MINNESOTA DEPARTMENT OF COMMERCE

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August 25, 2016

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

RE: **Review of the 2014-2015 Annual Automatic Adjustment Reports,**
Part II - MISO Day 2 Market, Including Asset Based Margins and Ancillary Services Market
Docket No. E999/AA-15-611

Dear Mr. Wolf:

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) Part II *Review of the 2014-2015 Annual Automatic Adjustment Reports, specifically the MISO Day 2 Market including Asset Based Margins and Ancillary Services Market Review* for rate-regulated electric utilities in Minnesota (FYE15 AAA). The Department recommends that the Minnesota Public Utilities Commission (Commission) accept the MISO Day 2, including Asset Based Margins and Ancillary Services Market, reporting.

The Department is available should the Commission have any questions about the FYE15 electric AAA Report review herein provided.

Sincerely,

/s/ NANCY A. CAMPBELL	/s/ CRAIG ADDONIZIO	/s/ MICHAEL ZAJICEK
Financial Analyst	Financial Analyst	Rates Analyst

NAC/CA/MJ/ja
Attachments

Review Of 2014-2015 (FYE15) Annual Automatic Adjustment Reports Part II

For Electric Utilities

Submitted To The
Minnesota Public Utilities Commission

Minnesota Department of Commerce

Docket No. E999/AA-15-611

August 25, 2016

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I. OVERVIEW

On June 15, 2016, the Division of Energy Resources of the Minnesota Department of Commerce (DOC or the Department) provided our Part I review of the automatic adjustment charges for the July 2014 - June 2015 (FYE15) reporting period, which were filed by five Minnesota electric utilities in compliance with Minnesota Rule 7825.2810. In these comments the Department provides our Part II review of Midcontinent Independent System Operator MISO Day 2 energy market (MISO Day 2, MISO Day 2 Market, Day 2, or Day 2 Market), including Asset Based Margins and Ancillary Services Market (ASM). The Department offers recommendations to the Minnesota Public Utilities Commission (Commission), which are summarized at the end of these comments.

The utilities addressed in the Department's review of MISO Day 2, including Asset Based Margins and Ancillary Services Market, are:

- Northern States Power Company d/b/a Xcel Energy, Incorporated – Electric Utility (NSP or Xcel Electric);
- Minnesota Power (Minnesota Power or MP);
- Otter Tail Power Company (Otter Tail or OTP); and
- Interstate Power Company – Electric Utility (Interstate Electric).[1]

The Department's review focused on whether the electric utilities had, during the period of July 1, 2014 to June 30, 2015, accurately adjusted their energy rates to reflect changes in fuel costs and revenues related to MISO Day 2 including Asset Based Margins and ASM. The Department's review also focused on fluctuation analysis, by comparing costs and revenues to past years' information, and allocation of costs and revenues between retail and wholesale sales.

II. EFFECTS OF MISO DAY 2 ON MINNESOTA RATEPAYERS

A. BACKGROUND ON MISO DAY 2

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

MISO's Day 2 energy market[2] 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

[1] The Department has included information request responses referenced in these comments as follows: Xcel Electric in DOC Attachment 1, Otter Tail Power in DOC Attachment 2, and no attachments for Minnesota Power and Interstate Electric.
[2] See the Open Access Transmission and Energy Markets Tariff (TEMT) in *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 101,163 (2004).

customers[3]), including retail customers. Traditionally the utilities generated most of the electricity needed to serve their customers, and bought or sold any surplus or deficit from or to neighboring utilities. In contrast, under MISO's tariff, utilities sell all power from their electric generation and other resources into the wholesale market, and purchase power back from the market to provide electric service for their ratepayers.

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

On April 1, 2005, MISO began operation of the Day 2 Energy Market, pursuant to its Transmission 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 fuel clause adjustment (FCA) on an interim basis subject to refund.[4]

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.[5]

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[3] TEMT § 1.208 (issued May 27, 2005).
[4] Order Authorizing Interim Accounting for MISO Day 2 Costs, Subject to Refund with Interest (April 7, 2005).
[5] Order Establishing Second Interim Accounting for MISO Day 2 Costs, Providing for Refunds, and Initiating Investigation (December 21, 2005 Order).

In addition the Commission established reporting requirements and accounting procedures to address the new regulatory dynamics created by MISO's Day 2 Market. In an effort to bring clarity to traditional utility operations, for example, the Commission directed the petitioning utilities to use "net accounting" for Day 2 costs, whereby both the proceeds of the "sale" and the costs of the "purchase" would be recorded in the same account. Because these two conceptual transactions tend to cancel each other, the utility's records reflect the net, or actual, cost or revenue from the operations. Finally, the Commission proposed an investigation into the best method for assuring low-cost electricity in Minnesota.[6] These basic principles are still in place.

Third, on reconsideration, Commission granted all parties additional time to address the requirement that utilities immediately implement a refund to their customers. By Order dated February 24, 2006, the Commission suspended the immediate refund obligation and restored the utilities' authorization to continue recovering all MISO Day 2 costs through the fuel clause. While this recovery remained as interim, subject to refund, the Commission also granted the utilities authority to implement deferred accounting for any costs that the Commission would later determine should not be recovered through the FCA. Utilities could continue deferring the MISO Day 2 administrative costs until roughly March 1, 2009, without interest; thereafter the accrual would stop and the accrued balance would be written off gradually without rate recovery (amortized) through roughly March 1, 2012, unless the utility received Commission authority to recover the balance through base rates. The ultimate issue of whether and how MISO Day 2 costs should be recovered on a permanent basis was deferred to allow opportunity for additional analysis.[7]

On June 22, 2006, the parties filed the *Joint Report and Recommendation Regarding MISO Day 2 Cost Recovery* (Joint Report) with the Commission.[8] 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 [annual automatic adjustment] reports (ordering paragraph 7).

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

[6] December 21, 2005 Order at Ordering Paragraph 10.
[7] Order on Reconsideration Suspending Refund, Granting Deferred Accounting and Requiring Filings at 7-8.
[8] 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.

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

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

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

Sometimes MISO will be unable to use the system's lowest-cost generators because doing so would require moving electricity through a transmission line that is already fully in use (constrained). When such transmission constraints arise, MISO selects a substitute generator connected to transmission lines with available capacity, even though the substitute may be more expensive to operate. As a result, the marginal price of electricity is not uniform throughout the grid, but varies by location. This fact gives rise to the term "locational marginal price" (LMP), for electricity at each location on the transmission grid. As noted in AAA filings since at least FYE2007, it has become evident that generation outages can have a significant effect on LMPs in the Day 2 market.

The DOC discusses our review 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 asset-based wholesale customers.

C. OVERALL REVIEW OF MISO DAY 2 CHARGES

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

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

- Grandfathered Charges.

The 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 FYE15 AAA Report. The Department notes that the amounts and totals reflected on Part J Section 5 Schedule 7 are at the total Company level.

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

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

AAA Reporting Period	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015
Net Costs	$226.2	$191.5	$195.9	$196.6	$200.5[9]	$222.9[10]	$101.7[11]

The Department notes that Xcel Electric's MISO Day 2 net costs assigned to retail ratepayers have generally been increasing each year, as shown in the table above. However, in the most recent FYE15 (2014-2015) the MISO Day 2 costs assigned to retail decreased significantly to $101.7 million compared to $222.9 million for FYE14, or a 54 percent decrease. This decrease is consistent with MISO's locational marginal price (LMP) being lower for the 2nd through 4th quarter of 2014. The Department notes that these lower market prices, or LMPs, followed lower gas prices and milder weather, as discussed below in Xcel's ASM section below. The Department did ask Xcel Electric, in DOC Information Request No. 14, to provide the reasons for why the MISO Day 2 costs assigned to retail customers decreased 54 percent, from $222.9 million for FYE14 to $101.7 million for FYE15. The Company provided the following response:

[9] Source: Xcel's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 7, Page 13 of 13.
[10] Source: Xcel's initial filing in Docket No. E999/AA-14-579, Part J, Section 5, Schedule 7, Page 13 of 13.
[11] Source: Xcel's initial filing in Docket No. E999/AA-15-611, Part J, Section 5, Schedule 7, Page 13 of 13.

The *2015 State of the Market Report for the MISO Electricity Markets*[12] prepared by MISO's Independent Market Monitor ("IMM") compares market operations and costs. In the executive summary, the IMM cites:

- A 50 percent decline in natural gas prices from 2014;
- A 45-50 percent decline in congestion costs from 2014 with the largest differences for the periods when the Polar Vortex occurred in 2014;
- A two percent drop in load from 2014 to 2015 due to mild weather; and
- An increase in the use of gas resources across the footprint.

These factors contributed to significantly lower MISO Day 2 costs as reflected in the following:

- A 32 percent drop in energy prices;
- A 40 decline in Revenue Sufficiency Guarantee payments;
- An increase from 17 percent to 23 percent of the energy output from gas resources, with such resources more often setting marginal price levels; and
- A decrease in real time price volatility as more flexible gas facilities were able to support system ramping requirements.

The Department reviewed Xcel Electric's MISO Day 2 charges for FYE15 and noted, as discussed above, a significant overall decrease in MISO Day 2 costs. As a result of the significant decrease in MISO Day 2 costs, the Department performed a limited review of charge types showing the greatest change between FYE14 and FYE 15, as discussed below.

a) #1a Day-Ahead Asset Energy, #1b Day-Ahead Congestion, #1c Day-Ahead Losses

In its review, the Department noted that the amount of Day-Ahead Asset Energy charges (revenues) assigned to retail ratepayers decreased by 44 percent from $319.2 million in FYE14 to $177.5 million in FYE15.

The Department noted that Day-Ahead Congestion charges significantly decreased from $98.62 million in FYE14 to $28.051 million in FYE15, or a 72% decrease on a total Company basis. Additionally, the Department noted that $26.416 million was assigned to retail customers out of the $28.051 total Company amount for FYE15, which is consistent with the allocation for FYE14.

The Department also noted that Day-Ahead Losses charges significantly decreased from $52.734 million in FYE14 to $34.835 million in FYE15, or almost a 34% decrease.

[12] From the MISO Website: www.misoenergy.org/MarketsOperations/IndependentMarketMonitor/Pages/IndependentMarketMonitor.aspx

As a result, based on our limited review, the Department concludes that the Company's Day-Ahead Asset Energy, Day-Ahead Congestion charges, and Day-Ahead Losses assigned to retail customers for FYE15 appear reasonable.

b) #34 Real-Time Schedule 24 Allocation Amount

In DOC Information Request No. 15 the Department asked Xcel, regarding MISO Day 2 charge type 34, Real-Time Schedule 24 Allocation Amount of ($460,032) assigned to intersystem/asset based customers for FYE15, to please explain and show that this credit (or a comparable credit) amount was given back to ratepayers in the current rate case for 2016 to 2020 via a classification to transmission revenues. Xcel provided the following response:

> MISO Schedule 24 revenues are budgeted in FERC 456 and included in the Other Electric Revenues line item of the cost of service model. See work papers R2-2 in Volume 4A Test Year Workpapers Base Data filed in Docket No. E002/GR- 15-826 for the budgeted Schedule 24 revenues and work paper R1A and R1B for the MN Jurisdictional balances. These work papers identify the Schedule 24 budgeted revenues included in other electric revenues for 2016 – 2018.
>
> MISO Schedule 24 expenses are budgeted in FERC 575 and included in Transmission Expenses line item of the cost of service models. See work paper O2-2A in Volume 4A Test Year Workpapers Base Data filed in Docket No. E002/GR- 15-826 for the budgeted Schedule 24 expense and work paper O2-2B for the MN Jurisdictional balances.
>
> For the 2016 test year and 2017 and 2018 plan years the budgeted Schedule 24 revenue exceeds the budgeted Schedule 24 expense. Therefore the net Schedule 24 revenue for 2016 – 2018 lowers the revenue deficiency for each of those years.
>
> In Docket No. E002/GR-15-826 the Company filed for a three year multi-year rate request and the work papers only reflect budgeted/forecasted data through 2018. However, the forecasted 2019 and 2020 Schedule 24 revenues would be treated in the same manner as the 2016 – 2018 data.

The Department was able to confirm the approximately $1.3 million in transmission revenues and $0.9 million[13] in transmission expense related to MISO Schedule 24 for 2016 to 2018, with, according to the Company, similar treatment for 2019 and 2020. Based on

[13] There was an additional approximately $190,000 in transmission expense for both Schedule 17 and Schedule 24.

our review, the Department considers the Company's treatment of MISO Schedule 24 to be reasonable.

c) #20 Real-Time Miscellaneous

In DOC Information Request No. 16, the Department asked Xcel to describe the categories of costs/revenues included in MISO Day 2 charge type 20, Real-Time Miscellaneous ($1,863,558 FYE15 total Company), including which revenues are related to Multi-Value Projects (MVPs) Auction Revenue Rights (ARRs) and how these amounts were given back to ratepayers. The Department also asked Xcel to support the Company's allocation between retail $1,266,875 and intersystem/asset based customers $596,683.

Xcel provided the following response:

> It is important to note that the real-time miscellaneous category on the AAA report combines several MISO charge types including Real Time Resource Adequacy Auction Amount, Real Time MVP Distribution Amount and Real Time Miscellaneous Amount. Only the Real Time MVP Distribution Amount is allocated to the intersystem/asset based category. Real-time miscellaneous charges of $1,086,335 relate to out-of-period dispute resolution adjustments, market-to-market settlements, and the automatic reserve sharing credits and charges. Other items included in this category are $177,215 in Resource Adequacy Auction Revenues and $598,683 related to Multi-Value Projects.
>
> The amount included in real-time miscellaneous allocated to asset-based/intersystem were credits for Multi-Value Projects (MVP), which represent monthly credits from MISO-held MVP ARRs. The MVP ARRs are treated as options and result in credits to those who paid for the MVPs. As such, it is appropriate to reclassify these balances to the asset-based/intersystem category.
>
> Credits for MISO-held MVP ARRs are recorded as a reduction to expense for MISO Schedule 26-A, Multi-Value Project Usage Rate. Amounts are refunded to customers through the TCR rider by virtue of net actual Schedule 26-A expense being recovered through that rider.

The Department appreciates Xcel Electric's response regarding how the various components of Real-Time Miscellaneous are recovered or credited back to ratepayers. Based on our review the Department considers the Company's treatment of Real-Time Miscellaneous to be reasonable.

d) Allocation of MISO Day 2 Charges

The Department also reviewed Xcel Electric's allocation of its MISO Day 2 charges across its retail, asset based wholesale/intersystem and its non-asset based wholesale/intersystem. The Department described Xcel Electric's allocation methods in detail in the Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports*.[14] The Department asked Xcel Electric in DOC Information Request No. 17 if Xcel had changed any of the allocation methods used to allocate MISO Day 2 charges between retail and asset-based wholesale during the 2014-2015 reporting period. The Company indicated that there have been no changes to the allocation methods for MISO Day 2 charges between retail and asset-based wholesale during the 2014-2015 reporting period.

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

2. Review of MP's MISO Day 2 Charges

The Department reviewed Minnesota Power's MISO Day 2 charges as reported in Attachment 9 to its FYE15 AAA Report and concludes that they are reasonable. MP's total MISO charges and the amount allocated to retail customers in FYE15[15] were significantly less than in prior years.

Minnesota Power
MISO Day 2 Charges and
Amounts Allocated to Retail

	Total MISO Charges ($ millions)	Change from Prior Year	MISO Charges Allocated to MP's Retail Customers ($ millions)	Change from Prior Year
FYE11	58.1		51.1	
FYE12	52.0	-10.5%	44.3	-13.3%
FYE13	62.7	20.6%	56.7	28.0%
FYE14	61.2	-2.4%	58.4	3.0%
FYE15	39.2	-35.9%	40.8	-30.1%

Source: Attachment 9 to MP AAA Reports

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

15 MP's algorithm for assigning energy costs to ratepayers results in the highest cost energy assigned to non-FCA customers first, and then the remaining costs are assigned to FCA customers (retail and municipal wholesale). Since the reported amounts are *net* MISO costs, the fact that retail is assigned more than 100% of MISO costs means that there were hours in which MISO wholesale purchases were less expensive than generation from MP's owned plants.

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*.[16] Because those allocation methods have not changed, the Department will describe them only briefly in this report.

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

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

3. *Review of OTP's MISO Day 2 Charges*

OTP allocates its MISO Day 2 charges across three categories including retail, asset-based wholesale, and non-asset-based wholesale. OTP also refers to these categories as its "resource," "marketing" (OTPW) and "dealing" (OTPD) portfolios. OTP's MISO Day 2 charges for retail and asset-based wholesale are billed under OTPW settlement statements. MISO Day 2 charges for non-asset-based wholesale are billed separately under OTPD settlement statements. A summary of MISO Day 2 charges assigned to the three categories is provided in Part H Section 3 Attachment K of OTP's 2014-2015 AAA Report. The Department notes that amounts and 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 (in Millions)

AAA Reporting Period	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015
Revenues	$115.1	$87.0	$113.8	$173.1	$102.6
Costs	$131.2	$115.0	$145.2	$215.3	$142.7
Net Costs	$16.1	$28.0	$31.4	$42.2	$40.1

The Department notes that the total net 2013-2014 MISO Day 2 charges increased from $31.4 million in 2012-2013 to $42.2 million in 2013-2014, or a $10.8 million increase. This was due to the fact that the 2013/2014 winter was one of the coldest in the last 20

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

years due to the “polar vortex’ weather pattern that existed across the upper Midwest, resulting in higher energy demand throughout MISO and an increase in market energy prices. Net MISO Day 2 charges for 2014-2015 stayed relatively the same, with a decrease of only $2.1 despite no similar “polar vortex” weather pattern. In response to Department Information Request No. 20, OTP explained that decreased revenues were taken in by the Company in FYE15 due to reduced generation in 2014/15 compared to 2013/14 and lower LMP prices.

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*.[17] In the 2013-2014 *Annual Automatic Adjustment Reports* proceeding, the Company stated in response to an information request that there were no changes in its allocation method since the previous report.[18] In the instant docket, the Department again requested that OTP explain whether any of the Company’s allocation methods have changed during the 2014-2015 reporting period, and if so, what the nature of these changes were and the effect these changes have had on the charges assigned to various customer categories in the 2014-2015 AAA Report. OTP responded that there were no changes to the allocation methods used during the 2014-2015 period.

The Department also reviewed OTP’s MISO bills to reconcile the billing amounts shown in OTP’s monthly allocation tables included in Part H, Section 5, Attachment K of OTP’s initial filing. OTP provided the necessary data to allow this review and the Department found no issues with the calculations.

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

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 in that it does not allocate MISO Day 2 costs between retail customers and the wholesale sector, as all energy costs, all energy revenues, and all MWhs are included in its FCA. Interstate Electric uses the net of all costs and revenues and divides this amount by all MWhs. DOC considers this approach to be an all-in method, which was approved in Interstate Electric’s prior rate cases. A benefit of this approach is simplicity, and the fact that there are no concerns about allocating proportions of MISO Day 2 costs between retail customers and the wholesale sector. Conversely, as part of this all-in process, efforts cannot be made to assign the lowest cost resources to retail customers.

As shown on Attachment C, page 13 of 13 for FYE11, FYE12, FYE13, FYE14, and FYE15 of the AAA reports, the Department noted a 51 percent decrease in Interstate Electric’s FYE15 MISO Day 2 charges (from FYE14 of $109.6 million to FYE15 of $55.7 million). Below is a table showing the net costs assigned to retail customers since 2010:

[17] The Department’s *Review of the 2010-2011 Annual Automatic Adjustment Reports* was filed June 1, 2012 in Docket No. E999/AA-11-792.
[18] Docket No. E999/AA-14-579

Table 4 - Historical MISO Day 2 Net Costs Assigned to Retail Customers

Period	Retail Costs	Retail Revenue	Retail Net Costs
2010-2011	$99,941,288	$20,127,899	$79,813,388
2011-2012	$92,291,999	$22,483,756	$69,808,243
2012-2013	$66,914,361	$25,260,345	$41,654,015
2013-2014	$138,772,043	$29,155,339	$109,616,704
2014-2015	$73,491,598	$17,765,654	$55,725,944

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

D. ASSET BASED MARGIN OR WHOLESALE REVENUE REVIEW

1. Xcel Electric

The Department reviewed Xcel Electric's asset-based margins in the FYE15 AAA to ensure asset-based margins were returned to ratepayers via the FCA. Specifically, the Department selected the asset-based margin of $9.959 million for December 2014 as shown on in the FYE15 AAA[19] and tied this back to Xcel Electric's FCA. The Company provided the following in its response and supplemental response to DOC Information Request No. 13:

> The $9.959 million reported in our 2015 AAA filing is a portion of the total asset based revenues. Various Cost of Goods Sold expenses are deducted from the total revenue to calculate the margins. The Minnesota jurisdictional portion credited to Minnesota ratepayers in the February 2015 fuel clause adjustment was $455,780. Please see below for additional detail:

[19] Source: Xcel's initial filing in Docket No. E999/AA-15-611, Part J, Section 5, Schedule 7, Page 6 of 13.

Minnesota Asset Based Margin Sharing	(Dec 2014) $- millions
(1) MISO Day 2 Intersystem Asset Based Revenue	$ 10.0
(2) Non-MISO Asset Based Revenue	$ 1.3
(3) Total Asset Based Revenue (1)+(2)	$ 11.3
(4) Less: Cost of Goods Sold	$ 9.7
(5) NSP System Asset Based Margins (3)–(4)	$ 1.6
(6) Less: Ratepayer Sharing (*)	$ **0.6**
(7) Less: Other Jurisdictions Specific Adjustments	$ 0.7
(8) Other Jurisdictions' Pass-Through/Company Retention	$ 0.3

* **Ratepayer Sharing Detail**	
Minnesota Jurisdiction	$ 1,141,178
Less: Other Jurisdictions Specific Adjustments	$ 685,397
Minnesota Net Portion	**$ 455,781**
Other NSP Jurisdictions	$ 171,439
Total NSP Ratepayers Sharing	$ 627,220

Supplement:
Please see Attachment A for a breakdown of the derivation of the asset based margin sharing refund for December 2014.

Also, please see Attachment B for a copy of our FCA February 2015 filing. Attachment 3, Page 1, of our FCA February 2015 filing shows that the asset based margin net amount of

> $455,780 was credited to Minnesota ratepayers. You will also note that ASM charges include both margins and expenses incurred in the Day 3 market. This net number can be positive or negative in any single month. (See Attachment 2, Page 11, of our FCA February 2015 filing).

The Company also provided the following Attachment A that provides a summary of the asset based margin calculation for December 2014:

Northern States Power Company, A Minnesota Corporation
Electric Operations - State of Minnesota
Minnesota Asset Based Margin Sharing - December 2014

MISO Day 2 Asset Based Revenue (See Page 2)	$	9,959,424
ASM Intersystem Asset Based Cost (See Pages 3 & 4)	$	(13,610)
Non-MISO Asset Based Revenue	$	1,319,293
Total Asset Based Revenue per Trade Margin	$	11,265,107
Less: Cost of Goods Sold per Trade Margin	$	(9,684,573)
NSP System Asset Based Margin	$	1,580,534
MN Margin Sharing % (Based on MWh Sales Weightuing)		72.20%
Minnesota Jurisdiction Margin	$	1,141,177
Less: Minnesota Jurisdiction Specific RSG/RNU Adjustment	$	(60,552)
Less: Minnesota Jurisdiction Specific C&L Adjustment	$	(624,846)
Asset Based Margin Sharing Refund to Minnesota Ratepayers (See Page 5, Refund)	**$**	**455,779**

Based on the Department's review of Xcel Electric's supplemental response to DOC Information Request No. 13 discussed above, the Department asked some follow-up questions and the Company provided responses via email. The Department asked for support for the costs of goods sold, which the Company provided. The Department also asked for support the "RSG/RNU Adjustment" and the "C&L Adjustment" which are cost allocations for RSG/RNU and Congestion and Losses based on a per-MWh basis assigned to wholesale/asset based margins. The Company provided this information on a spreadsheet, and based on our review of this additional information, the Department asked the Company to provided information to support the Municipal Time of Day Rate costs and the related revenues.[20] The Company provided the cost information for the Municipal Time of Day Rate, and has agreed to provide the revenue information for the Municipal Time of Day Rate in its reply comments. Additionally, the Department asked the Company to explain why the Municipal Time of Day Rate costs and revenues are not simply directly assigned these customers but instead are included in the asset based margin assigned to retail customers. The Company also agreed to provide this additional information in reply comments.

[20] The Department has attached the follow-up responses (which we labeled Xcel Electric's Follow-Up Responses) from Xcel based on our review of Supplemental Response to DOC Information Request No. 13.

2. *MP*

The table below summarizes MP's actual wholesale asset-based margins over the period 2009 through 2015, 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 six-year period ($256.3 million) is roughly equal to the total revenue credit ($256.5 million) over the same period. The Department will continue to monitor MP's wholesale margins in future AAA filings.

Minnesota Power
Wholesale Asset-Based Margins
2009-2015

Calendar Year	Actual Margin	Revenue Credit Built into Base Rates	Shareholders Benefit/(Loss)	Percent Difference
[a]	[b]	[c]	[d]=[b]-[c]	[e]=[d]/[c]
2009	$53.8	$30.3	$23.5	77.6%
2010	$33.9	$37.7	($3.8)	-10.1%
2011	$31.1	$37.7	($6.6)	-17.5%
2012	$29.5	$37.7	($8.2)	-21.8%
2013	$33.6	$37.7	($4.1)	-11.0%
2014	$34.7	$37.7	($3.0)	-8.1%
2015	$39.8	$37.7	$2.1	5.6%
7 Yr. Total	$256.3	$256.5	($0.2)	-0.1%

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 Docket No. E999/AA-12-757.
2013 Actual: MP Response to DOC Information Request No. 10 in Docket No. E999/AA-13-599.
2014 Actual: MP Response to DOC Information Request No. 6 in the Docket No. E999/AA-14-579.
2015 Actual: MP Response to DOC Information Request No. 9 in the instant proceeding.
2009 Revenue Credit in Base Rates: May 4, 2009 Order in Docket No. E015/GR-08-415, page 17.
2010-2015 Revenue Credit in Base Rates: November 2, 2010 Order in Docket E015/GR-09-1151.

3. *OTP*

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

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 IPL's total net fuel costs.

E. DOC INVOLVEMENT IN MISO PROCESSES

The DOC 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 the Federal Energy Regulatory Commission (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 Committee (AC) Meetings, Annual Stakeholder and Sector Meetings with MISO, Resource Adequacy Workgroup and Supply Adequacy Workgroup (RAWG/SAWG) Meetings, Planning Advisory Committee (PAC) Meetings, Midwest Transmission Expansion Plan (MTEP) Meetings, Demand Response Meetings and other MISO meetings to gain better understanding of MISO proposals prior to implementation.

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

The 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 by the Commission to bring all of the parties together and to facilitate the discussions. The Department also appreciates the participation of all entities in this process. In particular, the 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, 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 recommendations to the Commission.

The DOC intends to continue to audit the MISO Day 2 charges 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.

III. ANCILLARY SERVICES MARKET (ASM)

A. BACKGROUND

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

These ancillary capabilities are as follows:

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

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

Six Procurement charges:

1) Day-Ahead Regulation;
2) Day-Ahead Spinning Reserve Charge;
3) Day-Ahead Supplemental Reserve;
4) Real-Time Regulation;
5) Real-Time Spinning Reserve;
6) Real-Time Supplemental Reserve;

One Resource Energy charge:	1) Net Regulation Adjustment;
Three Cost Distribution charges:	1) Regulation; 2) Spinning Reserve Charge; and 3) Supplemental Reserve; and
Two Penalty charges:	1) Regulation Penalty Amount; and 2) Contingency Reserve Development Failure Penalty.

Prior to the start of MISO's ASM, ancillary services were procured in the MISO footprint by each utility through bilateral contracts via Balancing Authorities 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.

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 [Department] to develop a format that is acceptable.

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

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

11. The utilities shall file detailed and specific explanations for all Contingency Reserve Deployment Failure and Excess/Deficient Energy Charges incurred, including an

explanation as to why they should be recovered and what actions the utility took to minimize these charges.

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

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

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

B. XCEL ELECTRIC

Xcel Electric provided its ASM review in its FYE15 AAA filing in Part J, Section 5, Schedules 8 to 13 and in Part J, Section 6 as required by the Commission's August 23, 2010 Order in Docket M-08-528. Specifically, Xcel Electric stated the following regarding overall ASM market performance:[21]

> During the 2014-2015 AAA Period, MISO continued to operate the electric system reliably and has exceeded compliance thresholds for all North American Electric Reliability Corporation (NERC) reliability standards to which they are subject. The MISO Independent Market Monitor, which is tasked with monitoring both the behavior of Market Participants and the operation of the market, noted in its 2014 State of the Market Report that "The MISO energy and ancillary service markets generally performed competitively in 2014. Conduct of suppliers was broadly consistent with expectation for a workably competitive market." The Market Monitor also noted, "Energy prices in the first quarter of 2014 averaged $53.02 per MWh, over 80 percent higher than in the first quarter of 2013. Energy prices in the last three quarters averaged $35.29 per MWh, just 6 percent higher than the same period in 2013." These market prices closely followed natural gas prices during

[21] Source: Xcel's initial filing in Docket No. E999/AA-15-611, Part J, Section 6, Page 1 of 6.

> 2014, for which the report observed, "The first quarter exhibited extremely cold weather and tight natural gas market conditions caused by the 'polar vortex'. The rest of the year was characterized by mild weather and historically-low natural gas prices, leading to less extreme system conditions and less volatile market outcomes, especially in the summer months. As a result, the market outcomes varied considerably throughout the year." [Footnote omitted]

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

Total MISO ASM Charges Assigned to Retail (in millions)

AAA Reporting Period	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015
Net Costs	($3.9)[22]	$0.8[23]	$3.5[24]	$13.9[25]	$24.7[26]	$23.5[27]	$24.6[28]

The Department notes that Xcel's retail ASM costs increased over time and have been fairly consistent around $23 to $24 million for FYE13 to FYE15.

Xcel Electric also provided a calculation of its net savings related to ASM for FYE15.[29] The Company shows net ASM savings of $7.5 million for the total NSP system and $5.6 million for the Minnesota Jurisdiction. Xcel stated that these net savings are associated with optimizing the generation units that are carrying ancillary services across the entire MISO footprint. In addition, Xcel stated that its net savings calculation did not include any additional benefits that have accrued to ratepayers for the reduction in regional regulatory reserve requirements.

a) Excessive/Deficient Energy Deployment Charges (EDEDC)

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

The Department notes that Xcel's total system EDEDC decreased from $1,368,932[30] in FYE14 to $696,947 in FYE15, a decrease of 49 percent.

[22] Source: Xcel's initial filing in Docket No. E999/AA-09-961, Part J, Section 5, Schedule 13, Page 7 of 73.
[23] Source: Xcel's initial filing in Docket No. E999/AA-10-884, Part J, Section 5, Schedule 13, Page 13 of 13.
[24] Source: Xcel's initial filing in Docket No. E999/AA-11-792, Part J, Section 5, Schedule 13, Page 13 of 13.
[25] Source: Xcel's initial filing in Docket No. E999/AA-12-757, Part J, Section 5, Schedule 13, Page 13 of 13.
[26] Source: Xcel's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 13, Page 13 of 13.
[27] Source: Xcel's initial filing in Docket No. E999/AA-14-579, Part J, Section 5, Schedule 13, Page 13 of 13.
[28] Source: Xcel's initial filing in Docket No. E999/AA-15-611, Part J, Section 5, Schedule 13, Page 13 of 13.
[29] Source: Xcel's initial filing in Docket No. E999/AA-15-611, Part J, Section 6, Page 2 of 6.
[30] Source: Xcel's initial filing in Docket No. E999/AA-14-579, Part J, Section 6, Schedule 2, Page 1 of 2; sum of all months for FYE14.

According to Xcel Electric, a certain level of EDEDC is unavoidable given the current design of the ASM, which only allows a single average ramp rate value, instead of the different ramp rates that can occur as the unit moves from minimum to full load. The Company stated that its ASM net benefit calculation is a measure of the extent to which the Company has struck the appropriate balance between too much or too little flexibility being offered to MISO. The Company stated that its ASM net benefit of $7.5 million would not have been achievable if the Company had been offering ramp rates for units that would have all but eliminated the chance of incurring EDEDC charges. The Company also stated that:

> To minimize the incurrence of excessive charges, generation unit performance to MISO setpoints is monitored in real time by the system dispatcher to ensure that plants are keeping up with offered ramp rates. Computer displays show the dispatcher a graphical depiction of actual unit output compared to setpoint along with calculations of the deviation. The system analyst and system dispatcher communicate with the plants on a daily basis to discuss operational issues affecting unit performance and adjust offers to MISO accordingly. This iterative process helps ensure that these charges are, to the extent possible, minimized while still creating opportunities for lower overall costs for ratepayers. For these reasons, a certain level of Excessive Deficient Energy Deployment Charges is expected – and prudent – in light of the overwhelming benefits associated with high unit flexibility that more than offset these charges.
>
> In December 2012, MISO implemented changes in accordance with FERC Order 755 by adding a regulation mileage product to financially compensate for actual generator movement. An increase in EDEDC charged to the Company began in January 2013, which is attributed to the overall rate increase associated with the addition of the mileage component and higher LMPs. This increase was offset by an increase in the revenues received by the Company for Regulation. During the period of July 2014 through June 2015, EDEDC charges have declined by $671,984 as compared to the 2014 AAA period, ending June 30, 2014.

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

b) Contingency Reserve Deployment Failure Charges (CRDFC)

Xcel Electric provided its monthly Contingency Reserve Deployment Failure Charges (CRDFC) for FYE15 in Part J, Section 6 of its filing. CRDFC amounts are incurred when generation or demand response resources fail to deploy contingency reserves at or above the contingency reserve deployment instruction. These charges are assessed if a unit that is selected to provide spinning or supplemental reserves during a specific hour does not perform and MISO must then deploy another resource.

The Department notes that Xcel Electric's total system CRDFC decreased from $11,671[31] in FYE14 to $4,996 in FYE15, a decrease of 57 percent. Regarding its FYE15 CRDFC, Xcel stated that:

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

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

[31] Source: Xcel's initial filing in Docket No. E999/AA-14-579, Part J, Section 6, Schedule 2, Page 2 of 2; sum of all months for FYE14.

c) *#4 Real-Time Regulation, #5 Real-Time Spinning Reserve, #6 Real-Time Supplemental Reserve, #8b Real-Time Non Excessive Energy Congestion and the related allocations*

For Real-Time Regulation, the Department noted that out of a total net invoice amount of $143,130, retail was assigned costs of $723,660 and asset-based/wholesale was assigned revenues of ($866,790) for Real-Time Regulation Amount charges in FYE15. For Real-Time Spinning Reserve, the Department noted that, out of a total net invoice amount of ($155,858), retail was assigned costs of $325,374 and asset-based/wholesale was assigned revenues of ($481,231) in FYE15. For Real-Time Non Excessive Energy Congestion, the Department noted that out of a total net invoice amount of ($425,175), retail was assigned ($406,468) and asset-based/wholesale was assigned ($18,707).

As a result, the Department asked Xcel Electric to explain why it is reasonable for wholesale/intersystem sales to be assigned only revenue amounts for Real-Time Regulation, Real-Time Spinning Reserve, and Real-Time Supplemental Reserve while retail is assigned the costs, yet revenues are shared for Real-Time Non-Excessive Energy Congestion. In response to DOC Information Request No. 10, Xcel Electric provided the following response:

> Regulation reserve, spinning reserve and supplemental reserve are Ancillary Services which share a common allocation method. The allocation method nets hourly Day-Ahead and Real-Time results to determine Wholesale/Intersystem sales. As a result Day-Ahead and Real-Time Wholesale/Intersystem sales are combined on the same line item where it appears retail is only assigned cost.
>
> In actuality both Retail and Wholesale/Intersystem are assigned revenue during the allocation process. Demonstrations are provided in the table/example below.
>
> Example: The real-time regulation amount of ($92,773.70) on line 4 of the wholesale/intersystem column is an allocation of the Total Regulation Reserve amount of ($162,123.85) where Retail is assigned revenue of ($69,350.15) and wholesale/intersystem is assigned ($92,773.70).

line	Description	Retail	Wholesale/Intersystem	Total
1	Day-Ahead Regulation Amount	($137,956.71)		
4	Real-Time Regulation Amount	$68,606.56	($92,773.70)	
	Total Regulation Reserve	($69,350.15)	($92,773.70)	**($162,123.85)**
2	Day-Ahead Spinning Reserve Amount	($149,004.19)		
5	Real-Time Spinning Reserve Amount	$77,623.09	($76,977.30)	
	Total Spinning Reserve	($71,381.10)	($76,977.30)	**($148,358.40)**
3	Day-Ahead Supplemental Reserve	($50,626.73)		
6	Real-Time Supplemental Reserve Amount.	$10,536.68	($6,696.83)	
	Total Supplemental Reserve	($40,090.05)	($6,696.83)	**($46,786.88)**

> Real-Time Non Excessive Energy Congestion is a calculation done by Xcel Energy to identify the Marginal Congestion Component (MCC) included in the price of MISO energy (LMP). The MISO LMP is made up of three components: the Marginal Energy Component (MEC), the Marginal Congestion Component (MCC), and the Marginal Loss Component (MLC).
>
> Real-Time Non Excessive Energy Congestion is related to Energy and has a separate allocation method apart from Ancillary Services. Both cost and revenue are assigned to Retail and Wholesale/Intersystem.

The Department also asked Xcel in DOC Information Request No. 12 if there is actually wholesale/intersystem customers or if this is really ASM revenue that is assigned to shareholders. Xcel provided the following response:

> The amounts seen on the referenced page are allocations of MISO charge types as mentioned within our response to Information Request No. 11. There are no specific customers that comprise the wholesale/intersystem category; rather, they are MISO participants.
>
> Also, we note that for the Minnesota portion of ASM asset based margins, 100 percent of the margins are shared with retail customers. Shareholders do not retain any portion of the asset based margins allocated to Minnesota.

The Department appreciates Xcel Electric's responses and, based on our review, recommends that the Commission accept the Company's ASM reporting and allocations. The Department recommends, for future reporting, that Xcel report the revenues and costs of ASM charges separately, rather than reporting the amounts net which does not allow for the necessary transparency to confirm that allocations between retail and wholesale/intersystem sales are reasonable. The Department notes that we addressed the

ASM asset-based margins that are refunded to customers in the asset-based margins section above.

C. MP

MP addresses ASM costs and benefits in Attachment 10 to its FYE15 AAA Report. MP reported a net cost of $161,920 for FYE15, compared to net costs of $303,890 and $74,441 in FYE14, and FYE13, respectively. The Department reviewed MP's ASM charges and concludes that they are reasonable.

The Department notes that MP's real-time excessive deficient energy deployment charge amount decreased from $134,357 in FYE14 to $78,916 in FYE15, and that its contingency reserve deployment failure charge amount decreased from $2,757 to $288 over the same period.

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-A, page 6 compares MP's MISO Schedule 17 charges prior to the start of the ASM market to its Schedule 17 charges in FYE15. In FYE15, average monthly MISO Schedule 17 charges were $156,071, or $15,149.28 higher than the average monthly charges prior to the start of the ASM market. This equates to an average monthly increase of $0.00114 per mWh.

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

D. OTP

In Part H Section 4, Attachment L its FYE15 AAA Report, OTP provided its ASM information as required by the Commission's August 23, 2010 Order in Docket M-08-528. Specifically, OTP noted that ASM market transition has been smooth from an operational standpoint. OTP also indicated that there has been a positive economic benefit for OTP, as a result of maximizing capabilities of generating units, which has led to greater operational efficiency. OTP's Schedule 1 shows that OTP is a net seller of ASM products (Regulation, Spinning Reserve, and Supplemental Reserve). As a result, ASM provided net benefits of $24,977 to Minnesota ratepayers in 2015-2016. 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 from $204,356 in 2013-2014 to $24,977 in 2014-2015, an 87 percent decrease. In response to Department Information Request No. 18, OTP explained that the decrease was primarily due to a decrease in available resources due to the Big Stone Power Plant being down for air quality control testing, resulting in the plant providing only 63% of the electricity it provided in 2013/2014. A further contributing factor was a derate of the Coyote plant resulting in the plant providing only 77% of the electricity it provided in 2013/2014. Finally, large drops in the LMP market reduced the operating hours of OTP's plants.

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

E. INTERSTATE ELECTRIC

Included in Attachments D through F of its FYE15 AAA filing, Interstate Electric provided its ASM information as required by the Commission.[32] Pages 1 through 8 in Attachment D detail the Regulation, Spinning Reserve, Supplemental Reserve, and Other Charges and resulting subtotals for all four quarters included in FYE15. The DOC notes that for Spinning Reserves and Supplemental Reserves in FYE15, Interstate Electric was a net purchaser, and for Regulation Interstate Electric was a net seller. The DOC also notes that Other Charges (which consists of contingency reserve deployment failure, real-time excessive deficient energy deployment charge, and net regulation adjustment) for FYE15 was $473,253 compared to the FYE 14 amount of $716,066, or a nearly 34 percent reduction in Other Charges.

Interstate Electric provided an Economic Savings Analysis for all four quarters of the reporting year in Attachment E. The economic savings are realized because Interstate Electric is no longer required to "hold back" generators in order to provide ancillary services and can instead gain margin on the energy sales accrued by these generators. Prior to ASM, some low-cost coal generation had to be "held back" to allow Interstate Electric to self-provide ancillary services, which incurred an opportunity cost as the units could not be offered into the MISO market and garner a higher payment than the fuel and operating costs. Interstate Electric calculated these benefits, less the MISO Schedule 17 administrative costs for ASM, resulting in total net benefits of $1,097,843 for the current reporting period FYE15.[33] While the total net benefits for ASM for FYE15 is less than the benefits for FYE14 and FYE13, this is not surprising due to the lower LMP and lower overall ASM costs charged to ratepayers.

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

IV. RECOMMENDATIONS

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

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

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

[32] Commission's August 23, 2010 Order in Docket No. M-08-528.
[33] Attachment E, "Energy Savings less Sch. 17 Charges ASM Allocation" for all four quarters in the reporting period.

- The Department recommends that the Commission accept OTP’s MISO Day 2 reporting.

- The Department recommends that the Commission accept IPL’s MISO Day 2 reporting.

For Xcel Electric’s Asset Based Margins, the Department requested that the Company provide some additional information in reply comments regarding the revenues for the Municipal Time of Day Rate and why Xcel Electric does not direct assign these costs and revenues to the relevant customers but instead includes them in the asset based margins returned to all ratepayers.

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

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

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

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

- The Department recommends that the Commission accept IPL’s ASM reporting.

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☒ **Public Document**

Xcel Energy			
Docket No.:	E999/AA-15-611		
Response To:	MN Department of Commerce	Information Request No.	14
Requestor:	Nancy Campbell		
Date Received:	July 20, 2016		

<u>Question:</u>
Reference: Initial AAA filing, Part J, Section 5, Schedule 7 page 13 of 13
Subject: Total MISO Day 2 Charges Assigned to Retail

Please provide the general reasons for why the MISO Day 2 costs assigned to retail customers decreased to $101.7 million for FYE15, compared to $222.9 million for FYE14, or a 54 percent decrease.

<u>Response:</u>
The *2015 State of the Market Report for the MISO Electricty Markets*[1] prepared by MISO's Independent Market Monitor ("IMM") compares market operations and costs. In the executive summary, the IMM cites:

- A 50 percent decline in natural gas prices from 2014;
- A 45-50 percent decline in congestion costs from 2014 with the largest differences for the periods when the Polar Vortex occurred in 2014;
- A two percent drop in load from 2014 to 2015 due to mild weather; and
- An increase in the use of gas resources across the footprint.

These factors contributed to significantly lower MISO Day 2 costs as reflected in the following:

- A 32 percent drop in energy prices;
- A 40 decline in Revenue Sufficiency Guarentee payments;
- An increase from 17 percent to 23 percent of the energy output from gas resources, with such resources more often setting marginal price levels; and

[1] From the MISO Website: www.misoenergy.org/MarketsOperations/IndependentMarketMonitor/Pages/IndependentMarketMonitor.aspx

- A decrease in real time price volatility as more flexible gas facilities were able to support system ramping requirements.

Preparer	Nick Detmer
Title:	Manager
Department:	Commercial Operations
Telephone:	303.571.7030
Date:	August 1, 2016

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Xcel Energy			
Docket No.:	E999/AA-15-611		
Response To:	MN Department of Commerce	Information Request No.	15
Requestor:	Nancy Campbell		
Date Received:	July 20, 2016		

<u>Question:</u>
Reference: Initial AAA filing, Part J, Section 5, Schedule 7 page 13 of 13
Subject: MISO Day 2 Charge Type #34, real-time schedule 24 allocation amount

For MISO Day 2 charge type 34, real-time schedule 24 allocation amount of ($460,032) assigned to intersystem/asset based customers for FYE15, please explain and show that this credit (or comparable credit) amount was given back to ratepayers in the current rate case for 2016 to 2020 via a classification to transmission revenues.

<u>Response:</u>
MISO Schedule 24 revenues are budgeted in FERC 456 and included in the Other Electric Revenues line item of the cost of service model. See work papers R2-2 in Volume 4A Test Year Workpapers Base Data filed in Docket No. E002/GR- 15-826 for the budgeted Schedule 24 revenues and work paper R1A and R1B for the MN Jurisdictional balances. These work papers identify the Schedule 24 budgeted revenues included in other electric revenues for 2016 – 2018.

MISO Schedule 24 expenses are budgeted in FERC 575 and included in Transmission Expenses line item of the cost of service models. See work paper O2-2A in Volume 4A Test Year Workpapers Base Data filed in Docket No. E002/GR- 15-826 for the budgeted Schedule 24 expense and work paper O2-2B for the MN Jurisdictional balances.

For the 2016 test year and 2017 and 2018 plan years the budgeted Schedule 24 revenue exceeds the budgeted Schedule 24 expense. Therefore the net Schedule 24 revenue for 2016 – 2018 lowers the revenue deficiency for each of those years.

In Docket No. E002/GR-15-826 the Company filed for a three year multi-year rate request and the work papers only reflect budgeted/forecasted data through 2018. However, the forecasted 2019 and 2020 Schedule 24 revenues would be treated in the same manner as the 2016 – 2018 data.

Preparer:	Thomas E Kramer
Title:	Principal Rate Analyst
Department:	Revenue Requirements – North
Telephone:	612-330-5866
Date:	August 1, 2016

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Xcel Energy			
Docket No.:	E999/AA-15-611		
Response To:	MN Department of Commerce	Information Request No.	16
Requestor:	Nancy Campbell		
Date Received:	July 20, 2016		

Question:
Reference: Initial AAA filing, Part J, Section 5, Schedule 7 page 13 of 13
Subject: MISO Day 2 Charge Type #20, real-time miscellaneous

For MISO Day 2 charge type 20, real-time miscellaneous, please describe the categories of costs/revenues include in real-time miscellaneous for FYE15 of $1,863,558 total company, including which revenues are related to Multi-Value Projects (MVPs) Auction Revenue Right (ARR) and how these revenues were given back to ratepayers. Please also support the Company allocation between retail of $1,266,875 and intersystem/asset based customers of $596,683.

Response:
It is important to note that the real-time miscellaneous category on the AAA report combines several MISO charge types including Real Time Resource Adequacy Auction Amount, Real Time MVP Distribution Amount and Real Time Miscellaneous Amount. Only the Real Time MVP Distribution Amount is allocated to the intersystem/asset based category. Real-time miscellaneous charges of $1,086,335 relate to out-of-period dispute resolution adjustments, market-to-market settlements, and the automatic reserve sharing credits and charges. Other items included in this category are $177,215 in Resource Adequacy Auction Revenues and $598,683 related to Multi-Value Projects.

The amount included in real-time miscellaneous allocated to asset-based/intersystem were credits for Multi-Value Projects (MVP), which represent monthly credits from MISO-held MVP ARRs. The MVP ARRs are treated as options and result in credits to those who paid for the MVPs. As such, it is appropriate to reclassify these balances to the asset-based/intersystem category.

Credits for MISO-held MVP ARRs are recorded as a reduction to expense for MISO Schedule 26-A, Multi-Value Project Usage Rate. Amounts are refunded to customers through the TCR rider by virtue of net actual Schedule 26-A expense being recovered through that rider.

Preparer:	Matt Schmidt
Title:	Senior Market Operations Financial Analyst
Department:	Market Operations
Telephone:	303-571-7519
Date:	August 1, 2016

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Xcel Energy			
Docket No.:	E999/AA-15-611		
Response To:	MN Department of Commerce	Information Request No.	17
Requestor:	Nancy Campbell		
Date Received:	July 20, 2016		

Question:
Reference: Initial AAA filing, Part J, Section 5, Schedule 7 page 13 of 13
Subject: MISO Day 2 Charges

Did Xcel change any of the allocation methods used to allocate MISO Day 2 charges (revenues) between retail and asset-based wholesale during the 2014-2015 reporting period? If yes, please explain and support all changes in allocations.

Response:
There have been no changes to the allocation methods for MISO Day 2 charges between retail and asset-based wholesale during the 2014-2015 reporting period.

Preparer:	Peter Zapotocky
Title:	Manager
Department:	Commercial Accounting
Telephone:	303-571-6943
Date:	August 1, 2016

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Xcel Energy
Docket No.: E999/AA-15-611
Response To: MN Department of Commerce Information Request No. 13
Requestor: Nancy Campbell **Supplement**
Date Received: July 20, 2016

Question:
Reference: Initial AAA filing, Part J, Section 5, Schedule 7 page 6 of 13
Subject: MISO Day 2 – Asset Based Margins

Please provide support to show that the $9.959 million in MISO Day 2 asset based margins for December 2014 was credited to ratepayers via the fuel clause adjustment.

Response:
The $9.959 million reported in our 2015 AAA filing is a portion of the total asset based revenues. Various Cost of Goods Sold expenses are deducted from the total revenue to calculate the margins. The Minnesota jurisdictional portion credited to Minnesota ratepayers in the February 2015 fuel clause adjustment was $455,780.

Please see below for additional detail:

Minnesota Asset Based Margin Sharing	(Dec 2014) $- millions
(1) MISO Day 2 Intersystem Asset Based Revenue	$ 10.0
(2) Non-MISO Asset Based Revenue	$ 1.3
(3) Total Asset Based Revenue (1)+(2)	$ 11.3
(4) Less: Cost of Goods Sold	$ 9.7
(5) NSP System Asset Based Margins (3)–(4)	$ 1.6
(6) Less: Ratepayer Sharing (*)	$ **0.6**
(7) Less: Other Jurisdictions Specific Adjustments	$ 0.7
(8) Other Jurisdictions' Pass-Through/Company Retention	$ 0.3

* **Ratepayer Sharing Detail**	
Minnesota Jurisdiction	$ 1,141,178
Less: Other Jurisdictions Specific Adjustments	$ 685,397
Minnesota Net Portion	**$ 455,781**
Other NSP Jurisdictions	$ 171,439
Total NSP Ratepayers Sharing	**$ 627,220**

Supplement:

Please see Attachment A for a breakdown of the derivation of the asset based margin sharing refund for December 2014.

Also, please see Attachment B for a copy of our FCA February 2015 filing. Attachment 3, Page 1, of our FCA February 2015 filing shows that the asset based margin net amount of $455,780 was credited to Minnesota ratepayers. You will also note that ASM charges include both margins and expenses incurred in the Day 3 market. This net number can be positive or negative in any single month. (See Attachment 2, Page 11, of our FCA February 2015 filing).

Preparer: Peter Zapotocky/ John Chow
Title: Manager/Pricing Consultant
Department: Commercial Accounting/Regulatory Affairs
Telephone: 303-571-6943/612-330-7588
Date: August 5, 2016 **Supplemented: August 17, 2016**

Northern States Power Company, A Minnesota Corporation
Electric Operations - State of Minnesota

Minnesota Asset Based Margin Sharing - December 2014

MISO Day 2 Asset Based Revenue (See Page 2)	$	9,959,424
ASM Intersystem Asset Based Cost (See Pages 3 & 4)	$	(13,610)
Non-MISO Asset Based Revenue	$	1,319,293
Total Asset Based Revenue per Trade Margin	$	11,265,107
Less: Cost of Goods Sold per Trade Margin	$	(9,684,573)
NSP System Asset Based Margin	$	1,580,534
MN Margin Sharing % (Based on MWh Sales Weightuing)		72.20%
Minnesota Jurisdiction Margin	$	1,141,177
Less: Minnesota Jurisdiction Specific RSG/RNU Adjustment	$	(60,552)
Less: Minnesota Jurisdiction Specific C&L Adjustment	$	(624,846)
Asset Based Margin Sharing Refund to Minnesota Ratepayers (See Page 5, Refund)	**$**	**455,779**

Northern States Power Company, A Minnesota Corporation
Electric Operations - State of Minnesota

Minnesota Asset Based Margin Sharing - December 2014

MISO Day 2 Asset Based Revenue (See Page 2)	$	9,959,424
ASM Intersystem Asset Based Cost (See Pages 3 & 4)	$	(13,610)
Non-MISO Asset Based Revenue	$	1,319,293
Total Asset Based Revenue per Trade Margin	$	11,265,107
Less: Cost of Goods Sold per Trade Margin	$	(9,684,573)
NSP System Asset Based Margin	$	1,580,534
MN Margin Sharing % (Based on MWh Sales Weightuing)		72.20%
Minnesota Jurisdiction Margin	$	1,141,177
Less: Minnesota Jurisdiction Specific RSG/RNU Adjustment	$	(60,552)
Less: Minnesota Jurisdiction Specific C&L Adjustment	$	(624,846)
Asset Based Margin Sharing Refund to Minnesota Ratepayers (See Page 5, Refund)	**$**	**455,779**

Xcel Electric's
Follow-up
Responses to DOC
IR 13 Supplemental

From:	Chow, John
To:	Campbell, Nancy (COMM)
Cc:	Krug, Allen D; Zapotocky, Peter J; Edman, Timothy J
Subject:	FW: 2015 AAA - Follow-Up Questions on DOC-IR 13
Date:	Friday, August 19, 2016 2:33:40 PM
Attachments:	image002.png DOC IR 13 Follow-Up Questions.xlsx

Nancy,

Pursuant to our telephone discussion this morning regarding your follow-up questions, the following is a more detail description on the $9.7M Cost of Goods Sold trade margin:

NSP uses Cost Calculator to determine the cost that is associated with asset based sales. This proprietary software stack ranks dispatchable generation resource costs from highest to lowest on an hourly basis. Costs associated with short-term wholesale sales and market sales are assigned the most expensive dispatchable resources on an hourly basis. For example, if during a given hour, NSP made Asset Based sales for 100 MWh, Cost Calculator would go through the generation portfolio for that hour and assign the least economic 100 MWhs of production to the Asset Based sale. This process assures that native load customers pay no more for energy then they would have absent the Asset Based sale. Margins are calculated by taking the difference between the price that the energy was sold at and the costs that are assigned via Cost Calculator. In addition to the assigned Cost Calculator costs, there is an additional $32K of MISO admin costs.

	Sum of Costs	Sum of MWs	
Gen Book Fuel Costs			
Total Coal	$4,195,471	208,030	
Total Gas & Oil	$4,960,062	172,802	
Total Wind	$0	8,182	
Total Gen Book Fuel Costs	**$9,155,533**	**389,014**	**Refer to "Gen Book Fuel Detail" below**
Gen MISO Admin Costs	**$31,719**	-	
Municipal Time of Day Rate Costs	**$497,321**	**21,468**	
Total Gen COGS	**$9,684,573**	**410,483**	

The attachments include (1) Gen Book Fuel Detail (2) data source of paper of RSG/RNU Adjustment and (3) data source of C&L Adjustment.

Hope the above response has addressed your follow up-questions. If not, feel free to contact me again.

Thanks

John

Gen Book Fuel Detail

Unit	Sum of Total Cos	Sum of Total MWs
Anson Plant 2	($26,708)	(408)
Anson Plant 3	($3,174)	(43)
Anson Plant 4	($26,250)	(340)
Black Dog Plant 3	$49,163	2,984
Black Dog Plant 4	$345,380	16,683
Black Dog Plant 52	$800,268	29,488
Blue Lake Plant 3	($3,197)	(5)
Blue Lake Plant 7	($16,935)	(276)
Blue Lake Plant 8	($37,562)	(638)
High Bridge Plant 1	$1,267,875	41,699
High Bridge Plant 2	$1,381,566	47,555
Riverside Plant 1	$692,689	24,311
Riverside Plant 2	$814,708	27,709
French Island Plant 3	$859	2
French Island Plant 4	$402	1
King Plant 1	$722,021	37,207
Nobles 1	$0	(634)
Nobles 2	$0	(618)
Sherco 3	$1,025,776	46,804
Sherco 1	$947,039	48,254
Sherco 2	$1,108,080	56,143
Wheaton Plant 1	$5,001	14
Wheaton Plant 4	$3,914	27
Grand Meadow Wind	$0	844
Inver Hills Plant 1	$11,875	210
Inver Hills Plant 2	$1,627	17
Agassiz Beach, LLC	$0	16
FPL Energy Mower County, LLC	$0	806
Buffalo Ridge Wind Farm, LLC 1	$0	929
Buffalo Ridge Wind Farm, LLC 2	$0	852
Canon Falls 1	$237	7
Canon Falls 2	$202	6
Mankato	$158,228	4,733
Chanarambie Power Partners LLC 1	$0	525
Chanarambie Power Partners LLC 2	$0	1,027
Chanarambie Power Partners LLC 4	$0	434
North Community Turbines LLC 1	$0	(81)
North Community Turbines LLC 2	$0	(78)
Ewington	$0	(57)
GarMar Wind I	$0	225
LSP Cottage Grove	($67,550)	(1,312)

Northern States Power Company
2014 Allocation of RSG & RNU Charges to Wholesale

Date	DA RSG	RT RSG	RNU	MISO Gen %	DA RSG - Wholesale	RT RSG - Wholesale
Jan-14	$318,349	$66,737	$1,280,857	7.7%	$24,425	$5,120
Feb-14	$374,464	$953,092	$1,644,524	6.9%	$25,718	$65,458
Mar-14	$1,064,719	$1,709,979	$545,203	6.9%	$73,945	$118,758
Apr-14	$215,830	($628,859)	$1,481,500	4.4%	$9,563	($27,864)
May-14	$286,853	$91,656	$799,607	11.6%	$33,216	$10,613
Jun-14	$263,840	$273,896	$754,900	3.2%	$8,462	$8,784
Jul-14	$105,260	($126,910)	$651,313	1.8%	$1,899	($2,290)
Aug-14	$200,932	$202,604	$853,733	2.4%	$4,799	$4,839
Sep-14	$182,636	$153,059	$552,826	4.4%	$8,101	$6,789
Oct-14	$152,832	$178,912	$868,925	7.9%	$12,044	$14,099
Nov-14	$109,833	$147,663	$1,429,445	5.3%	$5,826	$7,833
Dec-14	$181,370	$167,304	$544,352	9.5%	$17,314	$15,972
Total NSP System	**$3,456,918**	**$3,189,132**	**$11,407,186**		**$225,313**	**$228,113**

RNU - Wholesale	Total - Wholesale				
$98,272	$127,817				
$112,946	$204,122				
$37,864	$230,568				
$65,643	$47,342				
$92,591	$136,420				
$24,210	$41,456				
$11,752	$11,361				
$20,391	$30,030				
$24,522	$39,413				
$68,475	$94,618				
$75,829	$89,488		MN Allocator		
$51,966	$85,252	x	72.2%	=	$ 61,553.82
$684,462	**$1,137,888**				

Gen Book Fuel Detail

Unit	Sum of Total Cos	Sum of Total MWs
Anson Plant 2	($26,708)	(408)
Anson Plant 3	($3,174)	(43)
Anson Plant 4	($26,250)	(340)
Black Dog Plant 3	$49,163	2,984
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French Island Plant 4	$402	1
King Plant 1	$722,021	37,207
Nobles 1	$0	(634)
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Sherco 3	$1,025,776	46,804
Sherco 1	$947,039	48,254
Sherco 2	$1,108,080	56,143
Wheaton Plant 1	$5,001	14
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Grand Meadow Wind	$0	844
Inver Hills Plant 1	$11,875	210
Inver Hills Plant 2	$1,627	17
Agassiz Beach, LLC	$0	16
FPL Energy Mower County, LLC	$0	806
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North Community Turbines LLC 2	$0	(78)
Ewington	$0	(57)
GarMar Wind I	$0	225
LSP Cottage Grove	($67,550)	(1,312)

From:	Flores, Kelsey N
To:	Campbell, Nancy (COMM)
Cc:	Krug, Allen D; Zapotocky, Peter J; Chow, John
Subject:	RE: 2015 AAA - Follow-Up Questions on DOC-IR 13
Date:	Friday, August 19, 2016 4:32:45 PM

Hi Nancy,

The municipal customers are being billed $537,166 of revenue in the trade margin that is being offset by the $497,321 of costs for a margin of $39,845. Please let me know if you have any additional questions.

Thank you,

Kelsey Flores, MBA
Xcel Energy | Responsible By Nature
Principal Financial Consultant, NSP Commercial Accounting
1800 Larimer Street, 12th Floor, Denver, CO 80202
P: 303.571.7024
F: 303.294.2986
E: Kelsey.n.flores@xcelenergy.com

From: Campbell, Nancy (COMM) [mailto:nancy.campbell@state.mn.us]
Sent: Friday, August 19, 2016 3:23 PM
To: Chow, John
Cc: Krug, Allen D; Zapotocky, Peter J; Flores, Kelsey N
Subject: RE: 2015 AAA - Follow-Up Questions on DOC-IR 13

I appreciate all the information you provided today in your earlier 2:33 pm email and in the 4:01 pm email below since it was very helpful in better understanding the asset based margin issue and supporting the amount credited to ratepayers via the FCA.

What I don't understand is why are $497,321 in Municipal Time of Day Rate Costs for December 2014 reducing the asset based margin provided retail customers? Since there are actual Municipal customers, wouldn't the municipal customers be charged these costs directly? Are retail customers also receiving the revenues related to these municipal customers?

Thanks and have a good weekend!

Nancy Campbell
Financial Analyst
Minnesota Department of Commerce
85 7th Place East, Suite 500, Saint Paul, MN 55101
P: 651-539-1821

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From: Chow, John [mailto:john.chow@xcelenergy.com]
Sent: Friday, August 19, 2016 4:01 PM
To: Campbell, Nancy (COMM)
Cc: Krug, Allen D; Zapotocky, Peter J; Flores, Kelsey N
Subject: FW: 2015 AAA - Follow-Up Questions on DOC-IR 13

Hi Nancy,

Please see answer to your questions below. Thanks.

John

From: Flores, Kelsey N
Sent: Friday, August 19, 2016 3:42 PM
To: Chow, John; Zapotocky, Peter J
Cc: Krug, Allen D; Edman, Timothy J
Subject: RE: 2015 AAA - Follow-Up Questions on DOC-IR 13

Municipal Time of Day Rate Cost are a Cost Calculator costing concept that falls below the asset based margins within the costing stack. These cost are specifically associated with a few wholesale customers; North Central Power Company, Inc.(NCP), Northwestern Wisconsin Electric Company (NWEC), CMMPA, Dahlberg Light & Power.

The Gen MISO Admin costs are comprised of the items below:

Cargill Financial Hedge	$ 4,498.00
MISO SalesAdmin Fees DA	$ 22,995.82
MISO SalesAdmin Fees RT	$ 3,692.07
MISO Sch 24 Sales Admin Fee DA	$ 2,721.27
MISO Sch 24 Sales Admin Fee RT	$ 434.10
DA RSG MWP Alloc to GEN	$ (15,732.48)
RT RSG MWP Alloc to GEN	$ 1,364.09
RT PV MWP Alloc to GEN	$ (13,244.26)
ASM NRGA Alloc to GEN	$ 2,571.86
RT ASM CRDFC	$ -
RT ASM EXE DFE DEP	$ 22,418.79
Total	$ 31,719.26

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Xcel Energy			
Docket No.:	E999/AA-15-611		
Response To:	MN Department of Commerce	Information Request No.	10
Requestor:	Nancy Campbell		
Date Received:	July 20, 2016		

Question:
Reference: Initial AAA filing, Part J, Section 5, Schedule 13 page 13 of 13
Subject: MISO Ancillary Services Market (ASM) Settlements

Please explain why it is reasonable for wholesale/intersystem to be assigned only revenue amounts for real-time regulation, real-time spinning reserve, real-time supplemental reserve, and real-time non excessive energy congestion, while retail is assigned costs for the first three categories and shares revenues for the last category listed.

Response:
Regulation reserve, spinning reserve and supplemental reserve are Ancillary Services which share a common allocation method. The allocation method nets hourly Day-Ahead and Real-Time results to determine Wholesale/Intersystem sales. As a result Day-Ahead and Real-Time Wholesale/Intersystem sales are combined on the same line item where it appears retail is only assigned cost.

In actuality both Retail and Wholesale/Intersystem are assigned revenue during the allocation process. Demonstrations are provided in the table/example below.

Example: The real-time regulation amount of ($92,773.70) on line 4 of the wholesale/intersystem column is an allocation of the Total Regulation Reserve amount of ($162,123.85) where Retail is assigned revenue of ($69,350.15) and wholesale/intersystem is assigned ($92,773.70).

line	Description	Retail	Wholesale/Intersystem	Total
1	Day-Ahead Regulation Amount	($137,956.71)		
4	Real-Time Regulation Amount	$68,606.56	($92,773.70)	
	Total Regulation Reserve	($69,350.15)	($92,773.70)	**($162,123.85)**

2	Day-Ahead Spinning Reserve Amount	($149,004.19)		
5	Real-Time Spinning Reserve Amount	$77,623.09	($76,977.30)	
	Total Spinning Reserve	($71,381.10)	($76,977.30)	**($148,358.40)**
3	Day-Ahead Supplemental Reserve	($50,626.73)		
6	Real-Time Supplemental Reserve Amount.	$10,536.68	($6,696.83)	
	Total Supplemental Reserve	($40,090.05)	($6,696.83)	**($46,786.88)**

Table based on Initial AAA filing, Part J, Section 5, Schedule 13 page 13 of 13

Real-Time Non Excessive Energy Congestion is a calculation done by Xcel Energy to identify the Marginal Congestion Component (MCC) included in the price of MISO energy (LMP). The MISO LMP is made up of three components: the Marginal Energy Component (MEC), the Marginal Congestion Component (MCC), and the Marginal Loss Component (MLC).

Real-Time Non Excessive Energy Congestion is related to Energy and has a separate allocation method apart from Ancillary Services. Both cost and revenue are assigned to Retail and Wholesale/Intersystem.

Preparer: Matt Schmidt
Title: Sr. Market Ops Financial Analyst
Department: Market Operations Accounting
Telephone: 303-571-7519
Date: August 1, 2016

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Docket No.:	E999/AA-15-611		
Response To:	MN Department of Commerce	Information Request No.	12
Requestor:	Nancy Campbell		
Date Received:	July 20, 2016		

Question:
Reference: Initial AAA filing, Part J, Section 5, Schedule 13 page 13 of 13
Subject: MISO Ancillary Services Market Settlements

Please explain if there is actually wholesale/intersystem customers or if this is really ASM revenue that is assigned/provided to shareholders. Please support your response.

Response:
The amounts seen on the referenced page are allocations of MISO chargetypes as mentioned within our response to Information Request No. 11. There are no specific customers that comprise the wholesale/intersystem category; rather, they are MISO participants.

Also, we note that for the Minnesota portion of ASM asset based margins, 100 percent of the margins are shared with retail customers. Shareholders do not retain any portion of the asset based margins allocated to Minnesota.

Preparer:	Pete Zapotocky
Title:	Commercial Accounting Manager
Department:	NSP Commercial Accounting Manager
Telephone:	303-571-6943
Date:	August 1, 2016

OTTER TAIL POWER COMPANY
Docket No: E999/AA-15-611

Response to: Minnesota Department of Commerce
Analyst: Michael Zajicek
Date Received: 07/21/2016
Date Due: 08/01/2016
Date of Response: 08/01/2016
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Information Request:

Reference: Initial AAA filing, Part H, Section 4, Attachment L

Subject: MISO Ancillary Services Market (ASM) Settlements

Please explain why ASM net benefits have decreased from $204,356 in 2013-2014 to $24,977 in 2014-2015, which amounts to an 87 percent decrease.

Attachments: 0

Response:

The revenues associated with ASM benefits are tied to plant output and availability. When generators are unavailable, de-rated, or not committed due to market pricing their ability to generate ASM revenues is greatly reduced. In 2014/15 OTP experienced a significant reduction in generation as compared to 2013/14. This reduction in generation was driven by three primary factors:

1. The Big Stone Plant outage necessary for integration of the AQCS project: The Big Stone Plant was offline from the end of February 2015 through the balance of the 2014/15 reporting period to complete the final integration of the Air Quality Control System (AQCS) project into the Big Stone Plant, as well as complete additional plant maintenance on turbine blading. Output for the plant during the 2014/15 reporting period was approximately 63% of 2013/14 levels.
2. The de-rated capacity of the Coyote plant as a result of a boiler feed pump failure: Coyote Plant was de-rated from January of 2015 through the balance of the 2014/15 reporting period. Output for the plant in 2014/15 was approximately 77% of 2013/14 levels.

3. A reduction of operating hours due to lower market pricing: Due to substantially lower LMP market pricing, OTP coal and natural gas generation were dispatched fewer hours in 2014/15 as compared to 2013/14. Total 2014/15 output for the combination of the Big Stone, Coyote, Hoot Lake and Solway plants was approximately 70% of 2013/14 levels.

In addition, per MW ASM pricing paid to generators substantially decreased from the 2013/14 reporting period to the 2014/15 reporting period.

Furthermore, the clearing and sale of ASM products into the market is dependent on the MISO co-optimization offer process. MISO co-optimizes a market participant's offers of energy, regulation, spin, and supplemental to maximize the market participant's revenue. During this process it is possible that revenues can move between energy products and ASM products depending on market conditions.

OTTER TAIL POWER COMPANY
Docket No: E999/AA-15-611

Response to: Minnesota Department of Commerce
Analyst: Michael Zajicek
Date Received: 07/21/2016
Date Due: 08/01/2016
Date of Response: 08/01/2016
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Information Request:

Reference: Initial AAA filing, Part H, Section 3, Attachment K, Page 26

Subject: MISO Day 2 Charges Assigned to Retail

Reference: Total net 2013-2014 MISO Day 2 charges assigned to retail increased from $31.4 million in 2012-2013 to $42.2 million in 2013-2014, or a $10.8 million increase. This was due to the fact that the 2013/2014 winter was one of the coldest in the last 20 years due to the "polar vortex" weather pattern that existed across the upper Midwest, resulting in higher energy demand throughout MISO and an increase in market energy prices. Net MISO Day 2 charges assigned to retail for 2014-2015 stayed relatively the same, with a decrease of only $2.1 despite no similar "polar vortex" weather pattern.

Please explain:

1. Why total net costs for the 2014-2015 MISO Day 2 charges assigned to retail remained at such a high level; and

2. Why total net costs for MISO Day 2 assigned to retail have been steadily rising over the past few years.

Attachments: 1

Attachment 1 to IR MN-DOC-20.pdf

Response:

The MISO Day 2 charges assigned to retail include both charges to load and revenues credited to generation. As mentioned above, there was no comparable "polar vortex" event in 2014/15. Market conditions in 2014/2015 were such that LMP prices were significantly lower as compared to 2013/14. As a result, per MWh charges to OTP load were reduced. However, this also resulted in per MWh revenues for OTP generation being reduced. In addition, total MWhs of output for OTP generation was substantially reduced in 2014/15 as compared 2013/14, as explained in OTP's response to IR MN-DOC-18. With the lower market prices, as well as lower dispatch of OTP plants, a higher percentage of energy was acquired from the market to take advantage of the lower energy prices in the market.

To help further illustrate the drivers in the year over year changes to total MISO day 2 charges, Attachment 1 to this response provides a year by year comparison of the net energy (DA and RT) amounts (MWhs and Dollars) for the last 3 reporting periods. The DA and RT energy totals are found on line 5 of the MISO Day 2 Charges- System Reports which is located in Part H Section 3 of Attachment K in the respective years AAA reports. This particular analysis looks at the actual energy volumes and costs, and helps illustrate the total amount of net energy which was procured from the MISO market each year.

Column E in Attachment 1 shows the total <u>net</u> MWhs acquired from the market over the three reporting years. During the 2013/2014 polar vortex year, actual net market purchases were the lowest of the three periods (883,757) MWhs. Because of the increased demand for energy and higher market prices, OTP's plants were dispatched at higher levels during that reporting period as shown in column C. Columns F and G reflect the average LMP cost of energy for both purchase and sales transactions. Column H shows the total net cost incurred (For DA and RT Energy). During the 2014/2015 reporting period, prices dropped significantly. Due to a combination of continued load growth as well as reduced generation dispatch during 2014/2015, approximately 1.425 million net MWhs was acquired from the market to serve OTP's load.

The table below summarizes the Net MWhs (Column A and as shown in Column C of Attachment 1) acquired from the market and compares them to the total system sales as reported in OTP's Annual Energy Adjustment Rider True-up filings for the respective reporting periods (Column B below). Column E reflects the approximate percentage of MWhs acquired from the market during the respective reporting periods. Despite the volatility in market prices over the last 3 years, OTP's average cost per MWh of energy has remained relatively stable, as reflected in column D below.

			(A)	(B)	(C)	(D)	(E)
				From Annual True-Up Filings Docket E017/M-03-30			
Line	AAA Reporting Period	Charge Type	From Attachment 1 Net MWhs (A) + (C)	Total System Sales MWhs (2)	Total System Cost (2)	Average Cost per MWh	% of system energy served from market (A/B)
1	2012/2013	Total Day Ahead & Real Time Energy	**(1,046,600)**	**4,405,289**	**$103,883,299**	$ 23.58	**24%**
2	2013/2014	Total Day Ahead & Real Time Energy	**(883,757)**	**4,636,516**	**$114,090,227**	$ 24.61	**19%**
3	2014/2015	Total Day Ahead & Real Time Energy	**(1,425,286)**	**4,588,130**	**$112,675,821**	$ 24.56	**31%**

Otter Tail Power Company

Total Day Ahead & Real Time Energy Amounts

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
			Retail								
Line	AAA Reporting Period	Charge Type	MWh (1)	Cost (1)	MWh (1)	Revenue (1)	**Net MWhs (A) + (C)**	Cost/ MWh (B)/(A)	Rev/ MWh (D)/(C)	Net Cost (B) + (D)	Avg Energy Cost/ MWh (H)/(E)
1	2012/2013	Total Day Ahead & Real Time Energy	(4,635,473)	$ (120,334,416)	3,588,873	$ 98,052,843	**(1,046,600)**	$ 25.96	$ 27.32	**$ (22,281,573)**	$ 21.29
2	2013/2014	Total Day Ahead & Real Time Energy	(4,959,325)	$ (175,738,995)	4,075,568	$ 146,011,923	**(883,757)**	$ 35.44	$ 35.83	**$ (29,727,072)**	$ 33.64
3	2014/2015	Total Day Ahead & Real Time Energy	(4,901,299)	$ (117,676,621)	3,476,013	$ 84,653,670	**(1,425,286)**	$ 24.01	$ 24.35	**$ (33,022,951)**	$ 23.17

(1) Source: Line 5 of Annual Report:Detail of MISO Day 2 Charges - System (Part H, Section 3) for respective reporting periods. These amounts reflect energy costs only and do not included congestion or losses.

CERTIFICATE OF SERVICE

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

MINNESOTA DEPARTMENT OF COMMERCE – REVIEW OF THE 2014-2015 ANNUAL AUTOMATIC ADJUSTMENT REPORT, PART II

Docket Nos. **E999/AA-15-611**

Dated this **25th** day of **August, 2016**.

/s/Linda Chavez

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