COMMERCE DEPARTMENT

September 13, 2017 **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 2015-2016 Annual Automatic Adjustment Reports**
Docket No. E999/AA-16-523

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 2015-2016 Annual Automatic Adjustment Reports* for rate-regulated electric utilities in Minnesota (FYE16 AAA). 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 FYE16 AAA herein provided.

Sincerely,

/s/ MARK A. JOHNSON
Public Utilities Analyst Coordinator

MAJ/lt
Attachments

PUBLIC REVIEW OF 2015-2016 (FYE16) ANNUAL AUTOMATIC ADJUSTMENT REPORTS

FOR ELECTRIC UTILITIES

SUBMITTED TO THE
MINNESOTA PUBLIC UTILITIES COMMISSION

DOCKET NO. E999/AA-16-523

SEPTEMBER 13, 2017

I. OVERVIEW

This document provides the Division of Energy Resources of the Minnesota Department of Commerce's (DOC or the Department) summary and partial review of the automatic adjustment charges for the July 2015 - June 2016 (FYE16) 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 Department notes that in *In the Matter of Interstate Power and Light Company's Petition for Approval of a Variance to Certain Minnesota Public Utilities Commission Rules and Orders Governing Annual Electric Automatic Adjustment Reports* (Docket No. E001/M-16-89), IPL asked for and received the variances necessary to remove the requirement to file a report for the current reporting period (July 1, 2015 to June 30, 2016).[1] As a result, IPL is not included in this report.

The four rate-regulated electric utilities required to provide information per Minnesota Rules filed the information necessary to meet their filing requirements.[2]

The Department's review focused on whether the electric utilities had, during the period of July 1, 2015 to June 30, 2016, accurately adjusted their energy rates to reflect changes in fuel costs according to Commission rules and Commission-approved rule variances.

[1] Commission's May 13, 2016 Order in Docket No. E001/M-16-89.
[2] 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.

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.[3]

Each reporting utility computed billing adjustments and total fuel costs on a system-wide basis. 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.[4]

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

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

[4] In the discussion of allocations throughout this report, the Department notes that the two categories to which costs and revenues are allocated are retail customers and 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.

> 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 Department reviewed each auditor's report filed and notes the following.

MP's auditors noted two exceptions where the difference between the "average monthly cost of fuel consumed per ton" and the "average monthly cost of fuel purchased per ton" was greater than 5 percent. MP's auditors stated that "[MP's] management explained that this variance is primarily due to the new transportation contract prices with BNSF being higher under the new terms [after January 1, 2016] as compared to the previous contract."[5] The Department recommends that MP provide a narrative in reply comments explaining and discussing this issue with enough detail to allow the Commission to make a determination regarding the reasonableness of the corresponding energy costs that were charged to MP's ratepayers.

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.

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.

[5] Source: page 14 of 187 of MP's FYE16 report in Docket No. E999/AA-16-523.

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:[6]

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

[TRADE SECRET DATA HAS BEEN EXCISED]

Table 1.1: Utilities Forecast of Annual Energy Costs

$/MWh	2017	2018	2019	2020	2021
	[TRADE SECRET DATA HAS BEEN EXCISED]				
(1) Dakota					
(2) MP					
(3) OTP					
(4) Xcel Electric					

(1) Exhibit D, page 2 of 2, Dakota's August 24, 2016 AAA report in Docket No. E999/AA-16-523.
(2) Attachment 4, page 3 of 3, MP's August 31, 2016 AAA report in Docket No. E999/AA-16-523.
(3) Page 162-166 of 235, OTP's September 1, 2016 AAA report in Docket No. E999/AA-16-523.
(4) Part G, Section 1, Schedule 1, pages 1-5 of 5, Xcel's September 1, 2016 AAA report in Docket No. E999/AA-16-523.

Table 1.2 Annual and Cumulative Percent Change in Forecasted Energy Costs

$/MWh	2017	2018	2019	2020	2021	2017-2021
	[TRADE SECRET DATA HAS BEEN EXCISED]					
(1) Dakota						
(2) MP						
(3) OTP						
(4) Xcel Electric						

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

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 2016 energy costs to actual 2016 energy costs.[7]

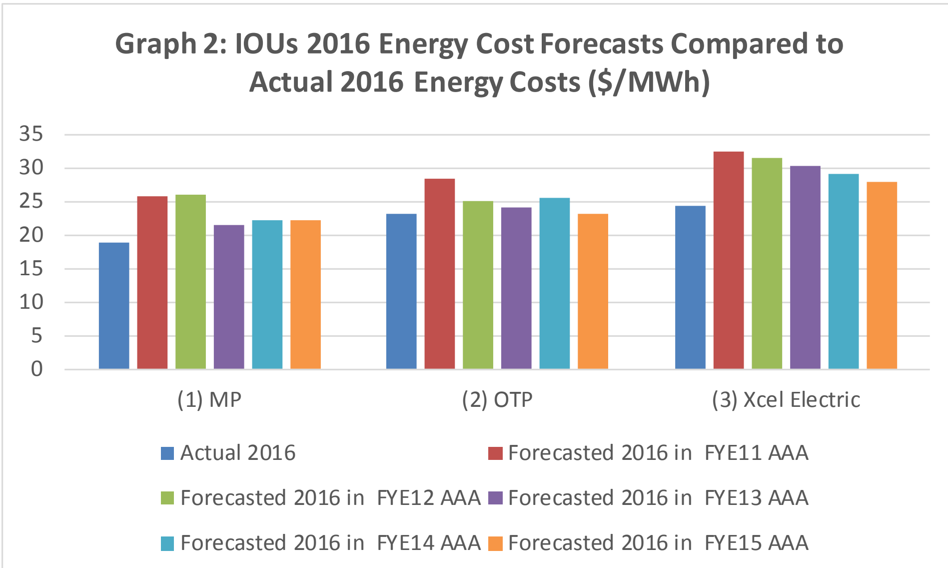

Table 2.1: IOUs 2016 Energy Cost Forecast Compared to Actual 2016 Energy Costs ($/MWh)

$/MWh	Actual 2016	Forecasted 2016 in FYE11 AAA	Forecasted 2016 in FYE12 AAA	Forecasted 2016 in FYE13 AAA	Forecasted 2016 in FYE14 AAA	Forecasted 2016 in FYE15 AAA
(1) MP	**18.79**	**25.76**	**25.98**	**21.60**	**22.22**	**22.10**
(2) OTP	**23.06**	**28.47**	**24.97**	**24.20**	**25.51**	**23.13**
(3) Xcel Electric	**24.25**	**32.52**	**31.38**	**30.21**	**29.10**	**27.91**

(1) Attachment 4, page 3 of 3, MP's FYE11-FYE15 AAA reports.
(2) OTP's FYE11-FYE15 AAA reports.
(3) Part G, Section 1, pages 1-5 of 5, Xcel Electric's FYE11-FYE15 AAA reports.

The Department notes that, while the utilities consistently over-forecasted energy costs, the forecasts generally became closer to 2016's actual annual costs, the closer to 2016 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.

[7] OTP and Xcel Electric's FYE11-FYE15 forecasts for 2016 are calendar year forecasts, while MP's forecast for 2016 is a fiscal year forecast.

Table 2.2 Annual Percent Deviation from Actual 2016 Energy Costs

	Actual 2016 $/MWH	Forecasted 2016 in FYE11 AAA	Forecasted 2016 in FYE12 AAA	Forecasted 2016 in FYE13 AAA	Forecasted 2016 in FYE14 AAA	Forecasted 2016 in FYE15 AAA
MP	**18.79**	**37.1%**	**38.27%**	**14.95%**	**18.25%**	**17.62%**
OTP	**23.06**	**23.4%**	**8.30%**	**4.93%**	**10.62%**	**0.30%**
Xcel Electric	**24.25**	**34.1%**	**29.40%**	**24.58%**	**20.00%**	**15.09%**

III. COMPLIANCES

The Department addresses the following reports in this section.[8]

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*

[8] 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.*

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).

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.

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 FYE16, the monthly generation costs allocated to retail and wholesale customers was provided for 2015.[9] Xcel illustrated its monthly comparison of generation cost allocation between retail and wholesale classes for the months of June, July and August of 2016.

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 2016, 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 2016 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 2016. The Department recommends that the Commission continue to require Xcel Electric to report this generation cost allocation data in future AAA filings.

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

[9] This information was provided in part as Part H, Section 2, Schedule 1 in the initial filing of Docket No. E999/AA-16-523 on September 1, 2016, and was subsequently provided in full in a supplemental filing in the same Docket on September 30, 2016.

Xcel Electric's FYE16 AAA report includes a copy of the prescribed letter by Xcel Electric to its external auditors[10] and a copy of the Deloitte & Touche, LLP Independent Auditors' Report,[11] which concluded:

> In our opinion, such Schedule presents, in all material respects, the fuel adjustment clause factors of the Company for the period July 1, 2015 to June 30, 2016, as calculated in accordance with the criteria established by the Minnesota Public Utilities Commission (the "Commission") 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, including the following revisions ("Commission Revisions"):…

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 the FYE17 AAA report.

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 Purchase Power Agreements (PPAs). For example, in Docket No. E002/M-02-51, the Commission required the following in Ordering Paragraph 1c:

Xcel shall identify in its monthly fuel clause adjustment report the date, length, cost to ratepayers and reason for each Qualifying Production Loss Event associated with the Navitas project and shall summarize all such events in its annual automatic adjustment (AAA) report.

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. There, in its April 4, 2006 Order, the Commission required in Ordering Paragraph 5 that "Xcel

[10] See Part F, Section 1 of Xcel Electric's FYE16 AAA report.
[11] See Part F, Section 2 of Xcel Electric's FYE16 AAA report.

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 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 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 FYE16 AAA filing a report on its projected wind curtailment payments over the 2016-2020 period for planned and existing projects and any commitments made to update the system.[12]

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 3.7 percent in FYE16.[13]

The Department notes that Xcel Electric's FYE16 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).

The FYE16 Wind Report states that the following three categories of events that were responsible for the FYE14 wind curtailments were also responsible for the FYE15 and FYE16 wind curtailments: [14]

1) Transmission Curtailment Events;

2) Dispatchable Intermittent Resource (DIR) Economic, Congestion and Negative Locational Marginal price (LMP) Related Curtailments (DIR Curtailment Events); and

3) Manual Economic, Congestion and Negative LMP Related Curtailments (Manual Curtailment Events).

The Department notes that the only outstanding issue related to Xcel Electric's FYE14 wind curtailments was that "the cost reduction [due to Manual Curtailment Events] would have been larger

[12] Part H, Section 5, Schedule 2 of Xcel Electric's FYE16 AAA report.
[13] Source: Attachment E1 to this report.
[14] Part H, Section 5, Schedule 2 of Xcel Electric's FYE15 AAA report.

if Xcel Electric curtailed only the facilities that do not receive Production Tax Credits."[15] As a result, the Department recommended that the Commission require Xcel Electric to discuss in a supplement of its FYE15 AAA report whether and why it is still reasonable to curtail wind facilities that are receiving Production Tax Credits, in response to Manual Curtailment Events.

Since Xcel Electric indicated that, in response to Manual Curtailment Events, it only curtailed wind facilities that are not receiving Production Tax Credits,[16] the Department will not pursue this issue further in this proceeding.

The Department recommends that the Commission accept Xcel Electric's Wind Curtailment compliance filing in the FYE16 AAA docket.

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. The additional information and analysis 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 notes that Xcel Electric's FYE16 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.

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

Pursuant to the Commission's Order dated July 14, 1981 in Docket No. E002/M-81-306, Xcel Electric included information on nuclear fuel expenses in Part H, Section 1, Schedule 1 of its FYE16 AAA filing. Xcel Electric's filing provided a history of nuclear fuel interim storage and disposal expenses included in

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[15] Department's August 26, 2015 response comments at 9-10 in Docket No. E999/AA-14-579.
[16] Source: Part H, Section 5, Schedule 2, Table 7 of Xcel Electric's FYE16 AAA report.

the determination of electric automatic adjustment charges. Xcel Electric shows payments to the Department of Energy (DOE), DOE credits, and beginning and ending balances for disposal costs and permanent disposal costs.

For background, the following are the four nuclear charges:

- DOE Yucca Mountain Permanent Disposal Costs, which is a $1 million per-kWh fee that is collected via the FCA; the Department notes that effective May 16, 2014 the DOE is no longer allowed to charge the spent nuclear fuel disposal fee and as a result this reporting period is the last in which the Company paid or collected this DOE fee via the FCA;[17]
- Interim Storage Costs that were collected from ratepayers and then used for Xcel Electric's Prairie Island Dry Cask Storage Project;
- Payments to the DOE for process plant enrichment services, where Xcel Electric was overcharged for the period 1986 to 1993, resulting in a $1.7 million refund to ratepayers through the February 2006 FCA; and
- Nuclear Decommissioning Costs, which are currently being requested to be collected through Xcel Electric's base rates in Docket No. E002/GR-15-826. The Commission's October 5, 2015 Order in Docket No. E002/M-14-761 approved a 60-year decommissioning period and a $14.0 million annual decommissioning accrual starting January 1, 2016.

Based on our review of Part H, Section 1, Schedule 1 of Xcel Electric's FYE16 AAA filing, the Department concludes that there have been no changes to this schedule since Xcel Electric's previous FYE15 AAA filing and that the ending balances for disposal costs and permanent disposal costs remain at $0. Moreover, since Xcel Electric is no longer required to pay DOE's nuclear storage assessment, the Department recommends that the Commission discontinue this reporting requirement (from 1981) in future AAA filings.

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.

[17] United States Court of Appeals for the District of Columbia suspended the collection of the nuclear disposal fees that are assessed annually on nuclear power plant operators by the DOE.

Xcel Electric stated that "the Company has not received any new revenue as described in this Order."[18] 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."[19] 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, 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.[20] When a plant experiences a forced outage, the utility must replace the megawatt hours that plant

[18] Source: Part H, Sections 1-9, page 4 of 5 of Xcel Electric's FYE16 AAA report.
[19] Source: Part H, Sections 1-9, pages 4-5 of 5 of Xcel Electric's FYE16 AAA report.
[20] Attachment E2 shows that outage costs have decreased as a share of energy costs since FYE07 and FYE08.

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 schedule outages through careful planning, prudent timing, and efficient completion of scheduled work." 06-1208 Order at 5.

As summarized below, Xcel, OTP, and MP are all spending more on maintenance of their generation facilities than was budgeted in their most recent rate cases prior to filing their FYE16 AAA reports. The Department also notes that, as shown in Attachment E2, outage costs have decreased as a share of net energy costs since FYE07 and FYE08.

Table 3
Comparison of Generation Maintenance Expense[21]
($ Millions)

	Test Year	Rate Case Budgeted	Actual 2013-2015 Average	Difference
Xcel	2014	193.7	201.2	7.5
OTP	2009	13.1	14.2	1.1
MP	2010	33.6	35.9	2.3

Due to the link between the level of maintenance expense and forced outages, and due to different current ratemaking incentives (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.

[21] Source: Attachment E3.

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 [Department] to continue monitoring this issue and to include a report on the electric utilities' plans in its next review.

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 kept attempting to generate a useful discussion and identification of ways to ensure that ratepayers were better protected from delays or lack of performance through the lessons learned by the utilities.

Xcel Electric is the only utility that discussed any improvements made due to lessons learned and "the reasonable contingency plans [developed by the utility] to mitigate against the risk of delays or lack of performance when contractors perform poorly and increase costs during plant outages."[22] Dakota Electric provided a general discussion about Great River Energy's contingency plans. MP stated only that "[d]uring this period, there were no delays or lack of performance by contractors identified which impacted the length of the outages and/or the replacement energy costs."[23]

Xcel Electric reproduced the following from its earlier reports:[24]

[22] Order Point 12 of the Commission's March 15, 2019 Order in Docket No. E999/AA-08-995.
[23] Attachment 19, page 2 of 2, MP's FYE16 AAA report.
[24] Part K, Section 3, pages 1-2 of 2, Xcel Electric's FYE16 AAA report.

> Contractor and Supplier performance has improved over the last several years. Xcel Energy attributes this quality improvement to three areas of focus.
>
> First, Xcel Energy has put into practice the use of a quality assurance and control protocol for the majority of our contracts. This proactive approach is designed to draw attention to the required quality steps Xcel Energy expects each contractor to follow.
>
> Second, Xcel Energy has awarded several alliance-like agreements with companies that consistently exceed others in technology; [sic] quality and contract management (including following the Scope of Work). As Xcel Energy increases the percentage of spend with these select companies, the possibility of contractor service or supplier product failure decreases.
>
> Third, Xcel Energy has invested time and resources in developing a better scope of work. Scope of work is measured by completion of the total work scope defined in the bid Technical Specification that is part of the Purchase Order and/or contract. By writing Scopes of Work with greater level of details and expectations, Xcel Energy gets a better quality project in the end.
>
> In the event problems arise with services, equipment, and/or materials provided by the vendor/supplier, the remedy is found in the Terms and Conditions of the Purchase Order and/or contract. Remedies for problems that adversely affect generating plant performance (such as de-rates or unplanned outages) include the direct costs of re-work, including labor and/or materials, depending on the nature of the problem.
>
> The Company strives to always contract for generation plant repair and maintenance services with parties who have a history of performing work safely, reliably, and in a timely manner. Therefore, we will continue to identify and work with these types of contractor issues on a going forward basis.

Even though the discussion does not address the issue of liability for replacement power costs, the Department appreciates the specific information that Xcel Electric provided.

Dakota Electric reproduced a simple overview from its earlier reports:[25]

> GRE's maintenance of generation assets is vital to ensure availability of the units when needed. GRE proactively works with contractors to achieve high performance contractor work during planned outages. GRE has multi-year contracts with major equipment manufacturers and outage support contractors (*i.e.*, General Electric & Siemens) to help ensure that planned outages meet scope, budget and schedule goals. A number of these contracts have performance-based incentives for meeting outage schedules and budgets. Also, GRE has multiple outage planning staff and tools to help ensure that appropriate contingency plans are in place to mitigate the risk of delays or performance for contractors working on planned outage activities. GRE's proactive planning with all stakeholders helps ensure that planned outages are completed in a timely and fiscally responsible manner.

As the utilities generally have not advanced this discussion, the Department suggests an industry standard used by the Nuclear Regulatory Commission (NRC) that the Commission may wish to consider to ensure that the rates utilities charge to ratepayers through the permissive FCA are reasonable. The NRC holds utilities with licenses to operate nuclear generation facilities responsible for all events that occur at such facilities, whether due to work performed by a contractor or a direct employee of a utility. The Minnesota Commission may wish to use a similar standard regarding work done by contractors at non-nuclear facilities, including responsibility for incremental costs of replacement power due to forced outages caused by improper work on generation facilities. For example, since utilities have maintained that it is not feasible to hold contractors accountable for their work, a potential solution might be for the utilities to supervise contractors directly rather than rely on contractors to supervise themselves.

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 fiscal-year-end 2011 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.

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[25] Exhibit A, page 7 of 12, Dakota Electric Association's FYE16 AAA Report.

In this docket, 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.

The goal is for utilities to share information about lessons learned during outages and develop best practices to minimize occurrences of forced outages, thus minimizing the cost of replacement power for which ratepayers may be charged. In addition, as indicated in our September 16, 2014 and December 31, 2014 Reports in Docket No. E999/AA-13-599, the Department continues to believe that utilities could reduce the costs that ratepayers pay for longer-than-expected plant outages by holding contractors more accountable for errors and delays, and by exploring reasonable insurance options.

For example, the Department notes that Xcel Electric was able to return insurance proceeds to ratepayers due to reimbursement for Excess Fuel Oil during the startup of Sherco Unit 3. Xcel Electric stated the following:[26]

> The March 2015 FERC Account 151 (fossil fuel) included a $503,486 settlement reimbursement from the insurance companies for the excess fuel oil that was consumed during the startup of Sherco Unit 3 following repairs. The Minnesota customers' share of this credit was about $364,429 based on March 2015 Minnesota jurisdictional MWh sales weighting relative to the NSP System total.

The Department notes that industry standards exist for ways to minimize forced outages. A December 2009 report by the Electric Power Research Institute (EPRI), "Field Guide: Boiler Tube Failure" described the importance of inspecting boiler tubes:

> In conventional and combined-cycle plants, boiler tube failures (BTFs) have been the main availability problem for as long as reliable statistics have been kept for each generating source. The three volumes of the Electric Power Research Institute (EPRI) report Boiler and Heat Recovery Steam Generator Tube Failures: Theory and Practice (1012757) present an in-depth discussion of the various BTF and degradation mechanisms, providing plant owners and operators with the technical basis to address tube failures and create permanent solutions. This field guide is based on the content of Boiler and Heat Recovery Steam Generator Tube Failures: Theory and Practice.
>
> **Results and Findings**

[26] Part E, Section 2, page 5 of 5, Xcel's FYE15 AAA report.

> Tube failures emanate from poor initial design, poor operation and maintenance, harsh fireside and cycle chemistry environments, and lack of management support for comprehensive reduction programs. A total of 35 tube failure mechanisms affecting conventional fossil plants are described in this field guide.

The EPRI Report, with which Minnesota utilities should be familiar, explained what must be clear to utilities about how to inspect boiler tubes to prevent failures and forced outages. Closely following this field guide may have reduced the amount of replacement power costs that have been charged to Minnesota ratepayers, for example, regarding the need to ensure that foreign material is excluded from generation facilities even when inspecting generation facilities:

> Foreign materials left in the boilers by careless inspectors have the potential to cause more damage faster than degradation itself. Be careful not to lose equipment that could plug or otherwise damage components. Also remember that finding and extracting dropped items can be costly and time-consuming.

- Bring only the tools that are necessary into the immediate inspection area.
- Secure loose items. Use lanyards when necessary.
- Make sure equipment caps (*e.g.*, lens caps, battery covers) are secured.
- Conduct pre- and post-inspection inventories of equipment.

Because the EPRI report identifies industry standards that utilities should already be following, the Department recommends that the Commission consider holding utilities financially responsible for replacement power costs due to any failure to remove foreign material from generation facility work areas.

Enforcement of this standard and the standard above of holding utilities accountable for contractor errors may be difficult to enforce. However, assuming that the FCA continues to function as it currently does, as a start the Commission may choose, for example, to require utilities to file the lengths (duration) and purposes of planned outages for the previous five years, along with the lengths and purposes for expected future outages for upcoming two years. Before being allowed recovery of the costs of any outages that are longer than expected, utilities at a minimum would need to explain sufficiently what caused the extensive delay and why it is reasonable to require ratepayers to pay for the incremental costs of replacement power.

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.

Regarding this reporting period, on July 29, 2016, Otter Tail submitted a compliance report and proposal to implement a true-up credit (decrease in rates) of $0.0003 per kWh. In Comments filed on August 12, 2016, the Department recommended that the Commission approve Otter Tail's compliance report and the true-up credit. The Commission's September 15, 2016 Order approved Otter Tail's true-up decrease in rates beginning September 1, 2016.

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."[27] Therefore, the Department concludes that Xcel Electric complied with the 2010 Order.

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.[28]

[27] Source: Part H, Sections 1-9, page 4 of 5 of Xcel Electric's FYE16 AAA report.
[28] Source: Attachment No. 14 of MP's FYE16 AAA report.

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,[29] the Commission approved Xcel Electric's proposal to recover community solar garden 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.

The Department reviewed Xcel Electric's Solar Garden Program Costs[30] and was able to tie the solar costs to Xcel Electric's monthly FCA filings with the exception of January through March 2016. For example, the amount contained in the monthly automatic adjustment filing for March 2016 is $5,233 compared with a beginning balance of $326 in the Company's FCA filing for August 2016.[31]

Xcel Electric addressed this issue in an email response to the Department on January 13, 2017. Xcel Electric stated in part that:

> Attached spreadsheet along with the following narrative provide an explanation and justification of our Community Solar Garden Program (CSGP) cost recovery in FCA. This spreadsheet attachment is developed in response to your request to provide monthly information in support of the CSGP amounts the Company recovers through the FCA. During our conversation you brought up the example using the calculation in May 2016 FCA filing (Docket No. E002/AA-16-372). In this calculation Xcel identified $5,233 (Attachment 1, page 2 line 5c) March 2016 CSGP cost and the Company was recovering $6,195 (Attachment 1, page 4 line 14) in May 2016 FCA. Given the cost of $5,233 you would like an explanation on the basis to recover a higher $6,195. Specifically you are interested in a description of our process to determine the CSGP recovery through this example. As illustrated in line [D] of the attached spreadsheet, $5,233 was the booked March 2016 CSGP cost recoverable from MN customers. Please note when these small amounts were booked to the general ledger the January 2016 – March 2016 Made in Minnesota (MIM) programs cost and standard QF tariff purchased energy costs were inadvertently identified as MN CSGP recovery. MIM program costs

[29] *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.
[30] Source: Part E, Section 5, Schedule 1, page 1 of 4, line 16b.
[31] Source: Docket No. E002/AA-16-645, Attachment 3, page 3.

> should have been recoverable in RDF Rider and energy purchase costs under QF tariffs are NSP system costs shared by all jurisdiction, not a MN only recovery. As shown on "Misc Adjustment" line (line[E]) we had backed out these errors in subsequent months. The correct amount for March 2016 should have been $327 (Line[A]). The sum of $5,233 and carryover from prior month of $963 (line [F]) was the $6,196 (line [G]) MN CSGP recovery for May 2016 FCA.
>
> As illustrated in the attached spreadsheet we began incorporating CSGP cost in November 2015 FCA calculation (Docket No. E002/AA-15-961) throughout 2016 the monthly recovery amounts have been small and monthly recovery factors are insignificant. However we anticipate CSGP amount will increase when more solar gardens are in operation. To proactively demonstrate and justify the cost of CSGP recovery we planned on incorporating similar attachment here to our monthly FCA filings sometime in 2017.

A copy of the above referenced spreadsheet is included in Attachment E-10 to these comments. The Department reviewed Xcel Electric's email response and spreadsheet detailing the community solar garden program costs included in the FCA. Based on our review, the Department concludes that the community solar program costs included in Xcel Electric's FCA appear reasonable.

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 104,000 Minnesota electric customers in the southern metropolitan area, in Dakota, Goodhue, Scott and Rice counties. Attachment E4 shows that DEA's resource adjustment includes $144,364,540 or $80.10/MWh in fuel costs, which includes generation capacity and transmission costs from its suppliers, during the reporting period.[32] This amount is over 1 percent higher than the $141,789,483 or $78.64/MWh cost in FYE15.

DEA recovered $146,436,020 in fuel costs and thus over-recovered fuel costs in FYE16 by $2,071,480 or 1.43 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 144,000 electric customers in northeastern Minnesota. MP's fuel costs were $143,457,231 for FYE16.[33] MP under-recovered its fuel costs by $2.6 million in FYE16, or approximately 1.81 percent of its actual costs. By comparison, in FYE15, MP's actual fuel costs in the FCA were $165,337,446 and MP over-recovered by approximately $6.8 million, or 4.12 percent.

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[32] 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 FYE16 energy needs from power suppliers, Great River Energy (GRE) and Energy Alternatives (EA).
[33] Source: Attachment E5.

Compared to FYE15 fuel costs of $19.12/MWh, MP's costs in FYE16 of $18.80/MWh were 2 percent lower.[34]

The Department notes that MP's level of under/over-recovery varies from month to month. In FYE16, MP's monthly under/over-recoveries ranged from a $3 million under-recovery in August 2015, to a $128,000 over-recovery in April 2016.

D. OTTER TAIL POWER COMPANY

Otter Tail serves more than 59,000 Minnesota electric customers, primarily in western Minnesota. During the reporting period, OTP's total fuel costs were $58,237,792 or $23.47/MWh for OTP's Minnesota operations in FYE16.[35] This level is 4.4 percent lower than the $24.56/MWh cost in FYE15.[36]

During FYE16, Otter Tail experienced a 1.23 percent over recovery in FYE16 as a whole. As a result, OTP is required to provide an annual true up credit of $0.0003 per kWh to its Minnesota ratepayers starting on September 1, 2016.[37]

E. XCEL ELECTRIC

Xcel Electric, which serves about 1.2 million electric customers in Minnesota, primarily in the metro area, had energy costs of $743,614,976 for FYE16, or $24.74/MWh.[38] This level is 9.7 percent lower than the $27.39/MWh cost in FYE15.[39]

Xcel Electric is the only electric utility to use a forecasted FCA method.[40] 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-recoveries of costs that it experienced two months prior to the month in which it applies a new FCA.

In its review of Xcel Electric's FYE16 monthly FCA filings, the Department noted three issues related to the calculation of the monthly fuel cost charge.

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[34] Source: Attachment E8.
[35] Source: Attachment E6.
[36] Source: Attachment E8.
[37] Source: Commission's September 15, 2016 Order in Docket No. E017/M-03-30.
[38] Source: Attachment E7.
[39] Source: Attachment E8.
[40] Source: Commission's October 24, 2014 Order in Docket No. E002/M-14-364.

First, using the same input data provided in Docket No. E002/AA-16-274, the Department noted that its calculation of the "Balance of Unrecovered Expenses" at the end of February 2016 -$4,787,555 was different from Xcel Electric's calculations, -$4,011,835.[41] Following discovery, Xcel Electric provided the following explanation for its apparent miscalculation of a lower amount of refund to its ratepayers:

> Pursuant to our discussion on December 29th 2016, here is an explanation of the true up question you have on our April 2016 FCA (Docket No. E002/AA-16-274). You are correct, on page 16 (line 12n) of 102, the "Per Unit True Up Amount" was based on -$4,011,835. However based on the formula on line 12n the computed amount was -$4,787,555. This $775,720 discrepancy is not an error but rather an adjustment to a prior month (actual January on March 2016 FCA) over-credit of Intersystem Sales amount. The Company had migrated to a new accounting system (SAP) on January 2016 where all the old accounts were mapped to the new codes. During this new roll out the Intersystem System (STOU) calculation incorrectly subtracting the GEN Book amount of $1,076,527 twice. As a result the March 2016 FCA resulted in $1,076,527 over credit of Intersystem Sales amount to retail customers. An adjustment was therefore made in April 2016 FCA by adding $775,721 to the true up to reverse the Minnesota's portion of the over credited amount. There is no further adjustment necessary. Attached is a detailed illustration of the cause and resolution of this discrepancy you have identified. This error was primarily related to the rollout of new accounting system. Once the migration and mapping of accounts get familiarized internally same error will unlikely be repeated. Due to the fact that our FCA database spreadsheets are designed to prepare fuel clause recovery reports its rigid programming structure made it difficult to illustrate accounting adjustment like this. In hindsight we should have reported this adjustment in the "Unusual Items Over $500,000 During FCA Reporting Period" on Attachment 6. We will utilize this reporting venue when circumstances of similar accounting adjustments arise in future.

Xcel Electric's explanation above addresses the discrepancy issue raised by the Department. However, Xcel Electric failed to comply with the Commission's April 6, 2012 Order in Docket No. E999/AA-10-884 which requires Xcel Electric to provide footnotes in monthly FCA filings and annual AAA filings to explain unusual adjustments of $500,000 and higher on a going forward basis. The Department notes that transparency regarding the calculation of this balance is important since it is directly used to

[41] Source: Line 12n, page 3 of Attachment 1, Xcel Electric's March 31, 2016 filing in Docket No. E002/AA-16-274.

calculate the FCA charge applied to ratepayers' following month bills. Ideally, Xcel Electric should clearly identify and justify any material adjustments made in the true-up calculations.

Second, using the same input data provided in Docket Nos. E002/AA-16-274, 16-372 and 16-492, the Department noted that its calculation of Xcel Electric's "Total System Costs" was different from Xcel Electric's calculations. The Department was able to trace this difference to the calculation of the "MISO ASM Charges-Total." Following discovery, Xcel Electric agreed with the Department that the sum of the three components of the "MISO ASM Charges-Total" yields a different total than the one shown in Xcel Electric's calculation. The Department concludes that the total amount is correct, and that the three components were incorrectly entered into Xcel Electric's spreadsheet. The Department verified that the "MISO ASM Charges-Total" is consistent with the "Total MISO ASM Charges" provided in Attachment 2, page 8 of Xcel Electric's filing. As a result, the Department concludes that these incorrect entries did not affect the calculation of the FCA charge.

For clarity of the record in this matter, the Department recommends that Xcel Electric provide in reply comments a discussion of the measures it has taken to alleviate the reoccurrence of incorrect data entry and failure to identify and justify material adjustments. The Department also recommends that Xcel Electric file the correct Attachment 1, page 2, in the relevant monthly FCA dockets (16-274, 16-372 and 16-492) with a narrative explaining the correction made.

Third, the Department noted that Xcel Electric stated the following regarding its refuse-derived fuel (RDF):

> **[TRADE SECRET DATA HAS BEEN EXCISED]**

In order to ensure that the **[TRADE SECRET DATA HAS BEEN EXCISED]** paid to Xcel Electric are reflected in retail rates, the Department asked Xcel Electric several questions regarding its RDF in DOC Information Request No. 29. Xcel Electric replied that:

> **A)** **[TRADE SECRET DATA HAS BEEN EXCISED]**
>
> B) The total Company amount of **[TRADE SECRET DATA HAS BEEN EXCISED]** during the 2014, 2015, and 2016 AAA reporting periods are as follows:

[TRADE SECRET DATA HAS BEEN EXCISED]

FYE2014	FYE2015	FYE2016

We note that the **[TRADE SECRET DATA HAS BEEN EXCISED]** for FYE2016 increased from prior periods primarily due to increased production at the plants and an additional supplier contract.

C) Yes, Xcel Energy included **[TRADE SECRET DATA HAS BEEN EXCISED]** in its 2016 Test Year in Docket No. E002/GR-15-826. The following table shows the revenue from refuse-derived fuel suppliers **[TRADE SECRET DATA HAS BEEN EXCISED]**. The Refuse-Derived Fuel Revenue is shown in Volume 4A Test Year Workpapers Base Data, Tab R1 Revenue Summary, Page R1-A, line 19 and is labeled "Production Associated Revenues."

Refuse-Derived Fuel Revenue (Production Associated Revenues)
Total Company $6,371,626
MN State $5,564,201
[TRADE SECRET DATA HAS BEEN EXCISED]

In summary, it is the Department's understanding that **[TRADE SECRET DATA HAS BEEN EXCISED]**

Sherco Unit 3 Litigation Update:

On August 18, 2017, Xcel Electric provided an update as to the status of Xcel Electric's litigation against General Electric Co. with respect to the Sherco Unit 3 outage, in accordance with the Commission's June 2, 2016 Order in Docket No. E999/AA-14-579 et al.

The Commission stated the following on page 5 of its June 2, 2016 Order:

> Sherco 3's outage caused Xcel Electric to incur greater energy-related costs than it otherwise would have. The ongoing litigation between Xcel Electric and General Electric may well reveal facts about the steps each of those parties took, or failed to take, that contributed to the outage and related costs.
>
> Consequently the Commission agrees with the Department and OAG that it would be premature to render a decision about these matters at this time. But the Commission also concurs with Xcel Electric that it would be premature to initiate another proceeding to address this issue while Xcel Electric and General Electric are already engaged in a separate proceeding. Rather, the Commission will simply defer its decision on this issue until the Commission has

> a sufficient record regarding the recovery of the cost of replacement energy.
>
> Finally, the Commission concurs with all parties that it may act in the future to remedy any inequities that it finds in Xcel Electric's recovery of replacement energy costs from ratepayers. This may include directing Xcel Electric to refund any excessive cost recovery.

Since litigation on this issue is still pending, the Department will continue to monitor this issue and will provide recommendations to the Commission once litigation has completed.

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:

- 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 report. The Department summarizes the companies' responses to the seven ordering paragraphs as discussed below.

A. THE SCHEDULE 10 ADMINISTRATIVE CHARGES PAID TO MISO UNDER THE MISO TARIFF.

The three Minnesota Electric Utilities provided the following administrative charges, referred to as "Schedule 10 costs," billed by MISO for the period July 2015 through June 2016:

Table 5: MISO Schedule 10 Costs for July 2015 through June 2016

	Total Company	Estimated MN Jurisdiction[42]
Xcel Electric	$10,420,471[43]	$7,674,429
Minnesota Power	$1,879,082[44]	$1,457,604
Otter Tail Power	$854,949[45]	$409,427
Total	$13,154,503	$9,541,461

The total amount charged to these companies for MISO Schedule 10 costs decreased by $44,239 or 0.34 percent from the previous reporting period. The total estimated Minnesota jurisdictional amount reflects a decrease of $86,232, or 0.90 percent, from the previous reporting period. Two of the IOUs' (NSP-Xcel and MP) MISO Schedule 10 costs decreased from the previous reporting period. However, OTP's MISO Schedule 10 costs increased from the previous reporting period by 5.66 percent. According to OTP the increase was mainly due to increases in customer energy usage, demand energy rates and native load demand (reserved capacity). OTP stated that there are no new or additional benefits to their customers as a result to this increase in the MISO Schedule 10 costs but as in the past years, customers continue to benefit from the market efficiencies that results from OTP being part of a centralized energy market that optimizes the economic dispatch of generation resources throughout the MISO footprint. [46]

The Department continues to monitor MISO Schedule 10 costs and expects the three Minnesota IOUs in MISO to show benefits related to these costs in their rate cases in order to continue to receive cost recovery. This recovery and analysis occurs in rate-case proceedings, and has occurred in Xcel Electric's, OTP's and MP's rate cases. Thus, these costs are not charged through the FCA; rather, they are charged through base rates.

On July 21, 2017, the Commission issued its Order regarding last years' AAA filings in Docket No. E999/AA-15-611. The Commission's Order stated in part the following regarding MISO Schedule 10 costs:

> The Commission concludes it is not necessary to require these details in AAA reports because the information is filed by electric utilities in

[42] Xcel Electric AAA initial filing's Part I, Section 1-7, Pg. 2 of 9, OTP AAA initial filing's Part D Section 5, Attachment A, and MP AAA initial filing's Attachment No. 6 provide the Minnesota Jurisdictional MISO Schedule 10 costs.
[43] MISO Schedule 10 costs paid by NSP-Xcel consist mostly of Minnesota costs, with some costs for Wisconsin, North Dakota and South Dakota. Xcel Electric's FYE16 Minnesota jurisdiction percentage of 73.65 percent reflects lower jurisdictional transmission and interchange allocations effective January 2015.
[44] MP's FYE16 average Minnesota retail jurisdictional percentage was 77.57 percent.
[45] OTP's FYE16 estimated Minnesota retail jurisdictional percentage in FYE16 for OTP was 47.89 percent.
[46] OTP Response to DOC Information Request No. 20.

> their general rate cases, which provide parties the opportunity for full record development on these issues.

Since the Commission's July 21, 2017 Order was issued long after the utilities filed their AAA reports in this proceeding, the Department reviewed the utilities' MISO Schedule 10 costs as noted above. The Department will discontinue reviewing utilities MISO Schedule 10 costs in future AAA filings.

B. 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.

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 which 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 that will be recovered over a five-year period, beginning on January 1, 2014, the date of the integration of the first Entergy Operating Company.

The Department included the actual MISO Schedule 10 costs paid by utilities for July 2015 to June 2016 in Table 5 above.

C. 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 reporting period July 2015 through June 2016.

D. EACH INSTANCE WHERE MISO DIRECTED THE CURTAILMENT OF DELIVERY OF A FIRM PURCHASE 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 reporting period July 2015 through June 2016.

E. CHANGES TO MISO TARIFFS THAT MAY ULTIMATELY AFFECT THE RATES OF RETAIL CUSTOMERS TO 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, 2015 to June 30, 2016, MISO submitted significant number of filings to FERC, including proposed tariff changes to the MISO Open Access Transmission and Energy Markets Tariff (TEMT or 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" quick link. Xcel Electric's Part D Section 7 in their AAA filing summarizes the MISO filings and other FERC proceedings with the potential for more substantial financial impact on the Company (and thus the rates charged to retail electric customers in Minnesota), and the Company's efforts to minimize MISO costs through its interventions and comments filed at FERC.

- 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 and Energy 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.

F. 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, MISO's administrative charges, offset by a decrease in costs due to elimination of transmission rate "pancaking" and elimination of the MAPP or MAIN fee.

The utilities generally agreed that they 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 Docket No. E999/AA-15-611 and in this docket, Xcel Electric provided the following response 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 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 [note], 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.

G. 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. CONCLUSIONS AND RECOMMENDATIONS FOR SECTIONS II THROUGH V

A. SECTION II, FILING REQUIREMENTS

The Department requests that MP provide a narrative in reply comments explaining and discussing the auditor's report exceptions related to the difference between the "average monthly cost of fuel consumed per ton" and the "average monthly cost of fuel purchased per ton," with enough details to allow the Commission to make a determination regarding the reasonableness of the corresponding energy costs (to be identified by MP).

B. SECTION III, COMPLIANCES

The Department recommends that the Commission accept the compliance filings A to M, as discussed in the relevant sections above.

C. SECTION IV, TOTAL FUEL COST REVIEW

The Department requests that, in addition to ensuring compliance with the Commission's April 6, 2012 Order in Docket No. E999/AA-10-884 requiring Xcel Electric to provide footnotes in monthly FCA filings and annual AAA filings to explain unusual adjustments of $500,000 and higher, Xcel Electric provide a transparent record of its calculation of the FCA charge in all future monthly FCA filings. Any adjustment made by Xcel Electric should be clearly identified and justified.

The Department also requests that Xcel Electric provide in reply comments a discussion of the measures it has taken to avoid the reoccurrence of incorrect data entry and its failure to identify and justify all material true-up calculation adjustments. The Department also requests that Xcel Electric file the correct Attachment 1, page 2, in the relevant monthly FCA dockets (16-274, 16-372 and 16-492) with a narrative explaining the correction made.

In addition, the Department suggests two possible industry standards for the Commission to consider putting in place, if the FCA regulations continue to operate as they currently do, namely:

- Hold utilities at least partially if not fully responsible for incremental costs of replacement power due to forced outages caused by improper work by contractors, and
- Hold utilities financially responsible for replacement power costs due to any failure to remove all foreign material from generation facility work areas.

D. SECTION V, EFFECTS OF MISO DAY 1 ON MINNESOTA RATEPAYERS

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 cost recovery of Schedule 10 costs.

VII. EFFECTS OF MISO DAY 2 ON MINNESOTA RATEPAYERS

A. BACKGROUND ON MISO DAY 2

This AAA report is based on ten 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[47] 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-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[48]), 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 Transmission and Energy Markets Tariff (TEMT). 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 for 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.

[47] See the Open Access Transmission and Energy Markets Tariff (TEMT) in *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 101,163 (2004).
[48] TEMT § 1.208 (issued May 27, 2005).

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.[49]

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 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.[50]

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.[51] These basic principles are still in place.

Third, on reconsideration, 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. 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.[52]

On June 22, 2006, the parties filed the *Joint Report and Recommendation Regarding MISO Day 2 Cost Recovery* (Joint Report) with the Commission.[53] The Joint Report was supplemented by the comments filed on November 6, 2006. In brief, the Joint Report recommended that the Commission authorize

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[49] Order Authorizing Interim Accounting for MISO Day 2 Costs, Subject to Refund with Interest (April 7, 2005).
[50] Order Establishing Second Interim Accounting for MISO Day 2 Costs, Providing for Refunds, and Initiating Investigation (December 21, 2005 Order).
[51] December 21, 2005 Order at Ordering Paragraph 10.
[52] Order on Reconsideration Suspending Refund, Granting Deferred Accounting and Requiring Filings at 7-8.
[53] 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.

utilities to recover most Day 2 costs via their fuel clauses. 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).

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 FYE2007, 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 MISO Day 2 Order, 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.

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 are broken out into 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 bill 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 on Schedule 7 page 13 of 13 of Xcel's Electric's FYE16 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: Total MISO Day 2 Charges Assigned to Retail (in millions)

AAA Reporting Period	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016
Net Costs	$195.9	$196.6	$200.5[54]	$222.9[55]	$101.7[56]	$54.6[57]

The Department notes that Xcel Electric's MISO Day 2 net costs assigned to retail ratepayers have decreased during the last two AAA reporting periods. This decrease is consistent with the fall in MISO's locational marginal prices (LMPs) since 2014. The Department notes that these lower market prices, or LMPs, followed lower gas prices and milder weather.

The Department reviewed Xcel Electric's MISO Day 2 charges for FYE16 and noted, as discussed above, a significant overall decrease in MISO Day 2 costs. As a result of the significant decrease in MISO Day 2 costs, the Department performed a limited review of some charge types showing significant changes between FYE15 and FYE16, as discussed below. In addition, the Department reviewed Xcel's allocation of MISO Day 2 costs.

a) Day-Ahead Asset Energy MWh's

In its review, the Department noted that the amount of Day-Ahead Asset Energy MWh assigned to retail ratepayers decreased from 7,966,107 in FYE14 to 5,775,623 in FYE15 to 3,113,067 in FYE16. The Department asked Xcel Electric to explain these decreases in DOC Information Request No. 32.

Xcel provided the following response:

> Day Ahead Asset Energy is the sum of the production from all NSP owned and purchased resources (those within the MISO footprint, *i.e.*, the figure excludes Interchange and Financial Schedule purchases) netted against the sum of all NSP load. A positive figure denotes greater load than resource production and a consequent purchase from the MISO market. The trend described illustrates that NSP is purchasing less from the MISO market over the three periods. The primary reasons for purchasing less from the market over the three periods are as follows:

[54] Source: Xcel Electric's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 7, Page 13 of 13.
[55] Source: Xcel Electric's initial filing in Docket No. E999/AA-14-579, Part J, Section 5, Schedule 7, Page 13 of 13.
[56] Source: Xcel Electric's initial filing in Docket No. E999/AA-15-611, Part J, Section 5, Schedule 7, Page 13 of 13.
[57] Source: Xcel Electric's initial filing in Docket No. E999/AA-16-523, Part J, Section 5, Schedule 7, Page 13 of 13.

> 1) The figure for Docket No. E999/AA-14-579 includes the effect of a Sherco 3 outage that lasted until October 27, 2013 (approximately one-third of that period) – an effect that decreased the net production component of the Day Ahead Asset Energy and raised the amount.
> 2) NSP has contracted for more wind resources during the three periods – an action that increased the net production component of the Day Ahead Asset Energy and lowered the amount.
> 3) Nuclear production increased for the 2015-2016 AAA period over the figure for the 2013-2014 and 2015-2015 AAA periods where production was similar – an action that increased the net production component of the Day Ahead Asset Energy and lowered the amount.

Based on the above, the Department concludes that Xcel Electric has adequately explained the decrease in Day-Ahead Asset Energy MWh assigned to retail ratepayers for FYE16.

b) Real Time Revenue Sufficiency Guarantee Make Whole Payment

The Department noted that the amount of Real Time Revenue Sufficiency Guarantee Make Whole Payments assigned to retail changed from a net cost of $818,466 in FYE15 to net revenues of ($511,107) in FYE16. The Department asked Xcel Electric to explain this change in DOC Information Request No. 34. In addition, the Department asked Xcel Electric to explain how it allocates this charge type between retail and asset-based wholesale.

Xcel provided the following response:

> The Real Time Revenue Sufficiency Guarantee Make Whole Payment figure of $818,466 (retail) reported in Docket No. E999/AA-15-611 for the 2014-2015 AAA reporting period included an adjustment of $1,571,138.25 that was made for the prior reporting period (2013-2014, specifically, March 2014). Absent this adjustment, the Real Time Revenue Sufficiency Guarantee Make Whole Payment for the 2014-2015 period would have been ($752,672.51) (retail). This figure compares well with the ($511,107) reported in Docket No. E999/AA-16-523 for the 2015-2016 AAA reporting period given that the charge type varies with market conditions which were different for 2015-2016 when compared to 2014-2015.

> The Real Time Revenue Sufficiency Guarantee Make Whole Payment is allocated between Retail and Asset-based Wholesale in the following manner. For every hour in which a generation unit has energy sales that are allocated to Asset-based Wholesale, a portion of that hour's corresponding Real Time Revenue Sufficiency Guarantee Make Whole Payment is also allocated to Asset-based Wholesale. That portion is determined by taking the Asset-based Wholesale generation volume for that hour and dividing it by the total generation for that unit in that particular hour. That percentage is multiplied by that generation unit's same hourly amount for Real Time Revenue Sufficiency Guarantee Make Whole Payment to get the portion that is allocated to Asset-based Wholesale. All remaining Real Time Revenue Sufficiency Guarantee Make Whole Payments, after subtracting out the Asset-based Wholesale amount, are allocated to Retail.

Based on the above, the Department concludes that the $1,571,138.25 adjustment for FYE15 explains the large year-over-year decrease in in Real Time Revenue Sufficiency Guarantee Make Whole Payments assigned to retail ratepayers, and that the allocation method is reasonable.

c) Allocation of MISO Day 2 Charges

The Department notes that Xcel Electric's total net MISO Day 2 costs/(revenues) totaled ($12,059,939) for retail and asset-based wholesale/intersystem in FYE16.[58] Of this amount, $54,563,778 in net costs were assigned to retail and ($66,623,717) in net revenues were assigned to asset-based wholesale/intersystem.[59]

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*.[60]

The Department asked Xcel Electric in DOC Information Request No. 30 if Xcel had changed any of the allocation methods used to allocate MISO Day 2 charges between retail and asset-based wholesale during the 2015-2016 reporting period. Xcel Electric indicated that there have been no changes to the

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[58] Source: Xcel Electric's initial filing in Docket No. E999/AA-16-523, Part J, Section 5, Schedule 7, Page 13 of 13.
[59] *Id.*
[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.

allocation methods for MISO Day 2 charges between retail and asset-based wholesale during the 2015-2016 reporting period.

Based on our review, the Department recommends that the Commission accept Xcel Electric's MISO Day 2 reporting for FYE16.

2. Review of MP's MISO Day 2 Charges

Attachment 9 to Minnesota Power's FYE16 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 and the amounts allocated to its retail customers in FYE15 and FYE16 were significantly less than in prior years.

Table 7
Minnesota Power
MISO Day 2 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%

Source: Attachment 9 to MP AAA Reports

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. 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). These charge types are associated with MISO's new Ramp Capability Product, which was implemented on May 1, 2016. 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.

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 two new charge types included in MP's fuel clause, 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 billed via the Real Time Revenue Neutrality Uplift Amount, an existing charge type that is already included in the fuel clause.

Because the Ramp Capability Product relates directly to operating reserves and energy pricing, is similar to ancillary service, and its cost is recovered through the Revenue Neutrality Uplift charge, which is already recovered through the fuel clause, the Department concludes that it is reasonable for MP to include the Day-Ahead and Real-Time Ramp Capability Amounts in its fuel clause. If those two new charge types were to be excluded from the fuel clause, 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 revenues.

The Department reviewed Minnesota Power's MISO Day 2 charges as reported in Attachment 9 to its FYE16 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*.[61] Because those allocation methods have not changed, the Department will describe them only briefly in this report.

Minnesota Power allocates energy-related charges (including several MISO Day 2 charges) using an algorithm which 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 it did not attempt to audit or verify the result of Minnesota Power's algorithm for allocating energy costs.

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

Based on our review, the Department recommends that the Commission accept Minnesota Power's MISO Day 2 reporting for FYE15.

3. Review of OTP's MISO Day 2 Charges

OTP has allocated its MISO Day 2 charges across three categories historically. These categories consist of retail, asset-based wholesale and non-asset-based wholesale. OTP has also referred 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 OPTW settlement standards. MISO Day 2 charges for non-asset-based wholesale are billed separately under the OTPD statement. A summary of MISO Day 2 charges assigned to the three categories is provided in Part H, Section 3, Attachment K of OTP's 2015-2016 AAA Report. The Department notes that amounts and total reflected in Attachment K are at the total Company level and not the Minnesota jurisdictional level.

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

Table 8: Otter Tail Power
Total MISO Day 2 Charges Assigned to Retail (Millions)

AAA Reporting Period	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016
Revenues	$87.0	$113.8	$173.1	$102.6	$70.8
Costs	$115.0	$145.2	$215.3	$142.7	$111.5
Net Costs	$28.0	$31.4	$42.2	$40.1	$40.7

The Department notes that one of the drivers for the level of OTP's MISO Day 2 charges is weather. The increase in net costs between 2012-2013 and 2013-2014 was driven in part by the extreme cold OTP's service territory experienced during the winter of 2013-2014. OTP's net costs for the 2015-2016 reporting period are in-line with those experienced in prior years. In response to Department Information Request No. 40, OTP explained: "lower average Locational Marginal Prices (LMPs) have influenced (lowered) the amount of OTP generation cleared in the market; however this also means that OTP was able to purchase cheaper energy for our customers from the wholesale energy market as compared to generating at our units."

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]

[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.

In previous AAA dockets, OTP has responded to annual information requests asking if there were no changes in its allocation method for MISO charges since its previous report. In the instant docket, the Department again requested that OTP explain whether any of the Company's allocation methods have changed during the 2015-2016 reporting period, and if so, what the nature of these charges were and the effect these changes have had on the charges assigned to various customer categories in the 2015-2016 AAA Report. OTP responded that there were no changes to the allocation methods used during the 2015-2016 period.

The Department also reviewed OTP's MISO bills to reconcile the billing amounts shown in OTP's monthly allocation tables in Part H, Section 3, Attachment K of OTP's initial filing. The Department found no issues with the calculations.

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

Table 9: Xcel Electric
Minnesota Asset-Based Margins (in millions)[63]

AAA Reporting Period	FYE12	FYE13	FYE14	FYE15	FYE16
Asset-Based Margins	$4.8	$7.9	$7.2	$4.0	$4.0

The Department reviewed Xcel Electric's asset-based margins for FYE16 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-15-611, the Department selected a monthly asset-based margin amount for testing. Specifically, the Department selected the asset-based margin of $6.033 million for February 2016[64] and tied this back to Xcel Electric's FCA. The Company provided the following in its response to DOC Information Request No. 33:

[63] Per Xcel Electric's Response to DOC Information Request No. 35, Attachments A-B; includes monthly true-up amounts.
[64] Source: Xcel Electric's initial filing in Docket No. E999/AA-16-523, Part J, Section 5, Schedule 7, Page 8 of 13.

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The $6.033 million reported in our 2016 AAA filing is a portion of the total asset based revenues prior to adjustment for the expense related to the revenues and jurisdictional allocations. Various Cost of Goods Sold expenses are deducted from the total revenue to calculate the margins. The Minnesota jurisdictional portion of the February MISO Day 2 asset revenues (credited to Minnesota ratepayers in the April 2016 fuel clause adjustment) was $943,652.

Please see below for additional detail:

Minnesota Asset Based Margin Sharing	(Feb 2016) $- millions	
(1) MISO Day 2 and ASM Intersystem Asset Based Revenue	$	6.0
(2) Non-MISO Asset Based Revenue	$	0.7
(3) Total Asset Based Revenue (1)+(2)	$	6.7
(4) Less: Cost of Goods Sold	$	5.0
(5) NSP System Asset Based Margins (3)–(4)	$	1.7
(6) Less: Ratepayer Sharing (*)	$	**1.1**
(7) Less: Other Jurisdictions Specific Adjustments	$	0.3

(8) Other Jurisdictions' Pass-Through/Company Retention	$ 0.3
* **Ratepayer Sharing Detail**	
Minnesota Jurisdiction	$ 1,214,917
Less: Other Jurisdictions Specific Adjustments	$ 271,265
Minnesota Net Portion	**$ 943,652**
Other NSP Jurisdictions	$ 181,142
Total NSP Ratepayers Sharing	**$ 1,124,794**

The Department traced the Minnesota Net Portion amount of $943,652 to Xcel Electric's April 2016 Fuel Clause Adjustment Report filed on March 31, 2016 in Docket No. E002/AA-16-274.[65] Based on our review, the Department concludes that Xcel Electric's asset-based margins appear to be reasonable.

2. MP

The table below summarizes MP's actual wholesale asset-based margins over the period 2009 through 2016, 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 eight-year period ($303.6 million) exceeds its total credits ($294.2 million) over the same period by 3.2 percent. The Department will continue to monitor MP's wholesale margins in future AAA filings.

[65] See Attachment 3, Page 1 of Xcel Electric's April 2016 Fuel Clause Adjustment Report.

Table 10: Minnesota Power
Wholesale Asset-Based Margins
2009-2016

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	25.3%
8 Yr. Total	$303.6	$294.2	$9.4	3.2%

Sources:

Actual Margin:

2009-2015: DOC August 25, 2016 *Review of the 2014-2015 Annual Automatic Adjustment Reports Part II, page 15.*

2016 Actual: MP Response to DOC Information Request No. 9 in the instant proceeding.

Revenue Credit in Base Rates:

2009: May 4, 2009 Order in Docket No. E015/GR-08-415

2010-2016: November 2, 2010 Order in Docket E015/GR-09-1151

3. OTP

As part of our review, the Department selected and reconciled a month of MISO Day 2 charges related to asset-based margins. The Department asked OTP, in DOC Information Request No. 37, for the support for the months of May and June 2016 for the development of the asset-based margins included on the August 2016 Energy Adjustment Rider. Based on our review of OTP's response, the Department concludes that OTP's asset-based charges for those two months appear reasonable. As a result, the Department concludes that OTP's approach for determining asset-based margins is reasonable.

OTP stated in its filing at Part H, Section 2 that, "As of January 1, 2015 the Company discontinued all Non-Asset-Based (non-retail) trading activities." The Department asked OTP, in DOC Information Request No. 38, for the basis for that decision. OTP replied:

> In August of 2014, the Company made a business decision to eliminate it Non-Asset Based trading activities. Some of the major factors contributing to that decision at that time, included:
>
> - Maturation of the MISO wholesale energy markets and available history of price spreads worked to shrink profit margins (*i.e.*, market became more efficient).
> - Reduced natural gas pricing contributed to less price volatility.
> - Reduction of active trading organizations.
> - Steady decrease in margins over the last decade.
>
> The Factors listed above, combined with the expenses of operating the Non-Asset Based trading activities, resulted in conditions where the decreasing margin potential could not justify the associated trading risks. As a result, a decision was made to eliminate Non-Asset Trading activities.

The Department notes that this information provided in this information request response is consistent with the Retail/Asset-Based/Non-Asset-Based information included in Part H, Section 3, Attachment K included in the filing. Except for some miscellaneous charges, OTP apparently did not transact any business for this category in FYE16.

The Department reviewed OTP's asset-based margins to ensure that these margins were returned to ratepayers via the FCA. Based on our review, the Department concludes that OTP's asset-based margins appear to be reasonable.

E. DOC 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 filings 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, Offer Cap Rulemaking, and Prorated Accumulated Deferred Income Tax issue.

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, the less-than-transparent nature of MISO billings in allocating between retail and asset-based wholesale transactions and some of the utilities' fuel clause ratemaking processes. Nonetheless, based on our review, the Department recommends that the Commission accept the utilities' MISO Day 2 reporting for FYE16.

The Department intends to continue to audit the MISO Day 2 charges and allocations between retail and wholesale customers in future AAA filings. The Department includes a list of all its recommendations formulated at this time, including recommendations for this MISO Day 2 section, below in the recommendations section.

VIII. 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 Development 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. M-08-528 (Commission's August 23, 2010 ASM Order) approved Xcel Electric's, MP's, and Interstate Electric's ASM accounting and recovery via the FCA and required reporting requirements as follows (the Department notes that OTP's ASM was approved via their rate case in 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.

New Ramp Product

The Department notes that, beginning in May 2016, MISO implemented new Ramp Capability Product, and with it, two new charge types: 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.

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 two new charges, the Day Ahead and Real Time Ramp Capability Amounts, are the charge types through which MISO market participants that provide ramp capabilities are compensated. The cost of providing ramp capabilities is allocated across all load and exports in the MISO energy market and billed via the Real Time Revenue Neutrality Uplift Amount, an existing MISO Day 2 charge type that is already included in the fuel clause.

Because the Ramp Capability Product relates directly to operating reserves and energy pricing, is similar to ancillary service, and its cost is recovered through the Revenue Neutrality Uplift charge, which is already recovered through the fuel clause, the Department concludes that it is reasonable for utilities to include the Day-Ahead and Real-Time Ramp Capability Amounts in the fuel clause. If those two new charge types were to be excluded from the fuel clause, 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 revenues.

MP included the two new charge types, Day Ahead and Real-Time Ramp Capability Amounts, in its fuel clause beginning with the implementation of the ramp capability product on May 1, 2016. The Department requests that Xcel and OTP explain in reply comments whether they included Day Ahead and Real-Time Ramp Capability Amounts in their fuel clauses.

B. XCEL ELECTRIC

Xcel Electric provided its ASM review in its FYE16 AAA filing in Part J, Section 5, Schedules 8 to 13 and in Part J, Section 6 as required by the Commission's August 23, 2010 Order in Docket M-08-528. Specifically, Xcel Electric stated the following regarding overall ASM market performance:[66]

> During the 2015-2016 AAA Period, MISO continued to operate the electric system reliably and has exceeded compliance thresholds for all North American Electric Reliability Corporation (NERC) reliability standards to which they are subject. The MISO Independent Market Monitor, which is tasked with monitoring both the behavior of Market Participants and the operation of the market, noted in its monthly reports that temperatures for the 2015-2016 AAA period were generally mild and summer 2015 loads were consistent with recent summers of 2014 and 2013, except for extreme heat in the South Region that led to several Hot Weather Alerts and a new all-time South Region peak load. Winter 2016 was characterized by above normal temperatures causing average load for winter 2016 to decrease 6.0% relative to winter 2015. Energy prices for the 2015 summer months were relatively low as natural gas prices declined 33% relative to 2014 summer prices. The 3-month average Day-Ahead LMP for summer 2015 was \$26.63/MWh and the 3-month average Real-Time LMP was \$26.06/MWh. The average Day-Ahead and Real-Time system-wide LMPs for the 2016 winter season were \$21.60/MWh and \$21.12/MWh respectively, a decrease of approximately 28% from the 2015 winter averages. Energy prices were at relatively low levels, mainly driven by low gas prices with Henry hub gas prices averaging \$2.09/MMBtu; a decline of 39.0% compared to last

[66] Source: Xcel Electric's initial filing in Docket No. E999/AA-16-523, Part J, Section 6, Page 1 of 4.

> winter and Power [*sic*] River Basin coal prices averaged $0.97/MMBtu; a decline of 22.8% compared to winter 2015. Also, MISO set a new wind generation record of 13.1 GW in February compared to a winter 2015 peak wind output of 11.9 GW. [Footnote omitted]

The Department notes that Xcel Electric's total net ASM charges/(revenues) totaled $21,931,080 for retail and asset-based wholesale/intersystem in FYE16.[67] Of this amount, $23,003,087 in net costs were assigned to retail and ($1,072,006) 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 11: Xcel Electric
Total MISO ASM Charges Assigned to Retail (in millions)

AAA Reporting Period	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016
Net Costs	$3.5[68]	$13.9[69]	$24.7[70]	$23.5[71]	$24.6[72]	$23.0[73]

The Department notes that Xcel Electric's retail ASM costs increased over time and have been fairly consistent around $23 to $24 million for FYE13 to FYE16.

Xcel Electric also provided a calculation of its net savings related to ASM for FYE16.[74] Xcel Electric shows net ASM savings of $6.7 million for the total NSP system and $5.0 million for the Minnesota 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 did not include any additional benefits that have accrued to ratepayers for the reduction in regional regulatory reserve requirements.

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[67] Source: Xcel Electric's initial filing in Docket No. E999/AA-16-523, Part J, Section 5, Schedule 13, Page 13 of 13.
[68] Source: Xcel Electric's initial filing in Docket No. E999/AA-11-792, Part J, Section 5, Schedule 13, Page 13 of 13.
[69] Source: Xcel Electric's initial filing in Docket No. E999/AA-12-757, Part J, Section 5, Schedule 13, Page 13 of 13.
[70] Source: Xcel Electric's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 13, Page 13 of 13.
[71] Source: Xcel Electric's initial filing in Docket No. E999/AA-14-579, Part J, Section 5, Schedule 13, Page 13 of 13.
[72] Source: Xcel Electric's initial filing in Docket No. E999/AA-15-611, Part J, Section 5, Schedule 13, Page 13 of 13.
[73] Source: Xcel Electric's initial filing in Docket No. E999/AA-16-523, Part J, Section 5, Schedule 13, Page 13 of 13.
[74] Source: Xcel Electric's initial filing in Docket No. E999/AA-16-523, Part J, Section 6, Page 2 of 4.

1) 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 $696,947 in FYE15 to $679,156[75] in FYE16, a decrease of $17,791.

According to Xcel Electric, a certain level of EDEDC is unavoidable given the current design of the ASM market because the benefits of offering resource flexibility and the potential costs of missing targets are appropriately weighed against procuring reserves elsewhere in the market or other NSP resources. Xcel Electric stated that its ASM net benefit calculation is a measure of the extent to which Xcel Electric has struck the appropriate balance between too much or too little flexibility being offered to MISO. Xcel Electric stated that its ASM net benefit of $6.7 million would not have been achievable if Xcel Electric had been offering ramp rates for enough units to all but eliminate the chance of incurring EDEDC charges. The Company also stated that:

> 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.
>
> In December 2012, MISO implemented changes in accordance with FERC Order 755 by adding a regulation mileage product to financially compensate for actual generator movement. An increase in EDEDC charged to the Company began in January 2013, which is attributed to the overall rate increase associated with the addition of the mileage component and higher LMPs. This increase

[75] Source: Xcel Electric's initial filing in Docket No. E999/AA-16-523, Part J, Section 6, Page 3 of 4.

> was offset by an increase in the revenues received by the Company for Regulation. During the period of July 2015 through June 2016, EDEDC charges have declined by $17,791 as compared to the 2015 AAA period, ending June 30, 2015.

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

2) Contingency Reserve Deployment Failure Charges (CRDFC)

Xcel Electric provided its monthly Contingency Reserve Deployment Failure Charges (CRDFC) for FYE16 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 $4,996 in FYE15 to $22,352 in FYE16. Regarding its FYE16 CRDFC, Xcel stated that:

> Part J, Section 6, Schedule 3 shows NSP incurred a total of $22,352 in CRDFC during the 2015-2016 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 if MISO has 15 minutes to meet the standard or less than 10 minutes.
>
> In short, CRDFCs are prudently incurred as NSP strives for the benefit 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.

Based on the above, the Department concludes that Xcel Electric's CRDFC charges appear reasonable and recommends that the Commission accept the Company's ASM reporting and allocations.

C. MP

MP addresses ASM costs and benefits in Attachment 10 to its FYE16 AAA Report. MP reported a net cost of $82,782 for FYE16, compared to net costs of $161,920 and $303,890 for FYE15 and FYE14, respectively. The Department reviewed MP's ASM charges and concludes that they are reasonable.

The Department notes that MP's real time excessive deficient energy deployment charge amount decreased to $60,829 in FYE16 from $78,916 in FYE15, and that MP incurred no contingency reserve deployment failure charges during FYE16, compared to charges of $288 and $2,757 in FYE15 and FYE16, respectively.

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.

Attachment 10-C, page 6 of 19 of Minnesota Power's filing compares MP's MISO Schedule 17 charges prior to the start of the ASM market to its Schedule 17 charges in FYE16. In FYE16, average monthly MISO Schedule 17 charges were $149,093, or $8,170 higher than the average monthly charges prior to the start of the ASM market. This equates to an average monthly increase of $0.00256 per MWh.

The Department recommends that the Commission accept Minnesota Power's ASM reporting.

D. OTP

In Part H, Section 4, Attachment L its FYE16 AAA Report, OTP provided its ASM information as required by the Commission's August 23, 2010 Order in Docket M-08-528. OTP's Schedule 1 shows that OTP is a net seller of ASM products (Regulation, Spinning Reserve, and Supplemental Reserve). As a result, ASM provided net benefits of $50,820 to Minnesota ratepayers in 2015-2016. OTP allocates all ASM charges on a per-MWh approach, netting costs and benefits of the various charges.

In Department Information Request No. 41 the Department asked OTP why ASM net benefits decreased from $204,356 in 2013-2014 to $50,820 in 2015-2016. The Company explained: "The revenues associated with ASM benefits are tied to plant output and availability. When generators are unavailable, de-rated, or not committed due to market pricing, their ability to generate ASM revenue is greatly reduced." This explanation is consistent with OTP's response regarding its overall MISO charges.

The Department recommends that the Commission accept OTP's ASM reporting.

IX. FUEL COSTS AND EFFECTS ON CUSTOMER BILLS

Attachment E9 shows various aspects of fuel charges and the effects on customers' bills for informational purposes.

1. Average Residential Bills for 2015

The graph on page 1 of 4 of Attachment E-9 illustrates the monthly average bills for residential customers in calendar year 2015. The information includes customer charges, energy charges, fuel clause adjustments, and Conservation Improvement Program (CIP) surcharges (as described on pp. 3-4 of Attachment E-9). Overall, Otter Tail Power had the highest average monthly residential bill of $88.67, followed by Dakota Electric at $83.86, Xcel Electric at $76.21 and Minnesota Power with the lowest average of $64.30 per month.

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

The graph on page 2 of 4 of Attachment E-9 shows the amounts that residential customers paid during calendar year 2015 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 11.91¢/kWh, Xcel Electric with an average of 10.67¢/kWh, Otter Tail with an average of 8.35¢/kWh, and Minnesota Power 7.45/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.

X. RECOMMENDATIONS FOR MISO DAY 2 AND ASM

As a result of the Department's review of the effects of the MISO Day 2 market, including Asset-Based Margins, on Minnesota ratepayers the Department recommends the following:

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

As a result of the Department's review of the effects of the Ancillary Services Market (ASM) on Minnesota ratepayers, the Department recommends the following:

- The Department recommends that the Commission accept Xcel Electric's ASM reporting.
- The Department recommends that the Commission accept MP's ASM reporting.

- The Department recommends that the Commission accept OTP's ASM reporting.

In addition, the Department requests that Xcel and OTP explain in reply comments whether they included Day Ahead and Real-Time Ramp Capability Amounts in their fuel clauses.

XI. ALL RECOMMENDATIONS AND REQUESTS FOR ADDITIONAL INFORMATION

A. RECOMMENDATIONS

The Department suggests two possible industry standards for the Commission to consider putting in place, if the FCA regulations continue to operate as they currently do, namely:

- Hold utilities at least partially if not fully responsible for incremental costs of replacement power due to forced outages caused by improper work by contractors, and
- Hold utilities financially responsible for replacement power costs due to any failure to remove all foreign material from generation facility work areas.

The Department recommends that the Commission accept the compliance filings required by Commission Order, as discussed above in Section III, items A through M.

The Department recommends that the Commission accept the utilities' MISO Day 2 reporting.

The Department recommends that the Commission accept the utilities' ASM reporting.

B. ADDITIONAL INFORMATION

Minnesota Power

The Department requests that MP provide a narrative in reply comments explaining and discussing the auditor's report exceptions related to the difference between the "average monthly cost of fuel consumed per ton" and the "average monthly cost of fuel purchased per ton," with enough details to allow the Commission to make a determination regarding the reasonableness of the corresponding energy costs (to be identified by MP).

Xcel Electric

The Department requests that Xcel Electric provide in reply comments a discussion of the measures it has taken to avoid the reoccurrence of incorrect data entry and its failure to identify and justify all material true-up calculation adjustments. The Department requests that Xcel Electric file the correct

Attachment 1, page 2, in the relevant monthly FCA dockets (16-274, 16-372 and 16-492) with a narrative explaining the correction made.

The Department also requests that Xcel Electric explain in reply comments whether they included Day Ahead and Real-Time Ramp Capability Amounts in their fuel clauses.

Otter Tail Power

The Department requests that OTP explain in reply comments whether they included Day Ahead and Real-Time Ramp Capability Amounts in their fuel clauses.

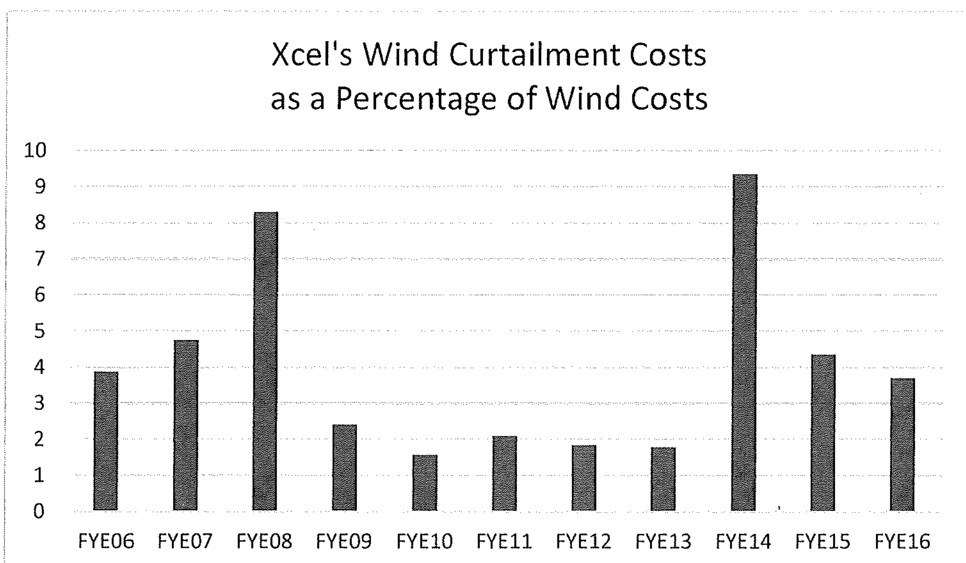
/lt

Attachment E1
Docket No. E999/AA-16-523

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	3.71
Min	1.58
Max	9.37

Source:
Xcel's monthly FCA input data emails.



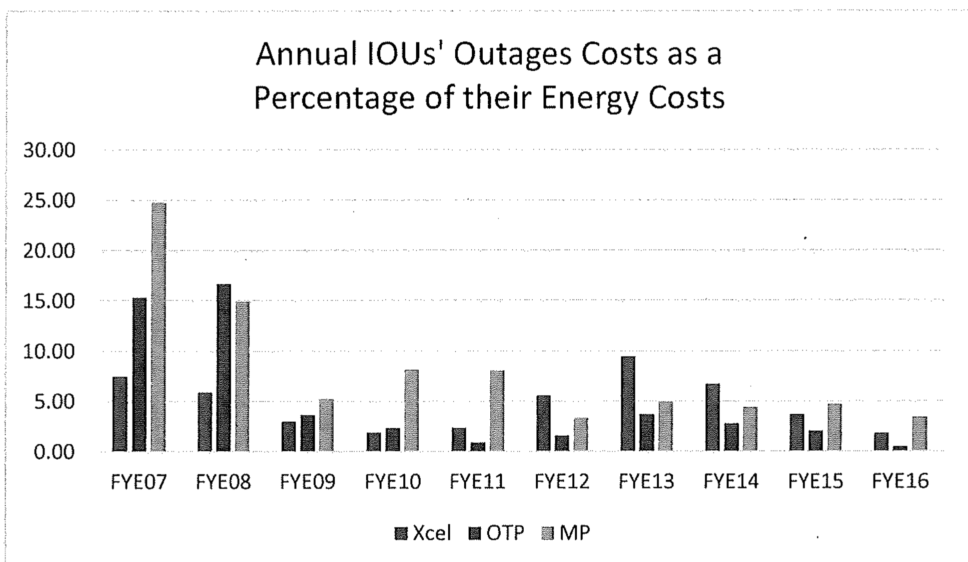
Attachment E2

Docket No. E999/AA-16-523

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	0.54	3.46
Min	1.88	0.54	3.37
Max	9.50	16.70	24.80

Source: IOUs' monthly FCA input data emails.



Attachment E3
Docket No. E999/AA-16-523
Maintenance Expenses of Generation Plants

Actual Maintenance Expense

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2013-2015 Average
Xcel	144,317,233	128,411,240	150,857,274	169,389,054	179,143,695	176,598,518	196,531,281	207,105,781	199,893,336	201,176,799
OTP	10,444,219	12,981,917	12,911,918	10,505,153	12,014,142	11,911,878	11,415,197	16,587,034	14,646,839	14,216,357
MP	34,498,017	29,819,678	29,031,118	45,307,981	45,683,871	42,970,316	36,565,651	37,626,273	33,446,967	35,879,630

	Most Recent Rate Case	Test Year	Test Year Budgeted Maintenance Expense	2013-2015 Avg. Actual Maintenance Expense	Difference: Actual less Budgeted
Xcel	GR-13-868	2014	193,685,566	201,176,799	7,491,233
OTP	GR-10-276	2009	13,142,718	14,216,357	1,073,639
MP	GR-09-1151	2010	33,619,194	35,879,630	2,260,436

Attachment E4
Docket No. E999/AA-16-523

DEA	kWh Sales (a)	MN Energy Costs (b)	MN Recovery (c)	MN Energy Costs ($/kWh) (d)	MN Recovery ($/kWh) (e)
Jul-15	170,713,493	$ 17,058,425	$ 15,189,141	0.100	0.089
Aug-15	185,881,575	$ 16,448,476	$ 16,596,020	0.088	0.089
Sep-15	173,002,813	$ 11,889,790	$ 13,740,092	0.069	0.079
Oct-15	144,808,238	$ 8,882,758	$ 11,489,247	0.061	0.079
Nov-15	127,908,747	$ 9,311,456	$ 10,106,314	0.073	0.079
Dec-15	138,137,584	$ 12,083,878	$ 10,900,415	0.087	0.079
Jan-16	154,655,670	$ 12,296,819	$ 12,162,832	0.080	0.079
Feb-16	151,886,583	$ 11,005,502	$ 11,953,276	0.072	0.079
Mar-16	139,580,905	$ 9,649,900	$ 10,842,321	0.069	0.078
Apr-16	128,371,516	$ 8,505,170	$ 9,916,498	0.066	0.077
May-16	131,258,619	$ 10,496,123	$ 10,058,385	0.080	0.077
Jun-16	154,378,043	$ 16,736,243	$ 13,481,479	0.108	0.087
FYE15	1,800,583,786	144,364,540	146,436,020	0.080	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)

Attachment E5
Docket No. E999/AA-16-523

MP's FYE16 Over (Under) Recovery of Energy Costs

MP	kWh Retail & Firm Resale (a)	FCA Retail Sales (b)	System Costs (c)
Jul-15	777,882,100	637,422,906	$13,899,106
Aug-15	777,570,107	638,073,336	$17,426,603
Sep-15	768,766,293	637,235,169	$15,487,972
Oct-15	761,958,596	632,575,218	$15,084,469
Nov-15	758,118,664	623,934,062	$12,551,073
Dec-15	792,081,100	644,583,741	$13,215,870
Jan-16	839,391,733	682,718,250	$15,648,452
Feb-16	796,379,336	654,339,373	$14,453,192
Mar-16	803,181,401	664,182,613	$13,640,574
Apr-16	709,737,339	605,255,384	$12,955,648
May-16	743,445,229	618,276,468	$14,928,168
Jun-16	716,258,389	595,284,605	$14,413,387
FYE16	9,244,770,287	7,633,881,125	$ 173,704,514

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

Minnesota base cost ($/kWh): July 15 - June 16 0.01018

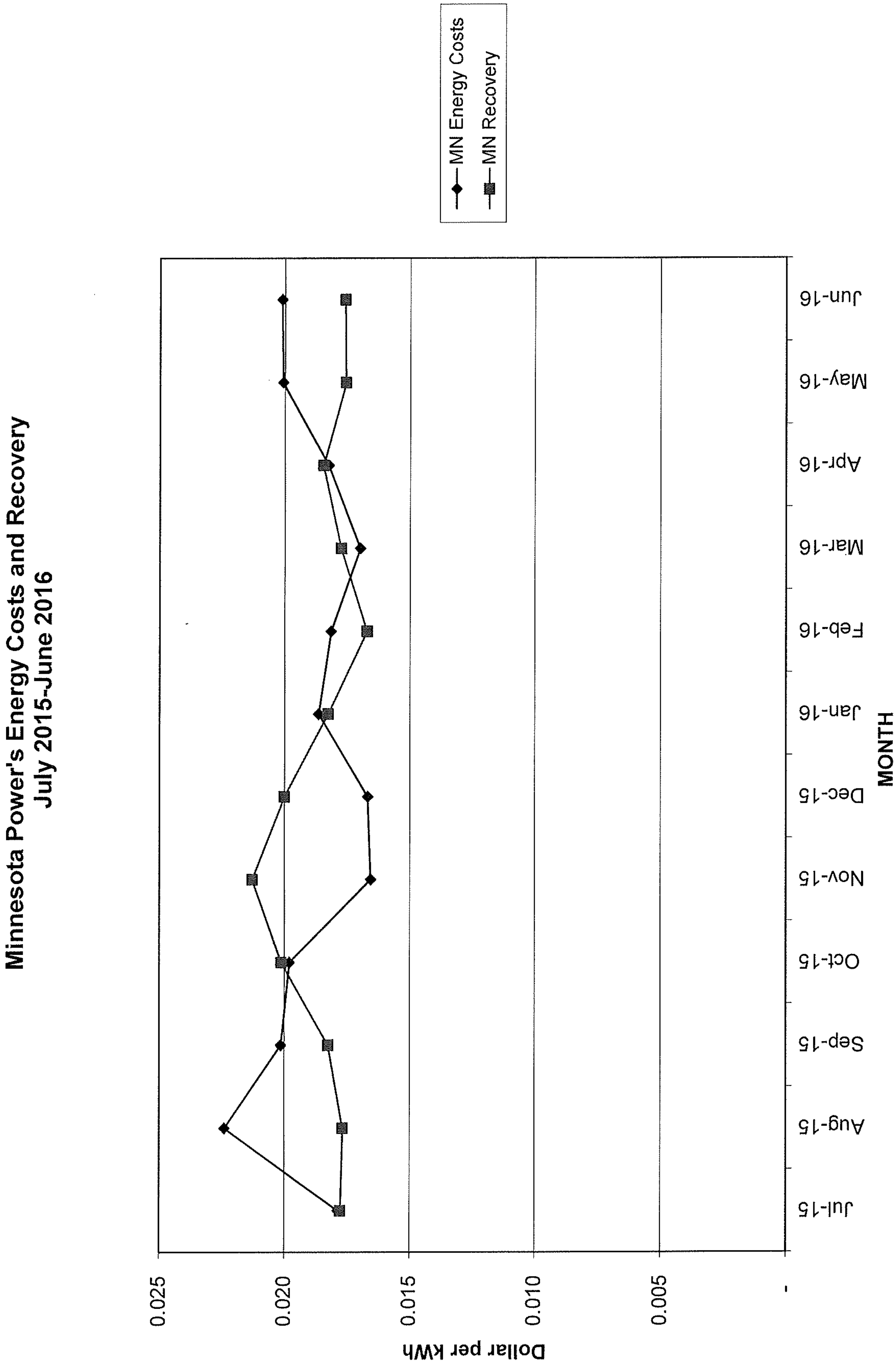
MP	FCA # 16 Recovery (d)	Old FCA # 16 Recovery (e)	Old FCA # 17 Recovery (f)	Base Cost Recovery (g)	MN Recovery (h)	MN Energy Costs (i)	Over(Under) Recovery (j)	MN Recovery ($/kWh) (k)	MN Energy Costs ($/kWh) (l)
Jul-15	4,830,918	$ -	-	$ 6,495,173	$ 11,326,090	$ 11,390,747	$ (64,657)	0.018	0.018
Aug-15	4,765,955	$ -	-	$ 6,512,529	$ 11,278,484	$ 14,299,223	$ (3,020,739)	0.018	0.022
Sep-15	5,139,220	$ -	-	$ 6,498,307	$ 11,637,526	$ 12,840,289	$ (1,202,762)	0.018	0.020
Oct-15	6,297,306	$ -	-	$ 6,434,324	$ 12,731,631	$ 12,524,989	$ 206,641	0.020	0.020
Nov-15	6,936,096	$ -	-	$ 6,354,004	$ 13,290,099	$ 10,332,348	$ 2,957,751	0.021	0.017
Dec-15	6,323,828	$ -	-	$ 6,575,453	$ 12,899,282	$ 10,751,657	$ 2,147,625	0.020	0.017
Jan-16	5,488,159	$ -	-	$ 6,982,642	$ 12,470,801	$ 12,725,868	$ (255,067)	0.018	0.019
Feb-16	4,239,487	$ -	-	$ 6,696,297	$ 10,935,785	$ 11,876,260	$ (940,475)	0.017	0.018
Mar-16	5,003,518	$ -	-	$ 6,782,739	$ 11,786,257	$ 11,277,821	$ 508,436	0.018	0.017
Apr-16	4,992,487	$ -	-	$ 6,180,994	$ 11,173,481	$ 11,045,911	$ 127,571	0.018	0.018
May-16	4,565,104	$ -	-	$ 6,293,727	$ 10,858,831	$ 12,414,991	$ (1,556,160)	0.018	0.020
Jun-16	4,407,609	$ -	-	$ 6,065,256	$ 10,472,864	$ 11,977,126	$ (1,504,262)	0.018	0.020
FYE16	$ 62,989,687	$ -	$ -	$ 77,871,446	$ 140,861,132	$ 143,457,231	$ (2,596,098)	0.018	0.0188

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)

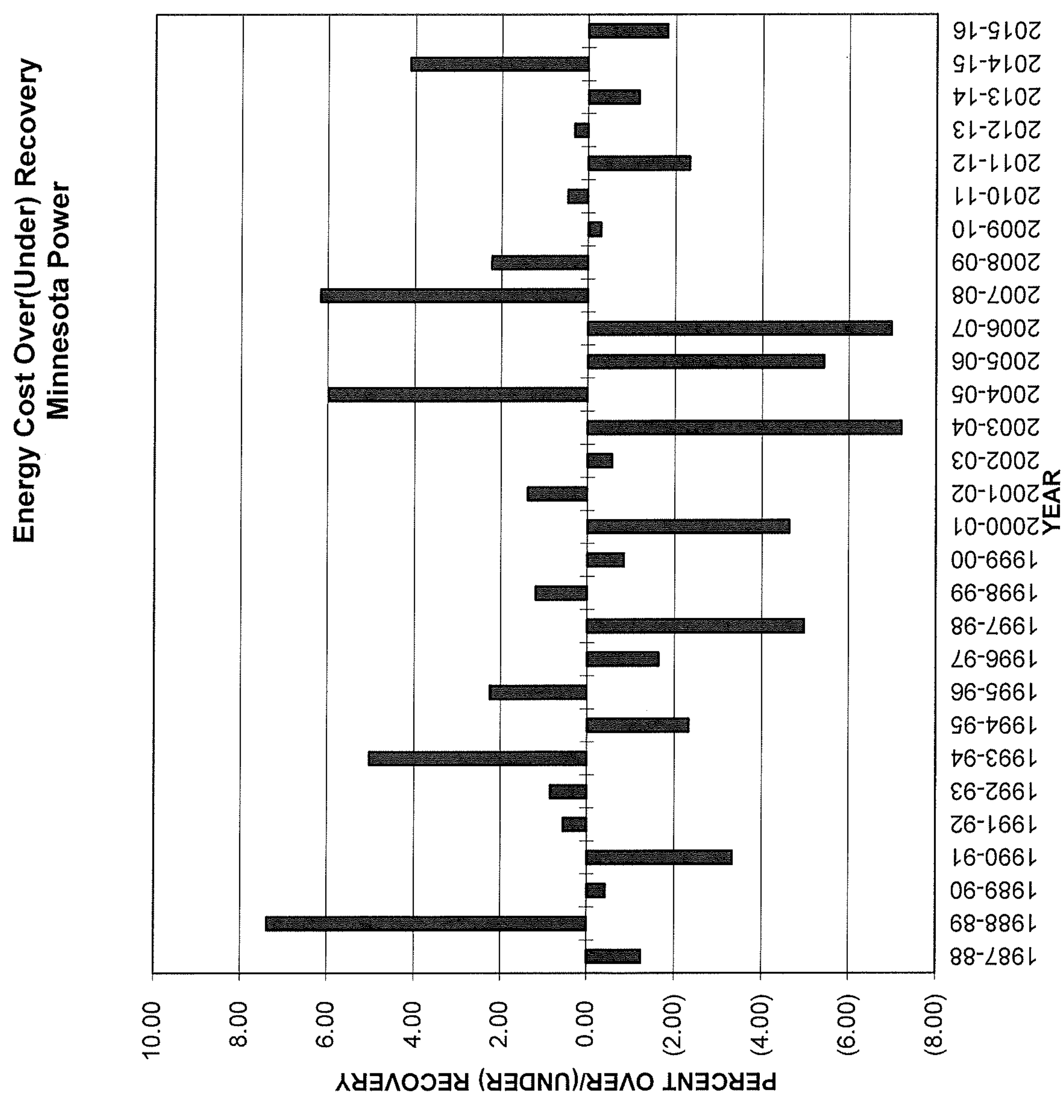
Total Company Recovery, July 2015 - June 2016, By Month

Month	**Minnesota Energy Costs** (a)	**Minnesota Recovery** (b)	**Over(Under) Recovery** (c)	**Over(Under) Percentage** (d)
July	$ 11,390,747	$11,326,090	($64,657)	(0.57%)
August	$ 14,299,223	$11,278,484	($3,020,739)	(21.13%)
September	$ 12,840,289	$11,637,526	($1,202,762)	(9.37%)
October	$ 12,524,989	$12,731,631	$206,641	1.65%
November	$ 10,332,348	$13,290,099	$2,957,751	28.63%
December	$ 10,751,657	$12,899,282	$2,147,625	19.97%
January	$ 12,725,868	$12,470,801	($255,067)	(2.00%)
February	$ 11,876,260	$10,935,785	($940,475)	(7.92%)
March	$ 11,277,821	$11,786,257	$508,436	4.51%
April	$ 11,045,911	$11,173,481	$127,571	1.15%
May	$ 12,414,991	$10,858,831	($1,556,160)	(12.53%)
June	$ 11,977,126	$10,472,864	($1,504,262)	(12.56%)
Total	**$ 143,457,231**	**$140,861,132**	**($2,596,098)**	**(1.81%)**

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


Minnesota Power's Energy Costs and Recovery
July 2015-June 2016
MN Energy Costs
MN Recovery
Dollar per KWh
0.025
0.020
0.015
0.010
0.005
-
MONTH
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
Jan-16
Feb-16
Mar-16
Apr-16
May-16
Jun-16

Percent


Energy Cost Over(Under) Recovery
Minnesota Power
PERCENT OVER/(UNDER) RECOVERY
10.00
8.00
6.00
4.00
2.00
0.00
(2.00)
(4.00)
(6.00)
(8.00)
YEAR
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

Attachment E6: Docket No. E999/AA-16-523
Page 1 of 2

OTP	kWh Retail & Firm Resale (a)	Sales Subject to FCA (kWh) (b)	System Costs (c)
Jul-15	334,042,722	173,850,633	$ 10,081,148
Aug-15	370,900,190	204,070,800	$ 10,637,667
Sep-15	364,584,007	202,307,495	$ 7,542,902
Oct-15	342,631,935	186,659,298	$ 8,085,740
Nov-15	359,045,181	190,496,284	$ 8,378,494
Dec-15	402,389,198	206,803,149	$ 10,462,288
Jan-16	479,963,658	242,300,867	$ 11,143,743
Feb-16	472,198,276	247,501,763	$ 9,687,483
Mar-16	434,673,233	230,702,205	$ 9,887,249
Apr-16	397,375,784	213,119,802	$ 7,699,140
May-16	349,198,168	195,433,968	$ 6,675,600
Jun-16	339,534,110	188,149,034	$ 8,771,716
FYE16	4,646,536,462	2,481,395,298	$ 109,053,170

Source (a): OTP's July 29, 2016 compliance report approved by the Commission's September 15, 2016 Order in Docket No. E017/M-03-30.
Source (b): OTP's July 29, 2016 compliance report approved by the Commission's September 15, 2016 Order in Docket No. E017/M-03-30.
Source (c): OTP's July 29, 2016 compliance report approved by the Commission's September 15, 2016 Order in Docket No. E017/M-03-30.

		7/15-4/15/16	4/16/16-6/16
MN Base Cost (($/kWh)		0.023163	0.02464

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-15	$ (299,666)	$ 4,026,902	$ 3,727,236	$ 5,383,647	$ (1,656,411)	0.021	0.031
Aug-15	$ (45,298)	$ 4,726,892	$ 4,681,594	$ 5,680,846	$ (999,252)	0.023	0.028
Sep-15	$ 739,732	$ 4,686,049	$ 5,425,781	$ 4,028,145	$ 1,397,636	0.027	0.020
Oct-15	$ 1,158,269	$ 4,323,589	$ 5,481,858	$ 4,318,037	$ 1,163,821	0.029	0.023
Nov-15	$ 306,571	$ 4,412,465	$ 4,719,036	$ 4,474,377	$ 244,659	0.025	0.023
Dec-15	$ (223,486)	$ 4,790,181	$ 4,566,695	$ 5,587,188	$ (1,020,493)	0.022	0.027
Jan-16	$ 73,026	$ 5,612,415	$ 5,685,441	$ 5,951,106	$ (265,665)	0.023	0.025
Feb-16	$ 385,700	$ 5,732,883	$ 6,118,583	$ 5,173,418	$ 945,165	0.025	0.021
Mar-16	$ 304,275	$ 5,343,755	$ 5,648,030	$ 5,280,099	$ 367,931	0.024	0.023
Apr-16	$ (360,838)	$ 5,062,985	$ 4,702,147	$ 4,111,581	$ 590,566	0.022	0.019
May-16	$ (596,058)	$ 4,815,493	$ 4,219,435	$ 3,564,978	$ 654,457	0.022	0.018
Jun-16	$ (655,653)	$ 4,635,992	$ 3,980,339	$ 4,684,370	$ (704,031)	0.021	0.025
FYE16	$ 786,574	$ 58,169,602	$ 58,956,176	$ 58,237,792	$ 718,385		0.023

Source (f): OTP's July 29, 2016 compliance report approved by the Commission's September 15, 2016 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)

Attachment E7
Docket No. E999/AA-16-523

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 Adj (g)	Balance (Cost-Revenues) (h)
Jul-15	$ 3,419,078	$ 3,347,986	$ 1,077,298	$ 80,942,036	$ 85,367,320	$ 76,026,700	$ 78,057	$ (5,843,485)
Aug-15	$ (4,629,421)	$ (4,555,604)	$ (4,474,045)	$ 79,220,757	$ 70,191,107	$ 74,169,835	$ (199,750)	$ (850,443)
Sep-15	$ (5,843,485)	$ (5,988,853)	$ (2,670,142)	$ 72,773,318	$ 64,114,323	$ 68,897,637	$ (173,332)	$ (1,233,503)
Oct-15	$ (850,443)	$ (848,728)	$ (3,763,352)	$ 67,934,469	$ 63,322,389	$ 60,167,119	$ -	$ (4,005,713)
Nov-15	$ (1,233,503)	$ (1,208,818)	$ (4,486,504)	$ 65,295,837	$ 59,600,515	$ 64,009,383	$ -	$ 3,175,365
Dec-15	$ (4,005,713)	$ (3,853,915)	$ (8,100,302)	$ 68,649,592	$ 56,695,375	$ 58,033,643	$ -	$ (2,667,445)
Jan-16	$ 3,175,365	$ 3,072,475	$ (305,714)	$ 68,285,361	$ 71,052,122	$ 64,591,209	$ -	$ (3,285,548)
Feb-16	$ (2,667,445)	$ (2,597,435)	$ 534,165	$ 62,250,760	$ 60,187,490	$ 58,067,383	$ -	$ (4,011,832)
Mar-16	$ (3,285,548)	$ (3,099,435)	$ (6,727,687)	$ 63,272,108	$ 53,444,986	$ 53,877,111	$ -	$ (2,853,423)
Apr-16	$ (4,011,832)	$ (3,825,109)	$ (1,545,575)	$ 57,537,326	$ 52,166,642	$ 50,266,305	$ -	$ (5,912,169)
May-16	$ (2,853,423)	$ (2,836,191)	$ (213,132)	$ 63,474,263	$ 60,424,940	$ 53,341,082	$ -	$ (9,937,281)
Jun-16	$ (5,912,169)	$ (5,993,003)	$ (2,597,232)	$ 71,035,902	$ 62,445,667	$ 62,167,569	$ (145,590)	$ (6,335,857)
FYE16		$ (28,386,630)	$(33,272,221)	$820,671,728	$ 759,012,876	$743,614,976		

(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): 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.
(h) = (a) - (e) + (f) + (g)

Note 1: DOC calculation showed that the Feb 2016 Balance of Unrecovered Expenses (line 12n of Attachment 1, page 3) should be -$4,787,555 instead of -$4,011,835, for a difference of $775,720. Xcel's January 10, 2017 response to discovery stated that the $775,720 was added to the true up to correct for an erroneous overcredit to retail customers in the March 2016 FCA.

Note 2:
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.

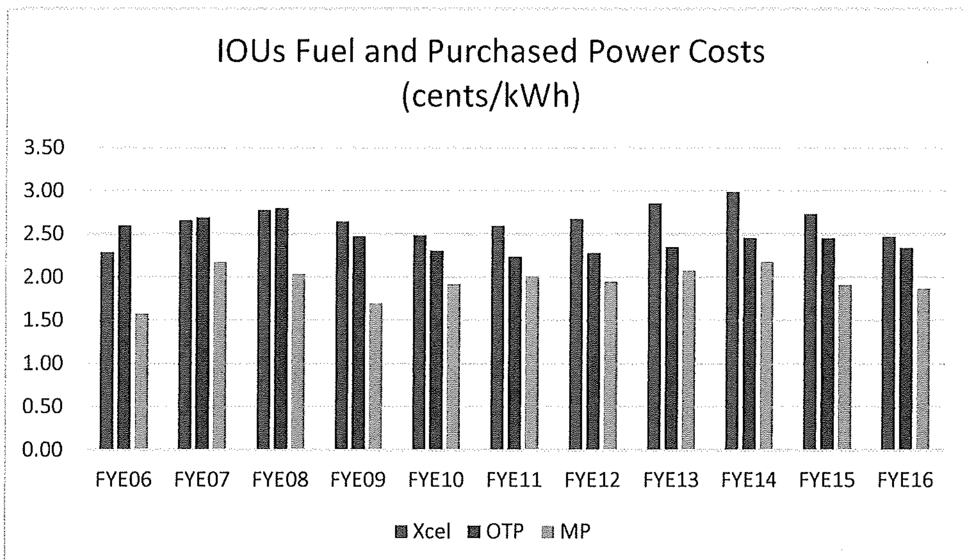
Attachment E8

Docket No. E999/AA-16-523

Utilities Fuel and Purchased Power Costs in cents per kWh

Cents/kWh	Xcel	OTP	MP
FYE06	2.29	2.60	1.58
FYE07	2.66	2.69	2.18
FYE08	2.78	2.81	2.04
FYE09	2.65	2.48	1.70
FYE10	2.49	2.31	1.92
FYE11	2.60	2.24	2.02
FYE12	2.68	2.29	1.95
FYE13	2.86	2.36	2.09
FYE14	2.99	2.46	2.19
FYE15	2.74	2.46	1.91
FYE16	2.47	2.35	1.88
Min	2.29	2.24	1.58
Max	2.99	2.81	2.19

Source: IOUs' monthly FCA input data emails.



Minnesota Electric Utilities' Average Residential Bills for 2015

Page 1 of 2

Xcel Electric		Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	2015 Monthly Av.
Av. residential monthly kWh usage		720	638	591	491	516	650	797	739	656	560	562	659	632
(1) Number of customers		1,118,891	1,119,993	1,120,837	1,121,853	1,121,623	1,121,729	1,121,196	1,121,931	1,122,522	1,124,279	1,125,245	1,125,968	13,466,067
(1) Residential sales (MWh)		806,056	714,408	662,016	550,475	579,227	729,668	893,139	829,526	736,301	629,881	632,804	741,854	8,505,355
(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 and Oct	0.0739	0.0739	0.0739	0.0739	0.0739	0.0739	0.0867	0.0867	0.0867	0.0867	0.0739			
June - Sep	0.0867													
Nov - Dec	0.0840											0.0840	0.0840	
En. Charge X kWh usage		$ 53.26	$ 47.16	$ 43.67	$ 36.28	$ 38.18	$ 56.40	$ 69.07	$ 64.11	$ 56.88	$ 41.42	$ 47.24	$ 55.34	
(2) Fuel Clause Adjustment ($/kWh)		0.03160	0.02707	0.02404	0.02950	0.02864	0.02753	0.02962	0.02484	0.02465	0.02605	0.02570	0.02324	
FCA X kWh usage		$ 22.76	$ 17.27	$ 14.20	$ 14.48	$ 14.79	$ 17.91	$ 23.60	$ 18.37	$ 16.17	$ 14.59	$ 14.45	$ 15.31	
CIP surcharge ($/kWh)														
(2) Jan-Sep 2015	$ 0.000545	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005				
(2) Oct-Dec 2015	$ 0.001386										$ 0.001386	$ 0.001386	$ 0.001386	
CIP surchrg. X customer's usage		$ 0.39	$ 0.35	$ 0.32	$ 0.27	$ 0.28	$ 0.35	$ 0.43	$ 0.40	$ 0.36	$ 0.78	$ 0.78	$ 0.91	
Total av. resid. monthly bill		$ 84.42	$ 72.77	$ 66.19	$ 59.02	$ 61.25	$ 82.67	$ 101.10	$ 90.88	$ 81.40	$ 64.79	$ 70.47	$ 79.57	$ 76.21
Av. Resid. energy charge + FCA ($/kWh)		10.55	10.10	9.80	10.34	10.26	11.42	11.63	11.16	11.14	10.00	10.97	10.72	10.67

(1) Source: Xcel Electric's 2016 Annual Jurisdictional Report, page E-29, April 29, 2016 (Docket No. 16-4).
(2) Source: Xcel Electric's response to IR 1 in Docket No. E999/AA-16-523.

Minnesota Power		Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	2015 Monthly Av.
Av. residential monthly kWh usage		1,045	757	910	584	566	555	686	647	564	620	673	841	704
(1) Number of customers		121,454	121,243	121,300	121,469	121,544	121,904	121,633	121,486	121,256	121,679	121,688	121,529	1,458,185
(1) Residential sales (MWh)		126,946	91,763	110,343	70,941	68,837	67,712	83,454	78,551	68,420	75,426	81,848	102,213	1,026,454
(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)														
0 to 300 kWh	0.05098	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	
301 to 500 kWh	0.06735	$ 13.40	$ 13.40	$ 13.40	$ 13.40	$ 13.40	$ 13.40	$ 13.40	$ 13.40	$ 13.40	$ 13.40	$ 13.40	$ 13.40	
501 to 750 kWh	0.08168	$ 20.34	$ 20.34	$ 20.34	$ 6.86	$ 5.42	$ 4.53	$ 15.20	$ 11.97	$ 5.25	$ 9.79	$ 14.10	$ 20.34	
751 to 1000 kWh	0.08445	$ 21.03	$ 0.58	$ 13.48									$ 21.03	
over 1000 kWh	0.08937	$ 4.04												
Total monthly energy charge		$ 74.10	$ 49.61	$ 62.52	$ 35.56	$ 34.12	$ 33.23	$ 43.90	$ 40.67	$ 33.95	$ 38.49	$ 42.79	$ 70.06	
(2) Fuel Clause Adjustment ($/kWh)		0.01143	0.00901	0.00768	0.00909	0.00890	0.00831	0.00811	0.00798	0.00862	0.01066	0.01190	0.01048	
FCA X kWh usage		$ 11.95	$ 6.82	$ 6.99	$ 5.31	$ 5.04	$ 4.62	$ 5.56	$ 5.16	$ 4.86	$ 6.61	$ 8.00	$ 8.81	
(2) CIP surcharge Jan-Oct	$ 0.004892													
Nov-Dec	$ 0.001909													
CIP surcharge X customer's bill		$ 5.11	$ 3.70	$ 4.45	$ 2.86	$ 2.77	$ 2.72	$ 3.36	$ 3.16	$ 2.76	$ 3.03	$ 1.28	$ 1.61	
Total av. resid. monthly bill		$ 99.16	$ 68.14	$ 81.96	$ 51.73	$ 49.93	$ 48.56	$ 60.82	$ 56.99	$ 49.57	$ 56.13	$ 60.08	$ 88.48	$ 64.30
Av. Resid. energy charge + FCA ($/kWh)		8.23	7.46	7.64	7.00	6.91	6.81	7.21	7.09	6.88	7.27	7.55	9.38	7.45

(1) Source: MP's 2015 Annual Jurisdictional Report, page E-29 extra, May 02, 2016. (Docket 16-4)
(2) Source: MP's response to IR 2 in Docket No. E999/AA-16-523.

Minnesota Electric Utilities' Average Residential Bills for 2015

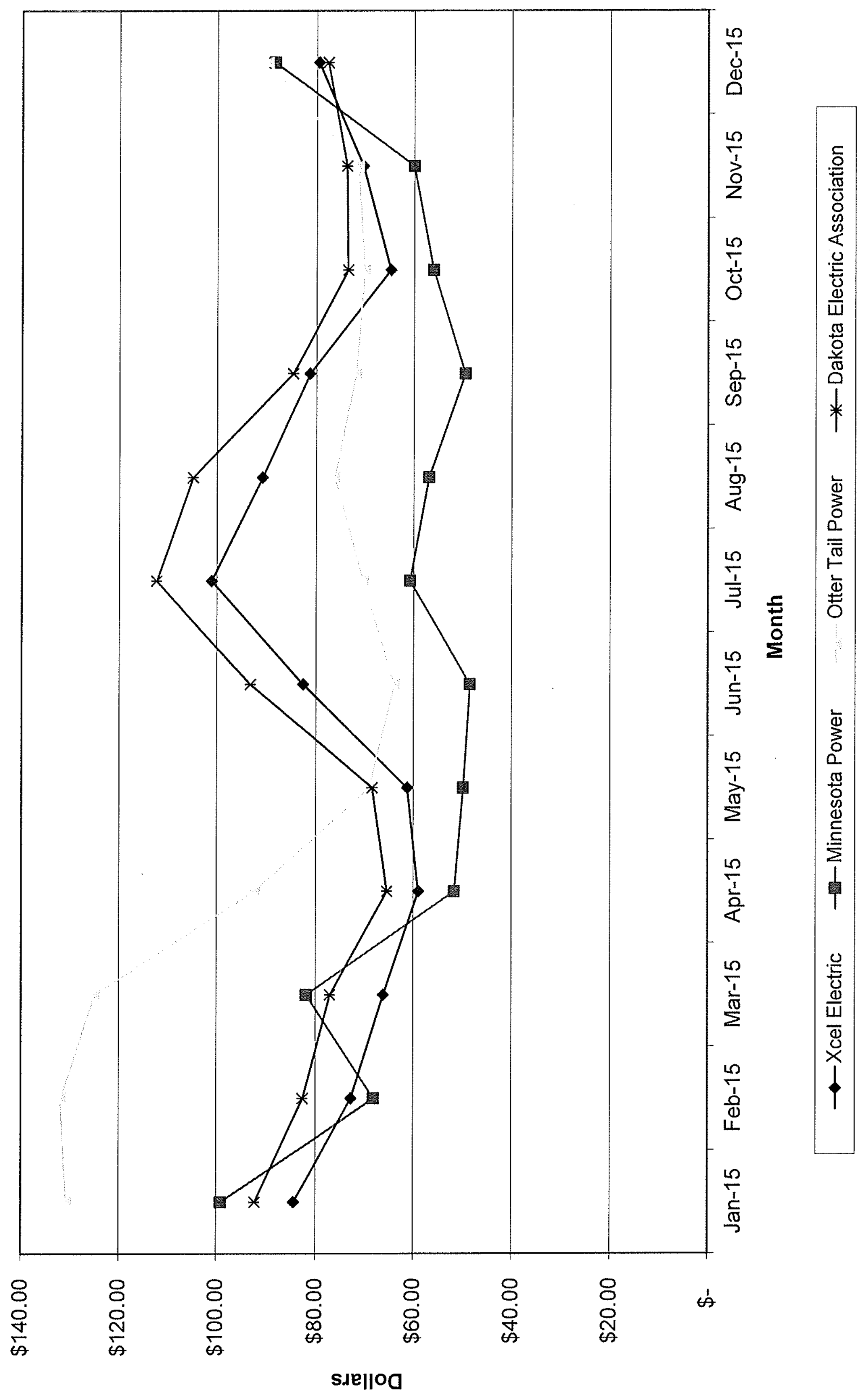
Otter Tail Power	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	2015 Monthly Av.
Av. residential monthly kWh usage	1,467	1,411	1,316	983	713	686	783	842	764	702	758	1,012	951
(1) Number of customers	47,403	47,491	47,571	47,556	47,635	48,651	48,703	48,751	48,848	48,368	47,588	47,752	576,317
(1) Residential Sales (MWh)	69,526	67,003	62,620	46,734	33,984	33,391	38,116	41,027	37,299	33,962	36,074	48,333	548,069
(2) Customer Charge	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	
(2) Energy charge ($/kWh)	0.08192	0.08192	0.08192	0.08192	0.08192	0.07976	0.07976	0.07976	0.07976	0.08192	0.08192	0.08192	
Total monthly energy charge	$ 120.15	$ 115.58	$ 107.84	$ 80.50	$ 58.44	$ 54.74	$ 62.42	$ 67.12	$ 60.90	$ 57.52	$ 62.10	$ 82.92	
(2) Fuel Clause Adjustment ($/kWh)	0.00127	0.00537	0.00642	0.00337	0.00289	0.00086	(0.00093)	0.00058	0.00307	0.00563	0.00096	(0.00166)	
FCA X kWh	$ 1.86	$ 7.58	$ 8.45	$ 3.31	$ 2.06	$ 0.59	$ (0.73)	$ 0.49	$ 2.34	$ 3.95	$ 0.73	$ (1.68)	
(2) CIP surcharge	0.00263	0.00263	0.00263	0.00263	0.00263	0.00263	0.00263	0.00263	0.00263	0.00287	0.00287	0.00287	
CIP surchrg. X customer's bill	$ 0.34	$ 0.35	$ 0.33	$ 0.24	$ 0.18	$ 0.17	$ 0.18	$ 0.20	$ 0.19	$ 0.20	$ 0.20	$ 0.26	
Total av. resid. monthly bill	$ 130.86	$ 132.00	$ 125.11	$ 92.56	$ 69.19	$ 64.00	$ 70.38	$ 76.31	$ 71.94	$ 70.17	$ 71.53	$ 89.99	$ 88.67
Av. Resid. energy charge + FCA ($/kWh)	8.32	8.73	8.83	8.53	8.48	8.06	7.88	8.03	8.28	8.76	8.29	8.03	8.35

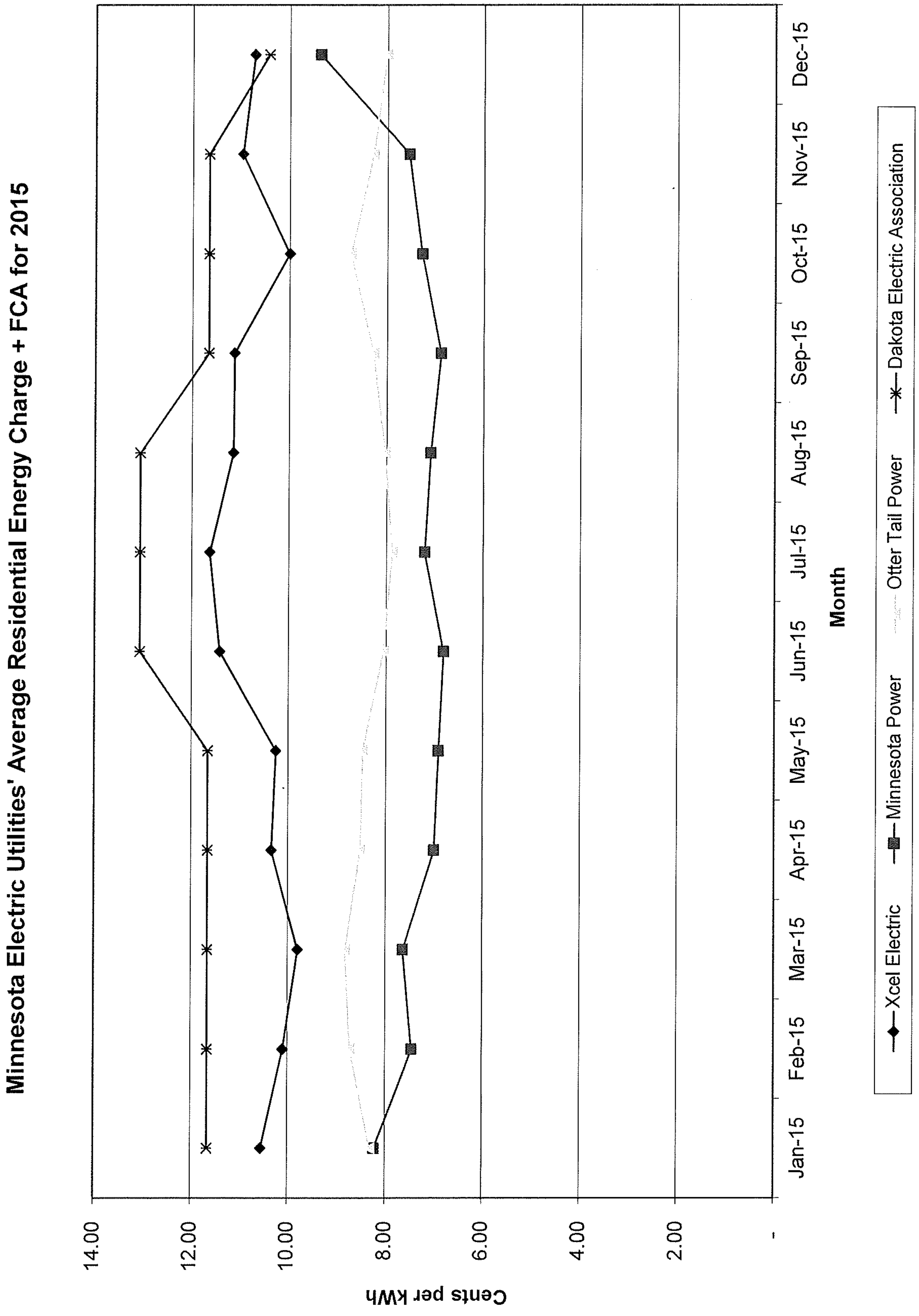
(1) Source: OTP's 2015 Annual Jurisdictional Report, page E-29, Apr 26, 2016. (Docket 16-4)
(2) Source: OTP's response to IR 3 in Docket No. E999/AA-16-523.

Dakota Electric Association	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	2015 Monthly Av.
(1) Av. residential monthly kWh usage	720	638	591	491	516	650	797	739	656	560	562	659	632
(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	$ 9.00	
(2) Energy Charge ($/kWh)	$ 0.10144	$ 0.10144	$ 0.10144	$ 0.10144	$ 0.10144	$ 0.11544	$ 0.11544	$ 0.11544	$ 0.10144	$ 0.10144	$ 0.10144	$ 0.10144	
En. Chrg. X kWh usage	$ 73.08	$ 64.71	$ 59.91	$ 49.77	$ 52.39	$ 75.09	$ 91.96	$ 85.35	$ 66.54	$ 56.83	$ 57.05	$ 66.83	
(2) Power Cost Adjustment (	0.0152	0.0152	0.0152	0.0152	0.0152	0.0152	0.0152	0.0152	0.0152	0.0152	0.0152	0.0028	
Power Cost Adj. X kWh	$ 10.95	$ 9.70	$ 8.98	$ 7.46	$ 7.85	$ 9.89	$ 12.11	$ 11.24	$ 9.97	$ 8.52	$ 8.55	$ 1.84	
(2) CIP & Property tax surcharge ($/kWh)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	-	
DSM surchrg. X customer's bill	$ 0.29	$ 0.26	$ 0.24	$ 0.20	$ 0.21	$ 0.26	$ 0.32	$ 0.30	$ 0.26	$ 0.22	$ 0.22	$ -	
Total av. resid. monthly bill	$ 92.32	$ 82.66	$ 77.13	$ 65.43	$ 68.44	$ 93.24	$ 112.39	$ 104.89	$ 84.77	$ 73.57	$ 73.82	$ 77.68	$ 83.86
Av. Resid. energy charge + FCA ($/kWh)	11.66	11.66	11.66	11.66	11.66	13.06	13.06	13.06	11.66	11.66	11.66	10.42	11.91

(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 4 in Docket No. E999/AA-16-523

Minnesota Electric Utilities' Average Residential Bills for 2015




Minnesota Electric Utilities' Average Residential Energy Charge + FCA for 2015
Cents per kWh
14.00
12.00
10.00
8.00
6.00
4.00
2.00
-
Jan-15
Feb-15
Mar-15
Apr-15
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
Month
Xcel Electric
Minnesota Power
Otter Tail Power
Dakota Electric Association

Northern States Power Company (Minnesota)

Minnesota Solar Gardens Recovery

Actual Month	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16
FCA Month	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17
Ledger															
[A] Solar Gardens Subscribed Bill Credit & RECs	$0.00	$444.73	$328.15	$137.85	$277.98	$358.56	$326.59	$596.87	$659.90	$10,369.31	$9,540.48	$6,817.75	$9,588.64	$4,748.66	$4,941.23
Solar Gardens Unsubscribed <40 KW	$356.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$38.97	$10.28
Solar Gardens Unsubscribed >40 KW	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,497.22	-$1,242.01	$320.38	$32.26	$0.00	$0.00	$0.00
[B] Solar Reward - Made in Minnesota *	$3,758.61	$4,955.42	$2,203.93	$759.00	$240.39	$436.55	$1,591.77	$4,089.77	$8,815.08	$12,036.31	$10,443.10	$7,289.80	$6,772.71	$6,103.82	$3,811.04
[C] Solar Rewards - QF Energy *	$2,966.24	$3,369.54	$1,784.42	$278.99	$55.38	$468.94	$3,314.35	$7,196.51	$13,410.96	$16,097.70	$15,325.53	$10,628.87	$9,499.80	$9,346.59	$5,139.58
Total	$7,080.85	$8,769.69	$4,316.50	$1,175.84	$573.75	$1,264.05	$5,232.71	$11,883.15	$24,383.16	$37,261.31	$35,629.49	$24,768.68	$25,861.15	$20,238.04	$13,902.13
Recovery From Minnesota Customers															
[D] Solar Expenses	$356.04	$444.73	$328.15	$137.85	$573.75	$1,264.05	$5,232.71	$596.87	$2,157.12	$9,127.30	$9,860.86	$6,850.01	$9,588.64	$4,787.63	$4,951.51
[E] Misc Adjustment *					($295.00)			($905.50)	($4,906.77)						
Total Current Month Solar	$356.04	$444.73	$328.15	$137.85	$278.75	$1,264.05	$5,232.71	($308.63)	($2,749.65)	$9,127.30	$9,860.86	$6,850.01	$9,588.64	$4,787.63	$4,951.51
[F] (Over)/Under Collected from Prior Months	$0.00	$0.00	$356.04	$444.73	$684.19	$582.58	$962.94	$1,846.63	$6,195.65	$1,538.00	$3,446.00	$10,665.30	($11,025.96)	$318.81	($89.19)
[G] Total Solar Expenses to Recover	$356.04	$444.73	$684.19	$582.58	$962.94	$1,846.63	$6,195.65	$1,538.00	$3,446.00	$10,665.30	$13,306.86	$17,515.31	($1,437.32)	$5,106.44	$4,862.32
Forecasted Calendar Month Sales	2,408,451	2,579,658	2,645,179	2,396,271	2,512,544	2,261,708	2,358,753	2,624,958	3,010,444	2,912,444	2,535,377	2,444,689	2,405,113	2,539,342	2,589,519
Less: Windsource	(11,505)	(12,781)	(12,254)	(11,200)	(10,211)	(10,282)	(11,471)	(10,471)	(12,547)	(13,415)	(12,136)	(11,470)	(10,261)	(11,399)	(11,584)
Total Forecasted Sales	2,396,946	2,566,877	2,632,925	2,385,071	2,502,333	2,251,426	2,347,282	2,614,487	2,997,897	2,899,029	2,523,241	2,433,219	2,394,852	2,527,943	2,577,935
Solar FCA Factor (¢/kWh)	0.000015	0.000017	0.000026	0.000024	0.000038	0.000082	0.000264	0.000059	0.000115	0.000368	0.000527	0.000720	(0.000060)	0.000202	0.000189
Fuel Adjustment Factor															
Residential	1.0185	1.0185	1.0185	1.0185	1.0185	1.0185	1.0185	1.0185	1.0185	1.0185	1.0185	1.0185	1.0185	1.0185	1.0185
C&I Non-Demand	1.0493	1.0493	1.0493	1.0493	1.0493	1.0493	1.0493	1.0493	1.0493	1.0493	1.0493	1.0493	1.0493	1.0493	1.0493
C&I Demand	1.0028	1.0028	1.0028	1.0028	1.0028	1.0028	1.0028	1.0028	1.0028	1.0028	1.0028	1.0028	1.0028	1.0028	1.0028
C&I Demand TOD On-Peak	1.2732	1.2732	1.2732	1.2732	1.2732	1.2732	1.2732	1.2732	1.2732	1.2732	1.2732	1.2732	1.2732	1.2732	1.2732
C&I Demand TOD Off-Peak	0.7987	0.7987	0.7987	0.7987	0.7987	0.7987	0.7987	0.7987	0.7987	0.7987	0.7987	0.7987	0.7987	0.7987	0.7987
Outdoor Lighting	0.7446	0.7446	0.7446	0.7446	0.7446	0.7446	0.7446	0.7446	0.7446	0.7446	0.7446	0.7446	0.7446	0.7446	0.7446
Fuel Clause Factor for Solar (¢/kWh)															
Residential	0.000015	0.000017	0.000026	0.000024	0.000039	0.000084	0.000269	0.000060	0.000117	0.000375	0.000537	0.000733	(0.000061)	0.000206	0.000192
C&I Non-Demand	0.000016	0.000018	0.000027	0.000025	0.000040	0.000086	0.000277	0.000062	0.000121	0.000386	0.000553	0.000755	(0.000063)	0.000212	0.000198
C&I Demand	0.000015	0.000017	0.000026	0.000024	0.000038	0.000082	0.000265	0.000059	0.000115	0.000369	0.000528	0.000722	(0.000060)	0.000203	0.00
C&I Demand TOD On-Peak	0.000019	0.000022	0.000033	0.000031	0.000048	0.000104	0.000336	0.000075	0.000146	0.000469	0.000671	0.000917	(0.000076)	0.000257	0.00
C&I Demand TOD Off-Peak	0.000012	0.000014	0.000021	0.000019	0.000030	0.000065	0.000211	0.000047	0.000092	0.000294	0.000421	0.000575	(0.000048)	0.000161	0.00
Outdoor Lighting	0.000011	0.000013	0.000019	0.000018	0.000028	0.000061	0.000197	0.000044	0.000086	0.000274	0.000392	0.000536	(0.000045)	0.000150	0.00
Actual Calendar Month Sales					2,372,681	2,162,456	2,378,548	2,662,417	3,013,278	3,039,933	2,527,118	2,401,420	2,258,691		
Less: Windsource					(12,755)	(10,645)	(10,991)	(12,478)	(12,892)	(15,251)	(12,812)	(13,017)	(11,811)		
Total Forecasted Sales	-	-	-	-	2,359,926	2,151,811	2,367,557	2,649,939	3,000,386	3,024,682	2,514,306	2,388,403	2,246,880	-	
Expected Recovery	356.04	444.73	684.19	582.58	962.94	1,846.63	6,195.65	1,538.00	3,446.00	10,665.30	13,306.86	17,515.31	(1,437.32)	5,106.44	4,
Actual Recovery	-	-	-	-	-	-	-	-	-	-	24,332.82	17,196.50	(1,348.13)	-	
(Over)/Under Collected from Prior Months	356.04	444.73	684.19	582.58	962.94	1,846.63	6,195.65	1,538.00	3,446.00	10,665.30	(11,025.96)	318.81	(89.19)	5,106.44	4,

* Adjustment to remove Made in Minnesota solar program costs (recoverable RDF Rider) and Solar Rewards solar energy paid under QF tariffs (NSP system costs shared by all jurisdictions).

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, 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
Public Review of the 2015-2016 Annual Automatic Adjustment (AAA) Reports

Docket No. E999/AA-16-523

Dated this 13th day of September 2017

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_16-523_AA-16-523
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_16-523_AA-16-523
Carl	Cronin	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_16-523_AA-16-523
Ian	Dobson	Residential.Utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_16-523_AA-16-523
Marie	Doyle	marie.doyle@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall P O Box 59038 Minneapolis, MN 554590038	Electronic Service	No	OFF_SL_16-523_AA-16-523
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_16-523_AA-16-523
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_16-523_AA-16-523
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_16-523_AA-16-523
Amber	Lee	ASLee@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	2665 145th St W Rosemount, MN 55068	Electronic Service	No	OFF_SL_16-523_AA-16-523
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_16-523_AA-16-523

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_16-523_AA-16-523
Randy	Olson	rolson@dakotaelectric.com	Dakota Electric Association	4300 220th Street W. Farmington, MN 55024-9583	Electronic Service	No	OFF_SL_16-523_AA-16-523
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_16-523_AA-16-523
Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company	200 First St SE Cedar Rapids, IA 52401	Electronic Service	No	OFF_SL_16-523_AA-16-523
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_16-523_AA-16-523