MINNESOTA DEPARTMENT OF COMMERCE

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December 31, 2014

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

RE: Response Comments of the Division of Energy Resources of the Minnesota Department of Commerce (DOC or the Department) to Electric Utilities' Reply Comments
Docket No. E999/AA-13-599

Dear Dr. Haar:

Attached please find the Department's *Response Comments* to the Office of the Attorney General-Antitrust and Utilities Division (OAG-AUD) *Reply Comments* and the electric utilities' *Reply Comments.* Specifically, the Department responds to the *Reply Comments* of the following parties:

- OAG-AUD, reply comments filed on September 26, 2014;
- Interstate Electric, reply comments filed on November 10, 2014;
- Minnesota Power, reply comments filed on November 10, 2014;
- Otter Tail Power Company, reply comments filed on November 10, 2014; and
- Xcel Electric, reply comments filed on November 10, 2014.

Based on the review of each of these parties' *Reply Comments*, the Department's *Reply Comments* contain revised recommendations to the original recommendations included in the Department's *Review of the 2012-2013 (FYE13) Annual Automatic Adjustment Reports for Electric Utilities* filed on September 16, 2014 (Report).

The Department recommends that the Minnesota Public Utilities Commission (Commission) adopt the Department's revised recommendations, as discussed in greater detail herein. The Department is available to answer any questions that the Commission may have.

Sincerely,

/s/ NANCY A. CAMPBELL
Financial Analyst

/s/ SAMIR OUANES
Rates Analyst

NAC/SO/lt
Attachment

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

REPLY COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

DOCKET NO. E999/AA-13-599

I. BACKGROUND

On September 16, 2014, the Division of Energy Resources of the Minnesota Department of Commerce (DOC or the Department) filed its *Review (Report) of the 2012-2013 (FYE13) Annual Automatic Adjustment Reports (AAA Reports)* with the Minnesota Public Utilities Commission (Commission) in the present docket. The Report pertains only to rate-regulated electric utilities. In its Report, the Department requested that the electric utilities address specific concerns in *Reply Comments*. The following are the electric utilities that filed reply comments on November 10, 2014:

- Interstate Electric (IPL);
- Minnesota Power (MP);
- Otter Tail Power Company (OTP); and
- Northern States Power, d/b/a Xcel Electric (Xcel).

In addition, the Office of the Attorney General-Antitrust and Utilities Division (OAG-AUD) filed *Reply Comments.* Below, the Department responds to each set of *Reply Comments* and provides the Department's recommendations based on our review.

II. DEPARTMENT ANALYSIS – COMPLIANCE ISSUES

A. PLANT OUTAGE CONTINGENCY PLANS AND SHARING LESSONS LEARNED

1. Background

At the outset, it is important to note that the discussion below does *not* address replacement power costs or utility practices regarding planned (unforced) outages that are generally within expectations. As discussed in the Department's comments and recommendations in Docket No. E999/AA-12-757 (12-757), due to discussions over the years between the Department and utilities, these and other issues have largely been resolved reasonably.

Instead, this discussion is about replacement power costs that are charged to ratepayers through the FCA during: unplanned (forced) outages. Specifically, in its April 6, 2012 Order in Docket Nos. E999/AA-09-961 and E999/AA-10-884 (2012 Order), the Commission required the investor-owned utilities (IOUs) to provide 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.

While the Department concluded that the IOUs complied with the 2012 Order in their initial FYE13 AAA reports, the Department requested that utilities provide the following additional information in reply comments to identify solutions to outage-related issues:

- How Minnesota and other utilities can share best practices across utilities in a timely manner (*e.g.*, videos as Xcel describes, electronic bulletins of best practices) to ensure that as many generation plants as possible maximize the days of operation and minimize the number of unexpected, or forced outages.
- Utilities should discuss any electronic databases that have been developed to share best practices in plant maintenance and repair.
- Utilities should discuss their efforts to obtain Business Interruption Insurance due to any factor that causes an unplanned outage or longer-than-expected planned outages.
- If utilities have not obtained Business Interruption Insurance, they should provide a full explanation as to why not.
- Utilities should discuss any revisions of language in contracts with contractors working on plants to increase the contractor's accountability in minimizing the length of the outage and ensuring that the plant runs smoothly.
- Utilities should discuss any efforts to recoup replacement power costs from contractors that worked on plants that subsequently had outages, or any other source of reimbursement for replacement power costs.
- If utilities did not pursue any reimbursement for replacement power costs, utilities should provide a full explanation as to why not.
- Utilities should provide the dates and duration of their scheduled and forced outages by plant since 2001.
- Utilities should discuss the general factors utilities consider in scheduling planned outages.

The IOUs provided the requested information in their November 10, 2014 respective reply comments.

As explained in the Report, the rationale for these questions is not for utilities to release confidential information. Instead, the goal is for utilities to share information about best practices to allow more generators to avoid forced outages so that, when forced outages occur for one utility, there will be more supplies of electricity from other suppliers, thereby reducing the cost of replacement power for the utility with the forced outage.

The Department's FYE11 investigation of forced outages for the IOUs highlighted the lack of incentive by the IOUs to minimize energy costs.[1] The Department concluded that the IOUs appear to act as if their ratepayers, not the IOUs' management and/or shareholders, should be held accountable for all of the costs of forced outages even when the outages are the result of a utility's employee errors or outside vendors' mistakes. The Department's investigation also highlighted the inherent difficulties the Commission faces in attempting to address such issues after-the-fact, particularly when utilities argue that the burden of proof regarding the statutory requirement concerning reasonable rates shifts from utilities to regulators.

As discussed further in the Department's reply comments to be filed by December 31, 2014 in Docket 12-757, the Department recommends an alternative ratemaking approach to encourage utilities to consider all costs in providing service, including replacement power costs, in short-term and long-term planning.

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 from ratepayers through the FCA, while costs to invest in and operate and maintain energy facilities are typically recovered through fixed base rates that do not change between rate cases. These two different recovery mechanisms – automatic adjustments and fixed recovery in rates – provide different incentives for utilities to minimize costs in practice.

Utilities have acknowledged that base-rate recovery provides a stronger incentive to minimize costs than FCA recovery. For example, as Otter Tail Power stated in a recent petition before the Commission:[2]

> …treating replacement energy costs differently [recovered through the FCA] from the allowance costs [recovered in base rates] would serve as a disincentive to purchase allowances even when doing so would be less costly than curtailing plant operations and purchasing replacement energy.

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 proposes such an incentive in its 12-757 comments.

However, because such a mechanism is not yet in place, and because the incentive to minimize total costs is not as strong when costs are automatically recovered from ratepayers, the Department concludes that the IOUs must show that they are meeting their burden of proof to show that rates they are charging are reasonable. For example, utilities should be aware of causes of forced outages before they request recovery of replacement

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[1] Department's December 12, 2012 Response Comments in Docket No. E999/AA-11-792.

[2] Docket No. E017/M-14-649, petition at 15.

energy costs. Further, utilities may be able to reduce the costs that ratepayers pay for longer-than-expected plant outages by holding their employees and contractors more accountable for errors and delays, and through insurance options.

2. Sharing Lessons Learned

In response to the Department's request for information on managing generator outages, utilities provided several responses.

OTP stated that the IOUs held several conference calls to share information about how they gather information and stay abreast of issues around plant operations and maintenance, in response to the Department's request for additional information discussed above. MP stated that they are members of the Fossil Operations and Maintenance Information Service (FOMIS), which provides members with access to an electronic user group forum where questions can be submitted for other utilities to answer, along with a searchable database to retrieve previous questions asked by other users and any responses.

The Department appreciates the IOUs' willingness to identify and share the sources of information they use.[3] Voluntary participation in forums, associations and conferences may be helpful; however, what is really needed is a system such as that used for nuclear power plants, as discussed in Xcel's comments (at 8-9):

> On the nuclear side, the Nuclear Organization at Xcel Energy has an extensive Operating Experience program that results in the sharing of operating experiences between nuclear power plants in the United States and around the world. Sharing of operating experience is required by the Nuclear Regulatory Commission and facilitated by Xcel Energy's membership in the Institute of Nuclear Power Operations (INPO) and the United Services Alliance (USA) peer groups.
>
> The creation of the nuclear industry's Operating Experience Program stems from the Three Mile Island accident and a recommendation by the Kemeny Commission for nuclear power plants to establish a means to systematically gather, review, and analyze operating experience at all nuclear power plants. In response, the US nuclear utilities industry established the INPO. The initial operating experience program was called the Significant Event Evaluation and Information Network (SEE-IN) Program. It was developed jointly by INPO and the Nuclear Safety Analysis Center at the Electric Power Research Institute (EPRI) in early 1980. The program objective was to provide a systematic means of sharing operating experience information among nuclear power plants.

[3] See OTP's list of forums for information sharing, Attachment 1 of OTP's Reply Comments.

> Following the reactor accident at Chernobyl Nuclear Power Plant in April 1986, utilities operating nuclear power plants worldwide formed the World Association of Nuclear Operators (WANO). The INPO Operating Experience Program interfaces with the WANO Operating Experience Program to ensure that INPO members benefit from international experience and to share U.S. nuclear industry experiences internationally.
>
> The objective of the Nuclear Operating Experience Program is to improve operating nuclear power plant safety and reliability by allowing each plant to learn from the operating experience of the world community of nuclear plants.

These important efforts to improve the reliability and safety of nuclear plants were not voluntary programs; instead, as Xcel stated, "Sharing of operating experience is required by the Nuclear Regulatory Commission." While Xcel does "not believe that any additional centralized systems are necessary for sharing best practices," the Department concludes that utilities have not shown why fossil-fueled generation facilities would not benefit from a mandatory centralized information system about outages and preventative efforts. There should be greater assurance that utilities are taking all reasonable steps to keep their plants operating safely and reliably. As fossil fuel plants continue to age, such a resource will become even more valuable.

For example, if the FOMIS program that MP described is at the same high standard as INPO, membership in such an organization, particularly if it is made up of owners of generation facilities similar to those in Minnesota, may be valuable. In any case, any utility requesting recovery of replacement power costs due to forced outages should be required to show that it has pursued all reasonable options both to avoid the forced outage and to minimize replacement power costs.

The Department does not agree with IPL that "it is difficult to convey sufficient information in a printed report that would aid other utilities in reducing forced outages." As discussed further under the Department's forced outages-related recommendations in Docket No. E999/AA-11-792, a big step forward to alleviate, for example, a reoccurrence of MP's January 2011 forced outage at Boswell Energy Center 4, which resulted in an additional cost to MP's ratepayers of more than half a million dollars through the FCA, would include:

1) a short description of the source of the forced outage (see Attachment E5 of the Department's Report),
2) the identification of the vendor that provided the "incompatible o-rings," and
3) quality management improvements such as oversight of contractors, including raising and following-up on red flags when replacement parts that need to be made of a specific material cannot be identified based on their color anymore.[4]

[4] Background information is available at pp. 40-45 of the Department's December 12, 2012 Response Comments in Docket No. E999/AA-11-792, available at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={29D584DF-51F7-4DC3-A2D2-38777542C303}&documentTitle=201212-81728-01 and summary in Attachment E5 of the Department's Report, available at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={8F4704DF-FF11-4E08-9DC4-4DA65EBD8FAD}&documentTitle=20149-103105-02

Again, Xcel Electric identified an important source for lessons learned specific to the nuclear industry, which describes the attributes of the program as follows:[5]

- The organization avoids complacency and cultivates a continuous learning. The attitude that "it can't happen here" is not allowed.
- Individuals are well informed of the underlying lessons learned from significant industry and station events, and are committed to not repeating these mistakes.

At least until there is a change in the FCA design, the Department recommends that the Commission require any IOU requesting recovery of replacement power costs due to forced outages to show that it has pursued all reasonable options both to avoid the forced outage and to minimize replacement power costs. At a minimum, Minnesota IOUS should develop a robust, searchable database applicable to non-nuclear facilities that shares the attributes of the SEE-IN program and provides for a systematic gathering, review, and analysis of operating experience at (Minnesota) IOUs-owned non-nuclear facilities. This database should help the IOUs identify and implement in-time solutions from the lessons learned from their own forced outages and other IOUs' forced outages and from their participation in industry forums.

Until a well-designed incentive mechanism is approved by the Commission, this searchable database would give utilities a basis to show the Commission, after-the fact, that their actions regarding plant operation and maintenance issues were prudent, a requirement necessary to meet the statutory requirement that rates charged by IOUs are reasonable.

3. Business Interruption Insurance

Utilities responded to the request for information about business interruption insurance largely by stating that it would not be a viable option; however, none of the utilities provided any quotes from insurance companies for the costs of business interruption insurance for fossil-fueled generation facilities.

According to OTP,

> Otter Tail requested a quote for this type of coverage. The minimum deductible for such coverage was not tied to a dollar value, but was instead tied to the length of time of the business interruption. In this particular case, the time element was 60 days. In other words, the coverage for business interruption would not start until *after* the forced outage or outage extension went beyond 60 days.

OTP concluded that "the cost of the additional premium for such coverage outweighed the benefit of adding that coverage." However, OTP did not provide the results of the quote or the cost of the premium.

[5] Source: http://www.nrc.gov/public-involve/conference-symposia/ric/past/2005/slides/04-f2-gard.pdf

MP has business interruption coverage, but only for its Bison wind assets and the DC line converter stations. MP purchased the coverage to "protect the low cost energy and related production tax credits for MP's customers." MP explained that it did not purchase business interruption insurance for its thermal or hydro generation assets based on "market conditions, the company's expected energy position, and available business interruption coverage terms." MP's assessment led the Company to conclude that it would not be cost effective to obtain such insurance. However, MP did not provide any data to support that claim.

Xcel Electric was the only utility that provided a cost estimate for the business interruption insurance; however, this estimate was Xcel's figure and was not supported by quotes from any insurance company. Xcel Electric also stated that it does "not believe that business interruption insurance for our non-nuclear fleet is cost effective or in the best interest of our customers." By contrast, Xcel Electric stated that it carries nuclear business interruption insurance because it is "very cost-effective," even though "the nuclear business interruption insurance does not start providing coverage until the outage has lasted at least 12 weeks."

Given the lack of support by utilities for their statements, the Department discussed this issue with Minnesota Insurance Regulators, who noted that, if utilities can pass all costs of replacement power through the FCA to ratepayers, the risk of high replacement power costs would be transferred to ratepayers, leaving little or no risk to insure for utilities. Even if, say, a utility bought business interruption insurance on behalf of its customers and charged ratepayers for those costs in the FCA, the mechanism would be flawed because the party that would bear the risk (ratepayers) would not be the party that could manage the risk (utilities) by abiding by inspection and repair guidelines, hold contractors accountable for their missteps, etc.:

> We can find ways to cover this exposure/risk, you can also utilize a Boiler & Machinery product and/or Business Interruption policy. The difficulty is that the Utilities have no "skin in the game", i.e., the regulation change needs to come first, the insurance industry could then respond. At this point, there is no incentive to the utility to purchase the coverage.

Of course, ratepayers could not ensure that utilities followed all of those practices to minimize the risk of an unplanned outage; thus, the risk/responsibility structure would be flawed. The Department discusses a way to balance this risk and responsibility more appropriately between ratepayers and shareholders in its comments and proposal in Docket 12-757.

4. Contractors' Accountability for Replacement Energy Costs

The IOUs appear to agree with IPL's statement that "construction contractors do not agree to include replacement power costs as a remedy for a project of any size." OTP stated:

> …it is Otter Tail's experience that most sophisticated vendors will not set agree [sic] to a project with the prospect of unlimited exposure to indirect damages (e.g., replacement power costs). On the other hand, contractors are usually able to insure against direct damages (e.g., physical injuries/death or property

> damage). Most sophisticated vendors will insist on language that forecloses recovery for indirect damages and also imposes a cap or limitation of liability.

However, Xcel Electric stated that in the past two years, it has used a "Quality Management" program with contractors, which uses approaches such as: (1) identifying and working with parties that have a history of performing work safely, reliably, and in a timely manner; (2) investing time and resources in developing a better scope of work; and (3) specifically identifying the required oversight for supplier repairs of plant equipment as well as independent inspection of the contractors performing the plant equipment/component installation activities.

Xcel's program, identified in more detail in Attachment D of its November 10 comments, appears to be a reasonable start to holding contractors more accountable for replacement power costs. If the FCA incentive is not changed, the Department recommends that the Commission require all utilities to adopt such a program, to the extent those practices are not already in place.

In addition, the Department recommends that the Commission require Xcel and other utilities add language to the "Supplier Warranties" section of the contracts to indicate that contractors may be liable for a limited amount of replacement power costs, such as a stated dollar amount per day, for any defect with respect to contractor work that caused a material delay in an outage. For example, Xcel could consider language such as the following:

> Upon receipt of notice from Company of any failure to comply with the terms of the Agreement including these General Conditions, without limitation, any defect with respect to the Work, either prior to or during the term of the Warranty Period, Supplier shall without additional compensation re-perform, repair or replace such defective Work within a reasonable time acceptable to Company and reimburse Company for Company's reasonable costs and expenses resulting from Company's cure of defective Work, (the cost of removal and reinstallation are not reimbursable by Contractor unless mutually agreed to on the Purchase Order/Work Order or if installation is part of Contractor's initial scope of Work) including any transportation costs incurred by Company, <u>a portion of replacement power costs not otherwise secured by the Company,</u> subject to the limitations and exclusions in Sections 30.2 and 30.3 below. If Supplier fails to timely reperform, repair or replace any such defective Work, Company may cause such defective Work to be replaced by another and the reasonable expense thereof shall be the responsibility of Supplier.

Such a provision would apply if the contractor did not perform satisfactorily, which was the concern the Department raised regarding Boswell 4 (the o-rings). By limiting the potential for contractor liability for replacement power costs only to when a contractor fails to comply with the contract, and limiting the amount of replacement power costs to a specific amount or formula, this provision should be acceptable to contractors. Nonetheless, this provision would place the responsibility for the higher replacement power costs on the entity that caused the higher costs and would reduce the amount of replacement power costs charged to ratepayers.

5. *Summary of the Lessons Learned Recommendations*

At least until the FCA incentive is changed, the Department recommends that the Commission require the following for IOUs:

1) Utilities seeking to recover replacement power costs due to a forced outage must provide;
    a. Information showing the causes of forced outages;
    b. Efforts the utility took to prevent the forced outage;
    c. Efforts the utility took to minimize the length of the forced outage;
    d. Efforts the utility took to protect ratepayers from having to pay for the costs of the forced outage;
    e. Efforts the utility took to recover replacement power costs from all potential sources; and
    f. The amount by which the replacement power costs exceed the power costs the utility would otherwise have charged ratepayers.
2) IOUs must develop a searchable database applicable to non-nuclear facilities that shares the attributes of the SEE-IN program and provides for a systematic gathering, review, and analysis of operating experience at (Minnesota) IOUs-owned non-nuclear facilities.
3) Utilities should adopt Xcel's program, identified in more detail in Attachment D of its November 10 comments, to hold contractors more accountable for replacement power costs, to the extent those practices are not already in place.
4) Xcel and other utilities should add language to the "Supplier Warranties" section of the contracts as discussed above to indicate that contractors may be liable for a limited amount of replacement power costs.

B. QUARTERLY REPORTING ON ACCOUNTING COSTS OF INTERSTATE ELECTRIC'S AUCTION REVENUE RIGHTS (ARR) (DOCKET NO. E001/M-09-455)

1. *Background*

In its Report, the Department noted in Section N that an erratum filed by Interstate Electric indicated that approximately $1.9 million in low-load auction revenue rights (ARR) proceeds were not properly credited back through the FCA during the specific months falling under the MISO 2012/2013 planning year, and would be credited back to customers as a make-whole payment in the Company's September and October 2014 FCA factors.[6] This correction is necessary because the October 2, 2009 Commission order in Docket No. E-001/M-09-455 required all ARR revenues to flow back to Minnesota customers.

The Department requested that Interstate Electric provide clarification confirming the crediting back of the proceeds, with regard to costs described in the Company's response to DOC IR 4, which detailed the accidental omission of revenues from quarterly reports between June 2012 and May 2013.

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[6] Report at 17

In its Report, the Department recommended that the Commission require IPL to provide the following information in Reply Comments:

A. Clarification whether the $1.9 million in low-load ARR proceeds are related to the costs described in Interstate Electrics response to DOC IR 4.
B. Confirmation that the refunded amounts have been correctly calculated and refunded to customers.
C. Information to identify solutions to issues regarding forced outages.

Interstate Electric's Reply Comments responded to the requested information.

2. Auction Revenue Rights (ARR) Proceeds

IPL indicated in Reply Comments:

> The approximately $1.9 million in low-load ARR proceeds, which were not properly credited back through the FCA as noted in Interstate Electric's erratum filing of the quarterly report for the 2012/2013 planning year, are the same costs as described in IPL's response to Department Information Request No. 4 in which the Company notes the accidental omission of revenues from quarterly reports for the period between June 2012 and May 2013.[7]

The Company confirmed that the ARR revenue inadvertently omitted from the quarterly reports did in fact flow to Minnesota customers through monthly MISO statements. The Department is satisfied that the low-load ARR proceeds are the same costs that the Company described in its response to DOC IR 4.

Interstate Electric provided Attachments A-C with its Reply Comments showing calculation and verification of the return of the approximately $1.9 million of ARR revenues to Minnesota customers.

3. Recommendations

The Department concludes that Interstate Electric did a reasonable job explaining and clarifying information requested by the Department regarding the refund to Minnesota customers of ARR revenues through the monthly FCA factors. The Department recommends that the Commission accept the Company's compliance filing N regarding quarterly filings of accounting costs for Auction Revenue Rights.

[7] Interstate Electric Company's November 10, 2014 Reply Comments, p. 2

III. SHERCO 3

A. SUMMARY OF DEPARTMENT'S REVIEW AND RECOMMENDATIONS IN THE REPORT

The Department's prudency review of Xcel Electric's replacement energy costs related to the Sherco 3 outage between November 2011 and December 2013 identified the additional fuel costs that have been charged to Xcel's ratepayers.

The Root Cause Analysis Report filed by Xcel Electric on October 21, 2013 in Docket Nos. E002/GR-13-868 and E002/AA-13-599 indicated that the outage was likely caused, not by abnormal operating conditions or maintenance practices, but by the original design of the finger-pinned blade attachments.

Following discovery by the Department, Xcel Electric provided a copy of the amended complaint filed by Xcel Electric, Southern Minnesota Municipal Power Agency (SMMPA), and insurers of Sherco 3 against General Electric entities (GE) to recover costs associated with the Sherco 3 outage.[8]

The amended complaint indicated that:

1) GE had specialized knowledge about the risks of stress corrosion cracking (SCC)-related failure associated with the finger dovetail (areas where turbine blades are inserted into the rotor wheel) in the Low Pressure (LP) turbine but failed to share information with Xcel Electric and SMMPA;

2) If this special knowledge had been shared with Xcel Electric and SMMPA, proper turbine inspection and maintenance could have prevented the substantial property damage caused by SCC in the LP turbine; and

3) Xcel Electric was not aware or informed directly or indirectly about the risks associated with SCC in LP turbines.

The Department noted that the legal process regarding Sherco 3 is likely to take several years to complete.

The Department also noted that, during the legal process, additional facts may be developed through either briefs or discovery that is not available to date.

Therefore, the Department concluded that the Commission may want to retain the right to revisit this issue if additional facts developed during the legal process contradict the record to date.

Finally, the Department noted that the Commission has the authority to make refunds and changes in allocations between retail and wholesale customers in the AAA filing, based on the review and recommendations by the Department (or other interested parties).

[8] The amended complaint was added to the record by the Department under Attachment E7 of the Report, available at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={8F4704DF-FF11-4E08-9DC4-4DA65EBD8FAD}&documentTitle=20149-103105-02

B. SUMMARY OF OAG-AUD'S REPLY COMMENTS AND XCEL'S REPLY COMMENTS

On September 26, 2014, the Office of the Attorney General-Antitrust and Utilities Division (OAG-AUD) filed reply comments in response to the Department's development of the record and recommendations regarding Sherco 3 in the Report.

The OAG-AUD recommended that:

> The Commission should continue to defer action on the issue of replacement power costs related to Sherco 3 while Xcel Energy's claims for those costs against third-parties are adjudicated. The record currently available does not support conclusions regarding liability for those costs. Alternatively, if the Commission does not want to wait for resolution of the litigation of these questions, it could commence its own investigation and process to answer those questions. In either event, the Commission does not have the necessary information at this time.

On November 19, 2014, Xcel Electric filed reply comments confirming that the litigation will take several years. Xcel stated that the GE trial date has been revised to September 2016.

Xcel Electric also stated that:

> Contrary to the OAG's suggestion, it is not necessary to direct the Company to provide continuous information for review—we have been and will continue to provide information relating to the Sherco 3 event and insurance recovery in the rate case and AAA dockets on a regular basis. We do not believe additional reporting requirements are needed at this time and will update the Commission as developments occur.
>
> …
>
> The OAG has additionally recommended consideration of opening a separate docket in which to monitor the GE litigation. We do not believe further procedural steps such as a docket to monitor another docket is necessary and certainly interested parties can monitor the litigation by following Docket Nos. E002/GR-13-868 and E002/GR-12-961, where we last filed an update on September 30, 2014.

The Department already noted in the Report that, during the legal process, additional facts may be developed through either briefs or discovery that are not available to date.

The Department agrees with Xcel Electric that it is not necessary to open a separate docket to monitor the litigation. Xcel Electric has committed to provide information relating to the Sherco 3 event and insurance recovery in the rate case and AAA dockets on a regular basis. Important information would include scheduling, findings about negligence, etc. Opening a separate Commission investigation would certainly be less efficient than the development of the record through the state district court action and likely would not benefit from the extensive information expected to be filed in that proceeding.

Finally, the Department notes that Xcel Electric agreed with the Department that "it may be necessary to reconsider the issue if additional information emerges through the litigation procedure."

Xcel Electric acknowledged that "to the extent there are further future developments leading to the specific award of our claim for replacement power costs in the GE litigation, the Commission can authorize such amounts can be dealt with [sic] at that time." The Commission could explicitly reserve the right to do so if it wishes.

Based on the record to date, the Department continues to recommend that the Commission find that the prudence of costs related to Sherco 3 outage between November 2011 and December 2013, as identified in the Report, remain subject to review by the Commission if additional facts develop during the legal process that contradict the record to date.

C. DEPARTMENT'S RECOMMENDATION

The Department continues to recommend that the Commission find that the prudence of costs related to Sherco 3 outage between November 2011 and December 2013, as identified in the Department's September 16, 2014 Report in Docket No. E999/AA-13-599, remain subject to review by the Commission if additional facts develop during the General Electric legal process that contradict the record to date.

IV. DEPARTMENT ANALYSIS – REVIEW OF MISO DAY 1 AND DAY 2 CHARGES & MODULE E – GENERATION DELIVERABILITY RESULTS, AND ASM

A. DOC'S RESPONSE TO XCEL ELECTRIC'S REPLY COMMENTS

The Department's Report asked Xcel Electric to respond to the following issues in reply comments:

1) Why the Company's total system Congestion and Financial Transmission Rights (FTR) Charges increased from $5,571,845[9] in fiscal year ending 2012 (FYE12) to $26,704,075[10] in fiscal year ending 2013 (FYE13), and why the percentage assigned to retail increased from 79.5 percent in FYE12 to 91.6 percent in FYE13.

2) Why the Company's total system MISO Revenue Sufficiency Guarantee (RSG) Charges (revenues) more than tripled from ($946,446)[11] in FYE12 to ($2,912,229)[12] in FYE13.

3) Why the Company's total system MISO Auction Revenue Rights (ARR) revenues nearly tripled from ($2,782,494)[13] in FYE12 to ($7,774,930)[14] in FYE13.

[9] Source: Xcel's initial filing in Docket 12-757, Part J, Section 5, Schedule 7, Page 13 of 13.
[10] Source: Xcel's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 7, Page 13 of 13.
[11] Source: Xcel's initial filing in Docket 12-757, Part J, Section 5, Schedule 7, Page 13 of 13.
[12] Source: Xcel's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 7, Page 13 of 13.
[13] Source: Xcel's initial filing in Docket 12-757, Part J, Section 5, Schedule 7, Page 13 of 13.
[14] Source: Xcel's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 7, Page 13 of 13.

4) Whether the Company's allocation methods used to allocate MISO Day 2 Charges changed during the 2012-2013 reporting period and, if so, the nature of these changes, why the allocator changes were reasonable and superior to previous allocators, and the effect these changes had on the charges assigned to various customer categories in the 2012-2013 AAA Report.

5) Why the Company's total system ASM costs increased from $10,665,160 in FYE12 to $22,631,901 in FYE13.

6) Whether the Company had determined the cause for the significant increase in the Excessive/Deficient Energy Deployment Charges (EDEDC) assigned to Sherco Units 1 and 2 in FYE13. In addition, the Department recommended that Xcel continue to work with MISO to mitigate these costs in the future.

7) Although the Department concluded that the Company's explanation for its Contingency Reserve Deployment Failure Charges appeared to be reasonable, the Department recommended that Xcel continue to work with MISO to mitigate these costs in the future.

The Department discusses Xcel Electric's responses to the Department's above issues and provides the Department's recommendations as a result of our additional review.

1) Congestion and FTR Charges

Beginning on page 2 of its reply comments, Xcel stated that the increase in congestion and FTR charges between FYE13 and FYE12 can be explained by the State of the Market Reports for MISO Electricity Markets (Reports), which is the Independent Market Monitor (IMM) for MISO prepared by Potomac Economics. According to Xcel, the 2012 Report stated that:

> Day-ahead congestion costs rose nearly 55 percent from $503 million in 2011 to $778 million in 2012. The sharp increase in day-ahead congestion was due in part to increased congestion on mid-to-low voltage constraints and continued enhancements to day-ahead processes to fully model potential transmission constraints in the day-ahead market. (Footnotes omitted).

In addition, the 2013 Report stated that:

> The increase in day-ahead congestion coincided with increases in fuel prices that generally increase the cost of redispatching generation to manage network power flows. Much of the increase occurred on internal constraints in the West Region, many of which are affected by the increasing output from wind resources. MISO has continued to enhance its day-ahead processes to fully model potential transmission constraints in the day-ahead market. (Footnote omitted).

With regards to the Department's question about the increase in percentage of Congestion and FTR Charges assigned to retail, Xcel stated that:

> As discussed above, congestion costs increased, and the largest sources of congestion costs are the low fuel cost baseload generators and renewable resources. One hundred percent of nuclear generation and at least seventy-five percent of coal generation are assigned to native customers. Wind cost assignment to retail customers is similarly large. These facilities are assigned the largest share of congestion costs.
>
> As explained above congestion and FTR charges are driven by the market conditions in a given reporting period. The market volatility influenced our decision to mitigate congestion and how we exercise our allocated FTRs. Therefore we believe charges incurred in one reporting period do not necessarily imply they should stay the same from past or future periods. For example, FYE13 congestion and FTR charges increased substantially from FYE12; however, the FYE12 amount was much lower than FYE1:

Congestion & FTR Charges	FYE 2013	FYE 2012	FYE 2011	FYE 2010
System	$26,704,07	$5,571,845	$16,298,90	$5,166,298
Retail	$24,474,23	$4,428,773	$14,758,70	$4,222,980
Retail %	91.6%	79.5%	90.6%	81.7%

The Department reviewed Xcel Electric's reply comments and agrees that fuel prices and wind resources account for a significant portion of its increase in congestion and FTR charges. Moreover, the Department notes that, as shown in the above table, it is not unusual for Xcel Electric to have significant fluctuations in its congestion and FTR charges and the percentages assigned to retail. The Department analyzed Xcel's congestion charges extensively in the previous AAA filing (e.g. Docket 12-757) and concluded that they were reasonable.[15] Based on the above, the Department concludes that Xcel Electric's congestion and FTR charges appear reasonable for FYE13.

2) MISO Revenue Sufficiency Guarantee (RSG) Charges (Revenues)

Beginning on page 4 of its reply comments, Xcel Electric stated that:

> In August 2012, FERC accepted MISO's cost allocation of Voltage and Local Relief (VLR) Mitigation filings. MISO changed the allocation method to direct charge the load zones where the VLR occurs. Typically highly variable resources such as wind are assigned a higher proportion of these costs as MISO needs to re-dispatch around the variability. The IMM provided further insight in the 2013 State of the Market for MISO Electricity Markets:

[15] See DOC's Response Comments in Docket 12-757, Pages 16-19.

RSG payments are made in both the day-ahead and real-time markets in order to ensure suppliers' offered costs are recovered when a unit is dispatched. Real-time RSG payments rose 54 percent from 2012 to $81 million, nearly half of which was due to the significant rise in fuel prices. Lower day-ahead purchases, particularly in the first half of the year, resulted in MISO making more resource commitments after the day-ahead market and increasing the capacity-related RSG payments. Day-ahead RSG payments increased by nearly 25 percent because of higher fuel prices and more VLR commitments, which are most often made day-ahead.

FERC recently approved changes we recommended to the allocation of RSG costs to make it substantially more consistent with their causes. These changes provide more efficient incentives to market participants.

As explained above, due to the timing of market events of late, the Company's RSG revenues might have exerted higher than normal fluctuation for FYE13 over FYE12. However the Company believes the report period for the AAA (12-months ending June 30) has coincidentally skewed the year to year deviation higher. When the RSG data is presented on a 2013 calendar month basis (January – December) the magnitude of annual fluctuation is less volatile, and the impact on RSG payments as a result of rising fuel prices was less drastic. The Company also notes the net RSG amounts in question were payments to the Company that helped offset other MISO charges. The FYE13 increase was a positive outcome to ratepayers.

Net MISO RSG Charges/(Revenues)	Calendar Year 2013	Calendar Year 2012	Calendar Year 2011
Amounts	($ 1,437,446)	($ 1,960,815)	($2,282,387787
% Change Over last Year	-26.7%	-14.1%	

The Department appreciates Xcel Electric's explanations regarding the increase in RSG charges (revenues). Given that these are revenue amounts, the Department notes that they are beneficial to ratepayers and offset some of the increase in congestion and FTR charges. Based on our review, the Department concludes that Xcel's RSG charges (revenues) appear reasonable for FYE13.

3) ARR

According to Xcel, higher congestion and FTR charges also produce higher ARR revenues. To illustrate this fact, Xcel provided the following table in its reply comments:

MISO Charges	FYE 2013	FYE 2012	FYE 2011	FYE 2010
Congestion & FTR Charges	$26,704,075	$5,571,845	$16,298,907	$5,166,298
Auction Revenue Rights (ARR)	($7,774,930)	($2,782,494)	($4,474,633)	($4,844,525)

The Department notes that ARR's are used to hedge congestions costs. Therefore, increases in congestion costs are likely to result in higher values for ARR's. As a result, the Department concludes that Xcel Electric has reasonably explained its increase in ARR revenues for FYE13.

4) Allocation of MISO Day 2 Charges

Xcel Electric stated on page 7 of their reply comments that their allocation of MISO Day 2 charges across their retail, asset based wholesale/intersystem, and non-asset based wholesale/intersystem did not change during the 2012-2013 AAA reporting period. The Department appreciates Xcel's clarification.

Based on all of the above, the Department recommends that the Commission accept Xcel Electric's MISO Day 2 reporting for FYE13.

5) Ancillary Services Market (ASM) Costs

Beginning on page 5 of its reply comments, Xcel Electric stated that the primary reason for the increase in total ASM costs was due to changes implemented by MISO to comply with FERC Order 755 (frequency response). Xcel Electric cited to the 2012 State of the Market Report for MISO Electricity Markets, which stated that MISO introduced a two-part offer and compensation structure for regulation on December 17, 2012. Under this new structure, MISO now pays participants separately for regulation capacity and "mileage." Xcel Electric stated that the mileage payment was only partially present through FYE12 but was present during the entire FYE13 timeframe. As a result, Xcel stated that the increases in both the number of months affected and the prices throughout the footprint contributed to its increase in ASM costs between FYE12 and FYE13. Xcel Electric provided the following table in its reply comments to illustrate this point:

MISO ASM	3rd Quarter	4th Quarter	1st Quarter	2nd Quarter
FYE 2013	$ 1,832,931	$ 5,350,441	$ 6,130,749	$ 9,317,780
FYE 2012	$ 23,035	$ 5,701,278	$ 2,058,215	$ 2,882,631
Difference	$ 1,809,896	($ 350,837)	$ 4,072,534	$ 6,435,148

The Department reviewed Xcel Electric's reply comments and the accompanying table. Based on our review, the Department concludes that Xcel Electric has reasonably explained the increase in ASM costs for FYE13.

6) Excessive/Deficient Energy Deployment Charges

Regarding the cause for the increase in Excessive/Deficient Energy Deployment Charges (EDEDC) amounts assigned to Sherco Units 1 and 2, Xcel Electric stated that:

> We concluded that the EDEDC amounts assigned to Sherco units 1 and 2 could be attributed to the bidirectional ramp rate which is at times challenging for the plants. For example, if the plants are being ramped up and then in the next 5-minutes set of instructions from MISO the plants are ordered to immediately start ramping down, performance to that set of instructions is difficult. The plants are mostly successful in making such transitions; however, occasionally temporary and minor unsteady-state operations result and the plant is unable to meet the MISO set point. When a plant is unable to follow the rapidly changing set points, MISO claws back regulation revenues thus making the costs appear higher while the revenues were also higher. NSP considered the cost/benefit to determine if it would be beneficial to reduce such flexibility offered to MISO by NSP and found that in FYE13, Sherco 1 generated $315,058 in revenues at a cost of $207,302 resulting in an overall benefit of $107,756. At this time NSP believes the right bidirectional ramp rate is being offered because a net benefit continues to result.
>
> In addition, the Department recommended that the Company continue to work with MISO to mitigate these costs in the future. We will continue to monitor these costs and corresponding plant performance.

The Department appreciates Xcel Electric's explanation that the large EDEDC amounts assigned to Sherco Units 1 and 2 could be due to the bidirectional ramp rate. Because there is a new benefit as noted above for ratepayers, the Department accepts Xcel's explanation as reasonable at this time. The Department will continue to monitor these costs in future AAA fillings.

Based on all of the above, the Department recommends that the Commission accept Xcel Electric's ASM reporting for FYE13.

B. DOC'S RESPONSE TO MP'S REPLY COMMENTS

On page 38 of the Report, the Department noted that MP's Day-Ahead Congestion charges in January 2013 were $2.7 million, but averaged only $0.5 million per month during the other eleven months of FYE13. In its response to Information Request No. 20, MP explained that a transmission constraint on the North Shore Loop created high prices until the constraint was relieved; however, MP provided no other information. The Department requested that MP describe in reply comments the nature of the transmission constraint (e.g., was there a transmission outage, higher-than-normal flows, etc.) and how it was relieved.

In its Reply Comments, MP identified several generation and transmission outages on its own system that occurred in January 2013. MP also noted that these outages occurred at the same time as high levels of generation outages on the MISO system, and stated that these factors combined to result in the high level of congestion charges observed that month. The outages on MP's system included:

- The 80 Line between Minntac and Forbes tripped off due to ice on the static wire;
  - The Department notes that in email correspondence with the Company, MP stated that this outage occurred January 6-7, during which time MISO had in excess of 14 GW of outages on its system.
- The 39 Line came off line due to icing;
  - In email correspondence, MP stated that this outage occurred January 23, when MISO had in excess of 14 GW of outages on its system.
- The 907 Line by Littlefork that connects to Manitoba Hydro had low gas pressure and came off line;
  - In email correspondence, MP stated that this outage occurred January 24, when two of MP's Taconite Harbor Units were off line due to tube leaks, and MISO had in excess of 12 GW of outages on its system.
- The Phase Shifter at International Falls experienced issues;
  - In email correspondence, MP stated that the tap changer (which controls the flow on the line) malfunctioned, which restricted flow on the line for about eight days.

These events explain why the Day-Ahead Congestion charges in January 2013 were so high. Based on its review of the information provided in MP's Reply Comments, the Department recommends that the Commission accept MP's MISO Day 2 reporting for FYE13.

C. DOC'S RESPONSE TO OTP'S REPLY COMMENTS

In our Report, the Department asked OTP to explain the following in reply comments:

1) why the total 2012-2013 MISO Day 2 charges increased from $28.0 million in 2011-2012 to $31.4 million in 2012-2013;
2) why the Company incurred such large Day Ahead Energy Losses (DA Loss Amt) in April, 2013 and why these costs are appropriately assigned to retail customers;
3) why the Company incurred increased Day Ahead and Real Time Energy Losses in the July 2012 to June 2013 period as compared to the previous year and why these costs are appropriately assigned to retail customers;
4) why the Company incurred such large Day Ahead Congestion (DA FBT Congestion Amt) costs in August, 2013 and why these costs are appropriately assigned to retail customers;
5) why the Company incurred such large RSG and Make Whole Payments costs in May, 2013 and why these costs are appropriately assigned to retail customers; and
6) whether any of the Company's allocation methods for MISO Day 2 charges changed during the 2012-2013 reporting period. If so, the Department recommended that OTP explain the nature of these changes and the effect these changes had on the charges assigned to various customer categories in the 2012-2013 AAA Report.

OTP first corrected issues with cost classification that caused OTP's Attachment K to incorrectly represent certain costs. OTP filed a corrected version of the attachment. OTP stated that the error occurred due to a software program developed in 2012 by OTP to quantify total congestion and loss amounts since those totals are not provided to OTP by MISO.

In their November 10, 2014 reply comments OTP stated:

> In Otter Tail's Attachment K, the Day Ahead Loss Amount (Line 9 in Attachment K), reported to the Department, is calculated in two-steps. First, the sum of the total losses calculated at each individual supply node is subtracted from the sum of the total losses calculated at each individual load node. Then, the DA FBT Loss Amount (Line 6 in Attachment K) needs to be subtracted from this number so as to not double account for the losses attributed to the Option B Grand Father Agreements ("GFAs") at Big Stone and Coyote. In Otter Tail's initial filing, the DA FBT amount was not subtracted out from the DA Loss Amount that was calculated. This resulted in overstating the DA Loss Amounts from October 2012 to June 2013 by the amount of DA FBT Loss.

OTP further stated that since loss amounts are subtracted from the total costs to determine the energy component, the result is that energy costs were understated by the same amount that losses were overstated.

OTP's reply to each of these issues is discussed in more detail below, along with the Department's response.

1) Total MISO Day 2 Charges

In their reply comments, OTP stated:

> There are two primary drivers for the overall increase in MISO day 2 charges for the 2012-2013 reporting period as compared to the 2011-2012 reporting period: load growth and the cost of energy.
>
> Total MWhs of Day Ahead ("DA") and Real Time ("RT") energy purchased increased from 4,377,548 MWhs in the 2011-2012 reporting period to 4,635,473 in the 2012-2013 reporting period, an increase of 5.89 percent. The average cost of DA and RT energy supplied to the Otter Tail load zone increased from a rate of $22.61 per MWh in 2011-12 to $26.49 per MWh in 2012-13. While both Otter Tail generation and the corresponding DA asset energy rates also increased over this same time period, those increases were not able to offset the increased charges to the Otter Tail load zone.

The Department reviewed OTP's reply comments and concludes that they reasonably explain the increase in MISO Day 2 charges between AAA reporting periods. As a result, the Department concludes that OTP's total MISO Day 2 charges for the 2012-2013 AAA reporting period are reasonable.

2) Day Ahead Energy Losses

OTP's reply comments stated:

> In Attachment 3, Otter Tail provides the corrected Attachment K schedule for April 2013. The initially reported DA Loss amount charge was $667,718.57. After making the corrections for the double counting of the DA FBT losses, the corrected DA Loss amount is now $194,235.08. With these updates, Otter Tail anticipates the Department may no longer have the same concern.
>
> Energy losses are an expense the company incurs in order to move energy from generating stations to retail load. Thus it is appropriate to assign these charges to retail customers.

The Department appreciates OTP's correction to costs and the Company's statement that overall, costs and revenues for the year were correct. The Department reviewed OTP's reply comments and concludes that the corrected DA Loss amount is reasonable. As a result the Department has no further concerns about OTP's Day Ahead Energy Losses for 2012-2013.

3) Day Ahead and Real Time Energy Losses

OTP's reply comments stated:

> As noted earlier in these Reply Comments, corrections to the DA Loss Amounts for the July 2012 to June 2013 reporting period have been made. With these updates, Otter Tail anticipates the original issue may no longer be a concern to the Department.
>
> Normal fluctuations in hourly supply and load levels create differences in losses from one reporting year to another. It is important to note that while the DA and RT Energy Losses have increased, both the RT Distribution of Losses Amount (Attachment K, Line 7) and the DA Losses Rebate on Option B GFA Amount (Attachment K, Line 11) have also increased in the July 2012 to June 2013 reporting period. When the corrected reporting and the loss rebates are considered, net losses have actually decreased for the July 2012 to June 2013 reporting period by $170,136.16.
>
> As mentioned above, energy losses are an expense the company incurs in order to move energy from generating stations to retail load. Thus it is appropriate to assign these charges to retail customers.

The Department concludes that OTP's corrected DA Loss amounts are reasonable. As a result the Department has no further concerns about OTP's Day Ahead and Real Time Energy Losses for July 2012 through June 2013.

4) Day Ahead Congestion

OTP's reply comments stated:

> Otter Tail believes the Department intended to request comment on the August 2012 monthly detail instead of August 2013. The DA FBT Congestion Amount documents the congestion costs associated with the financial bilateral transactions for the Option B Grand Fathered Agreements ("GFAs") sourcing at Big Stone and Coyote generating stations.
>
> Average congestion for the month of August 2012 was at the highest level for the reporting period between Coyote and Otter Tail load. Average congestion between Big Stone and Otter Tail load was at the third highest level for the reporting period.
>
> Since Option B status allows for a complete congestion hedge based on the day ahead financial bilateral transaction schedule for each GFA, it is important to note the companion charge type, DA Congestion Rebate on Option B GFA (Line 34 of Attachment K). For the August 2012 reporting, the amount is equal and offsetting to the DA FBT Congestion Amount.
>
> Congestion charges are an expense the company incurs in order to move energy from generating stations to retail load. Thus it is appropriate to assign these charges to retail customers.

The Department reviewed OTP's reply comments and concludes that they reasonably explain the high August 2013 Day Ahead Congestion costs. As a result, the Department concludes that OTP's August 2013 Day Ahead Congestion costs are reasonable.

5) RSG and Make Whole Payments

In their November 10, 2014 reply comments, OTP stated:

> The increase in RSG and Make Whole Payments for the month of May 2013 was primarily driven by a then recently installed automated real-time load forecasting software program. This software program reforecast Otter Tail load after the Day Ahead forecast was submitted, yet prior to actual Real Time values. Submitting updated forecast information prior to the real time allowed for potential netting (reducing) of deviations from the DA schedule, which in turn would reduce RSG charges. For a portion of the May 2013 month, Otter Tail discovered the load data transfer between Otter Tail and MISO was increasing the deviations. This resulted in increased RSG charges for a few days. Otter Tail immediately ceased use of the program when settlement statements revealed higher RSG charges. Otter Tail

was unable to determine the cause of the data transfer issue with MISO. At present, Otter Tail is not utilizing the above described reforecasting software.

RSG charges are a MISO expense which the company incurs in order to serve our retail load. Thus it is appropriate to assign these charges to retail customers.

The Department reviewed OTP's reply comments and concludes that, while OTP explained the source of the significantly higher RSG charges, OTP did not adequately explain why rate payers should be held solely responsible for the increased RSG and Make Whole Payments caused by the software issue. Nor is it clear how much testing OTP did of what was a new tool, prior to using it. The Department appreciates that OTP stopped using the defective software, but OTP has not provided a reasonable explanation for why all of the costs of the defective software use in May 2013 should be assigned to ratepayers and no amount should be disallowed. OTP's statement that "RSG charges are a MISO expense which the company incurs in order to serve our retail load" does not address this question.

Thus, the Department recommends that the Commission disallow at least 50 percent of the difference between the May 2013 RSG level and the average RSG monthly charges for this period or require OTP to identify (and explain) the portion of that amount that is due to the software issue.

6) MISO Day 2 Allocation Method Changes

In their November 10, 2014 reply comments OTP stated that OTP's method to allocate MISO Day 2 charges during the 2012-2013 reporting period did not change. Therefore the Department concludes that OTP adequately addressed the Departments question and no further response is needed on this issue.

V. DEPARTMENT RECOMMENDATIONS – COMPLIANCE FILINGS

- The Department 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 2013. The Department recommends that the Commission continue to require Xcel Electric to report this generation cost allocation data in future AAA filings.

- The Department recommends that the Commission accept Xcel Electric's Natural Gas Financial Instruments compliance filing in the FYE13 docket. The Department will review Xcel Electric's continued compliance with this requirement in the FYE14 AAA report.

- The Department recommends that the Commission accept Xcel Electric's FYE13 wind curtailment report.

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

- 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 filing in future AAA reports.

- The Department concludes that Xcel Electric complied with the January 29, 2009 Order in Docket No. E002/M-08-1098, requiring Xcel Electric to report in future AAA filings any revenue from any source as a result of the Renewable Energy Purchase Agreement with Koda Energy, and to itemize any such revenue by source and amount.

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

- The Department concludes that the IOUs complied with the April 6, 2012 Order in Docket No. E999/AA-10-884 (Ordering Point 8), requiring 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.

- The Department recommends that the Commission accept the IOUs' compliance filings regarding their actual expenses pertaining to maintenance of generation plants, with a comparison to the generation maintenance budget from the IOUs' most recent rate cases.
- The Department recommends that the Commission accept the IOUs' compliance filings regarding their plant outages' contingency plans.

- The Department recommends that the Commission accept the IOUs' compliance filings regarding sharing lessons learned about forced outages. However, the Department provides further recommendations below regarding recovery of replacement power costs.

- The Department concludes that Xcel Electric complied with the April 30, 2010 Order in Docket No. E002/M-10-161, requiring Xcel Electric to report on any curtailment from WM Renewable Energy, including the reasons for any curtailments and amounts paid, in its monthly fuel clause adjustment filings.

- The Department concludes that Minnesota Power is in compliance with the Commission's March 11, 2011 Order in Docket No. E015/M-10-961.

- The Department recommends that the Commission accept Interstate Electric's compliance with the October 2, 2009 Order in Docket No. E-001/M-09-455.

VI. DEPARTMENT RECOMMENDATIONS – RECOVERY OF REPLACEMENT POWER COSTS

At least until the FCA incentive is changed, the Department recommends that the Commission require the following for IOUs:

1) Utilities seeking to recover replacement power costs due to a forced outage must provide;
    a. Information showing the causes of forced outages;
    b. Efforts the utility took to prevent the forced outage;
    c. Efforts the utility took to minimize the length of the forced outage;
    d. Efforts the utility took to protect ratepayers from having to pay for the costs of the forced outage;
    e. Efforts the utility took to recover replacement power costs from all potential sources; and
    f. The amount by which the replacement power costs exceed the power costs the utility would otherwise have charged ratepayers.
2) IOUs must develop a searchable database applicable to non-nuclear facilities that shares the attributes of the SEE-IN program and provides for a systematic gathering, review, and analysis of operating experience at (Minnesota) IOUs-owned non-nuclear facilities.
3) Utilities should adopt Xcel's program, identified in more detail in Attachment D of its November 10 comments, to hold contractors more accountable for replacement power costs, to the extent those practices are not already in place.
4) Xcel and other utilities should add language to the "Supplier Warranties" section of the contracts as discussed above to indicate that contractors may be liable for a limited amount of replacement power costs.

VII. DEPARTMENT RECOMMENDATIONS – SHERCO 3 OUTAGE

- The Department continues to recommend that the Commission find that the prudence of costs related to Sherco 3 outage between November 2011 and December 2013, as identified in the Department's September 16, 2014 Report in Docket No. E999/AA-13-599, remain subject to review by the Commission if additional facts developed during the General Electric legal process contradict the record to date.

VIII. DEPARTMENT RECOMMENDATIONS – 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 continue to 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 continue to 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.

IX. DEPARTMENT RECOMMENDATIONS – MISO DAY 2

A. XCEL ELECTRIC

- Based on the information provided by Xcel Electric in its Reply Comments, the Department recommends that the Commission accept Xcel Electric's MISO Day 2 reporting for FYE13.

B. MINNESOTA POWER

- Based on the information provided by MP in its Reply Comments, the Department recommends that the Commission accept MP's MISO Day 2 reporting for FYE13.

C. OTTER TAIL POWER

The Department concludes that OTP adequately answered all questions in regards to MISO Day 2 Costs, but concludes that it is not reasonable to charge all of the incrementally higher charge accrued in the month of May 2013 for RSG and Make Whole payments to retail customers. Thus the Department recommends that the Commission disallow at least 50 percent of the difference between the May 2013 RSG level and the average RSG monthly charges for this period or require OTP to identify (and explain) the portion of that amount that is due to the software issue.

- The Department recommends that the Commission accept all other aspects of OTP's MISO Day 2 reporting.

D. INTERSTATE ELECTRIC

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

X. DEPARTMENT RECOMMENDATIONS – ANCILLARY SERVICES MARKET

A. XCEL ELECTRIC

- The Department recommends that the Commission accept Xcel Electric's ASM reporting for FYE13.

B. MINNESOTA POWER

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

C. OTTER TAIL POWER

- Based on our review, the Department recommends that the Commission accept Otter Tail Power's ASM reporting.

D. INTERSTATE ELECTRIC

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

/lt

CERTIFICATE OF SERVICE

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

Minnesota Department of Commerce
Response Comments

Docket No. **E999/AA-13-599**

Dated this 31st day of December 2014

/s/Sharon Ferguson

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