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Minnesota Department of Commerce

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June 5, 2013 **PUBLIC DOCUMENT**

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Review of the 2011-2012 Annual Automatic Adjustment Reports**
Docket No. E999/AA-12-757

Dear Dr. Haar:

Minnesota Rules 7825.2800 through 7825.2830 require natural gas and electric utilities implementing automatic adjustments in the recovery of fuel purchases to file annual automatic adjustment reports.

Attached is the Minnesota Department of Commerce, Division of Energy Resource's (Department or DOC) *Review of the 2011-2012 Annual Automatic Adjustment Reports* for rate-regulated electric utilities in Minnesota (FYE12 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 Minnesota Public Utilities Commission (Commission) have any questions about the FYE12 electric AAA herein provided.

Sincerely,

/s/ NANCY A. CAMPBELL
Financial Analyst

/s/ SAMIR OUANES
Rates Analyst

NAC/SO/ja
Attachments

REVIEW OF 2011-2012 (FYE12)
ANNUAL AUTOMATIC ADJUSTMENT REPORTS

FOR ELECTRIC UTILITIES

SUBMITTED TO THE
MINNESOTA PUBLIC UTILITIES COMMISSION

DOCKET NO. E999/AA-12-757

JUNE 5, 2013

PUBLIC DOCUMENT

TRADE SECRET DATA HAS BEEN EXCISED

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I. OVERVIEW

This report summarizes the Division of Energy Resources of the Minnesota Department of Commerce's (DOC or the Department) review of the automatic adjustment charges for the July 2011 - June 2012 (FYE12) reporting period, which were filed by five Minnesota electric utilities in compliance with Minnesota Rule 7825.2810. The Department offers recommendations to the Minnesota Public Utilities Commission (Commission) regarding the information contained in this report, which are summarized at the end of the report.

The utilities included in this report are:

- Dakota Electric Association (Dakota or DEA);
- Interstate Power Company – Electric Utility (Interstate Electric);
- 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 five rate-regulated electric utilities required to provide information per Minnesota Rules filed the information necessary to meet their filing requirements.[1]

The Department's review focused on whether the electric utilities had, during the period of July 1, 2011 to June 30, 2012, accurately adjusted their energy rates to reflect changes in fuel costs.

The Department also analyzed the utilities' procurement policies, dispatching procedures, cost-minimizing efforts, adjustment computations, and auditors' reports. The FYE12 reporting period coincides with the seventh full year of operation under the "Midcontinent Independent System Operator's Day 2 Energy Market" (MISO Day 2 Market). The Department dedicates Section VII of this report to addressing MISO Day 2 Market issues.

In addition, the Department also discusses in Section IV of these comments the overall effectiveness of this rate mechanism in ensuring that electric utilities take appropriate steps to minimize fuel costs in daily operations and in planning for future needs for the utilities' systems. The Department discusses this issue given concerns about utilities' efforts to minimize fuel costs, or sometimes even to consider fuel costs in planning for future needs.

II. FILING REQUIREMENTS

A. MINNESOTA RULES

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

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

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

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 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 five reporting electric utilities comply with the Commission's filing requirements, as described in Minnesota Rule 7825.2810, subpart 1.[3]

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.

All electric utilities submitted auditors' reports in compliance with Minnesota Rule 7825.2820. The Department reviewed each auditor's report filed and notes that there were no exceptions indicated by the auditors.

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

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

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

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

[3] 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.

B. SUMMARY OF FUEL COST PROJECTIONS

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. Dakota projects that its purchased power (energy and capacity) costs will **[TRADE SECRET DATA HAS BEEN EXCISED].**

Interstate Electric projects its energy costs to **[TRADE SECRET DATA HAS BEEN EXCISED].**

Minnesota Power projects its energy costs to **[TRADE SECRET DATA HAS BEEN EXCISED].**

Otter Tail projects its energy costs to **[TRADE SECRET DATA HAS BEEN EXCISED].**

Xcel Electric projects its energy costs, including fuel, purchases and sales to **[TRADE SECRET DATA HAS BEEN EXCISED].**

These fuel cost projections are summarized in the following tables.[4]

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

Table 1: Fuel Cost Projections ($/MWh) for 2013 through 2017

$/MWh	2012	2013	2014	2015	2016
TRADE SECRET DATA HAS BEEN EXCISED					
Dakota					
IPL					
MP					
OTP					
Xcel Electric					

Table 2: Annual Percent Changes in Fuel Cost for 2014 through 2017

	2013	2014	2015	2016
TRADE SECRET DATA HAS BEEN EXCISED				
Dakota				
IPL				
MP				
OTP				
Xcel Electric				

III. COMPLIANCES

The Department includes the reports listed below in this section. The Department notes that the analysis of compliances related to the MISO Day 1 and Day 2 markets are discussed in Section VI *Effects of the MISO Day 1 Market on Minnesota Ratepayers and VII Effects of the MISO Day 2 Market on Minnesota Ratepayers.*

- Investigation of Xcel Electric's Practices Regarding Energy Marketing and the Fuel Clause in Docket No. E002/CI-00-415.
- Natural Gas Financial Instruments (Xcel Electric's compliance filing) in Docket Nos. E002/M-01-1953 and E999/AA-02-951.
- Wind Curtailment Report (Xcel Electric's compliance filing) in Docket Nos. E002/M-00-622 and E002/M-02-51.
- FCA Settlement Agreement (Xcel Electric's compliance filing) in Docket No. E002/GR-05-1428.
- History of Nuclear Fuel Sinking Fund in Docket No. E002/M-81-306.

- Enbridge Energy Issues in Docket No. E017/M-06-1332.
- Offsetting Revenues and/or Compensation Received by Investor-Owned Utilities (IOUs) (Docket Nos. E002/M-08-1098, E002/M-10-486 and E999/AA-10-884)
- Maintenance Expenses of Generation Plants (Docket No. E999/AA-06-1208).
- Plant Outages Contingency Plans (Docket No. E999/AA-08-995).
- Sharing Lessons Learned regarding Forced Outages (Docket No. E999/AA-10-884).
- OTP's FCA True Up (E017/M-03-30).
- Curtailment of WM Renewable Energy (Docket No. E002/M-10-161).
- Report on purchased power agreement (PPA) with Manitoba Hydro (Docket No. E015/M-10-961).

The Department discusses each of these items below.

A. INVESTIGATION OF XCEL ELECTRIC'S PRACTICES REGARDING ENERGY MARKETING AND THE FUEL CLAUSE IN DOCKET NO. E002/CI-00-415

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. 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 also provided this data in its annual reporting filings for all years to date.

In its most recent compliance filing for FYE12, Xcel Electric provided the monthly generation costs allocated to retail and wholesale customers in its annual automatic adjustment report in Part H, Section 2, Schedule 1, dated August 31, 2012 and as updated in a supplemental filing dated November 28, 2012. On Schedule 1, Xcel Electric showed its monthly comparison of generation costs allocated to retail and wholesale customers for the months of June, July and August of 2012.

The DOC reviewed Xcel's monthly comparisons of generation costs allocated to retail customers and the wholesale sector for the above-stated months. The information filed by Xcel Electric appears to comply with the requirements of the Commission's Order. Xcel's data indicates that average generation costs allocated to retail customers was less than the average generation costs allocated only to the wholesale sector and the average costs for both wholesale and retail customers for the months June and July of 2012.

However, for the month of August 2012, average retail generation costs were slightly higher than average wholesale generation costs. The Company cited the following three reasons as the causes:

1) a one-time cost reclassification due to an incorrect allocation of gas expenses to Generation Gas in August 2012, as noted in the Company's October 2012 monthly FCA report filed on September 28, 2012;
2) an accounting accrual adjustment for wholesale gas generation of $250,733 for July 2012, which was recorded in August 2012 due to the timing of invoices and closing dates, and
3) more off-peak sales (which are cheaper cost sales) were made to wholesale compared to retail customers in August 2012 compared to June and July 2012

The Department considers these explanations provided by the Company to be reasonable. This information provides a high-level indication that Xcel Electric appears to have reasonably allocated generation costs between retail customers and the wholesale sector (this indication does not consider the cost allocation issues of MISO Day 2 charges between retail customers and the wholesale sector, which is discussed in the MISO Day 2 section of these comments, below).

The Department notes that it is useful to continue the high-level checks of the allocations between retail and wholesale sectors to help ensure that the lowest cost resources are assigned to retail customers. Based on our review, the DOC recommends that the Commission approve Xcel Electric's compliance filing on the high level cost allocation test between retail and wholesale customers for June, July and August 2012. The DOC recommends that the Commission continue to require Xcel Electric to report this generation cost allocation in future AAA filings.

B. NATURAL GAS FINANCIAL INSTRUMENTS: XCEL ELECTRIC'S COMPLIANCE FILING IN DOCKET NO. E002/M-01-1953 AND E999/AA-02-951

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.

Xcel Electric's FYE12 AAA report also includes a copy of the prescribed letter by Xcel Electric to its external auditors.[5] The report included a copy of the Deloitte & Touche LLP Independent Auditors' Report,[6] which concluded: "In our opinion, the accompanying Schedule presents, in all material respects, the accounting for the FCA of the Company for the period from July 1, 2011 to June 30, 2012 in accordance with the Riders and Dockets approved by the Commission."

The Department recommends that the Commission accept Xcel Electric's Natural Gas Financial Instruments compliance filing in the FYE12 docket. The Department will review Xcel Electric's continued compliance with this requirement in the FYE13 AAA report.

[5] See Part F, Section 1of the Xcel Electric FYE12 AAA report.
[6] See Part F, Section 2 of the Xcel Electric FYE12 AAA report.

C. WIND CURTAILMENT REPORT

In the past, various Commission Orders emphasized reporting and regulatory review of the curtailment practices used by Xcel Electric in connection with its wind PPAs. The Department notes that our report in E, G999/AA-05-1403 describes the background connected with this issue.

> The Department has continued to monitor the reasons for Xcel Electric's curtailments in monthly automatic adjustment filings. According to these reports, nearly all curtailments have been due to lack of firm transmission or due to directives from MISO pertaining to transmission. The Department notes that an extensive review of Xcel Electric's curtailment in previous years is available in Docket No. E, G999/AA-04-1279.

For this report, the Department concludes that Xcel Electric is substantially 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 FYE12 AAA filing a report of its projected curtailment payments over the next five years related to wind for planned and existing projects and any commitments made to update the system.[7]

In addition, following discovery from the Department, Xcel Electric provided an assessment of wind commitments and available or planned transmission capacity.[8] Xcel Electric concluded that:

> The engineering studies for the CapX2020 projects identified above have been completed and were included in the record of the Certificate of Need proceedings before the MPUC. The CapX2020 Twin Cities-Brookings County 345 kV line, along with the MVP [Multi value Projects] transmission projects, will further increase this generation outlet capacity and will address any major transmission needs in the NSP service territory for many years to come. The Company thus believes there is no need to commence additional load and capability studies in the NSP area.

The Department concludes that Xcel Electric is being proactive in addressing the curtailment issue (through the identification of future limits in transmission capacity and ways to address these limits).

The Department reviewed Xcel Electric's wind curtailment data. The level of curtailments was substantially cut back from its peak during FYE05 from 16.50 percent of the total cost of wind,[9] including curtailments, to 8.32 percent in FYE08, 2.42 percent in FYE09, and 1.94 percent in FYE12.[10]

[7] Part H, Section 5, Schedule 2 in Xcel Electric's FYE12 AAA filing.
[8] Attachment Exx.
[9] The total cost of wind refers to the wind projects that are included in Xcel's monthly FCAs' Wind Reports: Lake Benton I, Lake Benton II, Chanarambie, Moraine, Northern Alternative Energy, Velva, Fenton, FPL Energy Mower County, MinnDakota, Norgaard, and Wind Power Partners 1993.
[10] Source: Attachment xx, pp. 17-20 out of 24.

Based on Xcel Electric's responses above and the corresponding limited amount of curtailment during the July 2011-June 2012 period, the Department recommends that the Commission accept Xcel Electric's FYE12 wind curtailment report (Wind Report), with the exception of the curtailment payments made under the "other" category as discussed below.

The Commission's February 6, 2008 Order in Docket No. E, G999/AA-06-1208 required Xcel Electric to provide in future electric annual automatic adjustment filings a Wind Curtailment Summary Report Table similar to the table that Xcel is already providing in its AAA filings, but expanded to include the amount of any curtailment payments made under the following four curtailment categories:

1 = lack of firm transmission as described in Attachment C of the MISO Open Access Transmission Tariff, or any successor provision
2 = low load
3 = transmission loading relief or MISO directive for reasons other than (1) above
4 = other, which must be explained in detail if compensation is requested.

The Department notes that the Wind Report does not include a detailed explanation for the curtailment payments made under the "Other" category. The only information provided is the amount of MWhs curtailed and the amount of curtailment payments ($878 in October 2011 and $92,095 in March 2012) under the "Other" category for FYE12. In addition, the total amount of curtailment payments made under the "Other" category during FYE12 increased substantially to $540,526 according to Xcel Electric's most recent FCA filing (April 30, 2013, Docket No. E002/AA-13-331).

Therefore, the Department requests Xcel Electric to provide in reply comments:

- A chronological description of each and all events that led to the wind curtailments and corresponding curtailment payments made under the "other" category during FYE12.
- For each such event, the curtailment payments made and a complete description of the steps taken by Xcel Electric before and after the event to alleviate the need for such curtailments and curtailment payments.
- For each such event, Xcel Electric's complete justification for why Xcel Electric's ratepayers should bear the full cost of these curtailment payments.

The Department will provide its recommendations regarding the recovery of the $540,526 in curtailment payments made under the "Other" category during FYE12 following its review of Xcel's detailed explanation and justification in reply comments.

D. FCA SETTLEMENT AGREEMENT (XCEL ELECTRIC'S COMPLIANCE FILING IN DOCKET NO. E002/GR-05-1428)

During Xcel's 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 how Xcel Electric will try to mitigate volatility, cover risks associated with planned outages and optimize congestion cost hedging. 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 FYE12 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, if there are any concerns that need to be addressed.

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

Pursuant to the Commission's Order dated July 14, 1981 of the referenced docket, Xcel Electric included the required information in Part H, Section 1 of its FYE12 AAA filing. Xcel's filing provided history of nuclear fuel interim storage and disposal expenses included in the determination of electric automatic adjustment charges. Xcel Electric's Schedule 1 shows payments to the Department of Energy (DOE), DOE credits, and beginning and ending balances for disposal costs and permanent disposal costs.

For purposes of background, the following are the four nuclear charges:

- DOE Yucca Mountain Permanent Disposal Costs, which is a 1 mill per kWh fee that is collected via the FCA;
- Interim Storage Costs that were collected from ratepayers and then used for Xcel Electric's Prairie Island Dry Cast Storage Project;
- Payments to 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 were collected through Xcel Electric's base rates. Xcel recommended in its decommissioning study in Docket E002/M-11-939 a 36-year decommissioning period and an annual accrual of $11.2 million for decommissioning starting January 1, 2013. The Commission's December 4, 2012 Order approved a 60-year decommission period and a $14.2 million annual decommission accrual starting January 1, 2013.

Based on our review of Xcel Electric's Schedule 1 for the FYE12 AAA, which provides a history of nuclear fuel interim storage and disposal expenses, the DOC concludes that there are no significant changes from Xcel Electric's previous FYE11 AAA filing. The DOC notes that total permanent disposal costs paid to DOE were $427 million as of June 30, 2012, with annual amounts for recent years of approximately $11.6 to $12.9 million per year.

The DOC notes that Xcel Electric entered into a July 5, 2011 Settlement with DOE regarding DOE's partial breach of its contract to take spent nuclear fuel beginning January 31, 1998. Xcel Electric received compensation from DOE for the following cost categories: a) any additional pool storage and other plant modifications; b) dry cask storage and costs directly related to such storage (e.g. internal labor, overhead, operating and maintenance, and training and security); and

c) additional property taxes from the on-site dry cask storage or other plant modifications. The refund amounts, allocations, and other related issues are further discussed in Docket E002/M-11-807. On December 16, 2011, the Commission issued its Order approving the first DOE payment to Xcel to be refunded to customers. The DOC notes that a second DOE payment was made to Xcel Electric and was refunded to customers in March 2012. In November 2012, Xcel received its third payment from DOE, and will receive a forth payment around year end 2013. These two DOE refund payments will be placed in Xcel's decommissioning fund as payment for decommissioning costs with excess DOE payments used to offset future decommissioning costs. The fifth and final DOE payment under the settlement will be discussed in the next decommissioning study to determine how the DOE funds will be handled.

The DOC recommends that the Commission accept Xcel Electric's compliance filing regarding Xcel Electric's Nuclear Fuel Sinking Fund. The DOC will continue to monitor Xcel Electric's Nuclear Fuel Sinking Fund in future AAA filings.

F. ENBRIDGE ENERGY ISSUES IN DOCKET NO. E017/M-06-1332

The Commission's Order dated January 16, 2007 in Docket No. E017/M-06-1332 approved an electric service agreement (ESA) between Otter Tail Power and Enbridge Energy. The Commission's Order requires Otter Tail Power to report in its AAA report the following information:

- the amount of incremental energy purchased by the customer under the Large General Service (LGS) Rider,
- the retail rate paid by the customer, and
- the retail rate of the energy had System Marginal Energy Pricing been used to determine the retail rate paid by the customer.

As explained in Docket No. E017/M-06-1332, the principal change from the previous ESA to the current ESA was the change from pricing incremental energy in the LGS Rider on a System Marginal Energy Pricing (SMEP) basis to a Fixed Rate Energy Pricing (FREP) basis. These reporting requirements allow for monitoring the impact of the change from SMEP to FREP on Enbridge Energy's electrical usage.

The 2012 data shows that Enbridge Energy continues to purchase a significant amount of incremental energy. Had SMEP been used to determine the rate for the same amount of energy Enbridge Energy purchased for the July 2011 to June 2012 period, Enbridge would have paid less than it paid under FREP. As the Department has concluded in previous AAA reports, the information to date does not suggest that FREP pricing is resulting in higher energy use by Enbridge Energy.

The Department recommends that the Commission accept Otter Tail Power's Enbridge Energy compliance filing in this docket. The Department will continue to monitor this compliance filling in future AAA reports.

G. OFFSETTING REVENUES AND/OR COMPENSATION RECEIVED BY IOUS (DOCKET NOS. E002/M-08-1098, E002/M-10-486 AND E999/AA-10-884)

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

Xcel Electric stated that "the Company has not received any new revenue as described in this Order."[11] 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 "this biomass project is not yet in commercial operation."[12] 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 stated 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 AAA filings.

H. MAINTENANCE EXPENSES OF GENERATION PLANTS (DOCKET NO. E999/AA-06-1208)

In its February 6, 2008 Order (2008 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.[13] The Commission agreed with the Department and Large Power Interveners that "utilities have a duty to minimize unplanned facility outages through adequate maintenance, and

[11] Source: Part H, Sections 1-8, page 5 of 5 of Xcel's FYE12 AAA filing.
[12] Source: Part H, Sections 1-8, page 5 of 5 of Xcel's FYE12 AAA filing.

to minimize the costs of scheduled outages through careful planning, prudent timing, and efficient completion of scheduled work." 2008 Order at 5.

These high levels of outages raised the issue of whether the IOUs are spending as much to maintain their generation plants as they are charging to their customers in FCA rates which allow for automatic adjustment of rates to reflect increases in costs.

As summarized below, the Department notes that only MP and Xcel Electric are spending more on operation and maintenance (O&M) costs than they are charging to their customers in rates.[14]

Table 3: Comparison of Generation O&M costs

	Test Year	Rate Case	Historical 2009-11 Average	Difference from Rate Case
IPL	2009	$3,779,345	$3,260,868	($518,477)
MP	2010	$33,619,194	$40,007,657	$6,388,463
Xcel Electric	2011	$157,432,572	$166,463,341	$9,030,769
OTP	2011	$13,192,047	$11,727,090	($1,464,957)

Rate case and historical averages are calculated based on data provided by IPL, OTP, MP and Xcel. However, because IPL, Xcel Electric and OTP have all had more recent rate cases than the years shown in the table above, the Department requests that these utilities provide in their reply comments updated information on generation O&M costs being recovered in the most recent rate cases, and utilities' actual 2012 generation O&M costs.

Due to the link between the level of O&M on facilities and forced outages of facilities, and due to different current ratemaking incentives (incentive to minimize O&M costs 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' most recent rate cases in future AAA filings.

I. PLANT OUTAGES CONTINGENCY PLANS (DOCKET NO. E999/AA-08-995)

In its March 15, 2010 Order, the Commission required all IOUs to 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.

This requirement stems from the drastic increase in OTP's energy costs in November ($39/MWh) and December 2007 ($51.20/MWh) due to 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 agree 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).

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[13] Attachment E5 shows that the outage costs have since substantially decreased as a share of energy costs.
[14] Attachment E5 provides an annual breakdown of the IOUs' maintenance expenses of generation plants.

The Department attempted to generate a useful discussion of ways to ensure that ratepayers were better protected from delays or lack of performance through the lessons learned by the utilities. The Department recommend that utilities, at a minimum, identify and work with contractors that have reasonable contingency plans to alleviate the risk of delays or lack of performance.

While neither OTP nor Interstate Electric addressed working with contractors in their FYE12 filings, both MP and Xcel Electric discussed "the lessons learned and the contingency plans developed by the Company to mitigate against future risk of delays or lack of performance, when contractors perform poorly and increase costs during plant outages."

Xcel Electric provided a description of "the accountability measures for vendors/suppliers" it has established to help Xcel Electric "contract with parties for generation plant repair and maintenance services that have a history of performing work safely, reliably and in a timely manner."[15]

MP stated that the following:

> ***Identification and explanation of outage delays***
> During this period, there were no delays or lack of performance by contractors affecting the length of the outages.
>
> ***Lessons Learned and Contingency plans utilized***
> During this period, Boswell Unit 4 had had a six week planned maintenance outage. The critical path included repairs to the generator, but this time frame was also utilized to address repairs on a number of boiler and turbine auxiliaries.
>
> Included in the list of repairs during this time frame was the reapplication of a failing coating on the interior of the condenser water boxes, which was originally applied in 2010.
>
> The failing of the coating, in Minnesota Power's view, should have been repaired under the original warranty from the contractor and supplier. The contractor, Curran, felt it may not have been the product they supplied, but the application in which it was used, therefore voiding the warranty. An independent party was hired to help determine the cause of the coating failing flaking away under the plant operation. While the third party group shared Minnesota Power's view, there were many inspections, re-inspections, and general delays with the original contractor Curran to make the repairs. A Curran inspection crew was also removed from the site as a result of poor safety practices as they tried to assess the repair. This lack of performance, and unwillingness to own the repair under the warranty, forced Minnesota Power to execute a contingency plan to have the product applied and to return the unit

[15] Part K, Section 3 of Xcel's FYE12 AAA report.

> to service on schedule. This plan included the use of a different contracting group to make repairs to the coating add an additional cost.
>
> This work is still being contested under the warranty of the original purchase order and installation. While this lack of performance led to additional repair costs, a contingency plan was in place to be able to make the repair on time to avoid the much more significant cost of replacement power for our customers. Future plans will include, as this contract did, terms and conditions under the warranty that support quality work, which can be done safely and effectively. Other items that will be considered with these specialty contractors will be a more thorough review of the staff assigned to our contract.

The Department appreciates the specific information that Xcel and MP provided. The Department expects to continue to monitor the IOUs' plant outages contingency plans in future AAA filings.

J. SHARING LESSONS LEARNED REGARDING FORCED OUTAGES (DOCKET NO. E999/AA-10-884)

In its April 6, 2012 Order in Docket Nos. E99/AA-09-961 and E999/AA-10-884, the Commission required the IOUs to provide in supplemental filings to their fiscal-year 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.

In the FYE11 docket, the Department conducted an extensive audit of utilities' forced (unexpected) outages, assessing the extent to which utilities took reasonable steps to avoid such outages or minimize costs of replacement power (which are passed on to ratepayers through the FCA). At the time these comments are being prepared, that docket has not yet been brought before the Commission for decision; however, in those comments, the Department made a number of recommendations regarding recovery of replacement power costs during the forced outages.

In the FYE12 docket, MP, IPL and OTP provided the required information. The Department requests Xcel Electric to provide in reply comments discussion of how each of the identified forced outages could have been avoided or alleviated, preferably using the format in MP's supplemental filing. The Department commends MP for including the type of data, format and level of explanation regarding MP's forced outages, including information on outage category, primary reason for outage, equipment that resulted in the forced outage, description of equipment failure, change in energy cost, failure history during reporting period, and steps taken to alleviate reoccurrence.[16]

[16] See Table 1 of MP's September 7, 2012 Supplemental Filing for 2012 AAA in Docket No. E999/AA-12-757.

Regarding the changes in energy costs due to each outage, however, the Department agrees with Xcel Electric that there is no change in energy costs due to a forced outage when "generation from the power plant would have not have [sic] been utilized at the time of the outage because its economic dispatch costs were more than the cost of other Company generation or the MISO market price."[17] Utilities would need to document that the costs of replacement power were less than the costs of operating the facility on outage. In any case, it is not appropriate for replacement power costs to be negative, as MP has shown for some of its outages, since the plant would not have been used to produce electricity if were more expensive than the cost of power in the MISO market. Therefore, the Department recommends that MP provide in reply comments either a revised Table 1 with no changes in energy costs where MP initially calculated negative changes in energy costs as a result of forced outages, or fully justify such calculations (why it is reasonable to expect a reduction in energy costs as a result of forced outages).

As discussed further in Section IV below, the Department recommends an alternative ratemaking approach to holding utilities accountable for replacement power costs. This approach is also intended to encourage utilities to consider all costs in providing service, including replacement power costs, in short-term and long-term planning.

K. 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 Company's annual true-up filings.

On July 31, 2012, Otter Tail submitted a compliance report and proposal to implement a true-up increase of $0.0005 per kWh. In Comments filed on August 30, 2012, the Department recommended that the Commission approve Otter Tail's compliance report and the true-up debit. The Commission's October 9, 2012 Order approved Otter Tail's true-up increase in rates beginning September 1, 2012.

L. 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 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."[18] Therefore, the Department concludes that Xcel Electric complied with the 2010 Order.

M. REPORT ON MP'S PPA WITH MANITOBA HYDRO (DOCKET NO. E015/M-10-961)

The Commission's 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

[17] Xcel Electric's August 31, 2012 report in Docket No. E999/AA-12-757 at 261 of 302.
[18] Source: Part H, Sections 1-8, page 5 of 5 of Xcel's FYE12 AAA filing.

comparisons. The purpose of the data is to assess whether the costs of the Manitoba Hydro products are least cost.

Based on the Department's review of MP's AAA annual report, the Department concludes that MP is in compliance with the Commission's Order in Docket No. E015/M-10-961. MP's information indicates that costs of Manitoba Hydro products are least cost.

IV. FCA MECHANISM

A. BACKGROUND

During Xcel's current rate case proceeding, the Antitrust and Utilities Division of the Minnesota Office of the Attorney General (OAG) proposed to fix the level of recovery of energy costs on a calendar year basis at Xcel's proposed base cost of energy with a 3 percent cap.[19] OAG's proposal was based on the following observations. First, a significant amount of fuel and purchased power costs is expected to be recovered by Xcel during the test year, $825 million. Second, the fuel and purchased power costs are automatically passed through to customers through an automatic adjustment on customer's bills through the FCA each month. Third, there are no incentives for Xcel to control these costs except for the potential that costs may be disallowed after-the-fact as a result of the annual automatic adjustment review that is conducted after the end of the year for all IOUs. Fourth and finally, there is no internal incentive structure in place for Xcel to provide the oversight to control this cost on behalf of ratepayers.

1. DOC Analysis

The OAG raised important concerns regarding the current energy recovery mechanism that warrant Commission attention, not only for Xcel, but for all electric utilities. As indicated in the Department's April 5, 2004 Reply Comments in the matter of the *Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments* (Docket No. E999/CI-03-802), the FCA was originally designed to allow the utility to recover, outside of rate cases, costs that were largely outside of the control of the utility. The FCA also provided a way to pass savings to ratepayers if the actual cost of fuel dipped below the base cost included in rates. At the time that FCAs were originally put in place, there were few purchases of wholesale electric energy, and such rates were federally regulated, which provided another level of oversight for such costs included in automatic adjustments. Further, at that time, costs for electric energy purchased was low and fairly consistent with the cost of generating electricity on the utility's own system.

However, even at that time, there were drawbacks of the FCA, as noted in the Department's comments noted above:

> At the outset, an important disadvantage of the FCA appeared to be its potential to distort incentives by treating fuel costs differently than other costs. Distortion of incentives could occur in the following ways:

[19] February 28, 2013 Direct Testimony of John Lindell at 12-18 in Docket No. E002/GR-12-961.

- By easing the recovery of fuel costs, the FCA could encourage utilities to use fuel more intensively. In other words, the FCA could skew input selection in favor of fuel and against other inputs.
- By allowing utilities to pass fuel cost increase to [ratepayers], the FCA would weaken utilities' incentives to aggressively manage fuel costs. Specifically, the FCA could reduce utilities incentives to:
  (i) Select less volatile fuel sources over more volatile fuel sources when installing new plants;
  (ii) Switch existing plants to less volatile fuel sources; and
  (iii) Invest time and resources into negotiating lower prices for fuels currently in use.[20]

These disadvantages need to be considered in light of current circumstances, including the need to add more generation resources, the development of the MISO energy market, environmental regulations, and the effects of factors such as the following on the costs for fuel, replacement energy, and electricity procured through PPAs that is recovered through the fuel clause:

- the utility's ability to use tools such as demand response and energy efficiency (including interruptible programs) to manage costs,
- the extent to which the utility plans for and obtains sufficient reliable resources to meet the needs of its retail customers and the extent to which the utility either plans to rely on the MISO spot market or fails to implement plans to obtain sufficient resources,
- the extent to which the utilities plans for the availability and deliverability of natural gas and other replacement resources as the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standard (MATS) and other rules are implemented; and
- the extent to which utilities have sufficiently maintained their generation resources, to minimize the effects of unplanned outages.

While utilities are not in complete control of energy costs, utilities' choices have far more influence on FCA costs than has been the case previously. The Department's comments in the FYE11 AAA proceeding and in utility's resource plans, among others, point out ways that utilities' choices affect or could affect FCA costs. Further, it is expected that FCA costs will become far more volatile in the near future than in the past, as the MISO region as a whole responds or fails to respond to the MATS rule, aging infrastructure, and growth in demand as the economy recovers. Ratepayers should not be paying for a utility's failure to plan for and manage these developments.

It is critical to design incentive mechanisms to ensure that all utilities consider all costs of providing energy as utilities add resources and respond to growth in demand for power. The following provides more background and the Department's recommendation on an incentive method for the fuel adjustment clause.

[20] Source: Kaserman, David L. and Richard C. Tepel, "The Impact of the Automatic Adjustment Clause on Fuel Purchase and Utilization Practices in the U.S. Electric Utility Industry," Southern Economic Journal, Vol. 48, No. 3 (Jan. 1982), 686-700.

As noted above, the current design of the FCA in Minnesota allows utilities to recover fuel costs in a different way than costs recovered in base rates. IOUs' energy costs, including replacement power costs during generation outages and congestion costs when transmission facilities are constrained are automatically recovered through the FCA, while costs to invest in and operate and maintain energy facilities are typically recovered through fixed base rates. These two different recovery mechanisms – automatic adjustments and fixed recovery in rates – provide different incentives for utilities to minimize costs in practice.

Specifically, utilities have an incentive to minimize costs with fixed recovery, such as operation and maintenance (O&M) costs for energy facilities, to maximize profit for shareholders between rate cases. By contrast, IOUs have little incentive to minimize costs that are passed automatically through the FCA to ratepayers since there is no short-term benefit to shareholders in doing so. In fact, there are higher costs involved in minimizing fuel costs, such as aggressively pursuing lower cost contracts for fuel, pursuing extensive preventive maintenance of plants, replacing aging or ineffective resources. There may also be lower revenues through pursuing demand-side management resources. Further, by utilities relying extensively on the MISO market for energy, retail ratepayers are at risk for higher costs during scarcity pricing periods.

A well-designed incentive mechanism would encourage IOUs to minimize overall costs of providing energy, including costs that are currently passed through the FCA. To do so, such a mechanism should ensure that IOUs internalize their total cost of doing business, including their fuel and replacement power costs during outages. Under such an incentive mechanism, IOUs would have the appropriate incentives to keep these costs as low as possible because it would be in their own best interest to do so.

The Department's recent investigation of the IOUs' forced outages, along with Xcel's wind curtailments in Docket No. E999/AA-11- 792 (AAA 11-792 Docket) highlighted the IOUs' lack of incentive to minimize energy costs and the difficulty of assessing the IOUs' claimed prudency of such costs. The Department's review of the IOUs' FYE11 forced outages highlighted a fundamental issue: the IOUs appear to act as if their ratepayers, not the IOUs' management and/or shareholders, should be held accountable for the costs of forced outages even when the outages are the result of a utility's employee errors or outside vendors' mistakes.

As discussed further in the Department's December 12, 2012 Response Comments (DOC Response Comments) in the AAA 11-792 Docket, it took several rounds of discovery for the Department to receive information sufficient to identify potential issues and then assess the prudency of the costs even of a limited subset of potential issues. This resistance in providing the necessary information raises the concern that the identified issues may only be the tip of the iceberg. In addition, IOUs' responses to the issues raised by the Department in the AAA 11-792 Docket indicates that the IOUs do not treat energy costs as part of their total cost of doing business, i.e., energy costs are not treated as internalized costs.

The Department provides the following three simple examples from the DOC Response Comments in the AAA 11-792 Docket: the first two relate to forced outages and the third to wind curtailment payments. These examples demonstrate the IOUs' resistance to being held accountable for meeting their burden of proof for their own mistakes.

First, following extensive discovery from the Department, Xcel acknowledged that, as a result of a human error, a wrench fell into the buss duct work during maintenance of a power plant generator, and that, as a result, the King plant was off-line for about 30 hours in January 2011. In response to the Department's recommended disallowance of the corresponding increase in energy costs to ratepayers, Xcel stated that "[t]he [Department] Response Comments have not demonstrated that the Company's actions were not prudent under the circumstances. As such, the replacement energy costs meet the just and reasonable standard for FCR cost recovery." DOC Response Comments at 22-27. The Department notes that it is the utility's burden of proof to show that the costs it charges to its ratepayers are just and reasonable.

Second, following extensive discovery from the Department, MP's November 9, 2012 response still did not explain why MP's ratepayers should pay for the full amount of the increased energy costs passed through the FCA during FYE11, as a result of the use by a vendor of "replacement o-rings made of materials incompatible with the fluids used in the hydraulic system." MP described the difficulties related with finding reliable vendors and holding them accountable for mistakes. However, it does not appear that MP had a reasonable system or any system in place in place to prevent or alleviate the vendor's error. The only option discussed by MP to prevent or alleviate the error would be to have an engineer watch the entire rebuild process (5 weeks). Certainly there are other options. However, given the additional cost incurred by MP's ratepayers ($507,715) for this error, the additional cost of an engineer watching the entire rebuild process for five weeks would have been justified. DOC Response Comments at 39-46. The fact that MP defended its decision not to have an engineer watch the entire process for five weeks due to the cost of the engineer, and ignoring over a half million in costs for replacement power, shows that MP did not consider it to be reasonable to balance the costs of an engineer's five weeks of time against the costs of replacement power. This example indicates that MP has an adequate incentive to minimize costs of an engineer's time, but does not have an adequate incentive to minimize replacement power costs. The Department notes that in response to an earlier discovery in that proceeding regarding contractors' delays and/or lack of performance during FYE11, MP stated that "[d]uring this period, there were no delays or lack of performance by contractors affecting outages."[21] Clearly, the incompatible o-ring error should have been noted by MP in response to the Department's discovery.

Third, following extensive discovery from the Department, Xcel acknowledged its error in not placing the Lake Benton II wind project at the top of the curtailment list. This error resulted in increased energy costs that were passed through to ratepayers in the FCA. In response to the Department's recommended disallowance of the corresponding increase in energy costs to ratepayers, Xcel stated that "the wind curtailment costs are not unreasonable and should be recoverable." DOC Response Comments at 63-68.

While the Commission has not yet addressed these issues, the Department notes that in all such cases, the utility failed to take steps to ensure that ratepayers would not bear the costs of the utility's errors. These examples indicate that the IOUs could have minimized costs further if they had appropriate incentives to do so.

[21] June 1, 2012 Report-Attachment E18 thru E23, page 19 of 60, Docket No. E999/AA-11-792.

As noted above and in numerous comments by the Department in utilities' resource plans,[22] it will be important for utilities to have enough generation to meet their load given the upcoming EPA changes expected to significantly affect coal plants within the U.S., including the MISO footprint, effective 2015-2016. While the results will not be known until the MATS and other rules take effect, it has been estimated that 12.6 GW of coal plants in the MISO market may be at risk for retirement. The Department has included a MISO summary on EPA impacts with links to MISO analysis and on-going work below. The effects of this and potentially other rules, along with aging resources and the continuing economic recovery in Minnesota and the MISO region will likely put upward pressure on energy prices in the MISO market and put ratepayers at risk for significantly higher costs in the near future. As a result, under the current ratemaking structure, ratepayers of utilities that are relying on the MISO market excessively, rather than having sufficient generation to meet their load will likely see a significant increase in their bills as those energy costs are simply passed on to ratepayers with no risk or responsibility for untimely planning incurred by the utilities.

> MISO Summary on EPA Impacts:
> MISO completed its EPA Impact Analysis in 2012[23] and works to further evaluate compliance risks and facilitate optimal solutions. MISO is now conducting multi-faceted analyses that:
>
> - Calculate safe outage window capacities
> - Survey generation owners of compliance strategies
> - Track and forecast emissions by generation unit
> - Assess natural gas infrastructure capabilities –
>   - Phase 1 - Report
>   - Phase 2 - Report
> - Assess supply chain capabilities
> - Review Attachment Y retirement request processes
> - Determine Tariff changes and file with the FERC
>
> Through these consolidated analyses, MISO aims to inform state regulators and generation owners about potential risks and suggest strategies, including potential Tariff changes, to best comply with the regulations.
>
> Coal & Natural Gas Concerns
> Initial MISO analyses indicates approximately 86 percent of the coal fleet will require action to comply with the regulations. The 2011 EPA Impact Analysis found that some generators will retire while others will be retrofitted with additional environmental controls.
>
> Whether due to EPA related coal retirements or lower natural gas prices, MISO anticipates increased utilization of natural gas fuelled generation resulting in changes to the system's generation configuration and concerns about the ability of the current pipeline infrastructure's ability to deliver enough gas.

[22] The most recent example is the Department's June 3, 2013 comments in MP's resource plan, Docket No. E015/RP-13-53, page 37.
[23] See MISO's analysis at: EPA Impact Analysis. Links to other MISO analyses are in the text above, all of which is obtained from MISO's website.

To help ensure that utilities are efficient, ratemaking in regulation should provide a reasonable substitute for prices in a competitive market by requiring the regulated firm to consider and internalize all costs of providing service, including its energy costs. While the current regulatory construct worked when electric energy costs were fairly low and stable, and when there was excess generation capacity, the mechanism is not working under current circumstances, especially when utilities argue, in effect, that the burden of proof is on the Commission to disallow costs rather than the burden of proof being on the utility to show that their costs are reasonable. Such arguments turn ratemaking on its head and ignore the fact that the IOUs have the specific knowledge regarding their day-to-day operations; the Commission cannot be expected to micro-manage the utilities' operations.

The Department recommends that a more decentralized mechanism be used for IOUs to recover energy costs. This mechanism should be designed to ensure that energy costs are internalized by IOUs in the same manner that IOUs internalize capital costs (between rate cases) and thus would have an incentive to consider all costs as utilities make decisions. One such mechanism would be to set the level of energy costs a utility can recover over a given future period on the basis of a rolling average of previous actual energy costs ($/kWh) and let the IOUs manage their business the best they can. Over the long run, this approach should lead to lower energy costs and would include the effects of changes in the market over time. The issue here is whether regulators and IOUs are willing to take the risk of temporary excess benefits or costs.

2. *DOC Proposal*

While the Department is open to any reasonable proposal by other parties, the Department recommends that, rather than allowing utilities to recover all changes in energy costs on a month-to-month basis, recovery of energy costs should be fixed in a rate case, with no adjustment between rate cases, at the IOU's average energy costs ($/kWh) over the previous three years before a rate case is filed. While this approach could set the recovery of energy costs at a single rate throughout the year, it would be more appropriate to set the energy rates for each month of the year based on average costs for that month in the past three years, so that rates could provide better price signals to customers to reduce energy use during peak periods. This approach would give the IOUs clear incentives in between rate cases to minimize their total cost of doing business. That is, not only would utilities have an incentive to minimize capital and other costs recovered in base rates, but they would also have the same incentive to minimize energy costs.

The period for the calculation of this average should not be too short, to alleviate gaming of the system, nor too long, to take into account changes in the output mix of the IOUs. This balance is why the Department recommends a three-year period for calculating the average monthly costs.

As more recent years are added to the calculation proposed above in subsequent rate cases, the new three-year average would better reflect the costs of a firm that is minimizing its total cost of doing business. To ensure uniform treatment across all IOUs, the Department recommends that this new recovery mechanism be implemented at the earliest of each IOU's next rate case filing or July 1, 2014, which is the beginning of the next fiscal year (after the 2013-14 fiscal year) for annual automatic adjustments. The Department anticipates that the IOUs would continue to file monthly FCA filings and the annual automatic adjustment (AAA) reports for at least the near future, to assess how this approach is working in practice or to review any issues the Commission decides should be monitored under this approach.

In setting the fixed fuel cost rate, the Department prefers the use of a total comprehensive rate, i.e., all energy costs less offsetting asset-based and non asset based margins when applicable. However, the Department does not object to the use of a partial rate, i.e., all energy costs without offsetting asset-based and non asset-based margins. Given the different recovery mechanisms currently in place across IOUs and within IOUs as described in section V below, the Department is following up with discovery to collect the data that would be used for such proposals. This data will be filed and discussed in reply comments by the Department.

V. INDIVIDUAL ELECTRIC UTILITY EVALUATIONS

A. OVERVIEW

Table 4 summarizes the electric utilities' fuel-cost recovery during FYE12.[24] Xcel Electric's data is highlighted in the calculations below because the Company was granted a variance to charge FCA rates based on Xcel's forecast of fuel costs in the upcoming month, rather than the two-month average cost per kWh required by Minnesota Rules, and the Company adjusts its rates to refund or recover previous over- and under-recoveries of its energy costs through a monthly (2 lag-month) true-up.

TABLE 4
Summary of Automatic Fuel Adjustments
FYE12

Over-Recovery/ (Under-Recovery)	Utility	Fuel Cost Recovered ($)	Fuel Cost ($)	Over-Recovery/ (Under-Recovery) ($)(%)
DEA	$139,947,225	$137,938,728	$2,008,497	1.46%
Interstate Electric	$16,073,383	$17,125,241	($1,051,857)	(6.14%)
MP	$168,317,955	$172,309,289	($3,991,334)	(2.32%)
OTP	$45,472,638	$46,635,031	($1,162,393)	(2.49%)
Xcel Electric	*$820,658,807*	*$835,081,488*	*($14,422,681)*	*(1.73%)*

To review the electric utilities' calculations of automatic adjustment charges, the Department compared actual costs of fuel purchased during the year to the fuel costs recovered through automatic adjustments. The Department discusses each utility's recovery below.

The Department recognizes that utilities will normally experience small over-recoveries and under-recoveries. In the past, most fuel-cost variations have been caused by fluctuations in weather and by price volatility in the wholesale electric market. Higher-than-anticipated energy demand forces a utility to either generate or purchase additional power. As a result, marginal costs increase as demand increases, typically leading to under-recovery of fuel costs. The reverse is also true: lower-than-expected energy demand can cause fuel costs to fall and lead to

[24] Supporting spreadsheets for FYE12 data with Department's calculations are provided in Attachment E6 (Xcel Electric), Attachment E7 (IPL), Attachment E8 (MP), Attachment E9 (OTP) and Attachment E10 (Dakota).

over-recovery of fuel costs. The "2 and 3 lag-month" associated with the calculation of most utilities' energy-cost adjustments also leads to unexpected variations, since fuel costs incurred in a given month are recovered in later months.[25] Generator outages and a variety of other supply-side factors can also cause variations in fuel costs.

Prior to actions by the Federal Energy Regulatory Commission (FERC) that deregulated the wholesale market, fluctuations in wholesale prices were small on a month-to-month basis. However, these fluctuations are now much greater than before. As indicated above, the Department notes that the reporting period includes the seventh full year of costs incurred in the MISO Day 2 Market, which began on April 1, 2005. This issue is discussed further below.

B. DAKOTA ELECTRIC ASSOCIATION

Dakota serves about 101,000 Minnesota electric customers in the southern metropolitan area, in Dakota, Goodhue, Scott and Rice counties. Attachment E10 shows that DEA's resource adjustment includes $137,938,728 in fuel costs, which includes generation capacity and transmission costs from its suppliers, during the reporting period.[26]

Regulated utilities normally recover through their automatic adjustments only changes from the amounts set in a rate case of costs of fuel and energy from purchased power agreements; 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 increases Dakota's monthly over- and under-recoveries, since purchased capacity costs are not as closely linked to variations in sales as are energy costs. 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. INTERSTATE ELECTRIC

Interstate serves approximately 44,000 electric customers in Minnesota, primarily along the southern edge of Minnesota. As a relatively small electric utility, Interstate's level of fuel costs in the FCA was the lowest of all utilities, at $17,125,241 for FYE12.[27]

D. MINNESOTA POWER

Minnesota Power serves about 144,000 electric customers in northeastern Minnesota. MP's fuel costs in the FCA were $172,309,289 for FYE12.[28]

[25] During the reporting period, Interstate Electric, MP, and OTP used a moving-average process to calculate their energy-cost adjustments. The average costs that these utilities used for their adjustments were calculated using costs that were incurred two and three months prior to the month in which such costs were recovered. As noted above, Xcel Electric did not use this method during the reporting period.

[26] 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 energy needs from power suppliers, Great River Energy (GRE) and Energy Alternatives (EA).

[27] Source: Attachment E7.

E. 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 in the FCA were $46,635,031 for FYE12.[29]

F. XCEL ELECTRIC

Xcel Electric, which serves about 1.2 million electric customers in Minnesota, primarily in the metro area, had fuel costs in its FCA of $835,081,488 for FYE12.[30]

Xcel Electric is the only electric utility to use a forecasted FCA method, due to previous detrimental effects on Xcel's interruptible customers under the two-month lag approach.[31] Under this method Xcel Electric bases its monthly FCA on its one-month projection of fuel and purchased power costs. 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. As a result, unlike electric utilities that calculate their FCA using the method required in the Minnesota rules, Xcel Electric is expected to be better able to reflect current FCA costs in rates closer to the time when these costs are incurred.[32] Moreover, it is expected that Xcel Electric's recovery of costs, in general, will be more closely aligned with costs incurred, with less deviation in cost recovery compared to cost incurrence. However, while Xcel's monthly true-up should ensure that Xcel will recover costs closer to the time when those costs are incurred, this true-up method may also result in significant deviations in cost recovery in the month the true-up is implemented and distort information about current fuel costs.

The information in Table 4 above indicates that Xcel has the lowest percentage under-recovery during the most recent period, compared to other IOUs.

Preserve determination of recovery of replacement power costs for the Sherco Unit 3 extended plant outage to the September 1, 2013 AAA filing

One important point to note about Xcel's recover of costs during this period is the highly unusual, lengthy outage at its Sherco 3 unit. This issue has been discussed extensively in Xcel's most recent rate case, but at the time of these comments that case has not yet before the Commission for decisions. However, that case identified that the issue of replacement power costs should be addressed in this proceeding.

As a result of the Sherco 3 extended plant outage that began in November 2011 and is expected to return to service around September 2013, a significant level of replacement power costs have been charged to ratepayers via Xcel's FCA. Specifically, ratepayers have been charged $22.7 million in additional fuel costs for the period November 2011 to October 2012. The Department

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[28] Source: Attachment E8.
[29] Source: Attachment E9.
[30] Source: Attachment E6.
[31] See the Commission's May 4, 2012 Order in Docket No. E002/M-11-452.
[32] Under the method in the Commission's rules, a utility's cost recovery position may be positive or negative depending on the 12-month time frame selected over which cost recoveries are aggregated.

estimates replacement power costs to be approximately $40 million for the total extended plant outage. [33]

The Department notes that Xcel has not yet provided a report on the cause of Sherco Unit 3 outage, but according to the Company the report will be provided in the near term.[34] As a result, the Department recommends that the Commission preserve the determination of cost recovery related to the replacement power costs related to the Sherco Unit 3 extended plant outage until the next AAA filing made by the utilities in September 1, 2013, when full information about the cause of the extended plant outage is available and is able to be reviewed by the Department and other interested parties.

VI. EFFECTS OF THE 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;
- Interstate Electric, Docket No. E001/PA-01-1505, 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 four Minnesota electric investor-owned utility companies were required to provide the information below as part of their AAA report.[35] 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 four Minnesota Electric Utilities provided the following administrative charges, referred to as "Schedule 10 costs," billed by MISO for the period July 2011 through June 2012:

[33] See Campbell Direct Testimony pages 15 to 33, Campbell Surrebuttal Testimony pages 31 to 46.
[34] See Docket E002/GR-12-961, Hearing Transcript Volume 1, Xcel witness Kent Larson, pages 86-87, posted to edockets on May 3, 2013.
[35] See DOC Attachment E12 for all information request responses related to MISO Day 1.

Table 5: MISO Schedule 10 Costs for July 2011 through June 2012

	Total Company	Estimated MN Jurisdiction
Xcel Electric	$11,214,062[36]	$8,301,048
Interstate Power	$2,741,385[37]	$160,371
Minnesota Power	$2,032,963[38]	$1,576,970
Otter Tail Power	$738,838[39]	$343,452
Total	$16,727,248	$10,381,840[40]

The total amount charged to these companies for MISO Schedule 10 costs increased by $1,508,261 or 10% from the previous reporting period. The total estimated Minnesota jurisdictional amount resulted in an increase of $970,752 or a 10.31% increase from the previous reporting period. All four IOU's MISO Schedule 10 costs increased from the previous reporting period. Utilities noted that main reason for the Schedule 10 cost increase was due to the exit of First Energy on 5/31/2011 and Duke Ohio/Duke Kentucky on 12/31/2011 from the MISO footprint. When these members exited MISO, their loads were no longer in the denominator of the rate calculation, thus increasing the cost to remaining members. The Department recognizes that there are offsetting revenues for these stranded costs caused by First Energy and Duke Ohio/Duke Kentucky, which are returned to MISO members on MISO Schedules 37 and 38. In addition, the Department notes that in future AAA filings, MISO Schedule 10 costs are expected to decrease due to new MISO members, specifically Entergy.

The Department continues to monitor MISO Schedule 10 costs and expects the four Minnesota utilities in MISO to show benefits related to these costs in their rate cases before receiving cost recovery. This recovery and analysis occurs in rate-case proceedings, and has occurred in Xcel Electric's, Interstate Electric's, OTP's and MP's rate cases.

The Department recommends that the Commission require utilities to provide in the initial filing of all future electric AAA reports the Minnesota-jurisdictional MISO Schedule 10 costs, together with the allocation factor used, and support for why the allocator is reasonable. Additionally, the Department recommends that the Commission require the utilities to provide information to support any increases in MISO Schedule 10 costs of five percent or higher over the prior year's costs, including an explanation of benefits received by customers for these added costs. This additional information will expedite the Department's review of MISO Day 1 costs in future electric AAA filings.

[36] MISO Schedule 10 costs paid by NSP-Xcel consist mostly of Minnesota costs, with some costs for Wisconsin, North Dakota and South Dakota. The Department estimated the Minnesota jurisdiction's percentage of 74.02% using the jurisdictional allocator from Xcel's most recent rate case.

[37] MISO Schedule 10 costs paid by Alliant Energy for IPL for the AAA period. The Department assumed IPL's Minnesota's retail jurisdictional percentage at 5.85%.

[38] MISO Schedule 10 costs paid by MP for the AAA period with an average Minnesota retail jurisdictional percentage of 77.57%.

[39] MISO Schedule 10 costs paid by OTP for the AAA period. The estimated Minnesota retail jurisdictional percentage is 46.49%.

[40] Xcel's information request 15, OTP's information request 13, MP AAA initial filing's Attachment No. 6 and IPL's AAA initial filing's Attachment H provide the Minnesota Jurisdictional MISO Schedule 10 costs.

B. ANY AMOUNT OF MISO ADMINISTRATIVE CHARGE DEFERRED 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, 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.

The Department included the actual MISO Schedule 10 costs paid by utilities for July 2011 to June 2012 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 four utilities indicated that no such instances occurred during the reporting period July 2011 through June 2012.

D. EACH INSTANCE WHERE MISO DIRECTED THE CURTAILMENT OF A 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 four utilities indicated that no such instances occurred during the reporting period July 2011 through June 2012.

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 on retail rates in Minnesota of changes to MISO's tariffs. Specifically:

- During the period July 1, 2011 to June 30, 2012, MISO submitted significant number of filings to FERC, including proposed tariff changes to the MISO Open Access Transmission Energy and Operating Reserve Markets Tariff (Tariff), compliance filings, generation interconnection agreements subject to the Tariff, answers to complaints, and various other filings. Many of the proposed tariff changes and other filings may ultimately affect rates of retail electric customers in Minnesota in some manner. All MISO filings to FERC during the reporting period are available by month at the MISO web site (www.midwestiso.org) at the "FERC Filings and Orders" quick link. Xcel Electric's Part D, Section 8 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 Midwest ISO 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). They have begun to see cost allocations under the previously approved tariff schedules. MISO, with the support of Transmission Owners, filed changes to the RECB cost allocation process proposing that costs associated with Multi Value Projects (MVPs) be allocated across the entire MISO footprint rather than to nearby pricing zones. FERC approved this filing on December 16, 2010. Projects designated as MVPs are large scale transmission builds required to bring mandated energy (such as renewables) to load. The general consensus is that all loads will benefit from this type of build; therefore, all should share in the cost. MISO approved the first MVP for cost allocation, "The Michigan Thumb Project," and has given preliminary approval for the second MVP Project, "CAPX 2020 Brookings to Twin Cities Project." Utilities have begun to see charges associated with these projects in 2012.

- MISO 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 have noted some decreases in transmission revenues; however reduced transmission rates have benefited utilities that have needed to make energy purchases to serve native load customers. The utilities note that an increase in costs has occurred due to costs charged under Schedule 10, MISO's administrative charges (see discussion in section E.4.a above), but a decrease in costs has occurred due to the elimination of transmission rate "pancaking" and elimination of the MAPP or MAIN fee, which likely results in an slight overall net increase in cost.

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.

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 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 Market since its initial operation on April 2005 that 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 cost recovery of Schedule 10 costs.

The Department recommends that the Commission require utilities to provide in the initial filing of all future electric AAA reports the Minnesota-jurisdictional Schedule 10 costs together with the allocation factor used and support for why the allocator is reasonable. Additionally, the Department recommends that the Commission require utilities to provide information to support MISO Schedule 10 cost increases of five percent or higher over the prior year costs, including explanation of benefits received by customers for these added costs. This additional information would expedite the Department's review of MISO Day 1 costs in future electric AAA filings.

VII. EFFECTS OF THE MISO DAY 2 MARKETS ON MINNESOTA RATEPAYERS

A. BACKGROUND

This AAA report is based on seven full years of data under the MISO Day 2 energy market. Due to the significance of the MISO Day 1 and Day 2 markets on Minnesota ratepayers, the DOC dedicates this section to discussing the effects of these markets on the way utilities procure energy and the way these costs are reflected in rates.

MISO's Day 2 energy market[41] 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[42]), 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, MISO's tariff describes virtually all electric generation as a sale of electricity into a wholesale market, and describes the provision of electric service as

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

entailing a purchase of power back from the market. On the other hand, the Commission required utilities to continue to use the lowest cost resources to serve customers, so this fundamental aspect of service did not change. 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 Market, pursuant to its Transmission Energy Market 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.

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 FCA on an interim basis subject to refund.[43]

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 Schedule 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.[44]

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 would tend to cancel each other, the utility's records would 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.[45] These basic principles are still in place.

[43] Order Authorizing Interim Accounting for MISO Day 2 Costs, Subject to Refund with Interest (April 7, 2005).
[44] Order Establishing Second Interim Accounting for MISO Day 2 Costs, Providing for Refunds, and Initiating Investigation (December 21, 2005 Order).
[45] December 21, 2005 Order at Ordering Paragraph 10.

Third, on reconsideration, Commission granted all parties additional time in which 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 these 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.[46]

On June 22, 2006, the parties filed the Joint Report and Recommendation Regarding MISO Day 2 Cost Recovery (Joint Report) with the Commission.[47] The Joint Report was supplemented by the comments filed on November 6, 2006. In brief, the Joint Report recommended that the Commission authorize utilities to recover most Day 2 costs via their fuel 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 to the DOC several additional reporting requirements in their monthly FCA reports and AAA reports (ordering paragraph 7).

The DOC's analysis below is a limited review of MISO Day 2 overall charges, review of specific MISO Day 2 charges based on a fluctuation analysis, review of related allocations to customers, and review of 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 then 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.

[46] Order on Reconsideration Suspending Refund, Granting Deferred Accounting and Requiring Filings at 7-8.
[47] The Joint Report reflected the views of all parties except for what is now known as the Office of Attorney General, Anti-Trust and Utilities Division.

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 the past FYE2007 and FYE2008 AAA filings, it has become evident that generation outages can have a significant effect on LMPs in the Day 2 market.

The DOC discusses our review and audit of MISO Day 2 charges in the next section, including recommendations regarding overall cost review and allocation of MISO Day 2 charges between retail and 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; and
- Grandfathered Charges.

The DOC'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 FYE12 AAA Report. The Department notes that amounts 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:

Total MISO Day 2 Charges Assigned to Retail

AAA Reporting Period	2008-2009	2009-2010	2010-2011	2011-2012
Net Costs	$226.2 million	$191.5 million	$195.9 million	$196.6 million

The Department observes that Xcel Electric's MISO Day 2 net costs assigned to retail customers are generally increasing somewhat each year since the 2009-2010 year, although net costs were higher in 2008-2009 period when the MISO's locational marginal price (LMP) was higher.

The Department reviewed Xcel Electric's MISO Day 2 charges as reported in Part J Sections 1 to 3 narrative discussion and Part J Section 5 Schedules 1 through 7 for MISO Day 2 charges for the FYE12 AAA Report and continues to conclude that they are reasonable, with the exception of the two specific charge types described below, where the Department has asked for additional information.

First, the Department notes that Xcel's Day Ahead and Real Time Energy costs were about $8.6 higher ,or a 6.3 percent increase, in FYE12 ($146.1 million) compared to FYE11 ($137.5 million). As a result, the Department asks the Company to explain in its reply comments the reason for this increase in Day Ahead and Real Time Energy costs for FYE12.

Second, the Department notes that Xcel's Real Time Revenue Neutrality Uplift costs were about $4.7 million, or a 77.0 percent increase, in FYE12 ($10.9 million) compared to FYE 11 ($6.1 million). As a result, the Department asks the Company to in its reply comments the reasons for this increase in Real Time Revenue Neutrality Uplift costs for FYE12.

The Department also reviewed Xcel Electric's allocation of its MISO Day 2 charges across its retail, asset based wholesale/intersystem and non-asset based wholesale/intersystem. The Department described Xcel Electric's allocation methods in detail in the Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports*.[48] The Department recommends that Xcel Electric explain, in reply comments, if any of the Company's allocation methods have changed during the 2011-2012 reporting period. If so, the Department recommends that Xcel Electric explain, in reply comments, the nature of these changes and the effect these changes have had on the charges assigned to various customer categories in the 2011-2012 AAA Report.

The Department recommends that the Commission not accept Xcel Electric's MISO Day 2 reporting at this time, until the Company has provided the information above in its reply comments so the Department can review the information.

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

2. *Review of MP's MISO Day 2 Charges*

MP's Total MISO Day 2 Charges Assigned to Retail Customers

	2008-2009	2009-2010	2010-2011	2011-2012
Revenues	$10.5 million	$10.0 million	$12.2 million	$11.2 million
Costs	$37.8 million	$48.3 million	$73.0 million	$68.7 million
Net Costs	$27.3 million	$38.4 million	$60.9 million	$57.5 million

Source: MP FYE12 AAA Report. Amounts reported are the sum of MP's FPE Retail and FAC Resale customer categories.

MP's total MISO Day 2 total net costs are increasing, likely due to their growth in sales to large power customers in the most recent years. The Department reviewed Minnesota Power's MISO Day 2 charges as reported in Attachment 9 to its FYE12 AAA Report and concludes that they are reasonable, but requests that Minnesota Power provide additional information on two specific charges, described below.

Minnesota Power's Real Time Congestion Charges for the month of May, 2012 totaled negative $451,362, but did not fall below negative $200,000 in any other month. The Department requests that Minnesota Power, in reply comments, explain the conditions that led to this large credit.

Also in May, 2012, Minnesota Power's Real Time Miscellaneous Charges totaled negative $506,004. Real Time Miscellaneous charges did not exceed $20,000 in absolute terms in any other month. The Department requests that Minnesota Power describe in reply comments the nature of this charge in May, 2012, and provide any documentation it has received from MISO regarding the charge.

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*.[49]

Because those allocation methods have not changed, the Department describes 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.[50]

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

[50] As described in the Department's report in the FYE11 proceeding, the Department has some concerns about Minnesota Power's energy pricing algorithm. After highest-cost generation and purchases are allocated non-FCA customers, all remaining energy costs are then assigned to the FCA customers. In theory, this process should

The Department recommends that the Commission not accept MP's MISO Day 2 reporting at this time until the Company has provided the required information in its reply comments and the Department is able to review MP's information.

3. Review of OTP's MISO Day 2 Charges

OTP allocates its MISO Day 2 charges across three categories including retail, asset-based wholesale, and non-asset-based wholesale. OTP also refers to these categories as its "resource," "marketing" (OTPW) and "dealing" (OTPD) portfolios. OTP's MISO Day 2 charges for retail and asset-based wholesale are billed under OTPW settlement statements. MISO Day 2 charges for non-asset-based wholesale are billed separately under OTPD settlement statements. A summary of MISO Day 2 charges assigned to the three categories is provided in Attachment K of OTP's 2011-2012 AAA Report. The Department notes that amounts totals reflected in Attachment K are at the total Company level and not the Minnesota jurisdictional level.

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

Total MISO Day 2 Charges Assigned to Retail

AAA Reporting Period	2008-2009	2009-2010	2010-2011	2011-2012
Revenues	$253.9 million	$175.1 million	$115.1 million	$ 87.0 million
Costs	$276.3 million	$191.6 million	$131.2 million	$115.0 million
Net Costs	$22.4 million	$16.5 million	$16.1 million	$28.0 million

The Department reviewed OTP's MISO Day 2 charges as reported in Attachment K to its 2011-2012 AAA Report. The Department recommends that OTP explain, in reply comments, why the total 2011-2012 MISO Day 2 charges assigned to retail have increased from $16.1 million in 2010-2011 to $28.0 million in 2011-2012.

The Department also recommends that OTP provide additional information on two specific charges, described below.

OTP's Day Ahead Energy Losses (DA FBT Loss Amt) totaled $610,998.99 in August, 2011. This amount is significantly higher than the costs charged in other months during the 2011-2012 AAA reporting period. The Department recommends that OTP explain, in reply comments, why the Company incurred such large Day Ahead Energy Losses (DA FBT Loss Amt) in August, 2011.

OTP's Day Ahead Congestion (DA FBT Congestion Amt) costs totaled $245,090.15 in June, 2012. This amount is significantly higher than the costs charged to other months during the 2011-2012 AAA reporting period. The Department recommends that OTP explain, in reply

produce the same result as a process in which lowest-cost resources were directly allocated to FCA customers, and the remainder was assigned to non-FCA customers. However, the Department is concerned that unspecified differences between theory and reality (caused by estimation, rounding, difficulty measuring usage, etc.) may cause unintended distortions in the allocation process that inappropriately raise costs for FCA customers. Thus, the issues the Department raised in the FYE11 comments continue in this proceeding.

comments, why the Company incurred such large Day Ahead Congestion (DA FBT Congestion Amt) costs in June, 2012.

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*.[51] The Department recommends that OTP explain, in reply comments, if any of the Company's allocation methods have changed during the 2011-2012 reporting period. If so, the Department recommends that OTP explain, in reply comments, the nature of these changes and the effect these changes have had on the charges assigned to various customer categories in the 2011-2012 AAA Report.

The Department recommends that the Commission not accept OTP's MISO Day 2 reporting at this time until the Company has provided the required information in its reply comments and the Department is able to review OTP's information.

4. Review of IPL's MISO Day 2 Charges

Interstate Electric is unique in its treatment of MISO Day 2 costs compared to other Minnesota utilities. Interstate Electric does not allocate MISO Day 2 costs between retail customers and the wholesale sector, since Interstate Electric includes all energy costs, all energy revenues and all MWhs into its FCA. Interstate Electric uses the net of all costs and revenues and divides this amount by all MWhs. The DOC considers this approach to be an all-in method, which was approved in Interstate Electric's last two rate cases. One benefit of Interstate Electric's approach is its simplicity and the fact that there are no concerns about biased allocations of MISO Day 2 costs between retail customers and the wholesale sector. One drawback is that there is no attempt to assign the lowest cost resources to retail customers.

Interstate Electric's MISO Day 2 charges as shown on Attachment C of their FYE12 AAA filing, uses the format required by the Commission in its February 6, 2008 Order in Docket E999/AA-06-1208 ordering paragraphs 21 and 22.

As shown on Attachment C, page 13 of 13 for FYE11 and FYE12 AAA reports, the DOC noted a decrease in total company MISO Day 2 charges from FYE11 to FYE12. Specifically, total MISO Day 2 charges for FYE11 were a net cost of $82,058,623 and for FYE12 were a net cost of $71,737,920.

Based on a limited review, Interstate Electric's allocation of costs between Retail and Wholesale customers appears to be reasonable for the FYE12 reporting period and therefore the Department recommends that the Commission accept Interstate Electric's MISO Day 2 reporting.

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

Below is a table showing Net Costs assigned to Retail customers since FYE09.

	2008-2009	2009-2010	2010-2011	2011-2012
Revenues	$26.3 million	$11.5 million	$20.1 million	$22.5 million
Costs	$100.1 million	$102.8 million	$99.9 million	$92.3 million
Net Costs	$73.8 million	$91.3 million	$79.8 million	$69.8 million

D. ASSET BASED MARGIN OR WHOLESALE REVENUE REVIEW

1. Xcel Electric

Since the Department reviewed Xcel's asset based margins in its current rate case (Docket E002/GR-12-961), the Department performed a cursory review of Xcel Electric's asset based margins in the FYE12 AAA.

2. MP

The table below summarizes MP's actual wholesale asset-based margins over the period 2009 through 2012, 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 four-year period ($148.3 million) is roughly equal to the total revenue credit ($143.3 million) over the same period, differing by only three percent. However, on an annual basis, the difference between MP's actual margins and the revenue credit built into base rates fluctuates significantly, ranging from a $23.5 million benefit to shareholders in 2009 to an $8.2 million dollar loss for shareholders in 2012. The Department will continue to monitor MP's wholesale margins in future AAA filings.

Minnesota Power
Wholesale Asset-Based Margins

Calendar Year	Actual Margin	Revenue Credit Built into Base Rates	Shareholders Benefit/(Cost)	Percent Difference
[a]	[b]	[c]	[d]=[b]-[c]	[e]=[d]/[c]
2009	$53.8	$30.3	$23.5	78%
2010	$33.9	$37.7	($3.8)	-10%
2011	$31.1	$37.7	($6.6)	-18%
2012	$29.5	$37.7	($8.2)	-22%
Total	$148.3	$143.4	$4.9	3%

Sources:
2009 and 2010 Actuals: MP Response to DOC Information Request No. 58 in FYE09 and FYE10 AAA Proceeding
2011 Actual: MP's response to DOC Information Request No. 1 part (E) in Docket No. E015/M-11-1264.
2012 Actual: MP Response to DOC Information Request No. 21 in the instant proceeding
2009 Revenue Credit in Base Rates: May 4, 2009 Order in Docket No. E015/GR-08-415, page 17
2010-2012 Revenue Credit in Base Rates: November 2, 2010 Order in Docket E015/GR-09-1151

3. OTP

Regarding the issue of wholesale margin sharing, the Commission in OTP's rate case in Docket No. E017/GR-07-1178 decided to set a fixed level of asset-based margins in OTP's base rates, using a four-year average of asset-based margins, which resulted in a $5.41 million credit reduction to the benefit of ratepayers.

In OTP's most recently approved rate case in Docket No. E017/GR-10-239, the Commission approved a flow-through asset-based margin mechanism via the FCA (no longer a fixed credit method in base rates). As a result, OTP should have begun its sharing of asset-based margins with ratepayers in October 2011, which was to be reflected in OTP's December 2011 FCA.

The DOC reviewed the transition from fixed to the flow-through asset-based margins via the FCA in OTP's 2012 AAA filing. Moreover, the DOC confirmed that OTP began sharing its asset-based margins with ratepayers in its December 2011 FCA, in accordance with the Commission's decision in Docket No. E017/GR-10-239.

4. IPL

Due to IPL's all-in approach where all revenues and costs for retail and wholesale customers are included in their FCA and divided by total kWh, asset based margins are embedded in their total net fuel costs.

E. DOC INVOLVEMENT IN MISO PROCESSES

The DOC actively participates in 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 FERC on the more significant MISO filings. The OMS has also helped the DOC be more proactive in its interaction with MISO. The DOC continues to attend or listen to MISO Advisory Meetings, Annual Stakeholder and Sector Meetings with MISO, Resource Adequacy Workgroup and Supply Adequacy Workgroup (RAWG/SAWG) 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 DOC 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 DOC greatly appreciates the efforts and participation by the Commission and all entities in this process. In particular, the DOC 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 DOC concludes that the review of MISO Day 2 charges and allocations are complex. Due to the volume of information related to these transactions, and the less-than-transparent nature of MISO billings in allocating between retail and asset-based wholesale transactions and some of the utilities' fuel clause ratemaking processes.

Overall, utilities have improved the quality of their explanations regarding fluctuations and/or changes in MISO Day 2 overall costs and charges. As noted above, the DOC still has some remaining questions about overall MISO charges and cost allocations that we have asked utilities to respond to in their reply comments. Once this information is provided, the DOC will review the additional information and make our final recommendation to the Commission.

The DOC will continue to audit the MISO Day 2 charge and allocations between retail and wholesale customers. The DOC 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 have the responsibility to 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.

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 to the MISO as the Provider of Last Resort. 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. MISO's ASM began operations on January 6, 2009.

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 DOC 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 OES [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 OES [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.

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 meeting 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.

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

B. XCEL ELECTRIC

Xcel Electric provided its ASM review in its FYE12 AAA filing in Part J Section 5 Schedules 8 to 13 and in Part J Section 6 Schedules 1 to 3 as required by the Commission's August 23, 2010 Order in Docket M-08-528. Specifically, Xcel Electric provided the following information in their FYE11 regarding overall market performance of ASM to date as shown on Part J Section 6 page 1 of 6:

> During the 2010-2011 AAA Period, the Midwest ISO 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 behavior of the Market Participants and the operation of the market, noted in its 2010 State of the Market Report that the "ASM markets continue to perform as expected with no significant issues in 2010. ASM prices have been consistent with expectations and with ASM results in similar RTO markets. Ancillary service markets have produced significant benefits, leading to improved flexibility and less price volatility." The Market Monitor also noted an overall 10% decrease in regulation prices when compared to 2009 due primarily to an increase in capability by 16%.

The Department notes that Xcel did not provide any narrative for its ASM section in its current FYE12 AAA report, like they did in the FYE11 AAA. The Department recommends that Xcel Electric provide in their reply comments a brief narrative on ASM at the MISO level and at the Company level consistent with their report in FYE11 AAA. Further, Xcel should provide this information in future AAA filings, as required by the Commission's August 23, 2010 ASM Order, specifically ordering paragraph 10 as listed above in the background section.

Xcel Electric also provided (Part J Section 6 Schedule 1 pages 1 to 10) a calculation of their net savings related to ASM for FYE 2012. The Company shows $14.994 million in net savings for the total NSP system on page 10. Assuming the Minnesota Jurisdiction is 75 percent, the Department calculates a net savings for the Minnesota jurisdiction of $11.246 million. This net savings is associated with optimizing the generation units that are carrying ancillary services across the entire MISO footprint, and does not include any additional benefits that have accrued to ratepayers for reduction the regional regulatory reserve requirements. This calculation also reduces benefits by penalty charges and administrative costs.

Xcel Electric shows on its Part J Section 6 Schedule 2 the Excessive/Deficient Energy Deployment Charges of $102,868 for FYE12, which is down from $106,542 for FYE11. Xcel Electric also shows on its Part J Section 6 Schedule 3 the Contingency Reserve Deployment Failure Charges of $7,399 for FYE12, which is up from $1,731 for FYE11. The overall total of these charges is $110,267.56 for FYE12, slight increase from $108,273 for the FYE11 AAA period. The Department notes that the Company did not provide the causes for being charged for these Excessive/Deficient Energy Deployment and Contingency Reserve Development Failures for the current FYE 12 AAA period, as required by the Commission's August 23, 2010 ASM Order. As a result, Xcel Electric needs to provide that information in their reply comments.

Since the net amount for these two charges (Excessive/Deficient Energy Deployment Charges and Contingency Reserve Deployment Failure Charges) are up slightly and Xcel Electric has not explained the causes for these charges as required by the Commission's August 23, 2010 ASM Order, specifically ordering paragraph 11 as listed above in the background section, the DOC recommends that the Commission not accept Xcel Electric's ASM reporting at this time until the Company has provided the required information.

C. MP

MP addresses ASM costs and benefits in Attachment 10 to its FYE12 AAA Report. MP reports a net *cost* of $184,594 for FYE12, a notable reversal relative to FYE11, which saw a net *benefit* of $69,340. On page 3 of Attachment 10, MP attributed this change to a reduction in MWhs of regulation, spinning and supplemental reserves supplied by MP to the MISO market. The Department's review of MP's activity in the ASM market supports this assertion. Attachment 10-B to MP's FYE12 AAA Report contains a summary of MP's purchases and sales of ASM products. Attachment 10-B shows decreases in regulation services, spinning reserves and supplemental reserves supplied by MP in FYE12 relative to FYE11. Additionally, MP's procurement of each of the three services increased, which in combination with the decreased amounts supplied, resulted in large increases in MP's *net* purchases of each ASM product, measured on a mWh basis (MP was a net supplier of spinning reserves in FYE11 and FYE12, however, its net sales decreased in FYE12).

On page 3 of Attachment 10, MP stated generally that decreases in net ASM MWh supplied can be caused by factors which are out of the utility's control, including the amount of energy cleared at each unit, the amount of reserves cleared, reserve clearing price, reserve distribution costs and load ratio share. MP also stated that it changed its offer parameters at Boswell Unit 4 in order to clear more energy, leaving less of that unit's capacity available to be used for regulation service. The Department requests that MP describe this change and the reasons for it in more detail in reply comments.

Additionally, MP stated that limited hydro output at the Thomson Station reduced the amount of spinning reserves MP was able to offer into the market.

Attachment 10-A summarizes Minnesota Power's monthly charges for each ASM charge type. The Department notes that, in FYE12, MP incurred Contingency Reserve Deployment Failure Charges and Excessive/Deficient Energy Deployment Charges of $4,152 and $2,317, respectively, which are largely unchanged from FYE11. The Department considers Minnesota Power's costs to be reasonable. However, the increase in total ASM-related costs in FYE12 relative to FYE11 raises some minor concerns, so the Department will continue to monitor MP's activity in the ASM market in the future. Additionally, during its review, the Department noticed that the ASM charge amounts reported in Attachment 10-A do not exactly match the ASM charge amounts reported in Attachment 9, and requests that Minnesota Power explain the difference between the two Attachments in reply comments.

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 compares MP's MISO Schedule 17 charges prior to the start of the AMS market to its Schedule 17 charges in FYE12. In FYE12, average MISO Schedule 17 charges totaled $190,278, or $49,356 higher than the average monthly charges prior to the start of the ASM market. This amount equates to an average monthly increase of $0.01530 per MWh.

D. OTP

In Section V, Attachment L its FYE12 AAA Report, OTP provided its ASM information as required by the Commission's August 23, 2010 Order in Docket M-08-528. Specifically, OTP notes that ASM market transition has been smooth from an operational standpoint. OTP notes there has been a positive economic benefit for OTP, as a result of maximizing capabilities of generating units, which has lead to greater operational efficiency. 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 $32,764 to Minnesota ratepayers in 2011-2012. OTP allocates all ASM charges on a per MWh approach netting costs and benefits of the various charges.

The Department notes that ASM net benefits have decreased significantly from $230,559 in 2010-2011 to $32,764 in 2011-2012. The Department recommends that OTP explain this decrease in reply comments. The Department recommends that the Commission not accept OTP's ASM reporting at this time until the Company has provided the required information in its reply comments.

E. INTERSTATE ELECTRIC

On Attachments D through F of its FYE11 AAA filing, Interstate Electric provided its ASM information as required by the Commission's August 23, 2010 Order in Docket M-08-528. On Attachment D pages 1 through 8, Interstate Electric provided a summary of the 12 ASM charges for the period July 2011 through June 2012 categorized by Regulation, Spinning Reserve, Supplemental Reserve, and Other Charges. The DOC notes that Interstate Electric was a net purchaser for Regulation and Spinning Reserve and a net seller for Supplemental Reserve. Interstate Electric had charges in the Other Charges section totaling $70,334.[52] This amount compares to $73,995 reported in last year's AAA filing.[53]

In Attachment F, Interstate Electric reported three instances of Contingency Reserve Deployment Failure (CRDF) penalties, totaling $14,825 that was incurred during the current reporting period. This amount is an increase of approximately $12,000 compared to FYE11. Interstate Electric stated that,

> Almost all of the charges ($12,825.21) are related to a single instance on Hour Ending 16:00 on September 12, 2011, when the steam turbine at the Emery combined cycle plant was not able to ramp up at the offered ramp rate. Unfortunately, the Real Time Locational Marginal Price for that hour was $239.85 per MegaWatt-hour, which is extremely high and explains the high charge for that instance. IPL should be allowed to recover the CDRF charges in its rates. IPL follows good utility practices in maintaining its generating units, but even following good utility practices does not guarantee that a unit will *always* be responsive to control instructions in the exact manner expected.

[52] IPL 2012 Annual Filing Attachment D, "Other Charge Subtotal" for all quarters in the reporting period.
[53] IPL 2011 Annual Filing Attachment D, "Other Charge Subtotal" for all quarters in the reporting period.

The DOC will continue to review and monitor CRDF amounts in future AAA filings.

Interstate Electric provided a narrative in Exhibit H that describes its ASM compliance information in Attachments D through F and explains its economic analysis. The DOC notes that Excessive/Deficient energy Deployment Charges increased slightly from $38,002.50 in FYE 11 to $42,761.13 in FYE12.

Interstate Electric also provided an Economic Savings Analysis for all four quarters of the reporting year in Attachment E. Interstate Electric calculated the energy savings due to not holding back plants for ancillary services, less the MISO Schedule 17 administrative costs for ASM, resulting in total net benefits of $2,378,964.50 for the current reporting period. In the prior reporting period, total net benefits equaled $1,314,507.

The DOC believes that Interstate Electric has done a reasonable job with its ASM compliance filing and concludes that it's ASM reporting and charges via the FCA are reasonable based on our review. The DOC recommends that the Commission accept Interstate Electric's ASM reporting.

IX. CHARTS FOR INFORMATIONAL PURPOSES

Attachment E11 shows various aspects of fuel charges and the effects on customers' bills.

A. AVERAGE RESIDENTIAL BILLS FOR 2011

The graph on page 1 of 4 of Attachment E11 illustrates the monthly average bills for residential customers in 2011-12. The information includes customer charges, energy charges, fuel clause adjustments, and Conservation Improvement Program (CIP) surcharges (as described on pp. 3-4 of Attachment E11). Overall, Otter Tail had the highest average monthly residential bill of $86.12, followed by Interstate Electric at $85.17, Dakota Electric at $83.40, Xcel Electric at $72.23, and Minnesota Power with the lowest average of $62.68 per month.

B. ENERGY CHARGE + FCA (CENTS PER KWH) FOR EACH UTILITY

The graph on page 2 of 4 of Attachment E11 shows the amounts that residential customers paid 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 11.04¢/kWh, Interstate Electric with an average of 10.30¢/kWh, Xcel Electric with an average of 9.32¢/kWh, Otter Tail with an average of 7.43¢/kWh, and Minnesota Power 7.21¢/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 Section III Compliances, the Department recommends that the Commission accept the all compliance filings A to M, as discussed above.

Regarding Section IV (Freezing the FCA), while the Department is open to any reasonable proposal by other parties, the Department recommends that, rather than allowing utilities to recover all changes in energy costs on a month-to-month basis, recovery of energy costs should be fixed in a rate case, with no adjustment between rate cases, at the IOU's average energy costs ($/kWh) over the previous three years before a rate case is filed. While this approach could set the recovery of energy costs at a single rate throughout the year, it would be more appropriate to set the energy rates for each month of the year based on average costs for that month in the past three years, so that rates could provide better price signals to customers to reduce energy use during peak periods. This approach would give the IOUs clear incentives in between rate cases to minimize their total cost of doing business. That is, not only would utilities have an incentive to minimize capital and other costs recovered in base rates, but they would also have the same incentive to minimize energy costs.

The period for the calculation of this average should not be too short, to alleviate gaming of the system, nor too long, to take into account changes in the output mix of the IOUs. This balance is why the Department recommends a three-year period for calculating the average monthly costs.

As more recent years are added to the calculation proposed above in subsequent rate cases, the new three-year average would better reflect the costs of a firm that is minimizing its total cost of doing business. To ensure uniform treatment across all IOUs, the Department recommends that this new recovery mechanism be implemented at the earliest of each IOU's next rate case filing or July 1, 2014, which is the beginning of the next fiscal year (after the 2013-14 fiscal year) for annual automatic adjustments. The Department anticipates that the IOUs would continue to file monthly FCA filings and the annual automatic adjustment (AAA) reports for at least the near future, to assess how this approach is working in practice or to review any issues the Commission decides should be monitored under this approach.

In setting the fixed fuel cost rate, the Department prefers the use of a total comprehensive rate, i.e., all energy costs less offsetting asset-based and non asset based margins when applicable. However, the Department does not object to the use of a partial rate, i.e., all energy costs without offsetting asset-based and non asset-based margins. Given the different recovery mechanisms currently in place across IOUs and within IOUs as described in section V below, the Department is following up with discovery to collect the data that would be used for such proposals. This FCA

For Section V Individual Electric Utilities Evaluations, the Department recommends that the Commission preserve the determination of cost recovery related to the replacement power costs related to Xcel's Sherco Unit 3 extended plant outage until the next AAA filing made by the utilities in September 1, 2013, when full information about the cause of the extended plant outage is available and is able to be reviewed by the Department and other interested parties.

For Section VI Effects of the MISO Day 1 on Minnesota Ratepayers, the Department recommends the following:

- 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 cost recovery of Schedule 10 costs.

- The Department recommends that the Commission require utilities to provide in the initial filing of all future electric AAA reports the Minnesota-jurisdictional Schedule 10 costs together with the allocation factor used and support for why the allocator is reasonable. Additionally, the Department recommends that the Commission require utilities to provide information to support MISO Schedule 10 cost increases of five percent or higher over the prior year costs, including explanation of benefits received by customers for these added costs. This additional information would expedite the Department's review of MISO Day 1 costs in future electric AAA filings.

For Section VII Effects of the MISO Day 2 on Minnesota Ratepayers, the Department recommends the following:

<u>Xcel Electric</u>

- First, the Department notes that Day Ahead and Real Time Energy costs were about $8.6 higher or 6.3 percent increase in FYE12 of $146.1 million compared to FYE11 of $137.5 million. As a result, the Department asks Xcel Electric to explain in its reply comments the reason for this increase in Day Ahead and Real Time Energy costs for FYE12.

- Second, the Department notes that Real Time Revenue Neutrality Uplift costs were about $4.7 million or 77.0 percent increase in FYE12 of $10.9 million compared to FYE 11 of $6.1 million. As a result, the Department asks Xcel Electric to in its reply comments the reasons for this increase in Real Time Revenue Neutrality Uplift costs for FYE12.

- The Department recommends that Xcel Electric explain, in reply comments, if any of the Company's MISO Day 2 cost allocation methods have changed during the 2011-2012 reporting period. If so, the Department recommends that Xcel Electric explain, in reply comments, the nature of these changes and the effect these changes have had on the charges assigned to various customer categories in the 2011-2012 AAA Report.

- The Department recommends that the Commission not accept Xcel Electric's MISO Day 2 reporting at this time until the Company has provided the required information in its reply comments.

<u>Minnesota Power</u>

- The Department requests that Minnesota Power explain in reply comments the conditions that led to Real Time Congestion charges of negative $451,362 in May, 2012.

- The Department requests that Minnesota Power describe in reply comments the nature of the negative $506,004 Real Time Miscellaneous Charge in May, 2012, and provide any documentation received from MISO regarding the charge.

- The Department requests that Minnesota Power describe its reasons for changing its offer parameters for Boswell Unit 4 in order to clear more energy, leaving less of that unit's capacity available to be utilized for regulation service.

- The Department requests that Minnesota Power explain the differences in the FYE12 ASM charges reported in Attachment 9 and Attachment 10-A.

- The Department recommends that the Commission not accept MP's MISO Day 2 reporting at this time until the Company has provided the required information in its reply comments.

<u>Otter Tail Power</u>

- The Department has reviewed OTP's MISO Day 2 charges as reported in Attachment K to its 2011-2012 AAA Report. The Department recommends that OTP explain, in reply comments, why the total 2011-2012 MISO Day 2 charges assigned to retail have increased from $16.1 million in 2010-2011 to $28.0 million in 2011-2012.

- The Department also recommends that OTP provide additional information on two specific charges, described below.

- OTP's Day Ahead Energy Losses (DA FBT Loss Amt) totaled $610,998.99 in August, 2011. This is significantly higher than the costs charged to other months during the 2011-2012 AAA reporting period. The Department recommends that OTP explain, in reply comments, why the Company incurred such large Day Ahead Energy Losses (DA FBT Loss Amt) in August, 2011.

- OTP's Day Ahead Congestion (DA FBT Congestion Amt) costs totaled $245,090.15 in June, 2012. This is significantly higher than the costs charged to other months during the 2011-2012 AAA reporting period. The Department recommends that OTP explain, in reply comments, why the Company incurred such large Day Ahead Congestion (DA FBT Congestion Amt) costs in June, 2012.

- 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*.[54] The Department recommends that OTP explain, in reply comments, if any of the Company's allocation methods have changed during the 2011-2012 reporting period. If so, the Department recommends that OTP explain, in reply comments, the nature of these changes and the effect these changes have had on the charges assigned to various customer categories in the 2011-2012 AAA Report.

- The Department recommends that the Commission not accept OTP's MISO Day 2 reporting at this time until the Company has provided the required information in its reply comments.

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

Interstate Electric

- Based on a limited review, Interstate Electric's allocation of costs between Retail and Wholesale customers appears reasonable for the FYE12 reporting period and therefore the Department recommends the Commission accept Interstate Electric's MISO Day 2 reporting.

For Section VIII Ancillary Services Market (ASM), the Department recommends the following:

- The Department recommends that Xcel Electric provide a brief narrative on how the ASM is doing at the MISO level and at the Company level consistent with their report in FYE11 AAA, in their reply comments for FYE12 and in future AAA filings, as required by the Commission's August 23, 2010 ASM Order, specifically ordering paragraph 10 as listed above in the background section.

- Since the net amount for the two charges (Excessive/Deficient Energy Deployment Charges and Contingency Reserve Deployment Failure Charges) are up slightly and Xcel Electric has not explained the causes for these charges as required by the Commission's August 23, 2010 ASM Order, specifically ordering paragraph 11 as listed above in the background section, the DOC recommends the Commission not accept Xcel Electric's ASM reporting at this time until the Company has provided the required information in its reply comments.

- The Department requests that Minnesota Power explain the differences in the FYE12 ASM charges reported in Attachment 9 and Attachment 10-A in its reply comments prior to accepting its ASM reporting.

- The Department notes that ASM net benefits have decreased significantly from $230,559 in 2010-2011 to $32,764 in 2011-2012. The Department recommends that OTP explain this decrease in reply comments. The Department recommends that the Commission not accept OTP's ASM reporting at this time until the Company has provided the required information in its reply comments.

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