

Question:
Topic: Asset-Based Margins

Please provide the amount of asset-based margins returned to ratepayers via the fuel clause for the FYE18 reporting period.

Response:
The total realized Minnesota jurisdictional share of asset-based margins to be refunded for the FYE18 reporting period was $24.13 million. The actual amount returned to ratepayers via fuel cost charges was $24.62 million. The deviation was primarily due to forecast and actual sales true up. This information is included in Attachment A.

Preparer:	John Chow/James Schroeder
Title:	Pricing Consultant / Accounting – Financial Consultant
Department:	NSPM Regulatory / NSP Utility Accounting
Telephone:	612-330-7588 / 612-330-6208
Date:	January 7, 2019

Northern States Power Company
State of Minnesota - Electric Utility
Minnesota Asset Based Margin Sharing - 2018 AAA Period

Docket No. E999/AA-18-373
Information Request No. DOC-14
Attachment A
Page 1 of 1

Month Margin Realized **Fuel Clause Month**	**Jul-17** **Sep-17**	**Aug-17** **Oct-17**	**Sep-17** **Nov-17**	**Oct-17** **Dec-17**	**Nov-17** **Jan-18**	**Dec-17** **Feb-18**	**Jan-18** **Mar-18**	**Feb-18** **Apr-18**	**Mar-18** **May-18**	**Apr-18** **Jun-18**	**May-18** **Jul-18**	**Jun-18** **Aug-18**	**FYE 2018** **Total**
Monthly Refund & True-up													
Monthly Asset Based Margin from G/L	(1,631,273)	(1,539,423)	(1,408,666)	(2,061,726)	(1,898,925)	(2,261,375)	(3,724,985)	(1,886,195)	(1,947,286)	(1,191,521)	(2,376,763)	(2,464,219)	(24,392,357)
Month True-up	(40,784)	(61,078)	46,098	(61,827)	(2,568)	(549)	(10,430)	94,396	(2,156)	85,128	135,442	79,830	261,503
Total to be Refunded	(1,672,058)	(1,600,501)	(1,362,568)	(2,123,553)	(1,901,493)	(2,261,924)	(3,735,415)	(1,791,799)	(1,949,442)	(1,106,392)	(2,241,321)	(2,384,389)	(24,130,854)
Sales													
Forecasted Calendar Month Sales	2,540,042	2,417,950	2,317,239	2,544,338	2,594,774	2,261,066	2,425,332	2,102,859	2,315,948	2,613,465	2,944,430	2,867,059	
Less: Windsource Forecast	(13,543)	(12,896)	(11,536)	(14,476)	(14,895)	(13,614)	(14,424)	(13,353)	(14,897)	(13,583)	(16,295)	(17,422)	
Forecasted Sales	2,526,499	2,405,054	2,305,703	2,529,862	2,579,879	2,247,452	2,410,908	2,089,506	2,301,051	2,599,882	2,928,135	2,849,637	
Actual Calendar Month Sales	2,618,866	2,336,055	2,328,725	2,553,136	2,593,495	2,365,846	2,435,318	2,213,114	2,485,231	2,813,617	2,974,637	3,021,236	
Less: Windsource Actual	(22,720)	(23,904)	(27,391)	(23,944)	(27,775)	(24,603)	(25,800)	(24,329)	(24,320)	(26,177)	(28,640)	(34,342)	
Actual Sales	2,596,146	2,312,151	2,301,334	2,529,192	2,565,720	2,341,243	2,409,518	2,188,785	2,460,911	2,787,440	2,945,997	2,986,894	
Monthly Refund Factor	(0.065)	(0.064)	(0.061)	(0.081)	(0.074)	(0.101)	(0.155)	(0.090)	(0.085)	(0.046)	(0.081)	(0.086)	
Monthly True-up Refund Factor	(0.002)	(0.003)	0.002	(0.002)	(0.000)	(0.000)	(0.000)	0.005	(0.000)	0.003	0.005	0.003	
Total Refund Factor	(0.066)	(0.067)	(0.059)	(0.084)	(0.074)	(0.101)	(0.155)	(0.086)	(0.085)	(0.043)	(0.077)	(0.084)	
True-up Calculation													
Expected Refund	(1,672,057.76)	(1,600,501.35)	(1,362,568.15)	(2,123,552.53)	(1,901,493.33)	(2,261,923.68)	(3,735,414.95)	(1,791,798.71)	(1,949,441.56)	(1,106,392.41)	(2,241,320.65)	(2,384,388.88)	
Actual Refund	(1,718,155.38)	(1,538,690.25)	(1,359,996.34)	(2,123,003.76)	(1,891,063.93)	(2,356,297.19)	(3,733,259.00)	(1,876,926.91)	(2,084,883.80)	(1,186,222.97)	(2,254,983.94)	(2,499,253.69)	(24,622,737)
(Under)/Over Refunded Amount	46,097.62	(61,811.10)	(2,571.81)	(548.77)	(10,429.40)	94,373.51	(2,155.95)	85,128.20	135,442.24	79,830.56	13,663.29	114,864.80	
Allocation Factors													
Residential	1.0185	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	
C&I Non-Demand	1.0493	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	
C&I Demand	1.0028	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	
C&I Demand On Peak	1.2732	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	
C&I Demand Off Peak	0.7987	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	
Street Lighting	0.7446	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	
Refund Factor													
Residential	(0.067)	(0.068)	(0.060)	(0.085)	(0.075)	(0.102)	(0.158)	(0.087)	(0.086)	(0.043)	(0.078)	(0.085)	
C&I Non-Demand	(0.069)	(0.069)	(0.061)	(0.087)	(0.076)	(0.104)	(0.160)	(0.088)	(0.087)	(0.044)	(0.079)	(0.086)	
C&I Demand	(0.066)	(0.066)	(0.059)	(0.084)	(0.074)	(0.100)	(0.155)	(0.086)	(0.085)	(0.042)	(0.076)	(0.084)	
C&I Demand On Peak	(0.084)	(0.083)	(0.074)	(0.105)	(0.092)	(0.126)	(0.193)	(0.107)	(0.106)	(0.053)	(0.096)	(0.104)	
C&I Demand Off Peak	(0.053)	(0.054)	(0.048)	(0.069)	(0.060)	(0.082)	(0.127)	(0.070)	(0.069)	(0.035)	(0.063)	(0.068)	
Street Lighting	(0.049)	(0.053)	(0.047)	(0.067)	(0.059)	(0.080)	(0.124)	(0.068)	(0.068)	(0.034)	(0.061)	(0.067)	

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Xcel Energy		Information Request No. 15
Docket No.:	E999/AA-18-373	
Response To:	MN Department of Commerce	
Requestor:	Mark Johnson	
Date Received:	December 28, 2018	

Question:

Topic: ASM; 8a Real Time Non Excessive Energy Amount
Reference(s): Part J, Section 5, Schedule 13, Page 13 of 13 (17-492)
Part J, Section 5, Schedule 13, Page 13 of 13 (18-373)

Please explain why the total Real Time Non Excessive Energy Amount charges increased significantly from $8,041,460 in 17-492 to $26,347,229 in 18-373.

Response:

The increase in Real Time Non Excessive Energy (NXE) charges is primarily related to:

1) Higher Locational Marginal Prices on Real-Time balancing purchases. Higher prices contributed $11 million to the increase.
    a. The period January 2018 through February 2018 had significantly higher prices during a cold weather event (contributing $8 million).
2) A 7% increase in Real Time balancing purchases contributed $5.8 million (less impact of the price increase). The increase was spread across several resources.
3) The impact from an 11% decrease in Real-Time balancing sales was offset by higher prices.

Overall, the NXE charges of $26,347,229 presented in Docket No. E999/AA-18-373 are comprised of purchase and sale transactions where the purchases represent Real-Time balancing adjustments on Day-Ahead Sales of $1.1 billion. See the table below for illustration:

Real Time Non Excessive Energy Charges (NXE)

FY 2017	Dollars	MWh	$/MWh
Day Ahead Sales	$ 1,006,605,746	44,036,431	$ 22.86
NXE Real Time Sales	$ 74,434,102	3,589,398	$ 20.74
NXE Real Time Purchases	$ (80,882,501)	(3,683,910)	$ 21.96
NXE Real Time Total	$ (6,448,398)	(94,512)	
Congestion & Loss	$ (1,593,062)		
Reported NXE Energy Amount	$ (8,041,460)	(94,512)	
Total Sales	$ 1,000,157,347	43,941,919	$ 22.76

FY 2018	Dollars	MWh	$/MWh
Day Ahead Sales	$ 1,133,799,566	45,771,426	$ 24.77
NXE Real Time Sales	$ 74,767,724	3,193,972	$ 23.41
NXE Real Time Purchases	$ (97,703,916)	(3,949,157)	$ 24.74
NXE Real Time Total	$ (22,936,193)	(755,185)	
Congestion & Loss	$ (3,411,036)		
Reported NXE Energy Amount	$ (26,347,229)	(755,185)	
Total Sales	$ 1,110,863,373	45,016,241	$ 24.68

Change	Dollars	MWh	$/MWh
Day Ahead Sales	$ 127,193,820	1,734,995	$ 1.91
NXE Real Time Sales	$ 333,621	(395,426)	$ 2.67
NXE Real Time Purchases	$ (16,821,415)	(265,247)	$ 2.78
NXE Real Time Total	$ (16,487,794)	(660,673)	
Congestion & Loss	$ (1,817,974)		
Reported NXE Energy Amount	**$ (18,305,768)**	**(660,673)**	
Total Sales	$ 110,706,026	1,074,322	

Preparer: Matt Schmidt
Title: Sr. Market Operation Financial Analyst
Department: Market Operation Accounting
Telephone: 303-571-7519
Date: January 7, 2019

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-18-373	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	March 15, 2019
Type of Inquiry:	Financial	Response Due:	March 25, 2019

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Request Number: **17**
Topic: MISO Day 2 and ASM allocations
Reference(s): Attachment No. 9

Request:

Has MP changed any of its allocations for MISO Day 2 and Ancillary Services Market (ASM)? If yes, please identify all changes in allocations and explain why the change is a better method of allocation.

RESPONSE:

Minnesota Power has not changed its allocation methods.

To be completed by responder

Response Date: March 20, 2019
Response by: Leann Oehlerking-Boes
Email Address: lboes@mnpower.com
Phone Number: 218-355-3832

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-18-373	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	March 15, 2019
Type of Inquiry:	Financial	Response Due:	March 25, 2019

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Request Number: **18**
Topic: Asset Based Margins
Reference(s): MP's Rate Case GR-16-664

Request:

Please provide the actual costs, revenues, megawatt hours and resulting actual asset based margins for 2018. If 2018 assets based margins are plus or minus $100,000 compared to 2017 actual asset based margins, please explain the reason for the change.

RESPONSE:

Please see response to DOC IR 13 for E015/AA-17-492 in reference to the asset based margins approved in Minnesota Power's rate case E015/GR-16-664 which were set at $35.8 million (Minnesota Jurisdictional) as stated in J. Pierce, Supplemental Direct Testimony and Schedules, page 10, line 3, and Supplemental Direct Schedule 5, page 17. These schedules were used to create Table 1 and 2 below that compare2017 and 2018 Asset-Based Wholesale sales margins.

The 2018 asset-based margins were $39.7 million (Minnesota Jurisdictional) and approximately $5.4 million higher in 2018 than 2017. There were three main drivers for the increase in asset-based margins: 1) escalating energy sale prices due to defined contract terms, 2) higher than expected market energy prices for shorter term sales, and 3) and the addition of energy sales due to the loss of industrial and resale customers since the 2017 Rate Case . The cumulative effect of these changes resulted in higher asset-based margins in 2018.

Minnesota Power would like to note that when the margins from additional energy sales due to a loss of industrial and resale customers since the 2017 rate case are removed, it reduces the change from 2017 to 2018 to approximately $3.4 million in Minnesota Jurisdictional margins. From Minnesota Power's

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To be completed by responder

Response Date: March 25, 2019
Response by: Laurel Udenberg
Email Address: ludenberg@mnpower.com
Phone Number: (218) 723-7537

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-18-373	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	March 15, 2019
Type of Inquiry:	Financial	Response Due:	March 25, 2019

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

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perspective, the appropriate comparison between 2017 and 2018 asset-based sale margins would exclude these sales caused by the loss of customers.

The difference between 2018 and 2017 (Table 3) include contract price increase for the Basin Electric Cooperative power sale which provides the largest contribution to the Asset-Based Wholesale sale margin creation. This long term sale will expire in 2020 and no longer contribute to the Minnesota Jurisdictional margin value.

Please see TRADE SECRET “Table 1 – Asset-Based Wholesale Sales 2017 Actuals” below for actual costs, revenues and asset based margins for 2017.

Please see TRADE SECRET “Table 2 – Asset-Based Wholesale Sales 2018 Actuals” below for actual costs, revenues and asset based margins for 2018.

Please see TRADE SECRET “Table 3 – Asset-Based Wholesale Sales Difference between 2017 & 2018” below for the difference in asset based margins between 2017 and 2018.

To be completed by responder

Response Date: March 25, 2019
Response by: Laurel Udenberg
Email Address: ludenberg@mnpower.com
Phone Number: (218) 723-7537

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-18-373	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	March 15, 2019
Type of Inquiry:	Financial	Response Due:	March 25, 2019

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Table 1

Asset-Based Wholesale Sales 2017 Actuals									
	MWH	FUEL COST	MN JURISDICTION FUEL COST	SALES PRICE	MN JURISDICTION SALES PRICE	NET ENERGY MARGIN	MN JURISDICTION MARGIN	CAPACITY REVENUE	MN JURISDICTION CAPACITY REVENUE
MISO Market Sales	TRADE SECRET DATA EXCISED [redacted]								
AEP									
Basin 100 MW									
Basin capacity sales									
NextEra									
MDU									
MISO Resource Adequacy									
unidentified capacity sale									
MISO Costs									
Total Wholesale Energy Sales	**2,244,242**	**$ 51,514,973**	**$ 43,206,638**	**$ 79,367,618**	**$ 66,567,209**	**$ 27,852,646**	**$ 23,360,571**	**$ 13,375,272**	**$ 10,969,997**
							Total Margin		**$ 41,227,918**
							MN Jurisdictional Margin		**$ 34,330,568**
MN Jurisdictional									
Energy	0.83872								
Demand	0.82017								

To be completed by responder

Response Date: March 25, 2019
Response by: Laurel Udenberg
Email Address: ludenberg@mnpower.com
Phone Number: (218) 723-7537

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-18-373	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	March 15, 2019
Type of Inquiry:	Financial	Response Due:	March 25, 2019

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Table 2

Asset-Based Wholesale Sales
2018 Actuals

	Executed due to Industrial and Resale Load Loss	MWH	FUEL COST	MN JURISDICTION FUEL COST	SALES PRICE	MN JURISDICTION SALES PRICE	NET ENERGY MARGIN	MN JURISDICTION MARGIN	CAPACITY REVENUE	MN JURISDICTION CAPACITY REVENUE
		TRADE SECRET DATA EXCISED [redacted]								
MISO Market Sales										
SENA										
SENA	yes									
Basin 100 MW										
Basin Capacity Sales										
NextEra										
NextEra	yes									
MISO Market Sales	yes									
MMPA										
OTP										
TEA										
MISO Resource Adequacy										
MISO Costs										
Total Wholesale Energy Sales		2,147,649	$ 49,315,295	$ 41,576,246	$ 83,077,354	$ 70,040,024	$ 33,762,058	$ 28,463,778	$ 13,382,304	$ 11,289,311.27
								Total Margin		$ 47,144,362
								MN Jurisdictional Margin		$ 39,753,090
MN Jurisdictional										
Energy	0.84307									
Demand	0.84360									

To be completed by responder

Response Date: March 25, 2019
Response by: Laurel Udenberg
Email Address: ludenberg@mnpower.com
Phone Number: (218) 723-7537

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-18-373	☐Nonpublic	☒Public
Requested From:	Minnesota Power	Date of Request:	March 15, 2019
Type of Inquiry:	Financial	Response Due:	March 25, 2019

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Table 3

Asset-Based Wholesale Sales			
Difference between 2018 & 2017 Actual MN Jurisdictional Margins			
	2017	**2018**	**Difference**
	[redacted] TRADE SECRET DATA EXCISED		
Basin 100 MW			
Other Bilateral Sales *			
Sales due to Industrial & Resale Load Loss *			
MISO Market Sales			
Capacity Sales			
MISO Costs			
Total Wholesale Energy Sales	34,330,568	39,753,090	5,422,522

To be completed by responder

Response Date: March 25, 2019
Response by: Laurel Udenberg
Email Address: ludenberg@mnpower.com
Phone Number: (218) 723-7537

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-18-373	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	March 15, 2019
Type of Inquiry:	Financial	Response Due:	March 25, 2019

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Request Number: **19**
Topic: MISO Day 2 and ASM net costs
Reference(s): Attachment No. 9

Request:

a) Page 77 of 80 of Attachment 9 shows the July 2017 to June 2018 "Grand Total" of $55,746,384, does this amount reflect the total for both MISO Day 2 and ASM net costs? Please explain your response.

b) Page 77 of 80 of Attachment 9 shows the July 2017 to June 2018 "Subtotal" of $456,115, does this amount reflect the total ASM net costs? Please explain your response.

RESPONSE:

a) Yes – the $55,746,384 includes all MISO Day 2 And ASM charges. Please refer to Table 1 below for the breakdown of MISO Day 2 and ASM charges for July 2017 – June 2018.

Table: 1

July 2017 - June 2018		
Energy Charges	$	35,490,276.77
Energy Loss Charges	$	12,131,694.68
Administration Charges	$	1,920,206.64
Congestion, FTR, and ARR Charges	$	3,166,826.02
RSG and Make Whole Charges	$	557,778.81
RNU and Misc. Charges	$	2,023,486.16
ASM Charges	$	456,114.93
Grand Total	$	55,746,384.01

To be completed by responder

Response Date: March 20, 2018
Response by: Leann Oehlerking-Boes
Email Address: lboes@mnpower.com
Phone Number: 218-355-3832

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-18-373	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	March 15, 2019
Type of Inquiry:	Financial	Response Due:	March 25, 2019

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

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b) Yes – The $456,115 is the total ASM charges from June 2017 – July 2018. The only ASM charges not included in the subtotal of $456,115 are Excessive and Non-Excessive Energy charges which are included in the Energy section "subtotal" of $35,490,276.77 on Page 75 of AA-18-373 Attachment 9. Please refer to Table 2 below for the breakdown of MISO ASM charges by month.

Table: 2

ASM Charges		
Jul-17	$	40,816.19
Aug-17	$	33,862.87
Sep-17	$	30,794.59
Oct-17	$	51,745.00
Nov-17	$	52,357.80
Dec-17	$	15,495.83
Jan-18	$	73,455.77
Feb-18	$	38,475.81
Mar-18	$	40,396.59
Apr-18	$	38,783.44
May-18	$	19,316.96
Jun-18	$	20,614.08
Grand Total	$	456,114.93

To be completed by responder

Response Date: March 20, 2018
Response by: Leann Oehlerking-Boes
Email Address: lboes@mnpower.com
Phone Number: 218-355-3832

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-18-373	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	March 15, 2019
Type of Inquiry:	Financial	Response Due:	March 25, 2019

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Request Number: **20**
Topic: MISO Day 2 and ASM net costs
Reference(s): Attachment No. 9 for Docket Nos. AA-16-523 and AA-17-492

Request:

a) Please explain the main drivers that caused the Day 2 and ASM total net costs to increase from $44.597 million for July 2016 to June 2017 on Attachment 9 page 77 of 80 to $55.746 million for July 2017 to June 2018 on Attachment 9 page 77 of 80.

b) Please explain the main drivers for the $400,342 in Regulation Reserve Cost Distribution Amount and the $400,888 in Spinning Reserve Cost Distribution Amount for July 2017 to June 2018 on Attachment 9 page 77 of 80.

RESPONSE:

a) Asset Energy increased roughly 12 million dollars from July 2016 – June 2017 to July 2017 – June 2018. All of the increase was in the Day Ahead which was caused by increased Day Ahead LMP prices. DA LMP's at MP.MP averaged $23.76 from July 2016 – June 2017 and escalated to $25.85 from July 2017 – June 2018.

b) Regulation Reserve Cost Distribution and Spinning Reserve Cost Distribution are Distribution Charges that are MISO procurement costs that are distributed to Asset Owners based on their load.

To be completed by responder

Response Date: March 25, 2019
Response by: Ryan LaCoursiere
Email Address: rlacoursiere@mnpower.com
Phone Number: 218-355-3678

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-18-373	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	March 15, 2019
Type of Inquiry:	Financial	Response Due:	March 25, 2019

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Request Number: **21**
Topic: ASM net costs
Reference(s): Attachment No. 9 for Docket Nos. AA-16-523 and AA-17-492

Request:

For ASM total costs, please explain the difference in the $456,115 for the period July 2017 to June 2018 on Attachment 9 page 77 of 80 and the $457,229 as discussed in "ASM Charge Summary" section on Attachment 10, page 3 of 12.

RESPONSE:

The ASM costs as shown on Attachment 9 are based on when they were recorded in the Company's general ledger and allocated to the fuel clause adjustment. The ASM costs as shown on Attachment 10 are based on the operating day they pertain to. Attachment 10 numbers are updated through the most current settlement statements received prior to preparing the attachment for filing with the AAA.

To be completed by responder

Response Date: March 20, 2019
Response by: Leann Oehlerking-Boes
Email Address: lboes@mnpower.com
Phone Number: 218-355-3832

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number: E015/AA-18-373 ☐Nonpublic ☒Public
Requested From: Minnesota Power Date of Request: March 15, 2019
Type of Inquiry: Financial Response Due: March 25, 2019

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Request Number: **22**
Topic: MISO Day 2 and ASM charges
Reference(s): Attachment No. 9

Request:

a) Please provide the MISO bills including a summary sheet of the MISO bills that support the $5.283 million in MISO Day 2 and ASM net costs for March 2018 (Attachment 9, page 53 of 80).

b) Please provide all plant outages both planned and forced for the month of **March 2019**, including the cost of each outage and the causes of each outage.

c) Please support MP's cost allocation of $4,445,483 in costs and $551,594 in revenues (for a net costs of $3,893,889) assigned to FPE Retail out of the Grand Total of $5,283,039 for MISO Day 2 and ASM net costs in **March 2017** (Attachment 9, page 53 of 80).

RESPONSE:

a) Attachment 1 is a summary that shows what was billed for March 2018 through the MISO weekly bills in order to support the $5.283 million in MISO Day 2 and ASM net costs. The MISO bills are included as Attachment 6 – Attachment 19. There are differences between what was included in AA-18-373 Attachment 9 and what is shown on the MISO bills due to our accrual process.

b) It was verified that March 2018 is the month we should provide information for. Attachment 20 shows the planned and forced outages for the month of March, as well as the costs and causes associated with each outage.

To be completed by responder

Response Date: March 25, 2019
Response by: Taylor Murphy
Email Address: tmurphy@mnpower.com
Phone Number: 218-355-3591

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-18-373	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	March 15, 2019
Type of Inquiry:	Financial	Response Due:	March 25, 2019

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

In addition, the below table is an excerpt of the information provided as part of AA-18-373 Attachment 16 filed on August 31, 2018.

Minnesota Power's Force Outages

Unit	Event Type	DOC Primary Reason for the Outage	GADS Equivalent MWh lost	GADS Start Date/Time of Actual Outage	GADS End Date/Time of Actual Outage	DOC Equipment or Condition that Resulted in the Outage	DOC Description of Equipment Failure (including identified root cause)	DOC Steps Taken to Alleviate Reoccurrence	DOC Change in Energy
BEC 2	Unplanned Outage	Boiler Reheat Tube Leak	2,252	3/12/18 22:30	3/14/18 8:07	Superheat tube leak.	Long-term overheating and external corrosion.	Repaired tube leak. During this outage opportunity, additional tubes in the surrounding area were inspected and repaired as needed. No long term plan due to retirement of unit at end of 2018.	$ 890
BEC 3	Unplanned Outage	Condenser Tube Leak Repair	10,349	3/14/18 20:15	3/16/18 1:39	Condenser.	Water chemistry contamination occurred as a result of a condenser tube leak.	Repaired two leaks in the north waterbox. Ultrasonic testing and repairs along with changing valves to allow safe isolation of condenser to repair while unit online to be completed on next available longer planned outage.	$ 11,248

c) It was verified that March 2018 is the month we should provide information for. MP's cost allocation of $4,445,483 in costs and $551,594 in revenues assigned to FPE Retail are supported by the data shown in Attachment 2.

To be completed by responder

Response Date: March 25, 2019
Response by: Taylor Murphy
Email Address: tmurphy@mnpower.com
Phone Number: 218-355-3591

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-18-373	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	March 15, 2019
Type of Inquiry:	Financial	Response Due:	March 25, 2019

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Request Number: **23**
Topic: FTRs & ARRs
Reference(s): Attachment No. 11

Request:

a) Please provide the revenues related to the transactions that sink on lines 1-7, 12, 15 and 17-24 on Attachment 11 page 3 of 5. Please compare the costs to the related revenues and provide why this benefits ratepayers if the overall impact is a net cost.

b) Please provide the revenues related to the transactions that sink on and lines 1-2, 6-7, 11-12, 14-15 and 17-18 of Attachment 11 page 4 of 5. Please compare the costs to the related revenues and provide why this benefits ratepayers if the overall impact is a net cost.

<u>RESPONSE</u>:

a) Please see TRADE SECRET "Table 1 - Monthly FTR Purchases" below, which illustrates the FTR Costs/Benefits associated with the transactions as referenced on Attachment 11 page 3 of 5. Minnesota Power's utilization of the Monthly FTR Auction provides a benefit to customers by managing congestion price volatility exposure on financial bilateral transactions.

To be completed by responder

Response Date: March 25, 2019
Response by: Nate Elling
Email Address: nelling@mnpower.com
Phone Number: (218) 723-7494

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number: E015/AA-18-373 ☐Nonpublic ☒Public
Requested From: Minnesota Power Date of Request: March 15, 2019
Type of Inquiry: Financial Response Due: March 25, 2019

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Table 1

Monthly FTR Purchases

Source	Sink	Class Period	Month	Awarded FTRs	Clearing $/MW Month	Total Monthly Cost	FTR Value $/MW Month	FTR Revenue	FTR Cost/Benefit
TRADE SECRET DATA EXCISED [redacted]									

To be completed by responder

Response Date: March 25, 2019
Response by: Nate Elling
Email Address: nelling@mnpower.com
Phone Number: (218) 723-7494

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-18-373	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	March 15, 2019
Type of Inquiry:	Financial	Response Due:	March 25, 2019

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

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b) Please see TRADE SECRET "Table 2 - Annual FTR Purchases" below, which illustrates the FTR Costs/Benefits associated with the transactions as referenced on Attachment 11 page 4 of 5. Minnesota Power's utilization of the Annual FTR Auction provides a benefit to customers by managing congestion price volatility exposure on financial bilateral transactions.

Table 2

Annual FTR Purchases

Source	Sink	Class Period	Season	Awarded FTRs	Clearing $/MW Month	Total Monthly Cost	FTR Value $/MW Month	FTR Revenue	FTR Cost/Benefit

TRADE SECRET DATA EXCISED

[redacted]

To be completed by responder

Response Date: March 25, 2019
Response by: Nate Elling
Email Address: nelling@mnpower.com
Phone Number: (218) 723-7494

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-18-373	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	March 15, 2019
Type of Inquiry:	Financial	Response Due:	March 25, 2019

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Request Number: **24**
Topic: Generation Maintenance Expenses
Reference(s): Attachment No. 12

Request:

Please provide the 2018 actuals and 2017 test year amounts approved in GR-16-664 for generation maintenance expense, in the same format as Attachment No. 12. Please explain any significant differences.

RESPONSE:

Refer to DOC IR 24 Attachment 24.xls for the requested 2018 actuals and approved test year generation maintenance expense information. Explanations for significant differences are explained below.

Steam Power Generation Maintenance:
FERC account 510 Maintenance of Supervision and Engineering:
2018 actual expense is lower than the 2017 approved test year expense due to the planned retirement of Boswell Units 1&2 and the resulting staff reductions.

FERC account 511 Maintenance of Structures:
Actual 2018 expenses included filter replacements, HVAC and safety equipment. The 2017 test year maintenance did not include all these items.

FERC account 512 Maintenance of Boiler Plant:
2017 test year expense included a scheduled 3 week maintenance outage for Boswell 4. 2018 actuals reflect 7 day maintenance outage completed at Boswell Unit 4. 2018 actuals also reflect a 6 week outage at Hibbard Renewable Energy Center.

To be completed by responder

Response Date: March 25, 2019
Response by: Rhonda Munger, Budget Analyst Senior; Sara Carlson, Cost and Pricing Analyst Senior
Email Address: rmunger@mnpower.com; scarlson@mnpower.com
Phone Number: 218-313-4496; 218-355-3019

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-18-373	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	March 15, 2019
Type of Inquiry:	Financial	Response Due:	March 25, 2019

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

<u>FERC account 513 Maintenance of Electric Plant</u>:
2018 actuals reflect higher maintenance costs for the Boswell 4 cooling tower, condensate pump and turbine valve.

<u>FERC account 514 Maintenance of Misc. Steam Plant</u>:
The 2018 actuals reflect a lower maintenance spending at Hibbard Renewable Energy Center compared to 2017 test year and also reflect reduced maintenance spending at Boswell 4 for the restrooms, page phone system, lighting and grounds maintenance areas.

Other Power Generation - Wind
<u>FERC account 554 Maintenance of Misc. Other Pwr Generation Plt</u>:
Actual 2018 expenses in FERC account 554 are higher due to changes in wind generation maintenance agreements and higher wind tech labor expense.

To be completed by responder

Response Date: March 25, 2019
Response by: Rhonda Munger, Budget Analyst Senior; Sara Carlson, Cost and Pricing Analyst Senior
Email Address: rmunger@mnpower.com; scarlson@mnpower.com
Phone Number: 218-313-4496; 218-355-3019

Minnesota Power

Docket E015/AA-18-373
DOC IR 24 Attachment 24.xls

	FERC Acct	2018 Actual Expenses [1]	Final Rates Test Year 2017 E015/GR-16-664	Variance
Steam Power Generation				
Maintenance Supervision and Engineering	510	3,357,688	4,913,827	(1,556,139)
Maintenance of Structures	511	1,018,541	582,993	435,548
Maintenance of Boiler Plant	512	9,613,150	16,051,910	(6,438,760)
Maintenance of Electric Plant	513	2,713,305	2,143,926	569,379
Maintenance of Misc. Steam Plant	514	3,867,090	5,109,261	(1,242,171)
		20,569,774	28,801,917	(8,232,143)
Hydraulic Power Generation				
Maintenance Supervision and Engineering	541	384,193	514,969	(130,776)
Maintenance of Structures	542	76,957	73,962	2,995
Maintenance of Reservoirs, Dams and Waterways	543	1,317,590	604,374	713,216
Maintenance of Electric Plant	544	1,002,687	1,581,601	(578,914)
Maintenance of Misc. Hydraulic Plant	545	1,242,398	1,058,911	183,487
		4,023,825	3,833,817	190,008
Other Power Generation - Wind				
Maintenance Supervision and Engineering	551	18,976	19,855	(879)
Maintenance of Structures	552	2,964	15,000	(12,036)
Maintenance of Generating and Electric Plant	553	9,234,251	9,116,984	117,267
Maintenance of Misc. Other Pwr Generation Plt.	554	2,201,046	211,331	1,989,715
		11,457,237	9,363,170	2,094,067
Total Generation Maintenance		36,050,836	41,998,904	(5,948,068)

[1] 2018 actuals are based on preliminary numbers that are subject to further review, adjustment, and audit.
Minnesota Power's 2018 FERC Form 1 is scheduled to be filed April 1, 2019.

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-18-373	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	March 15, 2019
Type of Inquiry:	Financial	Response Due:	March 25, 2019

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Request Number: **25**
Topic: Offsetting Revenues
Reference(s): Attachment No. 15

Request:

Please show that the revenues on page 2 of 2 of Attachment 15, were passed back to ratepayers in the fuel clause for the month of December 2017 in Docket No. 18-100.

RESPONSE:

The amount shown on Attachment 3 to the 2017-2018 AAA filing on page 2 of 5 for the line entitled "Less: Fuel Costs Recovered Through Inter-System Sales" includes more than just the amount of the off - setting revenues shown in Attachment 15 on page 2 of 2. Fuel costs recovered through inter-system sales includes all the costs allocated to MP's inter-system sales including but not limited to: company owned generation costs used to make asset based sales, costs of purchases sold to the market that were no longer needed to cover load, margins (gain or loss) from sales of purchases no longer needed to cover load and MISO costs allocated to asset based sales.

The portion of fuel costs recovered through inter- system sales that relates to generation or purchased power costs is calculated on an hourly basis through MP's energy pricing program. In any hour, costs from company generation or one or more purchase could be allocated to a particular inter-system sale depending on the volume of the sale and how many purchase MWh are not needed for load and can be allocated to that sale.

The current reports from MP's energy pricing program identify how many MWh from each purchase are used to cover load, but do not currently show which particular inter-system sale they allocated to. If a

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To be completed by responder

Response Date: March 25, 2019
Response by: Ryan LaCoursiere
Email Address: rlacoursiere@mnpower.com
Phone Number: 218-355-3678

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-18-373	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	March 15, 2019
Type of Inquiry:	Financial	Response Due:	March 25, 2019

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

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purchase is not used to cover load, then it was "liquidated" or sold to the market. That sale could be to a counterparty or more often than not, it is sold to the MISO market, along with other purchases, not needed to cover load in that particular hour.

Since MP's current reports do not provide a breakdown of which purchases were used to serve each particular sale, MP is unable to show how Attachment 15 "ties to the month FCA Intersystem Sales for the AAA period".

The total for "Fuel Costs Recovered Through Inter-System Sales" for the reporting period July 2017 – June 2018 were $108,825,203 while the offsetting revenues related to MP's purchase power contracts was only $28,551,051, illustrating that there is more than just purchase power costs and margins included in that number as noted above.

To be completed by responder

Response Date: March 25, 2019
Response by: Ryan LaCoursiere
Email Address: rlacoursiere@mnpower.com
Phone Number: 218-355-3678

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-18-373	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	March 15, 2019
Type of Inquiry:	Financial	Response Due:	March 25, 2019

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Request Number: **26**
Topic: Congestion Cost Analysis
Reference(s): Attachment No. 18 on page 3 of 3

Request:

a) Please explain why FTR Revenues for Boswell Units (lines 4 to 7) materially decreased from July 2016 to June 2017 compared to July 2017 to June 2018.

b) Please explain the drivers for the increase in Net Congestion Costs of approximately $415,000 from July 2016 to June 2017 compared to July 2017 to June 2018.

RESPONSE:

a) FTR Revenues for the Boswell Units decreased from 2016 to 2017 due to a market reduction in the difference in the Marginal Congestion Component (MCC) of the Locational Marginal Price (LMP) between the Boswell units and Minnesota Power's load node.

b) The main drivers for the change in the Net Congestions Costs between FYE 17 and FYE 18 related to the reduction in the FTR Revenues as explained in part a above; the fact that there was $70,000 of negative net congestion related to the Taconite Harbor Units in FYE 17 which were not running in FYE 18; and decreased negative net congestion from Thomson Hydro was mainly due to less MWhs of generation from the unit.

To be completed by responder

Response Date: March 25, 2019
Response by: Nate Elling
Email Address: nelling@mnpower.com
Phone Number: (218) 723-7494

OTTER TAIL POWER COMPANY
Docket No: E999/AA-18-373

Response to: Minnesota Department of Commerce
Analyst: Michael Zajicek
Date Received: 12/27/2018
Date Due: 01/07/2019
Date of Response: 01/07/2019
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Information Request:

Request Number: **9**
Topic: MISO Day 2 Charges
Reference(s): Initial AAA Filing Part H, Section 3, Attachment K, Page 26

Request:

1. Did Otter Tail change any of the allocation methods used to allocate MISO Day 2 charges (revenues) between retail and asset-based wholesale during the 2017-2018 reporting period?

2. Did Otter Tail change any of the allocation methods used to allocate ASM costs (revenues) during the 2017-2018 reporting period?

Attachments: 0

Response:

1. There have been no changes to the allocations of the MISO Day 2 charges (revenues) between retail and asset-based wholesale during the 2017-2018 reporting period.

2. There have been no changes to the allocations of the ASM costs (revenues) during the 2017-2018 reporting period.

OTTER TAIL POWER COMPANY
Docket No: E999/AA-18-373

Response to: Minnesota Department of Commerce
Analyst: Michael Zajicek
Date Received: 12/27/2018
Date Due: 01/07/2019
Date of Response: 01/07/2019
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Information Request:

Request Number: **10**
Topic: MISO Day 2 Charges
Reference(s): Initial AAA Filing Part H, Section 3, Attachment K, Page 1-26

Request:

Please provide a narrative on why MISO Day 2 charges for Day-Ahead Non-Asset Energy Amount and Real-Time Congestion fluctuate from reporting period to reporting period.

Attachments: 0

Response:

The Day-Ahead Non-Asset Energy Amount (DA_NASSET_EN) is the net charges and credits related to all day-ahead interchange schedules and day-ahead financial schedules settled at commercial pricing nodes where a MISO asset owner does not own an asset. For Otter Tail, this charge type is associated with subsidized federal energy provided by the Western Area Power Administration (WAPA) to serve municipal, tribal, and agency loads located within the Otter Tail service territory where Otter Tail is the supplemental provider. WAPA injects energy into the MISO interface, which is credited to Otter Tail (since Otter Tail does not have an asset at the interface, the energy credit falls in the Day-Ahead Non-Asset Energy Amount charge type). Otter Tail wheels this energy to the WAPA/Otter Tail shared loads where it is withdrawn from the grid and is included as part of the Otter Tail load zone within MISO. The table below illustrates that the Day-Ahead Non-Asset Energy Amount has been quite stable for the 2017/18 reporting period, both in MWhs and revenue. Month to month fluctuations of this charge type are driven by the changing MWh schedule injected by WAPA at the MISO interface and the changing day-ahead LMP price at the MISO interface.

Day-Ahead Non-Asset Energy Amount		
Month	**MWh**	**Revenue**
Jul-17	4,113	$114,958.23
Aug-17	4,498	$125,206.99
Sep-17	3,902	$96,934.76
Oct-17	4,308	$106,105.07
Nov-17	4,565	$105,678.65
Dec-17	5,542	$110,342.09
Jan-18	4,989	$163,869.40
Feb-18	5,142	$113,957.88
Mar-18	4,997	$109,993.71
Apr-18	4,787	$109,045.55
May-18	4,033	$102,425.54
Jun-18	3,611	$105,631.14
Total	**54,488**	**$1,364,149.01**
Average	**4,541**	**$113,679.08**

The Real-Time Congestion charge is not a stand-alone MISO charge type. Congestion is one component of the total Locational Marginal Price (LMP). The total LMP consists of an energy component, loss component, and congestion component. MISO includes all congestion charges within their Day Ahead and Real Time Asset Energy and Non-asset Energy charge types. Otter Tail separately calculates Day Ahead and Real Time Congestion charges and subtracts these values from either the DA Asset Energy or Real Time Asset Energy charge types, as reported by MISO, and lists them as distinct line items in our MISO reports. The Day Ahead Congestion charge is calculated by subtracting the Day Ahead congestion component at an Otter Tail Load generator from the Day Ahead congestion component at the Otter Tail load zone, then multiplying this difference by the total MWs of energy, at that generator, serving Otter Tail load. This is done for each generator serving Otter Tail load. Real time congestion is calculated in a similar manner, but also accounts for deviations from the Day Ahead clearing results. Fluctuations of the Real Time Congestion charge can be impacted by numerous factors including, but not limited to: Over/under forecasting for load, transmission outages, inaccurate wind forecasts, generator de-rates/outages, and changing generation dispatch instructions from MISO.

OTTER TAIL POWER COMPANY
Docket No: E999/AA-18-373

Response to: Minnesota Department of Commerce
Analyst: Michael Zajicek
Date Received: 12/27/2018
Date Due: 01/07/2019
Date of Response: 01/07/2019
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Information Request:

Request Number: **11**
Topic: Asset Based Margins
Reference(s): Click or tap here to enter text.

Request:

1. Please provide the actual costs and revenues and resulting actual asset-based margin for the 2017-2018 reporting period.

2. Please provide the amount of asset-based margins returned to ratepayers via the fuel clause for the 2017-2018 reporting period, or cite where in the report this information is provided. Please provide support for the development of asset-based margins.

Attachments: 3

Attachment 1 to IR MN-DOC-11.pdf
Attachment 2 to IR MN-DOC-11.pdf
Attachment 3 to IR MN-DOC-11.pdf

Response:

Attachment 1 to IR MN-DOC-11 contains the Asset Based margin costs and revenues for the time period of July 2017 through June 2018. This information is also found in the initial filing Part H Section 3 Attachment K, Columns F through I.

Asset based margins are determined through Otter Tail's internal program developed at the beginning of the MISO market which matches Otter Tail load to Otter Tail's supply stack (generation, PPA's, Market purchases) on a least cost, committed basis. In the event Otter Tail Resources sell excess energy into the MISO market, those asset-based sales and associated costs, including fuel (collectively asset-based margins), are accounted for in Otter Tail's Marketing book. All asset-based margins are passed through the fuel clause.

Attachment 2 to IR MN-DOC-11 provides excerpts from the monthly reports generated from OTP's system that provides the detail behind the MISO costs and revenues attributable to OTP generation in excess of those levels necessary to serve retail load and accounted for in the Marketing Book. A summary page is included which reflects the total MISO revenues of $7,087,560.47 and MISO costs of $(695,234.13) as reported in Part H Section 3 Attachment K (marked s Not Public) in Docket No. E999/AA-18-373.

Attachment 3 to IR MN-DOC-11 provides support detail for the associated fuel costs attributable to the Marketing Book sales. Total fuel costs were $(5,476,728.02).

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
July 2017 - June 2018 Includes Any Adjustments

		(A)	(B)	(C)	(D)	(E)
			ASSET BASED WHOLESALE			
	Charge Type Description	Acct	MWh	Cost	MWh	Revenue
No.						
1	DA Mkt Admin Amount	555.01	0	$ (7,583.74)	0	$ -
2	DA Asset Energy Amount	555.02	0	$ -	95,621	$ 2,949,670.69
3	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (6,579.07)	0	$ 2.14
4	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ 7,438.28
5	DA Schedule 24 Allocation Amount	555.33	0	$ (1,209.86)	0	$ -
6	RT Mkt Admin Amount	555.18	0	$ (16,748.40)	0	$ 1,386.20
7	RT Revenue Neutrality Uplift Amount	555.28	0	$ (51,242.85)	0	$ 9,369.41
8	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (15,104.84)	0	$ 433.82
9	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ (0.26)	0	$ 225,473.76
10	RT Schedule 23 Allocation Amount	555.34	0	$ (2,508.22)	0	$ 233.39
11	RT Price Volatility Make Whole Payment	555.42	0	$ (408.94)	0	$ 17,980.57
12	RT ASM Non-Excessive Energy Amount	555.55	(24,401)	$ (588,236.08)	178,973	$ 3,858,846.69
13	RT ASM Excessive Energy Amount	555.56	(226)	$ (5,611.87)	872	$ 16,725.52
14	NET MISO (Rev-Cost and MWh)		(24,627)	$ (695,234.13)	275,466	$ 7,087,560.47
15	Fuel Cost				(250,839)	$ (5,476,728.02)
16	**TOTAL ASSET BASED WHOLESALE**				**0**	**$ 915,598.32**

Monthly Allocation Report - Monthly Plus Adjustments July 2017

Operating Dates: 4/1/2005 -- 7/23/2017

Settlement Dates: 6/30/2017 -- 7/30/2017

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	10,328.231	-692.74	10,328.231	-692.74
DA_ASSET_EN	MARKET	5035.0002.0962	10,328.231	350,770.13	0.000	0.00	10,328.231	350,770.13
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.19	0.000	-307.24	0.000	-307.05
DA_RSG_MWP	Market	5035.0011.0962	0.000	254.94	0.000	0.00	0.000	254.94
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	10,328.231	-108.28	10,328.231	-108.28
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	20,140.180	-1,370.41	20,140.180	-1,370.41
RT_ASM_EXE	MARKET	5035.0056.0962	1.231	26.98	0.000	0.00	1.231	26.98
RT_ASM_NXE	MARKET	5035.0055.0962	15,991.405	360,353.72	-3,508.200	-89,637.57	12,483.205	270,716.15
RT_PV_MWP	MARKET	5035.0042.0962	0.000	1,957.63	0.000	0.00	0.000	1,957.63
RT_RNU	MARKET	5035.0028.0962	0.000	338.72	0.000	-2,661.18	0.000	-2,322.46
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	26.46	0.000	-1,149.88	0.000	-1,123.42
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	67,549.79	0.000	0.00	0.000	67,549.79
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.00	20,140.180	-212.77	20,140.180	-212.77

Monthly Allocation Report - Monthly Plus Adjustments August 2017

Operating Dates: 4/1/2005 -- 8/24/2017

Settlement Dates: 7/31/2017 -- 8/31/2017

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	1,602.085	-108.91	1,602.085	-108.91
DA_ASSET_EN	MARKET	5035.0002.0962	1,602.085	63,749.14	0.000	0.00	1,602.085	63,749.14
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.26	0.000	-135.15	0.000	-134.89
DA_RSG_MWP	Market	5035.0011.0962	0.000	36.93	0.000	0.00	0.000	36.93
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	1,602.085	-20.06	1,602.085	-20.06
RT_ADMIN	MARKET	5035.0018.0962	0.000	100.28	9,294.386	-626.47	9,294.386	-526.19
RT_ASM_EXE	MARKET	5035.0056.0962	153.050	2,761.01	0.000	0.00	153.050	2,761.01
RT_ASM_NXE	MARKET	5035.0055.0962	8,684.039	216,956.12	-463.799	-10,170.68	8,220.240	206,785.44
RT_PV_MWP	MARKET	5035.0042.0962	0.000	445.32	0.000	0.00	0.000	445.32
RT_RNU	MARKET	5035.0028.0962	0.000	383.82	0.000	-1,265.77	0.000	-881.95
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	20.40	0.000	-523.43	0.000	-503.03
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	10,692.78	0.000	0.00	0.000	10,692.78
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	15.63	9,294.386	-99.05	9,294.386	-83.42

Monthly Allocation Report - Monthly Plus Adjustments September 2017

Operating Dates: 4/1/2005 -- 9/21/2017

Settlement Dates: 9/1/2017 -- 9/28/2017

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	5,060.357	-368.11	5,060.357	-368.11
DA_ASSET_EN	MARKET	5035.0002.0962	5,060.357	156,020.27	0.000	0.00	5,060.357	156,020.27
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	1.21	0.000	-561.91	0.000	-560.70
DA_RSG_MWP	Market	5035.0011.0962	0.000	884.78	0.000	0.00	0.000	884.78
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	5,060.357	-56.60	5,060.357	-56.60
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.20	23,967.815	-1,718.59	23,967.815	-1,718.39
RT_ASM_EXE	MARKET	5035.0056.0962	18.307	297.62	0.000	0.00	18.307	297.62
RT_ASM_NXE	MARKET	5035.0055.0962	21,497.145	401,953.35	-2,458.893	-39,137.08	19,038.252	362,816.27
RT_PV_MWP	MARKET	5035.0042.0962	0.000	3,240.42	0.000	-0.06	0.000	3,240.36
RT_RNU	MARKET	5035.0028.0962	0.000	1,678.21	0.000	-5,653.15	0.000	-3,974.94
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	46.43	0.000	-1,583.08	0.000	-1,536.65
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	11,228.71	0.000	-0.25	0.000	11,228.46
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.03	23,967.815	-266.57	23,967.815	-266.54

Monthly Allocation Report - Monthly Plus Adjustments October 2017

Operating Dates: 4/1/2005 -- 10/23/2017
Settlement Dates: 9/29/2017 -- 10/30/2017

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	9,027.794	-714.07	9,027.794	-714.07
DA_ASSET_EN	MARKET	5035.0002.0962	9,027.794	302,162.86	0.000	0.00	9,027.794	302,162.86
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.02	0.000	-773.72	0.000	-773.70
DA_RSG_MWP	Market	5035.0011.0962	0.000	2,515.49	0.000	0.00	0.000	2,515.49
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	9,027.794	-103.47	9,027.794	-103.47
RT_ADMIN	MARKET	5035.0018.0962	0.000	95.86	20,882.549	-1,959.12	20,882.549	-1,863.26
RT_ASM_EXE	MARKET	5035.0056.0962	27.687	513.15	0.000	0.00	27.687	513.15
RT_ASM_NXE	MARKET	5035.0055.0962	18,744.903	381,373.26	-2,113.131	-51,388.37	16,631.772	329,984.89
RT_PV_MWP	MARKET	5035.0042.0962	0.000	3,554.88	0.000	-0.97	0.000	3,553.91
RT_RNU	MARKET	5035.0028.0962	0.000	352.19	0.000	-8,962.44	0.000	-8,610.25
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	41.70	0.000	-1,226.70	0.000	-1,185.00
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	61,115.77	0.000	0.00	0.000	61,115.77
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	15.29	20,882.549	-252.03	20,882.549	-236.74

Monthly Allocation Report - Monthly Plus Adjustments November 2017

Operating Dates: 4/1/2005 -- 11/22/2017

Settlement Dates: 10/31/2017 -- 11/29/2017

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	3,827.864	-356.67	3,827.864	-356.67
DA_ASSET_EN	MARKET	5035.0002.0962	3,827.864	124,463.34	0.000	0.00	3,827.864	124,463.34
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.01	0.000	-1,302.59	0.000	-1,302.58
DA_RSG_MWP	Market	5035.0011.0962	0.000	2,185.36	0.000	0.00	0.000	2,185.36
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	3,827.864	-49.38	3,827.864	-49.38
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	20,172.265	-1,776.96	20,172.265	-1,776.96
RT_ASM_EXE	MARKET	5035.0056.0962	466.477	9,339.31	0.000	0.00	466.477	9,339.31
RT_ASM_NXE	MARKET	5035.0055.0962	18,164.329	407,087.06	-1,572.583	-36,066.86	16,591.746	371,020.20
RT_PV_MWP	MARKET	5035.0042.0962	0.000	1,699.18	0.000	0.00	0.000	1,699.18
RT_RNU	MARKET	5035.0028.0962	0.000	1,055.87	0.000	-3,250.80	0.000	-2,194.93
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	31.49	0.000	-1,632.78	0.000	-1,601.29
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	20,615.63	0.000	0.00	0.000	20,615.63
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.01	20,155.655	-263.22	20,155.655	-263.21

Monthly Allocation Report - Monthly Plus Adjustments December 2017

Operating Dates: 4/1/2005 -- 12/25/2017

Settlement Dates: 11/30/2017 -- 1/1/2018

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	374.176	-31.28	374.176	-31.28
DA_ASSET_EN	MARKET	5035.0002.0962	374.176	12,712.84	0.000	0.00	374.176	12,712.84
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.00	0.000	-389.03	0.000	-389.03
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	374.176	-4.91	374.176	-4.91
RT_ADMIN	MARKET	5035.0018.0962	0.000	23.44	14,366.294	-1,219.38	14,366.294	-1,195.94
RT_ASM_EXE	MARKET	5035.0056.0962	50.385	609.40	-225.670	-5,611.87	-175.285	-5,002.47
RT_ASM_NXE	MARKET	5035.0055.0962	14,363.186	267,801.31	-438.719	-8,519.55	13,924.467	259,281.76
RT_PV_MWP	MARKET	5035.0042.0962	0.000	781.36	0.000	0.00	0.000	781.36
RT_RNU	MARKET	5035.0028.0962	0.000	192.22	0.000	-4,077.10	0.000	-3,884.88
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	147.52	0.000	-161.59	0.000	-14.07
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	3,427.55	0.000	0.00	0.000	3,427.55
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	3.97	14,366.294	-192.94	14,366.294	-188.97

Monthly Allocation Report - Monthly Plus Adjustments January 2018

Operating Dates: 4/1/2005 -- 1/23/2018

Settlement Dates: 1/2/2018 -- 1/30/2018

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	1,626.164	-115.64	1,626.164	-115.64
DA_ASSET_EN	MARKET	5035.0002.0962	1,626.164	79,827.72	0.000	0.00	1,626.164	79,827.72
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.15	0.000	-586.32	0.000	-586.17
DA_RSG_MWP	Market	5035.0011.0962	0.000	6.40	0.000	0.00	0.000	6.40
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	1,626.164	-19.53	1,626.164	-19.53
RT_ADMIN	MARKET	5035.0018.0962	0.000	4.78	11,752.084	-853.81	11,752.084	-849.03
RT_ASM_EXE	MARKET	5035.0056.0962	16.558	397.25	0.000	0.00	16.558	397.25
RT_ASM_NXE	MARKET	5035.0055.0962	10,720.445	296,605.89	-1,036.795	-40,792.34	9,683.650	255,813.55
RT_PV_MWP	MARKET	5035.0042.0962	0.000	1,012.23	0.000	0.00	0.000	1,012.23
RT_RNU	MARKET	5035.0028.0962	0.000	974.33	0.000	-1,916.29	0.000	-941.96
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	3.57	0.000	-2,258.07	0.000	-2,254.50
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	17,921.49	0.000	0.00	0.000	17,921.49
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.77	11,752.084	-142.01	11,752.084	-141.24

Monthly Allocation Report - Monthly Plus Adjustments February 2018

Operating Dates: 4/1/2005 -- 2/20/2018
Settlement Dates: 1/31/2018 -- 2/27/2018

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	550.671	-37.87	550.671	-37.87
DA_ASSET_EN	MARKET	5035.0002.0962	550.671	12,416.72	0.000	0.00	550.671	12,416.72
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.02	0.000	-245.71	0.000	-245.69
DA_RSG_MWP	Market	5035.0011.0962	0.000	58.13	0.000	0.00	0.000	58.13
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	550.671	-6.47	550.671	-6.47
RT_ADMIN	MARKET	5035.0018.0962	0.000	246.23	13,108.010	-873.74	13,108.010	-627.51
RT_ASM_EXE	MARKET	5035.0056.0962	1.148	28.60	0.000	0.00	1.148	28.60
RT_ASM_NXE	MARKET	5035.0055.0962	12,741.818	284,046.34	-369.506	-8,105.27	12,372.312	275,941.07
RT_PV_MWP	MARKET	5035.0042.0962	0.000	587.63	0.000	-0.07	0.000	587.56
RT_RNU	MARKET	5035.0028.0962	0.000	324.04	0.000	-1,014.56	0.000	-690.52
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	27.33	0.000	-246.27	0.000	-218.94
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	2,368.40	0.000	0.00	0.000	2,368.40
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	41.87	13,108.010	-150.94	13,108.010	-109.07

Monthly Allocation Report - Monthly Plus Adjustments March 2018

Operating Dates: 4/1/2005 -- 3/22/2018

Settlement Dates: 2/28/2018 -- 3/29/2018

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	1,300.525	-122.03	1,300.525	-122.03
DA_ASSET_EN	MARKET	5035.0002.0962	1,300.525	32,966.92	0.000	0.00	1,300.525	32,966.92
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.00	0.000	-307.27	0.000	-307.27
DA_RSG_MWP	Market	5035.0011.0962	0.000	77.58	0.000	0.00	0.000	77.58
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	1,300.525	-16.38	1,300.525	-16.38
RT_ADMIN	MARKET	5035.0018.0962	0.000	915.41	13,825.460	-1,277.14	13,825.460	-361.73
RT_ASM_EXE	MARKET	5035.0056.0962	3.242	77.97	0.000	0.00	3.242	77.97
RT_ASM_NXE	MARKET	5035.0055.0962	13,221.814	282,069.73	-600.404	-11,964.02	12,621.410	270,105.71
RT_PV_MWP	MARKET	5035.0042.0962	0.000	444.85	0.000	0.00	0.000	444.85
RT_RNU	MARKET	5035.0028.0962	0.000	387.98	0.000	-2,312.67	0.000	-1,924.69
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	5.68	0.000	-326.47	0.000	-320.79
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	9,619.60	0.000	0.00	0.000	9,619.60
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	155.81	13,825.460	-173.12	13,825.460	-17.31

Monthly Allocation Report - Monthly Plus Adjustments April 2018

Operating Dates: 4/1/2005 -- 4/22/2018

Settlement Dates: 3/30/2018 -- 4/29/2018

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	3,983.450	-423.24	3,983.450	-423.24
DA_ASSET_EN	MARKET	5035.0002.0962	3,983.450	108,385.74	0.000	0.00	3,983.450	108,385.74
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.28	0.000	-500.24	0.000	-499.96
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	3,983.450	-53.54	3,983.450	-53.54
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	16,870.701	-1,821.85	16,870.701	-1,821.85
RT_ASM_EXE	MARKET	5035.0056.0962	58.977	937.00	0.000	0.00	58.977	937.00
RT_ASM_NXE	MARKET	5035.0055.0962	15,389.848	337,472.32	-1,422.556	-30,987.27	13,967.292	306,485.05
RT_PV_MWP	MARKET	5035.0042.0962	0.000	918.97	0.000	0.00	0.000	918.97
RT_RNU	MARKET	5035.0028.0962	0.000	960.82	0.000	-2,846.93	0.000	-1,886.11
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	23.29	0.000	-1,484.83	0.000	-1,461.54
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	7,599.40	0.000	-0.01	0.000	7,599.39
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.01	16,870.701	-229.77	16,870.701	-229.76

Monthly Allocation Report - Monthly Plus Adjustments May 2018

Operating Dates: 4/1/2005 -- 5/23/2018

Settlement Dates: 4/30/2018 -- 5/30/2018

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	32,509.175	-2,500.68	32,509.175	-2,500.68
DA_ASSET_EN	MARKET	5035.0002.0962	32,509.175	911,810.38	0.000	0.00	32,509.175	911,810.38
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.00	0.000	-730.63	0.000	-730.63
DA_RSG_MWP	Market	5035.0011.0962	0.000	955.62	0.000	0.00	0.000	955.62
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	32,509.175	-455.01	32,509.175	-455.01
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	20,025.170	-1,589.89	20,025.170	-1,589.89
RT_ASM_EXE	MARKET	5035.0056.0962	52.491	1,429.37	0.000	0.00	52.491	1,429.37
RT_ASM_NXE	MARKET	5035.0055.0962	13,357.607	273,723.99	-6,634.338	-169,445.28	6,723.269	104,278.71
RT_PV_MWP	MARKET	5035.0042.0962	0.000	1,658.37	0.000	0.00	0.000	1,658.37
RT_RNU	MARKET	5035.0028.0962	0.000	2,232.64	0.000	-4,381.32	0.000	-2,148.68
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	26.65	0.000	-2,325.29	0.000	-2,298.64
RT_RSG_MWP	Market	5035.0030.0962	0.000	2,249.88	0.000	0.00	0.000	2,249.88
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.00	20,025.170	-280.48	20,025.170	-280.48

Monthly Allocation Report - Monthly Plus Adjustments June 2018

Operating Dates: 4/1/2005 -- 6/21/2018
Settlement Dates: 5/31/2018 -- 6/28/2018

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	25,430.407	-2,112.50	25,430.407	-2,112.50
DA_ASSET_EN	MARKET	5035.0002.0962	25,430.407	794,384.63	0.000	0.00	25,430.407	794,384.63
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.00	0.000	-739.26	0.000	-739.26
DA_RSG_MWP	Market	5035.0011.0962	0.000	463.05	0.000	0.00	0.000	463.05
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	25,430.407	-316.23	25,430.407	-316.23
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	19,893.429	-1,661.04	19,893.429	-1,661.04
RT_ASM_EXE	MARKET	5035.0056.0962	22.289	307.86	0.000	0.00	22.289	307.86
RT_ASM_NXE	MARKET	5035.0055.0962	16,096.322	349,403.60	-3,782.128	-92,021.79	12,314.194	257,381.81
RT_PV_MWP	MARKET	5035.0042.0962	0.000	1,679.73	0.000	-407.84	0.000	1,271.89
RT_RNU	MARKET	5035.0028.0962	0.000	488.57	0.000	-12,900.64	0.000	-12,412.07
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	33.30	0.000	-2,186.45	0.000	-2,153.15
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	11,084.76	0.000	0.00	0.000	11,084.76
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.00	19,893.429	-245.32	19,893.429	-245.32

Monthly Allocation Report - Monthly Plus Adjustments July 2017 - June 2018

Operating Dates: 4/1/2005 -- 6/21/2018
Settlement Dates: 6/30/2017 -- 6/28/2018

Charge Type	Portfolio	Account Cd		MW Rev	Dollar Rev	MW Cost	Dollar Cost
DA_ADMIN	MARKET	5035.0001.0962		0	$ -	0	$ (7,583.74)
DA_ASSET_EN	MARKET	5035.0002.0962		95,621	$ 2,949,670.69	0	$ -
DA_RSG_DIST	MARKET	5035.0010.0962		0	$ 2.14	0	$ (6,579.07)
DA_RSG_MWP	MARKET	5035.0011.0962		0	$ 7,438.28	0	$ -
DA_SCHD_24_ALC	MARKET	5035.0033.0962		0	$ -	0	$ (1,209.86)
RT_ADMIN	MARKET	5035.0018.0962		0	$ 1,386.20	0	$ (16,748.40)
RT_ASM_EXE	MARKET	5035.0056.0962		872	$ 16,725.52	(226)	$ (5,611.87)
RT_ASM_NXE	MARKET	5035.0055.0962		178,973	$ 3,858,846.69	(24,401)	$ (588,236.08)
RT_PV_MWP	MARKET	5035.0042.0962		0	$ 17,980.57	0	$ (408.94)
RT_RNU	MARKET	5035.0028.0962		0	$ 9,369.41	0	$ (51,242.85)
RT_RSG_DIST1	MARKET	5035.0029.0962		0	$ 433.82	0	$ (15,104.84)
RT_RSG_MWP	MARKET	5035.0030.0962		0	$ 225,473.76	0	$ (0.26)
RT_SCHD_24_ALC	MARKET	5035.0034.0962		0	$ 233.39	0	$ (2,508.22)
				275,466	$ 7,087,560.47	(24,627)	$ (695,234.13)

Marketing Book Costs - Monthly July 2017

Operating Dates: 6/23/2017 -- 7/23/2017

Settlement Dates: 6/30/2017 -- 7/30/2017

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	4,221.227	$115,906.76	-$89,566.53	$26,340.23
	Real Time	5,872.497	$144,093.63	-$124,479.81	$19,613.82
	Total:	**10,093.724**	**$260,000.39**	**-$214,046.34**	**$45,954.05**
OTP.COYOT1	Day Ahead	384.519	$6,764.41	-$4,302.78	$2,461.63
	Real Time	4,478.604	$68,747.17	-$50,115.51	$18,631.66
	Total:	**4,863.123**	**$75,511.58**	**-$54,418.29**	**$21,093.29**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	26.850	$900.54	-$10,929.57	-$10,029.03
	Total:	**26.850**	**$900.54**	**-$10,929.57**	**-$10,029.03**
OTP.HOOTL2	Day Ahead	1,071.504	$40,302.82	-$29,680.67	$10,622.15
	Real Time	47.050	-$1,796.41	-$1,318.61	-$3,115.02
	Total:	**1,118.554**	**$38,506.41**	**-$30,999.28**	**$7,507.13**
OTP.HOOTL3	Day Ahead	2,320.865	$87,779.72	-$65,541.23	$22,238.49
	Real Time	1,074.817	$24,252.14	-$30,586.86	-$6,334.72
	Total:	**3,395.682**	**$112,031.86**	**-$96,128.09**	**$15,903.77**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	27.645	$779.05	-$2,884.03	-$2,104.98
	Total:	**27.645**	**$779.05**	**-$2,884.03**	**-$2,104.98**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	29.411	$816.57	-$14,284.00	-$13,467.43
	Total:	**29.411**	**$816.57**	**-$14,284.00**	**-$13,467.43**
OTP.SLWAYO1	Day Ahead	2,330.116	$100,016.42	-$70,387.33	$29,629.09
	Real Time	927.562	$32,950.41	-$24,813.48	$8,136.93
	Total:	**3,257.678**	**$132,966.83**	**-$95,200.81**	**$37,766.02**
Day Ahead	**Total**	**10,328.231**	**$350,770.13**	**-$259,478.54**	**$91,291.59**
Real Time	**Total**	**12,484.436**	**$270,743.10**	**-$259,411.87**	**$11,331.23**
Margins	**Total**	**22,812.667**	**$621,513.23**	**-$518,890.41**	**$102,622.82**

Marketing Book Costs - Monthly August 2017

Operating Dates: 7/24/2017 -- 8/24/2017

Settlement Dates: 7/31/2017 -- 8/31/2017

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	66.809	$1,575.77	-$1,398.98	$176.79
	Real Time	5,404.414	$123,993.64	-$113,168.48	$10,825.16
	Total:	**5,471.223**	**$125,569.41**	**-$114,567.46**	**$11,001.95**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	232.698	$3,892.68	-$2,603.85	$1,288.83
	Total:	**232.698**	**$3,892.68**	**-$2,603.85**	**$1,288.83**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	25.069	$595.84	-$595.84	$0.00
	Total:	**25.069**	**$595.84**	**-$595.84**	**$0.00**
OTP.HOOTL2	Day Ahead	70.027	$2,297.34	-$1,939.74	$357.60
	Real Time	188.550	$4,522.30	-$5,274.65	-$752.35
	Total:	**258.577**	**$6,819.64**	**-$7,214.39**	**-$394.75**
OTP.HOOTL3	Day Ahead	408.419	$14,534.21	-$11,533.77	$3,000.44
	Real Time	1,227.284	$27,556.47	-$35,095.09	-$7,538.62
	Total:	**1,635.703**	**$42,090.68**	**-$46,628.86**	**-$4,538.18**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	28.066	$614.73	-$614.73	$0.00
	Total:	**28.066**	**$614.73**	**-$614.73**	**$0.00**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	29.009	$818.77	-$818.77	$0.00
	Total:	**29.009**	**$818.77**	**-$818.77**	**$0.00**
OTP.SLWAYO1	Day Ahead	1,056.830	$45,341.82	-$29,182.14	$16,159.68
	Real Time	1,144.889	$44,671.78	-$32,643.45	$12,028.33
	Total:	**2,201.719**	**$90,013.60**	**-$61,825.59**	**$28,188.01**
Day Ahead	**Total**	**1,602.085**	**$63,749.14**	**-$44,054.63**	**$19,694.51**
Real Time	**Total**	**8,279.979**	**$206,666.21**	**-$190,814.86**	**$15,851.35**
Margins	**Total**	**9,882.064**	**$270,415.35**	**-$234,869.49**	**$35,545.86**

Marketing Book Costs - Monthly Adjustments
August 2017

Docket No. E999/AA-18-373

Operating Dates: 4/1/2005 -- 7/23/2017
Settlement Dates: 7/31/2017 -- 8/31/2017

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.HOOTL2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	93.311	$2,880.24	-$2,613.32	$266.92
	Total:	**93.311**	**$2,880.24**	**-$2,613.32**	**$266.92**
OTP.SLWAYO1	Day Ahead	0.000	$0.00	-$883.66	-$883.66
	Real Time	0.000	$0.00	-$204.13	-$204.13
	Total:	**0.000**	**$0.00**	**-$1,087.79**	**-$1,087.79**
Day Ahead	**Total**	**0.000**	**$0.00**	**-$883.66**	**-$883.66**
Real Time	**Total**	**93.311**	**$2,880.24**	**-$2,817.45**	**$62.79**
Margins	**Total**	**93.311**	**$2,880.24**	**-$3,701.11**	**-$820.87**

Marketing Book Costs - Monthly September 2017

Operating Dates: 8/25/2017 -- 9/21/2017

Settlement Dates: 9/1/2017 -- 9/28/2017

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	3,272.101	$93,668.17	-$69,599.41	$24,068.76
	Real Time	8,782.013	$202,233.06	-$185,091.10	$17,141.96
	Total:	**12,054.114**	**$295,901.23**	**-$254,690.51**	**$41,210.72**
OTP.COYOT1	Day Ahead	197.140	$2,400.16	-$2,140.94	$259.22
	Real Time	8,595.306	$104,016.50	-$93,536.68	$10,479.82
	Total:	**8,792.446**	**$106,416.66**	**-$95,677.62**	**$10,739.04**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.287	$6.08	-$6.08	$0.00
	Total:	**0.287**	**$6.08**	**-$6.08**	**$0.00**
OTP.HOOTL2	Day Ahead	76.715	$2,364.73	-$2,125.01	$239.72
	Real Time	29.894	$506.96	-$856.35	-$349.39
	Total:	**106.609**	**$2,871.69**	**-$2,981.36**	**-$109.67**
OTP.HOOTL3	Day Ahead	975.270	$35,812.53	-$27,541.61	$8,270.92
	Real Time	292.652	$5,132.25	-$8,300.50	-$3,168.25
	Total:	**1,267.922**	**$40,944.78**	**-$35,842.11**	**$5,102.67**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.044	$0.97	-$0.97	$0.00
	Total:	**0.044**	**$0.97**	**-$0.97**	**$0.00**
OTP.SLWAYO1	Day Ahead	539.131	$21,774.68	-$16,789.57	$4,985.11
	Real Time	1,352.043	$51,146.27	-$39,688.10	$11,458.17
	Total:	**1,891.174**	**$72,920.95**	**-$56,477.67**	**$16,443.28**
Day Ahead	**Total**	**5,060.357**	**$156,020.27**	**-$118,196.54**	**$37,823.73**
Real Time	**Total**	**19,052.239**	**$363,042.09**	**-$327,479.78**	**$35,562.31**
Margins	**Total**	**24,112.596**	**$519,062.36**	**-$445,676.32**	**$73,386.04**

Marketing Book Costs - Monthly Adjustments September 2017

Operating Dates: 4/1/2005 -- 8/24/2017

Settlement Dates: 9/1/2017 -- 9/28/2017

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	3.844	$65.06	-$80.50	-$15.44
	Total:	**3.844**	**$65.06**	**-$80.50**	**-$15.44**
OTP.HOOTL2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.163	$2.53	-$4.52	-$1.99
	Total:	**0.163**	**$2.53**	**-$4.52**	**-$1.99**
OTP.SLWAYO1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.313	$4.22	-$8.61	-$4.39
	Total:	**0.313**	**$4.22**	**-$8.61**	**-$4.39**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**4.320**	**$71.81**	**-$93.63**	**-$21.82**
Margins	**Total**	**4.320**	**$71.81**	**-$93.63**	**-$21.82**

Marketing Book Costs - Monthly October 2017

Operating Dates: 9/22/2017 -- 10/23/2017

Settlement Dates: 9/29/2017 -- 10/30/2017

Asset		MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	4,792.438	$135,491.35	-$103,712.09	$31,779.26
	Real Time	3,334.811	$64,948.83	-$71,565.06	-$6,616.23
	Total:	**8,127.249**	**$200,440.18**	**-$175,277.15**	**$25,163.03**
OTP.COYOT1	Day Ahead	114.085	$1,459.15	-$1,368.41	$90.74
	Real Time	9,612.003	$139,800.31	-$107,365.93	$32,434.38
	Total:	**9,726.088**	**$141,259.46**	**-$108,734.34**	**$32,525.12**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.073	$2.25	-$2.25	$0.00
	Total:	**0.073**	**$2.25**	**-$2.25**	**$0.00**
OTP.HOOTL2	Day Ahead	1,188.430	$48,056.34	-$33,047.83	$15,008.51
	Real Time	161.492	$5,229.84	-$4,615.97	$613.87
	Total:	**1,349.922**	**$53,286.18**	**-$37,663.80**	**$15,622.38**
OTP.HOOTL3	Day Ahead	2,094.476	$82,362.60	-$59,539.38	$22,823.22
	Real Time	755.131	$18,553.03	-$21,501.89	-$2,948.86
	Total:	**2,849.607**	**$100,915.63**	**-$81,041.27**	**$19,874.36**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	73.380	$1,961.78	-$15,968.23	-$14,006.45
	Total:	**73.380**	**$1,961.78**	**-$15,968.23**	**-$14,006.45**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	99.870	$3,007.87	-$30,275.69	-$27,267.82
	Total:	**99.870**	**$3,007.87**	**-$30,275.69**	**-$27,267.82**
OTP.SLWAYO1	Day Ahead	838.365	$34,793.42	-$24,877.26	$9,916.16
	Real Time	2,560.758	$95,720.36	-$73,857.91	$21,862.45
	Total:	**3,399.123**	**$130,513.78**	**-$98,735.17**	**$31,778.61**
Day Ahead	**Total**	**9,027.794**	**$302,162.86**	**-$222,544.97**	**$79,617.89**
Real Time	**Total**	**16,597.518**	**$329,224.27**	**-$325,152.93**	**$4,071.34**
Margins	**Total**	**25,625.312**	**$631,387.13**	**-$547,697.90**	**$83,689.23**

Marketing Book Costs - Monthly Adjustments October 2017

Operating Dates: 4/1/2005 -- 9/21/2017

Settlement Dates: 9/29/2017 -- 10/30/2017

Asset		MWH	Revenue	Fuel	Profit
OTP.HOOTL3	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	61.941	$1,273.78	-$1,759.46	-$485.68
	Total:	**61.941**	**$1,273.78**	**-$1,759.46**	**-$485.68**

Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**61.941**	**$1,273.78**	**-$1,759.46**	**-$485.68**
Margins	**Total**	**61.941**	**$1,273.78**	**-$1,759.46**	**-$485.68**

Marketing Book Costs - Monthly   November 2017

Operating Dates: 10/24/2017 -- 11/22/2017

Settlement Dates: 10/31/2017 -- 11/29/2017

Asset		MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	1,682.279	$46,532.64	-$37,772.02	$8,760.62
	Real Time	11,075.469	$248,493.92	-$237,679.67	$10,814.25
	Total:	**12,757.748**	**$295,026.56**	**-$275,451.69**	**$19,574.87**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	2,940.999	$42,194.29	-$32,850.85	$9,343.44
	Total:	**2,940.999**	**$42,194.29**	**-$32,850.85**	**$9,343.44**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	45.980	$672.70	-$672.70	$0.00
	Total:	**45.980**	**$672.70**	**-$672.70**	**$0.00**
OTP.HOOTL2	Day Ahead	273.815	$8,241.98	-$7,579.59	$662.39
	Real Time	386.733	$9,485.00	-$10,795.76	-$1,310.76
	Total:	**660.548**	**$17,726.98**	**-$18,375.35**	**-$648.37**
OTP.HOOTL3	Day Ahead	789.227	$27,011.80	-$22,281.12	$4,730.68
	Real Time	1,044.760	$24,213.24	-$29,631.88	-$5,418.64
	Total:	**1,833.987**	**$51,225.04**	**-$51,913.00**	**-$687.96**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.373	$20.07	-$20.07	$0.00
	Total:	**0.373**	**$20.07**	**-$20.07**	**$0.00**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.756	$19.07	-$19.07	$0.00
	Total:	**0.756**	**$19.07**	**-$19.07**	**$0.00**
OTP.SLWAYO1	Day Ahead	1,082.543	$42,676.92	-$35,705.00	$6,971.92
	Real Time	1,563.153	$55,467.79	-$46,234.96	$9,232.83
	Total:	**2,645.696**	**$98,144.71**	**-$81,939.96**	**$16,204.75**
Day Ahead	**Total**	**3,827.864**	**$124,463.34**	**-$103,337.73**	**$21,125.61**
Real Time	**Total**	**17,058.223**	**$380,566.08**	**-$357,904.96**	**$22,661.12**
Margins	**Total**	**20,886.087**	**$505,029.42**	**-$461,242.69**	**$43,786.73**

Marketing Book Costs - Monthly Adjustments November 2017

Operating Dates:

Settlement Dates: **10/1/2017 - 10/31/2017**

Asset		MWH	Revenue	Fuel	Profit
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.000	-$140.40	$4,554.84	-$4,414.44
	Total:	**0.000**	**-$140.40**	**$4,554.84**	**-$4,414.44**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.000	-$139.90	$4,544.43	-$4,414.53
	Total:	**0.000**	**-$139.90**	**$4,544.43**	**-$4,414.53**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**0.000**	**-$280.30**	**$9,099.27**	**-$8,828.97**
Margins	**Total**	**0.000**	**-$280.30**	**$9,099.27**	**-$8,828.97**

Marketing Book Costs - Monthly

December 2017

Operating Dates: 11/23/2017 -- 12/25/2017

Settlement Dates: 11/30/2017 -- 1/1/2018

Asset		MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	60.405	$1,538.35	-$1,356.29	$182.06
	Real Time	10,575.313	$195,592.62	-$226,946.19	-$31,353.57
	Total:	**10,635.718**	**$197,130.97**	**-$228,302.48**	**-$31,171.51**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	2,777.788	$48,663.55	-$31,027.67	$17,635.88
	Total:	**2,777.788**	**$48,663.55**	**-$31,027.67**	**$17,635.88**
OTP.HOOTL2	Day Ahead	110.206	$3,376.26	-$3,041.11	$335.15
	Real Time	252.964	$5,282.49	-$7,100.13	-$1,817.64
	Total:	**363.170**	**$8,658.75**	**-$10,141.24**	**-$1,482.49**
OTP.HOOTL3	Day Ahead	69.447	$2,428.03	-$1,950.77	$477.26
	Real Time	69.875	$1,742.75	-$1,990.52	-$247.77
	Total:	**139.322**	**$4,170.78**	**-$3,941.29**	**$229.49**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	6.223	$122.44	-$2,152.46	-$2,030.02
	Total:	**6.223**	**$122.44**	**-$2,152.46**	**-$2,030.02**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	5.971	$117.93	-$2,246.65	-$2,128.72
	Total:	**5.971**	**$117.93**	**-$2,246.65**	**-$2,128.72**
OTP.SLWAYO1	Day Ahead	134.118	$5,370.20	-$4,082.75	$1,287.45
	Real Time	360.678	$10,242.69	-$9,507.68	$735.01
	Total:	**494.796**	**$15,612.89**	**-$13,590.43**	**$2,022.46**
Day Ahead	**Total**	**374.176**	**$12,712.84**	**-$10,430.92**	**$2,281.92**
Real Time	**Total**	**14,048.812**	**$261,764.47**	**-$280,971.30**	**-$19,206.83**
Margins	**Total**	**14,422.988**	**$274,477.31**	**-$291,402.22**	**-$16,924.91**

Marketing Book Costs - Monthly Adjustments December 2017

Operating Dates: 4/1/2005 -- 11/22/2017

Settlement Dates: 11/30/2017 -- 1/1/2018

Asset		MWH	Revenue	Fuel	Profit
OTP.HOOTL3	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-299.630	-$7,677.60	$8,461.56	$783.96
	Total:	**-299.630**	**-$7,677.60**	**$8,461.56**	**$783.96**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**-299.630**	**-$7,677.60**	**$8,461.56**	**$783.96**
Margins	**Total**	**-299.630**	**-$7,677.60**	**$8,461.56**	**$783.96**

Marketing Book Costs - Monthly January 2018

Operating Dates: 12/26/2017 -- 1/23/2018

Settlement Dates: 1/2/2018 -- 1/30/2018

Asset		MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	295.336	$8,440.73	-$6,498.84	$1,941.89
	Real Time	5,496.343	$109,862.62	-$117,951.60	-$8,088.98
	Total:	**5,791.679**	**$118,303.35**	**-$124,450.44**	**-$6,147.09**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	1,423.562	$30,997.68	-$15,901.13	$15,096.55
	Total:	**1,423.562**	**$30,997.68**	**-$15,901.13**	**$15,096.55**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	3.190	$59.84	-$1,305.41	-$1,245.57
	Total:	**3.190**	**$59.84**	**-$1,305.41**	**-$1,245.57**
OTP.HOOTL2	Day Ahead	271.001	$11,146.73	-$7,541.17	$3,605.56
	Real Time	433.940	$18,576.10	-$12,174.08	$6,402.02
	Total:	**704.941**	**$29,722.83**	**-$19,715.25**	**$10,007.58**
OTP.HOOTL3	Day Ahead	368.418	$17,235.94	-$10,380.68	$6,855.26
	Real Time	259.176	$6,507.40	-$7,392.01	-$884.61
	Total:	**627.594**	**$23,743.34**	**-$17,772.69**	**$5,970.65**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	22.902	$1,974.84	-$12,729.84	-$10,755.00
	Total:	**22.902**	**$1,974.84**	**-$12,729.84**	**-$10,755.00**
OTP.SLWAYO1	Day Ahead	691.409	$43,004.32	-$36,234.05	$6,770.27
	Real Time	885.543	$65,844.06	-$52,195.81	$13,648.25
	Total:	**1,576.952**	**$108,848.38**	**-$88,429.86**	**$20,418.52**
Day Ahead	**Total**	**1,626.164**	**$79,827.72**	**-$60,654.74**	**$19,172.98**
Real Time	**Total**	**8,524.656**	**$233,822.54**	**-$219,649.88**	**$14,172.66**
Margins	**Total**	**10,150.820**	**$313,650.26**	**-$280,304.62**	**$33,345.64**

Marketing Book Costs - Monthly Adjustments January 2018

Operating Dates: 4/1/2005 -- 12/25/2017

Settlement Dates: 1/2/2018 -- 1/30/2018

Asset		MWH	Revenue	Fuel	Profit
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-1.368	-$33.07	$15.12	-$17.95
	Total:	**-1.368**	**-$33.07**	**$15.12**	**-$17.95**
OTP.HOOTL3	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	1,176.920	$22,565.43	-$33,643.20	-$11,077.77
	Total:	**1,176.920**	**$22,565.43**	**-$33,643.20**	**-$11,077.77**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**1,175.552**	**$22,532.36**	**-$33,628.08**	**-$11,095.72**
Margins	**Total**	**1,175.552**	**$22,532.36**	**-$33,628.08**	**-$11,095.72**

Marketing Book Costs - Monthly

February 2018

Operating Dates: 1/24/2018 -- 2/20/2018

Settlement Dates: 1/31/2018 -- 2/27/2018

Asset		MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	524.485	$11,397.68	-$11,019.00	$378.68
	Real Time	8,401.386	$179,196.27	-$180,293.74	-$1,097.47
	Total:	**8,925.871**	**$190,593.95**	**-$191,312.74**	**-$718.79**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	1,392.198	$26,485.61	-$15,550.85	$10,934.76
	Total:	**1,392.198**	**$26,485.61**	**-$15,550.85**	**$10,934.76**
OTP.HOOTL2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	377.301	$6,756.86	-$10,475.81	-$3,718.95
	Total:	**377.301**	**$6,756.86**	**-$10,475.81**	**-$3,718.95**
OTP.HOOTL3	Day Ahead	4.213	$117.71	-$119.94	-$2.23
	Real Time	1,366.093	$28,965.33	-$39,404.10	-$10,438.77
	Total:	**1,370.306**	**$29,083.04**	**-$39,524.04**	**-$10,441.00**
OTP.SLWAYO1	Day Ahead	21.973	$901.33	-$759.83	$141.50
	Real Time	653.269	$23,677.55	-$21,603.15	$2,074.40
	Total:	**675.242**	**$24,578.88**	**-$22,362.98**	**$2,215.90**
Day Ahead	**Total**	**550.671**	**$12,416.72**	**-$11,898.77**	**$517.95**
Real Time	**Total**	**12,190.247**	**$265,081.62**	**-$267,327.65**	**-$2,246.03**
Margins	**Total**	**12,740.918**	**$277,498.34**	**-$279,226.42**	**-$1,728.08**

Marketing Book Costs - Monthly Adjustments February 2018

Operating Dates: 4/1/2005 -- 1/23/2018

Settlement Dates: 1/31/2018 -- 2/27/2018

Asset		MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	2.190	$45.67	-$46.99	-$1.32
	Total:	**2.190**	**$45.67**	**-$46.99**	**-$1.32**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	1.132	$22.86	-$12.65	$10.21
	Total:	**1.132**	**$22.86**	**-$12.65**	**$10.21**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-0.033	-$0.62	$13.50	$12.88
	Total:	**-0.033**	**-$0.62**	**$13.50**	**$12.88**
OTP.HOOTL3	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	179.888	$10,819.32	-$5,067.80	$5,751.52
	Total:	**179.888**	**$10,819.32**	**-$5,067.80**	**$5,751.52**
OTP.SLWAYO1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.036	$0.74	-$2.15	-$1.41
	Total:	**0.036**	**$0.74**	**-$2.15**	**-$1.41**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**183.213**	**$10,887.97**	**-$5,116.09**	**$5,771.88**
Margins	**Total**	**183.213**	**$10,887.97**	**-$5,116.09**	**$5,771.88**

Marketing Book Costs - Monthly March 2018

Operating Dates: 2/21/2018 -- 3/22/2018

Settlement Dates: 2/28/2018 -- 3/29/2018

Asset		MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	1,034.967	$24,193.93	-$20,598.80	$3,595.13
	Real Time	5,223.625	$97,625.90	-$107,347.89	-$9,721.99
	Total:	**6,258.592**	**$121,819.83**	**-$127,946.69**	**-$6,126.86**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	747.120	$15,727.55	-$9,150.67	$6,576.88
	Total:	**747.120**	**$15,727.55**	**-$9,150.67**	**$6,576.88**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	22.228	$1,116.67	-$9,096.14	-$7,979.47
	Total:	**22.228**	**$1,116.67**	**-$9,096.14**	**-$7,979.47**
OTP.HOOTL2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	71.466	$1,775.05	-$2,007.84	-$232.79
	Total:	**71.466**	**$1,775.05**	**-$2,007.84**	**-$232.79**
OTP.HOOTL3	Day Ahead	99.000	$3,147.43	-$2,818.82	$328.61
	Real Time	5,356.007	$115,177.75	-$155,378.78	-$40,201.03
	Total:	**5,455.007**	**$118,325.18**	**-$158,197.60**	**-$39,872.42**
OTP.SLWAYO1	Day Ahead	166.558	$5,625.56	-$4,497.63	$1,127.93
	Real Time	1,144.570	$33,586.79	-$32,819.45	$767.34
	Total:	**1,311.128**	**$39,212.35**	**-$37,317.08**	**$1,895.27**
Day Ahead	**Total**	**1,300.525**	**$32,966.92**	**-$27,915.25**	**$5,051.67**
Real Time	**Total**	**12,565.016**	**$265,009.71**	**-$315,800.77**	**-$50,791.06**
Margins	**Total**	**13,865.541**	**$297,976.63**	**-$343,716.02**	**-$45,739.39**

Marketing Book Costs - Monthly Adjustments March 2018

Operating Dates: 4/1/2005 -- 2/20/2018

Settlement Dates: 2/28/2018 -- 3/29/2018

Asset		MWH	Revenue	Fuel	Profit
OTP.HOOTL3	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	59.636	$5,173.97	-$1,690.75	$3,483.22
	Total:	**59.636**	**$5,173.97**	**-$1,690.75**	**$3,483.22**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**59.636**	**$5,173.97**	**-$1,690.75**	**$3,483.22**
Margins	**Total**	**59.636**	**$5,173.97**	**-$1,690.75**	**$3,483.22**

Marketing Book Costs - Monthly April 2018

Operating Dates: 3/23/2018 -- 4/22/2018

Settlement Dates: 3/30/2018 -- 4/29/2018

Asset		MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	2,025.809	$46,478.98	-$41,546.51	$4,932.47
	Real Time	6,867.360	$131,367.55	-$145,679.99	-$14,312.44
	Total:	**8,893.169**	**$177,846.53**	**-$187,226.50**	**-$9,379.97**
OTP.COYOT1	Day Ahead	5.899	$101.52	-$66.01	$35.51
	Real Time	4,579.229	$87,633.75	-$51,761.19	$35,872.56
	Total:	**4,585.128**	**$87,735.27**	**-$51,827.20**	**$35,908.07**
OTP.HOOTL2	Day Ahead	497.476	$14,699.41	-$12,439.01	$2,260.40
	Real Time	120.919	$4,345.86	-$3,169.11	$1,176.75
	Total:	**618.395**	**$19,045.27**	**-$15,608.12**	**$3,437.15**
OTP.HOOTL3	Day Ahead	673.282	$19,842.99	-$16,909.17	$2,933.82
	Real Time	466.198	$9,870.91	-$12,066.01	-$2,195.10
	Total:	**1,139.480**	**$29,713.90**	**-$28,975.18**	**$738.72**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	6.989	$132.86	-$3,637.75	-$3,504.89
	Total:	**6.989**	**$132.86**	**-$3,637.75**	**-$3,504.89**
OTP.SLWAYO1	Day Ahead	780.984	$27,262.84	-$21,179.59	$6,083.25
	Real Time	1,984.726	$74,076.78	-$56,858.72	$17,218.06
	Total:	**2,765.710**	**$101,339.62**	**-$78,038.31**	**$23,301.31**
Day Ahead	**Total**	**3,983.450**	**$108,385.74**	**-$92,140.29**	**$16,245.45**
Real Time	**Total**	**14,025.421**	**$307,427.71**	**-$273,172.77**	**$34,254.94**
Margins	**Total**	**18,008.871**	**$415,813.45**	**-$365,313.06**	**$50,500.39**

Marketing Book Costs - Monthly Adjustments April 2018

Operating Dates: 4/1/2005 -- 3/22/2018

Settlement Dates: 3/30/2018 -- 4/29/2018

Asset		MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.304	$5.17	-$5.97	-$0.80
	Total:	**0.304**	**$5.17**	**-$5.97**	**-$0.80**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.050	$1.16	-$0.61	$0.55
	Total:	**0.050**	**$1.16**	**-$0.61**	**$0.55**
OTP.HOOTL2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.324	$5.07	-$9.00	-$3.93
	Total:	**0.324**	**$5.07**	**-$9.00**	**-$3.93**
OTP.HOOTL3	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.170	$3.27	-$4.94	-$1.67
	Total:	**0.170**	**$3.27**	**-$4.94**	**-$1.67**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**0.848**	**$14.67**	**-$20.52**	**-$5.85**
Margins	**Total**	**0.848**	**$14.67**	**-$20.52**	**-$5.85**

Marketing Book Costs - Monthly May 2018

Operating Dates: 4/23/2018 -- 5/23/2018

Settlement Dates: 4/30/2018 -- 5/30/2018

Asset		MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	20,665.276	$551,825.31	-$435,913.90	$115,911.41
	Real Time	4,162.671	$50,936.88	-$86,509.90	-$35,573.02
	Total:	**24,827.947**	**$602,762.19**	**-$522,423.80**	**$80,338.39**
OTP.COYOT1	Day Ahead	2,745.847	$57,604.16	-$30,153.74	$27,450.42
	Real Time	2,019.016	$37,433.15	-$22,185.90	$15,247.25
	Total:	**4,764.863**	**$95,037.31**	**-$52,339.64**	**$42,697.67**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	80.862	$2,828.11	-$26,478.50	-$23,650.39
	Total:	**80.862**	**$2,828.11**	**-$26,478.50**	**-$23,650.39**
OTP.HOOTL2	Day Ahead	3,715.866	$116,871.01	-$89,564.61	$27,306.40
	Real Time	-189.772	-$4,432.94	$4,271.51	-$161.43
	Total:	**3,526.094**	**$112,438.07**	**-$85,293.10**	**$27,144.97**
OTP.HOOTL3	Day Ahead	3,323.086	$109,565.49	-$82,240.20	$27,325.29
	Real Time	444.836	$10,123.97	-$11,648.89	-$1,524.92
	Total:	**3,767.922**	**$119,689.46**	**-$93,889.09**	**$25,800.37**
OTP.JAMSPK1	Day Ahead	9.000	$246.42	-$3,944.70	-$3,698.28
	Real Time	23.095	$565.04	-$11,946.46	-$11,381.42
	Total:	**32.095**	**$811.46**	**-$15,891.16**	**-$15,079.70**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	6.610	$144.59	-$3,810.27	-$3,665.68
	Total:	**6.610**	**$144.59**	**-$3,810.27**	**-$3,665.68**
OTP.SLWAYO1	Day Ahead	2,050.100	$75,697.99	-$56,085.36	$19,612.63
	Real Time	228.421	$8,137.01	-$8,524.73	-$387.72
	Total:	**2,278.521**	**$83,835.00**	**-$64,610.09**	**$19,224.91**
Day Ahead	**Total**	**32,509.175**	**$911,810.38**	**-$697,902.51**	**$213,907.87**
Real Time	**Total**	**6,775.739**	**$105,735.81**	**-$166,833.14**	**-$61,097.33**
Margins	**Total**	**39,284.914**	**$1,017,546.19**	**-$864,735.65**	**$152,810.54**

Marketing Book Costs - Monthly Adjustments May 2018

Operating Dates: 4/1/2005 -- 4/22/2018

Settlement Dates: 4/30/2018 -- 5/30/2018

Asset		MWH	Revenue	Fuel	Profit
OTP.SLWAYO1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.021	$0.50	-$0.83	-$0.33
	Total:	**0.021**	**$0.50**	**-$0.83**	**-$0.33**

Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**0.021**	**$0.50**	**-$0.83**	**-$0.33**
Margins	**Total**	**0.021**	**$0.50**	**-$0.83**	**-$0.33**

Marketing Book Costs - Monthly June 2018

Operating Dates: 5/24/2018 -- 6/21/2018

Settlement Dates: 5/31/2018 -- 6/28/2018

Asset		MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	12,010.398	$311,992.83	-$243,534.43	$68,458.40
	Real Time	8,005.564	$165,510.90	-$166,091.28	-$580.38
	Total:	**20,015.962**	**$477,503.73**	**-$409,625.71**	**$67,878.02**
OTP.COYOT1	Day Ahead	412.390	$6,192.57	-$4,535.39	$1,657.18
	Real Time	3,850.944	$83,148.33	-$42,509.63	$40,638.70
	Total:	**4,263.334**	**$89,340.90**	**-$47,045.02**	**$42,295.88**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	9.348	$177.62	-$3,175.92	-$2,998.30
	Total:	**9.348**	**$177.62**	**-$3,175.92**	**-$2,998.30**
OTP.HOOTL2	Day Ahead	3,599.464	$119,658.87	-$86,730.35	$32,928.52
	Real Time	-281.186	-$5,980.64	$6,714.40	$733.76
	Total:	**3,318.278**	**$113,678.23**	**-$80,015.95**	**$33,662.28**
OTP.HOOTL3	Day Ahead	5,839.888	$208,916.87	-$144,400.71	$64,516.16
	Real Time	-299.717	-$16,458.78	$7,189.03	-$9,269.75
	Total:	**5,540.171**	**$192,458.09**	**-$137,211.68**	**$55,246.41**
OTP.SLWAYO1	Day Ahead	3,568.267	$147,623.49	-$104,433.38	$43,190.11
	Real Time	1,051.530	$31,337.90	-$33,695.92	-$2,358.02
	Total:	**4,619.797**	**$178,961.39**	**-$138,129.30**	**$40,832.09**
Day Ahead	**Total**	**25,430.407**	**$794,384.63**	**-$583,634.26**	**$210,750.37**
Real Time	**Total**	**12,336.483**	**$257,735.33**	**-$231,569.32**	**$26,166.01**
Margins	**Total**	**37,766.890**	**$1,052,119.96**	**-$815,203.58**	**$236,916.38**

Marketing Book Costs - Monthly Adjustments July 2017 - June 2018

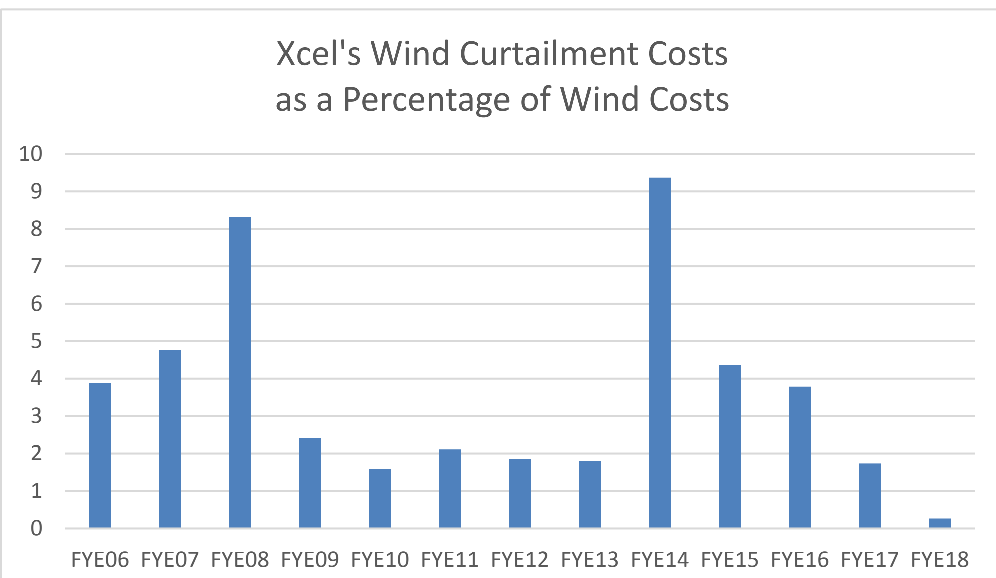
Operating Dates: 6/23/2017 -- 06/21/2018
Settlement Dates: 6/30/2017 -- 6/28/2018

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	50,651.530	$1,349,042.50	($1,062,516.80)	$286,525.70
	Real Time	83,207.804	$1,713,971.72	($1,762,938.17)	($48,966.45)
	Total:	**133,859.334**	**$3,063,014.22**	**($2,825,454.97)**	**$237,559.25**
OTP.COYOT1	Day Ahead	3,859.880	$74,521.97	($42,567.27)	$31,954.70
	Real Time	42,649.281	$688,731.52	($474,558.00)	$214,173.52
	Total:	**46,509.161**	**$763,253.49**	**($517,125.27)**	**$246,128.22**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	213.854	$6,359.03	($52,248.91)	($45,889.88)
	Total:	**213.854**	**$6,359.03**	**($52,248.91)**	**($45,889.88)**
OTP.HOOTL2	Day Ahead	10,874.504	$367,015.49	($273,689.09)	$93,326.40
	Real Time	1,693.149	$47,158.31	($49,429.24)	($2,270.93)
	Total:	**12,567.653**	**$414,173.80**	**($323,118.33)**	**$91,055.47**
OTP.HOOTL3	Day Ahead	16,965.591	$608,755.32	($445,257.40)	$163,497.92
	Real Time	13,236.037	$287,794.63	($379,512.09)	($91,717.46)
	Total:	**30,201.628**	**$896,549.95**	**($824,769.49)**	**$71,780.46**
OTP.JAMSPK1	Day Ahead	9.000	$246.42	($3,944.70)	($3,698.28)
	Real Time	188.673	$6,030.41	($45,398.73)	($48,197.20)
	Total:	**197.673**	**$6,276.83**	**($49,343.43)**	**($51,895.48)**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	171.671	$4,785.87	($46,910.99)	($50,944.18)
	Total:	**171.671**	**$4,785.87**	**($46,910.99)**	**($50,944.18)**
OTP.SLWAYO1	Day Ahead	13,260.394	$550,088.99	($405,097.55)	$144,991.44
	Real Time	13,857.512	$526,864.85	($432,659.08)	$94,205.77
	Total:	**27,117.906**	**$1,076,953.84**	**($837,756.63)**	**$239,197.21**
Day Ahead	**Total**	**95,620.899**	**$2,949,670.69**	**($2,233,072.81)**	**$716,597.88**
Real Time	**Total**	**155,217.981**	**$3,281,696.34**	**($3,243,655.21)**	**$20,393.19**
Margins	**Total**	**250,838.880**	**$6,231,367.03**	**($5,476,728.02)**	**$736,991.07**

Xcel's wind curtailment costs as a percentage of wind costs

%	Xcel
FYE06	3.88
FYE07	4.76
FYE08	8.32
FYE09	2.42
FYE10	1.58
FYE11	2.11
FYE12	1.86
FYE13	1.80
FYE14	9.37
FYE15	4.37
FYE16	3.79
FYE17	1.74
FYE18	0.27
Min	0.27
Max	9.37

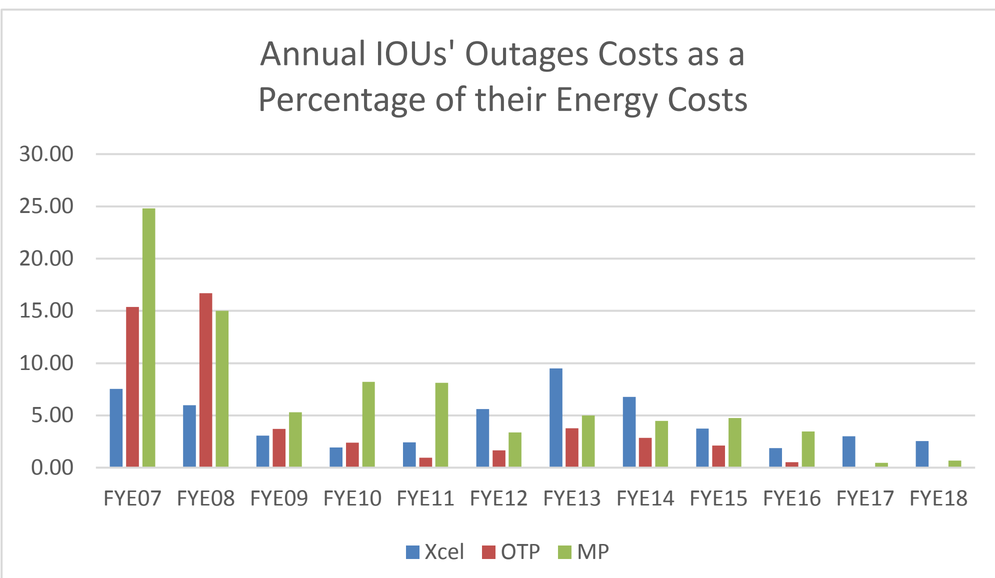
Source:
Xcel's monthly FCA input data emails.



Utilities Outages Costs in Percentage of Fuel and Purchased Power Costs

%	Xcel	OTP	MP
FYE07	7.55	15.38	24.80
FYE08	5.97	16.70	15.02
FYE09	3.06	3.70	5.29
FYE10	1.92	2.38	8.20
FYE11	2.41	0.95	8.12
FYE12	5.60	1.66	3.37
FYE13	9.50	3.77	4.99
FYE14	6.77	2.86	4.48
FYE15	3.75	2.12	4.74
FYE16	1.88	0.52	3.46
FYE17	3.00	0.00	0.45
FYE18	2.54	0.00	0.67
Min	1.88	0.00	0.45
Max	9.50	16.70	24.80

Source: IOUs' monthly FCA input data emails.



Maintenance Expenses of Generation Plants

Actual Maintenance Expense

	2014	2015	2016	2017	2016-2017 Average
Xcel	207,105,781	199,893,337	187,845,248	160,546,634	174,195,941
OTP	16,587,034	14,646,839	13,573,426	12,540,306	13,056,866
MP	42,236,247	40,475,462	38,505,407	38,555,947	38,530,677

MP's data includes wind maintenance expenses when compared to previous DOC reported 2014-2016 data.

	Most Recent Rate Case	Test Year	Test Year Budgeted Maintenance Expense	2016-2017 Avg. Actual Maintenance Expense	Difference: Actual less Budgeted	Percentage Difference
Xcel	GR-15-826	2016	$ 184,709,427	$ 174,195,941	$ (10,513,486)	-5.7%
OTP	GR-15-1033	2016	$ 15,099,063	$ 13,056,866	$ (2,042,197)	-13.5%
MP	GR-16-664	2017	$ 42,468,677	$ 38,555,947	$ (3,938,000)	-9.3%

The average actual maintenance expense is based on the 2017 actual data for MP.

DEA	kWh Sales (a)	MN Energy Costs (b)	MN Recovery (c)	MN Energy Costs ($/kWh) (d)	MN Recovery ($/kWh) (e)
Jul-17	172,165,881	$ 19,175,714	$ 15,120,285	0.111	0.088
Aug-17	184,500,023	$ 15,865,237	$ 16,504,451	0.086	0.089
Sep-17	161,393,241	$ 12,271,724	$ 12,707,606	0.076	0.079
Oct-17	147,395,016	$ 8,732,984	$ 11,638,569	0.059	0.079
Nov-17	138,755,482	$ 9,951,550	$ 10,973,323	0.072	0.079
Dec-17	142,587,312	$ 11,693,814	$ 11,238,999	0.082	0.079
Jan-18	162,351,533	$ 12,987,306	$ 12,725,131	0.080	0.078
Feb-18	145,730,260	$ 11,352,817	$ 11,326,196	0.078	0.078
Mar-18	131,482,709	$ 9,595,552	$ 10,080,955	0.073	0.077
Apr-18	138,785,897	$ 9,030,820	$ 10,709,170	0.065	0.077
May-18	136,131,990	$ 11,973,546	$ 10,302,787	0.088	0.076
Jun-18	167,031,258	$ 17,512,964	$ 14,623,661	0.105	0.088
FYE18	1,828,310,602	150,144,028	147,951,133	0.082	0.081

Source (a): Dakota's AAA filing, Exhibit CII, page 1

Source (b): Dakota's AAA filing, Exhibit CII, page 1.

Source (c): Dakota's AAA filing, Exhibit CII, page 1.

(d) = (b)/(a)

(e) = (c)/(a)

MP	kWh Retail & Firm Resale (a)	FCA Retail Sales (b)	System Costs (c)
Jul-17	833,137,623	694,688,351	$19,792,136
Aug-17	843,311,121	709,104,619	$18,921,792
Sep-17	813,821,718	686,791,914	$16,381,674
Oct-17	815,111,324	684,837,247	$15,937,033
Nov-17	851,054,102	709,364,329	$18,206,947
Dec-17	903,209,916	744,264,670	$19,336,218
Jan-18	915,124,769	755,733,952	$19,627,643
Feb-18	857,837,352	717,089,681	$17,970,535
Mar-18	878,547,398	736,290,378	$19,737,577
Apr-18	821,032,462	688,748,545	$17,967,457
May-18	806,873,496	684,969,468	$17,941,475
Jun-18	784,335,320	664,724,407	$18,381,341
FYE18	10,123,396,601	8,476,607,561	$ 220,201,828

Source (a): MP's monthly FCAs
Source (b): MP's monthly FCAs.
Source (c): MP's monthly FCAs

Minnesota base cost ($/kWh): July 17 - June 18 0.01018

MP	FCA # 16 Recovery (d)	Old FCA # 16 Recovery (e)	Old FCA # 17 Recovery (f)	Base Cost Recovery (g)	MN Recovery (h)	MN Energy Costs (i)	Over(Under) Recovery (j)	MN Recovery ($/kWh) (k)	MN Energy Costs ($/kWh) (l)
Jul-17	7,186,459	$ -	-	$ 7,060,205	$ 14,246,664	$ 16,505,795	$ (2,259,131)	0.021	0.024
Aug-17	6,727,834	$ -	-	$ 7,207,055	$ 13,934,889	$ 15,912,308	$ (1,977,419)	0.020	0.022
Sep-17	7,997,214	$ -	-	$ 6,979,807	$ 14,977,020	$ 13,825,121	$ 1,151,899	0.022	0.020
Oct-17	8,815,636	$ -	-	$ 6,950,794	$ 15,766,431	$ 13,388,568	$ 2,377,862	0.023	0.020
Nov-17	7,876,427	$ -	-	$ 7,209,047	$ 15,085,474	$ 15,173,303	$ (87,829)	0.021	0.021
Dec-17	7,191,343	$ -	-	$ 7,579,028	$ 14,770,371	$ 15,934,707	$ (1,164,335)	0.020	0.021
Jan-18	7,816,021	$ -	-	$ 7,716,078	$ 15,532,099	$ 16,210,493	$ (678,394)	0.021	0.021
Feb-18	8,083,677	$ -	-	$ 7,332,445	$ 15,416,123	$ 15,023,029	$ 393,094	0.021	0.021
Mar-18	8,291,227	$ -	-	$ 7,499,687	$ 15,790,914	$ 16,544,445	$ (753,531)	0.021	0.022
Apr-18	7,603,349	$ -	-	$ 7,017,060	$ 14,620,409	$ 15,069,818	$ (449,409)	0.021	0.022
May-18	7,895,342	$ -	-	$ 6,963,713	$ 14,859,055	$ 15,233,721	$ (374,666)	0.022	0.022
Jun-18	7,962,544	$ -	-	$ 6,754,104	$ 14,716,647	$ 15,581,140	$ (864,493)	0.022	0.023
FYE18	$ 93,447,074	$ -	$ -	$ 86,269,024	$ 179,716,097	$ 184,402,448	$ (4,686,351)	0.021	0.0218

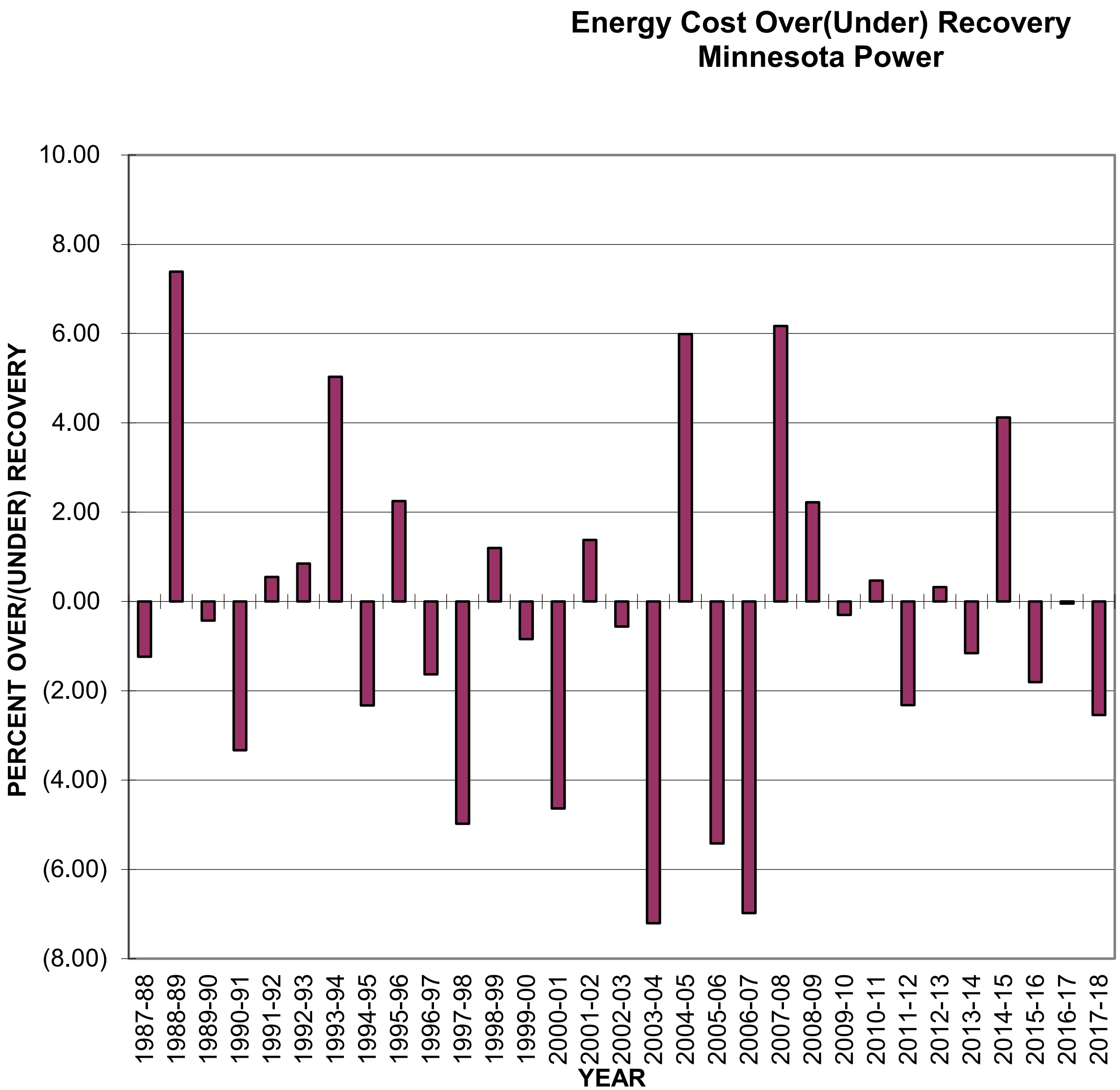
Source (d-g): Department's calculations based on data provided in MP's monthly FCAs.
(h) = SUM(d:g)
(i)=(b)*(c)/(a)
(j) = (h) - (i)
(k) = (h)/(b)
(l) = (i)/(b)

Total Company Recovery, July 2017 - June 2018, By Month

Month	**Minnesota Energy Costs**	**Minnesota Recovery**	**Over(Under) Recovery**	**Over(Under) Percentage**
	(a)	(b)	(c)	(d)
July	$ 16,505,795	$14,246,664	($2,259,131)	(13.69%)
August	$ 15,912,308	$13,934,889	($1,977,419)	(12.43%)
September	$ 13,825,121	$14,977,020	$1,151,899	8.33%
October	$ 13,388,568	$15,766,431	$2,377,862	17.76%
November	$ 15,173,303	$15,085,474	($87,829)	(0.58%)
December	$ 15,934,707	$14,770,371	($1,164,335)	(7.31%)
January	$ 16,210,493	$15,532,099	($678,394)	(4.18%)
February	$ 15,023,029	$15,416,123	$393,094	2.62%
March	$ 16,544,445	$15,790,914	($753,531)	(4.55%)
April	$ 15,069,818	$14,620,409	($449,409)	(2.98%)
May	$ 15,233,721	$14,859,055	($374,666)	(2.46%)
June	$ 15,581,140	$14,716,647	($864,493)	(5.55%)
Total	**$ 184,402,448**	**$179,716,097**	**($4,686,351)**	**(2.54%)**

Source: Department's calculations.
(c) = (b) - (a)
(d)= (c)/(a)

Percent


Energy Cost Over(Under) Recovery
Minnesota Power
10.00
8.00
6.00
4.00
2.00
0.00
(2.00)
(4.00)
(6.00)
(8.00)
PERCENT OVER/(UNDER) RECOVERY
1987-88
1988-89
1989-90
1990-91
1991-92
1992-93
1993-94
1994-95
1995-96
1996-97
1997-98
1998-99
1999-00
2000-01
2001-02
2002-03
2003-04
2004-05
2005-06
2006-07
2007-08
2008-09
2009-10
2010-11
2011-12
2012-13
2013-14
2014-15
2015-16
2016-17
2017-18
YEAR

OTP	kWh Retail & Firm Resale (a)	Sales Subject to FCA (kWh) (b)	System Costs (c)
Jul-17	350,703,255	189,033,929	$ 8,290,147
Aug-17	363,679,214	197,103,746	$ 9,449,473
Sep-17	355,169,993	186,497,455	$ 8,700,696
Oct-17	321,596,747	168,067,542	$ 7,042,442
Nov-17	412,889,701	209,308,931	$ 9,452,036
Dec-17	443,316,990	221,347,374	$ 10,765,238
Jan-18	534,625,772	261,330,662	$ 12,973,575
Feb-18	511,903,870	251,316,077	$ 11,856,998
Mar-18	455,828,172	222,178,447	$ 12,574,674
Apr-18	427,953,526	215,515,102	$ 8,885,728
May-18	379,127,957	198,033,172	$ 9,183,296
Jun-18	368,288,959	200,716,187	$ 7,806,259
FYE18	4,925,084,156	2,520,448,624	$ 116,980,562

Source (a): OTP's July 31, 2018 compliance report approved by the Commission's October 9, 2018 Order in Docket No. E017/M-03-30.
Source (b): OTP's July 31, 2018 compliance report approved by the Commission's October 9, 2018 Order in Docket No. E017/M-03-30.
Source (c): OTP's July 31, 2018 compliance report approved by the Commission's October 9, 2018 Order in Docket No. E017/M-03-30.

MN Base Cost (($/kWh)
MN Base Cost (($/kWh)

0.024640 July-October 2017
0.024652 November 2017-June 2018

OTP	Net FCA Recovery (f)	Base Cost Recovery (g)	MN Recovery (h)	MN Energy Costs (i)	Over (Under) Recovery (j)	MN Recovery ($/kWh) (k)	MN Energy Costs ($/kWh) (l)
Jul-17	$ (221,696)	$ 4,657,796	$ 4,436,100	$ 4,242,545	$ 193,555	0.023	0.022
Aug-17	$ 267,633	$ 4,856,636	$ 5,124,269	$ 4,835,838	$ 288,431	0.026	0.025
Sep-17	$ (124,730)	$ 4,595,297	$ 4,470,567	$ 4,452,646	$ 17,921	0.024	0.024
Oct-17	$ 35,986	$ 4,141,184	$ 4,177,170	$ 3,604,022	$ 573,148	0.025	0.021
Nov-17	$ 124,996	$ 5,159,884	$ 5,284,880	$ 4,837,150	$ 447,730	0.025	0.023
Dec-17	$ (304,068)	$ 5,456,655	$ 5,152,587	$ 5,509,191	$ (356,604)	0.023	0.025
Jan-18	$ (568,144)	$ 6,442,323	$ 5,874,179	$ 6,639,324	$ (765,144)	0.022	0.025
Feb-18	$ (260,651)	$ 6,195,444	$ 5,934,793	$ 6,067,907	$ (133,114)	0.024	0.024
Mar-18	$ (85,037)	$ 5,477,143	$ 5,392,106	$ 6,435,183	$ (1,043,077)	0.024	0.029
Apr-18	$ (200,044)	$ 5,312,878	$ 5,112,834	$ 4,547,338	$ 565,497	0.024	0.021
May-18	$ 116,329	$ 4,881,914	$ 4,998,243	$ 4,699,620	$ 298,622	0.025	0.024
Jun-18	$ (72,557)	$ 4,948,055	$ 4,875,498	$ 3,994,911	$ 880,587	0.024	0.020
FYE18	$ (1,291,983)	$ 62,125,211	$ 60,833,228	$ 59,865,677	$ 967,551		0.02375

Source (f): OTP's July 31, 2018 compliance report approved by the Commission's October 9, 2018 Order in Docket No. E017/M-03-30.
(g) = (b)*MN base cost
(h) = (f) + (g)
(i) = (c)*Total Revised Sales Subject to FCA/Net Total System Sales
(j) = (h) - (i)
(k) = (h)/(b)
(l) = (i)/(b)

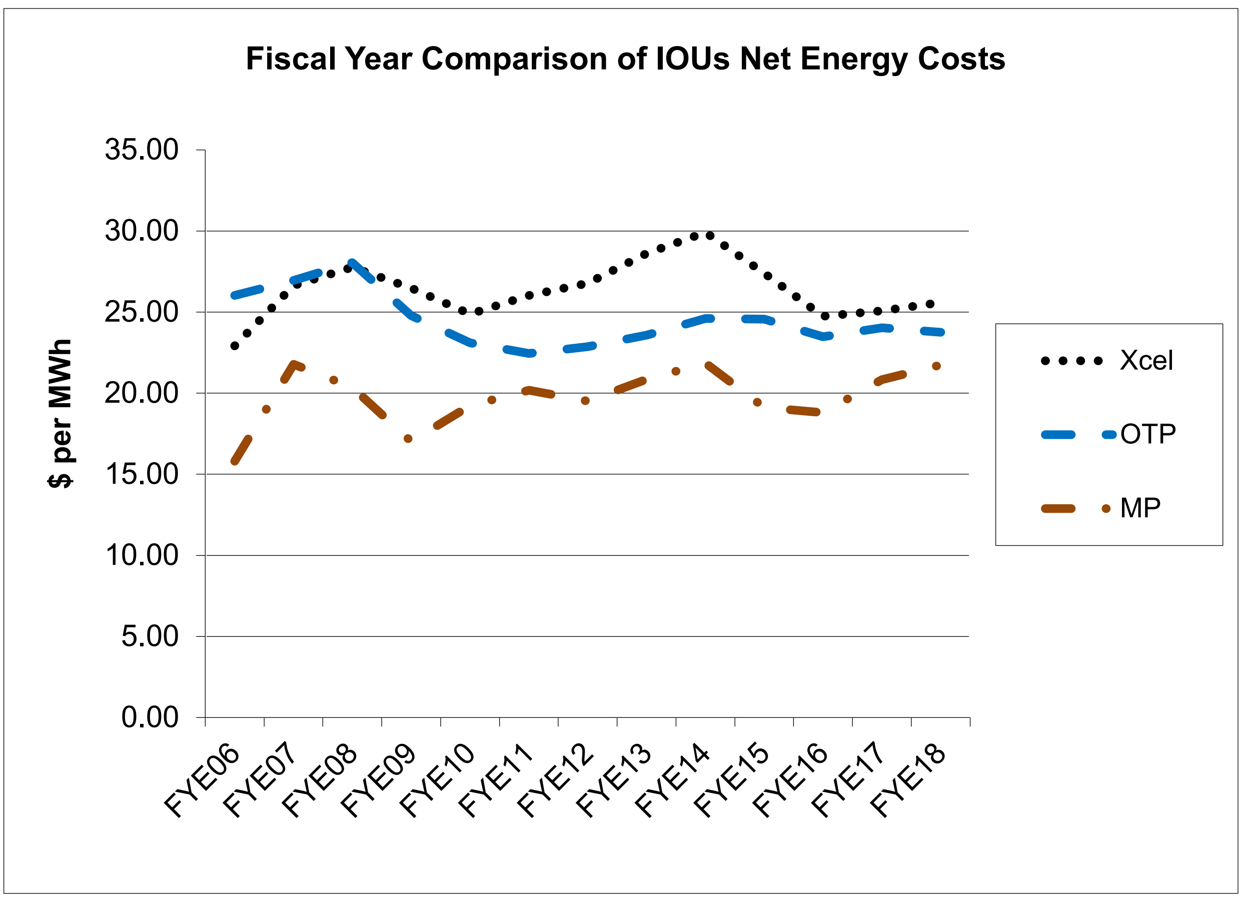
Xcel Electric	Prior Balance (a)	True Up Recovery (b)	FCA Recovery (c)	Base Cost Recovery (d)	Fuel Clause Revenues (e)	MN Energy Costs (f)	Saver's Switch True Up & SES Exemption (g)	Solar Gardens Recovery Net of Credit (h)	FYE15 AAA PI Refund & Gain from Inver Hills Flint Hill Sherco Land (i)	Balance (Cost-Revenues) (j)
Jul-17	$ (4,564,963)	$ (4,499,180)	$ 5,573,571	$ 78,215,410	$ 79,289,801	$ 75,040,436	$ (24,721)	$ 1,545,018	$ -	$ (7,294,031)
Aug-17	$ (12,784,978)	$(11,566,384)	$ (79,548)	$ 71,070,840	$ 59,424,908	$ 64,595,972	$ (294,528)	$ 1,083,508	$ (37,296)	$ (6,862,230)
Sep-17	$ (7,294,031)	$ (7,500,492)	$ (363,186)	$ 69,519,715	$ 61,656,037	$ 63,164,232	$ (149,459)	$ 1,403,783	$ -	$ (4,647,319)
Oct-17	$ (6,862,230)	$ (6,578,893)	$ 2,144,346	$ 61,790,109	$ 57,355,562	$ 61,734,405	$ -	$ 1,491,177	$ -	$ (992,210)
Nov-17	$ (4,647,319)	$ (4,632,917)	$ 2,436,476	$ 61,597,505	$ 59,401,064	$ 64,023,112	$ -	$ 1,626,438	$ -	$ 1,601,167
Dec-17	$ (992,210)	$ (989,801)	$ (1,463,763)	$ 67,631,385	$ 65,177,821	$ 65,379,613	$ -	$ 1,067,338	$ -	$ 276,920
Jan-18	$ 1,601,167	$ 1,584,885	$ 2,093,970	$ 68,432,769	$ 72,111,624	$ 67,016,580	$ -	$ 2,023,834	$ -	$ (1,470,043)
Feb-18	$ 276,920	$ 272,502	$ 4,290,739	$ 59,270,290	$ 63,833,531	$ 56,687,761	$ -	$ 1,853,044	$(1,929,053)	$ (6,944,859)
Mar-18	$ (1,470,043)	$ (1,466,963)	$ 457,117	$ 64,474,056	$ 63,464,210	$ 59,587,405	$ 90,331	$ 4,906,624	$ -	$ (349,893)
Apr-18	$ (6,944,859)	$ (7,240,524)	$ 4,073,719	$ 58,379,071	$ 55,212,266	$ 57,762,036	$ -	$ 5,456,880	$ -	$ 1,061,791
May-18	$ (349,893)	$ (373,807)	$ 7,104,919	$ 65,882,387	$ 72,613,499	$ 64,426,624	$ -	$ 5,406,768	$ -	$ (3,130,000)
Jun-18	$ 1,061,791	$ 1,138,278	$ 5,295,585	$ 74,690,678	$ 81,124,541	$ 66,591,942	$ 37,403	$ 4,863,736	$(1,528,903)	$ (10,098,572)
FYE18		$(41,853,296)	$ 31,563,945	$800,954,215	$790,664,864	$766,010,118				

(a) = (h) with a two-month lag.
Source (b), (c), (d) & (f): Xcel's monthly FCA data with further Department calculations under the Department's review of the monthly FCAs.
(e) = (b) + (c) + (d)
Source (g-i): Xcel's monthly FCAs. More info on the Saver's Switch discount program is provided in
Xcel's May 7, 2007 Supplemental Information Compliance filing in Docket No. E002/GR-05-1428.
(j) = (a) - (e) + (f) + (g) + (h) + (i)

Note 1:
Xcel's FCA factor is the ratio of (system costs - intersystem sales - Windsource costs) by (system retail MWh, resale MWh and Windso MWh).
Minnesota costs are the product of the FCA factor by MN sales (MWh) subject to FCA factor (retail minus Windsource).
Xcel's FCA revenues are calculated on the basis of MN sales (MWh) subject to FCA factor.

Utilities Fuel and Purchased Power Costs in $ per MWh

$/MWh	Xcel	OTP	MP
FYE06	22.92	26.02	15.80
FYE07	26.64	26.95	21.78
FYE08	27.77	28.05	20.37
FYE09	26.48	24.79	17.02
FYE10	24.89	23.10	19.24
FYE11	26.02	22.45	20.18
FYE12	26.77	22.86	19.52
FYE13	28.61	23.58	20.86
FYE14	29.91	24.61	21.85
FYE15	27.39	24.56	19.12
FYE16	24.74	23.47	18.79
FYE17	25.08	24.04	20.84
FYE18	25.60	23.75	21.75
Min	22.92	22.45	15.80
Max	29.91	28.05	21.85



Source: Calculations based on data from: (1) AAA reports up to FYE09, and (2) utilities' monthly FCA data emails after FYE09.

Minnesota Electric Utilities' Average Residential Bills for 2017

Xcel Electric		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017 Monthly Av.
Av. residential monthly kWh usage		701	542	574	472	515	696	815	650	635	518	572	686	615
(1) Number of customers		1,137,009	1,137,681	1,138,912	1,139,281	1,139,887	1,140,379	1,140,344	1,141,231	1,141,458	1,142,489	1,143,503	1,144,259	13,686,433
(1) Residential sales (MWh)		797,372	616,932	654,213	537,395	586,599	793,836	929,259	742,132	724,319	591,722	654,117	785,347	8,413,243
(2) Customer Charge		$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	
(2) Energy charge ($/kWh)														
Jan-May	0.0804	0.0804	0.0804	0.0804	0.0804	0.0804	0.0940	0.0940	0.0940	0.0940	0.0903	0.0903	0.0903	
June - Sep	0.0940													
Oct - Dec	0.0903													
En. Charge X kWh usage		$ 56.38	$ 43.60	$ 46.18	$ 37.92	$ 41.37	$ 65.40	$ 76.56	$ 61.09	$ 59.62	$ 46.78	$ 51.67	$ 61.99	
(2) Fuel Clause Adjustment ($/kWh)		0.02565	0.02384	0.02261	0.02734	0.02852	0.02745	0.02682	0.02260	0.02354	0.02464	0.02570	0.02543	
FCA X kWh usage		$ 17.99	$ 12.93	$ 12.99	$ 12.90	$ 14.68	$ 19.11	$ 21.86	$ 14.70	$ 14.94	$ 12.76	$ 14.70	$ 17.45	
CIP surcharge ($/kWh)														
(2) Jan-Sep 2017	$ 0.002164	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$ 0.001875	$ 0.001875	$ 0.001875	
(2) Oct-Dec 2017	$ 0.001875													
CIP surchrg. X customer's usage		$ 1.52	$ 1.17	$ 1.24	$ 1.02	$ 1.11	$ 1.51	$ 1.76	$ 1.41	$ 1.37	$ 0.97	$ 1.07	$ 1.29	
Total av. resid. monthly bill		$ 83.89	$ 65.70	$ 68.41	$ 59.84	$ 65.17	$ 94.01	$ 108.18	$ 85.20	$ 83.93	$ 68.51	$ 75.44	$ 88.73	$ 78.92
Av. Resid. energy charge + FCA ($/kWh)		10.61	10.42	10.30	10.77	10.89	12.14	12.08	11.66	11.75	11.50	11.60	11.58	11.27

(1) Source: Xcel Electric's 2016 Annual Jurisdictional Report, page Sales & Degree E-29, May 1, 2018 (Docket No. 18-4).
(2) Source: Xcel Electric's response to IR 16 in Docket No. E999/AA-18-373.

Minnesota Power	Jan-Apr	May-Dec	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017 Monthly Av.
Av. residential monthly kWh usage			925	743	770	610	571	536	653	598	551	601	773	937	689
(1) Number of customers			122,267	122,131	122,150	122,120	122,185	122,824	122,456	122,438	122,152	122,353	122,354	122,113	1,467,543
(1) Residential sales (MWh)			113,095	90,768	93,996	74,532	69,756	65,815	80,000	73,206	67,291	73,518	94,540	114,439	1,010,955
(2) Customer Charge			$ 8.45	$ 8.45	$ 8.45	$ 8.45	$ 8.41	$ 8.41	$ 8.41	$ 8.41	$ 8.41	$ 8.41	$ 8.41	$ 8.41	
(2) Energy charge ($/kWh)															
0 to 300 kWh	0.05383	0.05356	$ 16.15	$ 16.15	$ 16.15	$ 16.15	$ 16.07	$ 16.07	$ 16.07	$ 16.07	$ 16.07	$ 16.07	$ 16.07	$ 16.07	
301 to 500 kWh	0.07112	0.07076	$ 14.15	$ 14.15	$ 14.15	$ 14.15	$ 14.08	$ 14.08	$ 14.08	$ 14.08	$ 14.08	$ 14.08	$ 14.08	$ 14.08	
501 to 750 kWh	0.08625	0.08582	$ 21.48	$ 21.48	$ 21.48	$ 9.52	$ 6.09	$ 3.08	$ 13.16	$ 8.40	$ 4.37	$ 8.66	$ 23.40	$ 21.37	
751 to 1000 kWh	0.08918	0.08873	$ 15.52	$ (0.70)										$ 16.61	
over 1000 kWh	0.09437	0.09390													
Total monthly energy charge			$ 67.30	$ 51.09	$ 51.78	$ 39.82	$ 36.24	$ 33.23	$ 43.31	$ 38.55	$ 34.52	$ 38.81	$ 53.55	$ 68.13	
(2) Fuel Clause Adjustment ($/kWh)			0.01183	0.01180	0.01244	0.01121	0.01106	0.01175	0.01109	0.01017	0.01249	0.01382	0.01191	0.01034	
FCA X kWh usage			$ 10.94	$ 8.77	$ 9.57	$ 6.84	$ 6.31	$ 6.30	$ 7.25	$ 6.08	$ 6.88	$ 8.30	$ 9.20	$ 9.69	
(2) CIP surcharge Jan-June		$ 0.003961													
July-Dec		$ 0.006519													
CIP (CPA+CCRC) surcharge X customer's bill			$ 3.66	$ 2.94	$ 3.05	$ 2.42	$ 2.26	$ 2.12	$ 4.26	$ 3.90	$ 3.59	$ 3.92	$ 5.04	$ 6.11	
Total av. resid. monthly bill			$ 90.35	$ 71.25	$ 72.85	$ 57.53	$ 53.22	$ 50.06	$ 63.22	$ 56.94	$ 53.40	$ 59.44	$ 76.20	$ 92.34	$ 66.40
Av. Resid. energy charge + FCA ($/kWh)			8.46	8.05	7.97	7.65	7.45	7.38	7.74	7.47	7.52	7.84	8.12	8.30	7.83

(1) Source: MP's 2015 Annual Jurisdictional Report, page E-29 extra, May 01, 2018. (Docket 18-4)
(2) Source: MP's response to IR 16 in Docket No. E999/AA-18-373

Minnesota Electric Utilities' Average Residential Bills for 2017

Otter Tail Power	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017 Monthly Av.
Av. residential monthly kWh usage	1,378	1,243	1,069	910	713	719	747	774	716	623	919	1,057	904
(1) Number of customers	47,951	47,904	48,000	47,964	48,166	49,056	49,054	49,254	49,219	48,697	48,185	48,270	581,720
(1) Residential Sales (MWh)	66,067	59,522	51,327	43,631	34,340	35,274	36,634	38,105	35,259	30,323	44,279	51,027	525,788
(2) Customer Charge	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 9.75	$ 9.75	
(2) Energy charge ($/kWh)	0.08340	0.08340	0.08340	0.08340	0.08340	0.08124	0.08124	0.08124	0.08124	0.0834	0.09064	0.09064	
Total monthly energy charge	$ 114.91	$ 103.63	$ 89.18	$ 75.87	$ 59.46	$ 58.42	$ 60.67	$ 62.85	$ 58.20	$ 51.93	$ 83.29	$ 95.82	
(2) Fuel Clause Adjustment ($/kWh)	0.00164	0.00272	0.00221	(0.00208)	(0.00211)	(0.00232)	(0.00148)	0.00109	(0.00027)	0.00059	0.00100	(0.00099)	
FCA X kWh	$ 2.26	$ 3.38	$ 2.36	$ (1.89)	$ (1.50)	$ (1.67)	$ (1.11)	$ 0.84	$ (0.19)	$ 0.37	$ 0.92	$ (1.05)	
(2) CIP surcharge	0.00275	0.00275	0.00275	0.00275	0.00275	0.00275	0.00275	0.00275	0.00275	0.00536	0.00536	0.00536	
CIP surchrg. X customer's bill	$ 0.35	$ 0.32	$ 0.28	$ 0.23	$ 0.18	$ 0.18	$ 0.19	$ 0.20	$ 0.18	$ 0.33	$ 0.50	$ 0.56	
Total av. resid. monthly bill	$ 126.01	$ 115.82	$ 100.32	$ 82.70	$ 66.64	$ 65.43	$ 68.25	$ 72.39	$ 66.69	$ 61.13	$ 94.47	$ 105.08	$ 85.41
Av. Resid. energy charge + FCA ($/kWh)	8.50	8.61	8.56	8.13	8.13	7.89	7.98	8.23	8.10	8.40	9.16	8.97	8.39

(1) Source: OTP's 2017 Annual Jurisdictional Report, page E-29, Apr 30, 2018. (Docket 18-4)
(2) Source: OTP's response to IR 16 in Docket No. E999/AA-18-373.

Dakota Electric Association	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017 Monthly Av.
(1) Av. residential monthly kWh usage	701	542	574	472	515	696	815	650	635	518	572	686	615
(2) Customer Charge	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	
(2) Energy Charge ($/kWh)	$ 0.11680	$ 0.11680	$ 0.11680	$ 0.11680	$ 0.11680	$ 0.13080	$ 0.13080	$ 0.13080	$ 0.11680	$ 0.11680	$ 0.11680	$ 0.11680	
En. Chrg. X kWh usage	$ 81.91	$ 63.34	$ 67.09	$ 55.09	$ 60.11	$ 91.05	$ 106.59	$ 85.06	$ 74.12	$ 60.49	$ 66.81	$ 80.16	
(2) Power Cost Adjustment ($/kV	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	
Power Cost Adj. X kWh	$ 2.10	$ 1.63	$ 1.72	$ 1.42	$ 1.54	$ 2.09	$ 2.44	$ 1.95	$ 1.90	$ 1.55	$ 1.72	$ 2.06	
(2) CIP & Property tax surcharge ($/kWh)	-	-	-	-	-	-	-	-	-	-	-	-	
DSM surchrg. X customer's bill	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total av. resid. monthly bill	$ 93.01	$ 73.96	$ 77.82	$ 65.51	$ 70.65	$ 102.14	$ 118.03	$ 96.01	$ 85.02	$ 71.05	$ 77.53	$ 91.22	$ 85.16
Av. Resid. energy charge + FCA ($/kWh)	11.98	11.98	11.98	11.98	11.98	13.38	13.38	13.38	11.98	11.98	11.98	11.98	12.33

(1) Source: Xcel's average residential kWh usage figures were used as a proxy, because Dakota does not file a detailed MN Annual Jurisdictional Report.
(2) Source: Dakota's response to IR 16 in Docket No. E999/AA-18-373

CERTIFICATE OF SERVICE

I, Linda Chavez, hereby certify that I have this day served copies of the following document on the attached list of persons by electronic filing, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

MINNESOTA DEPARTMENT OF COMMERCE – REVIEW OF 2017-2018 ANNUAL AUTOMATIC ADJUSTMENT REPORTS

Docket Nos. **E999/AA-18-373**

Dated this **26th** day of **April, 2019**.

/s/Linda Chavez

____

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_18-373_AA-18-373
Derek	Bertsch	derek.bertsch@mrenergy.com	Missouri River Energy Services	3724 West Avera Drive PO Box 88920 Sioux Falls, SD 57109-8920	Electronic Service	No	OFF_SL_18-373_AA-18-373
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_18-373_AA-18-373
Seth	DeMerritt	Seth.DeMerritt@wecenergygroup.com	MERC (Holding)	700 North Adams PO Box 19001 Green Bay, WI 543079001	Electronic Service	No	OFF_SL_18-373_AA-18-373
Ian	Dobson	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_18-373_AA-18-373
Marie	Doyle	marie.doyle@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall P O Box 59038 Minneapolis, MN 554590038	Electronic Service	No	OFF_SL_18-373_AA-18-373
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_18-373_AA-18-373
Bruce	Gerhardson	bgerhardson@otpco.com	Otter Tail Power Company	PO Box 496 215 S Cascade St Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_18-373_AA-18-373
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_18-373_AA-18-373
Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company	200 1st Street SE PO Box 351 Cedar Rapids, IA 524060351	Electronic Service	No	OFF_SL_18-373_AA-18-373

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Leann	Oehlerking Boes	lboes@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_18-373_AA-18-373
Randy	Olson	rolson@dakotaelectric.com	Dakota Electric Association	4300 220th Street W. Farmington, MN 55024-9583	Electronic Service	No	OFF_SL_18-373_AA-18-373
Catherine	Phillips	catherine.phillips@we-energies.com	We Energies	231 West Michigan St Milwaukee, WI 53203	Electronic Service	No	OFF_SL_18-373_AA-18-373
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_18-373_AA-18-373
Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company	215 S Cascade St PO Box 496 Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_18-373_AA-18-373
Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company	200 First St SE Cedar Rapids, IA 52401	Electronic Service	No	OFF_SL_18-373_AA-18-373
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_18-373_AA-18-373
Mary	Wolter	mary.wolter@wecenergygroup.com	Minnesota Energy Resources Corporation (HOLDING)	231 West Michigan St Milwaukee, WI 53203	Electronic Service	No	OFF_SL_18-373_AA-18-373