COMMERCE DEPARTMENT

April 30, 2021 **PUBLIC DOCUMENT**

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, Minnesota 55101-2147

RE: **PUBLIC Comments of the Minnesota Commerce Department, Division of Energy Resources**
Docket No. E999/CI-19-704

Dear Mr. Seuffert:

Attached are the **PUBLIC** Comments of the Minnesota Commerce Department, Division of Energy Resources (Department), in the following matter:

> In the Matter of an Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities.

The Department recommends that the Minnesota Public Utilities Commission (Commission) **take certain actions on a going forward basis**. The Department is available to answer any questions that the Commission may have in this matter.

Sincerely,

/s/ ADWAY DE, PH.D.
Energy Planner, Principal

AD/ja
Attachment

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PUBLIC Comments of the Minnesota Commerce Department
Division of Energy Resources

Docket No. E999/CI-19-704

I. INTRODUCTION

A. PROCEDURAL HISTORY

On November 13, 2019, the Minnesota Public Utilities Commission (Commission) issued its *Order Accepting 2017-2018 Electric Reports and Setting Additional Requirements* (2019 Order) in Docket No. E999/AA-18-373. In the 2019 Order the Commission included the following Order Points:

> 8. Minnesota Power, Otter Tail, and Xcel shall submit an annual compliance filing analyzing the potential options for seasonal dispatch generally, and potential options and strategies for utilizing "economic" commitments for specific coal-fired generating plants. The utilities shall include a specific explanation of barriers or limitations to each of these potential options, including but not limited to technical limits of the units and contract requirements (shared ownership, steam offtake contracts, minimum fuel supply requirements, [sic] (shared ownership, steam offtake contracts, minimum fuel supply requirements, etc.) as relevant, on March 1, 2020, and each year thereafter.
> 9. The Commission will open an investigation in a separate docket and require Minnesota Power, Otter Tail, and Xcel to report their future self-commitment and self- scheduling analyses using a consistent methodology by including fuel cost and variable O&M costs, matching the offer curve submitted to MISO [Midcontinent Independent System Operator, Inc.] energy markets.
> 10. In the investigation docket, Minnesota Power, Otter Tail, and Xcel shall provide stakeholders with the underlying data (work papers) used to complete their analyses, in a live Excel spread sheet, including, at a minimum, the data points listed below for each generating unit, with the understanding that this may include protected data.

On January 11, 2021, the Commission issued its *Order Evaluating Self-commitment and Self-scheduling Reports and Establishing Additional Filing Requirements* approving the March 1, 2020 filings by Northern States Power Company, doing business as Xcel Energy (Xcel) and Otter Tail Power Company (Otter Tail) covering July 1, 2018 to December 31, 2019. The Commission also ordered Minnesota Power to provide a more detailed filing for the same time period by February 1, 2021, and amended the requirements for the March 1, 2021 filings. Specifically, the

Commission ordered:

1. A complete analysis of the costs and benefits of economic or seasonal dispatch relative to self-scheduling at six named facilities for Minnesota Power, Otter Tail, and Xcel.
2. Inclusion of ancillary services revenues and other make-whole payments as a separate column on all reporting on revenue.
3. Provision of unit fuel cost and unit variable cost as separate line items.
4. Inclusion of an analysis including fixed fuel costs, if any fuel costs are usually excluded by the utility from MISO offer curves or otherwise treated as fixed.
5. Include preventative maintenance in operations and maintenance (O&M) costs.
6. Label any hours with unavoidable self-commitment, including cause.
7. Analysis of self-commitment should include all production costs, including variable O&M, fuel, and other variable costs associated with the plant.
8. Provision of information including minimum decommit time for each unit, number of times each unit incurred losses over a duration greater than or equal to that minimum, which of those periods had losses greater than startup costs, and sum of losses in excess of startup costs.
9. Analysis of economic dispatch options for co-owned plants.
10. Analysis of benefits of reducing minimum operating levels.
11. Creation of a template by the utilities with party input to standardize future filings in this docket, for approval by the Executive Secretary.

On February 11, 2021, Minnesota Power filed a standardized hourly template on behalf of itself and the other utilities in compliance with the January 11, 2021 Order.

On February 22, 2021, the Commission approved the reporting template to be used by utilities for their annual compliance filing.

On March 1, 2021, Xcel, Otter Tail and Minnesota Power filed their second annual compliance filings covering January 1,2020 to December 31, 2020. Xcel's report provided data regarding Allen S. King Generating Station (King), Monticello Nuclear Generating Station (Monticello), Prairie Island Nuclear Generating Station (Prairie Island) units 1 and 2; and Sherburne County Generating Station (Sherco) units 1, 2, and 3.[1] Minnesota Power's report provided data regarding Boswell Energy Center (Boswell) units 3 and 4.[2] Also, Otter Tail's report provided data regarding the Big Stone Plant (Big Stone) and Coyote Station (Coyote).

[1] Regarding Sherco unit 3, Southern Minnesota Municipal Power Agency (SMMPA) owns 41 percent and Xcel owns the remainder. SMMPA serves 18 municipal electric utilities in Minnesota.

[2] Regarding Boswell unit 4, WPPI Energy owns 20 percent and Minnesota Power owns the remainder. WPPI Energy serves 51 cooperative and municipal electric utilities.

Table *1* below shows the ownership arrangements for Big Stone and Coyote.

Table 1. OTP Unit Ownership Arrangements[3]

Utility	Big Stone Ownership Share	Coyote Ownership Share	ISO Membership
Otter Tail Power Company	53.9%	35.0%	MISO
Montana Dakota Utilities	22.7%	25.0%	MISO
NorthWestern Energy	23.4%	10.0%	SPP
Minnkota Power Cooperative	0.0%	30.0%	MISO

B. MISO MARKET BACKGROUND

1. Capacity Market Operations

For purposes of this proceeding there are two stages to MISO's market construct. The first stage is the Planning Resource Auction (PRA), a voluntary annual capacity auction. According to MISO, the PRA is a way for market participants to meet resource adequacy (capacity) requirements. As an alternative to participating in the PRA, utilities can submit a Fixed Resource Adequacy Plan (FRAP). A FRAP shows the utility's capacity requirements and the resources that will be used to meet those obligations.

Resources that either clear the annual PRA or are used in a FRAP— stage 1 of MISO's market—must be offered into stage two of MISO's market construct, the energy market stage. As clarified by Otter Tail, this must-offer requirement does not allow utilities to de-commit. This means that, once a unit is accepted in the PRA or used in a FRAP, the utility cannot make a unit unavailable to MISO for dispatch, on a seasonal basis or otherwise, except for when the unit is on mechanical outage, overhaul, testing, etc.

2. Energy Market Operations

The 2019 Order described the operations of MISO's energy market, stage 2 of the market process, as follows:

> MISO markets identify the supply of electric generation available throughout the MISO regions, and the anticipated (and, in real time, the actual) demand for electricity in each area, selecting generators for dispatch in a manner designed to minimize overall costs to the system

[3] Note that NorthWestern Energy provides electric and/or natural gas services to 349 cities in the western two-thirds of Montana, eastern South Dakota and central Nebraska. Montana-Dakota Utilities is a subsidiary of MDU Resources Group, Inc., a company providing retail natural gas and/or electric service to parts of Montana, North Dakota, South Dakota and Wyoming. Minnkota Power Cooperative serves as operating agent for the Northern Municipal Power Agency; Northern Municipal Power Agency actually owns the share of Coyote and serves 12 municipal electric utilities in eastern North Dakota and northwestern Minnesota.

> while meeting reliability requirements. MISO unit commitment is the process that determines which generators (and other resources) will operate to meet the upcoming need. MISO scheduling and dispatch sets the hourly output for each committed resource, using simultaneously co-optimized Security Constrained Unit Commitment and Security Constrained Economic Dispatch to clear and dispatch the energy and reserve markets.
>
> A market participant—that is, anyone registered for participation in MISO markets—can specify the production cost of its generator, and MISO will refrain from dispatching the resource until market prices meet or exceed that level, again, subject to reliability requirements. But under some circumstances a participant will prefer to commit its generator to be available for MISO dispatch ("self-commit"), and unilaterally set the generator's output level ("self-schedule"), accepting whatever market price results rather than waiting.

MISO's energy market has both a day ahead (DA) market and a real time (RT) market.[4] Essentially, the DA market is a forward market for energy and operating reserves. Transactions in the DA market occur the day before the operating day. The DA market creates binding results for next operating day and sets the DA locational marginal prices (LMP).

Transactions in the RT market occur throughout the operating day. Essentially, the RT market is a spot market for energy and operating reserves. The RT market balances supply and demand under actual system conditions, dispatches the least cost resources every five minutes, and thus provides transparent economic signals, especially RT LMPs.

3. *Energy Market Structure Changes*

At the March 5, 2020 meeting of the Market Subcommittee, MISO[5] discussed the potential need for changes to the current market structure in terms of a Forward Market Mechanism. At the meeting, MISO was looking for input on what information is required for decision making about unit availability. Thus, MISO is pursuing potential changes to the energy market structure that might impact any decisions made by the Commission in this proceeding.

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[4] The following information summarizing the MISO markets impacting this proceeding are taken from MISO's *Level 100 - Energy and Operating Reserves Markets* training materials. These materials are available at:
https://miso.csod.com/clientimg/miso/MaterialSource/adda678c-bb1d-4ff4-8374-2e3c37905bfc_Level_100 Energy_and_Operating_Reserves_Markets.pdf
Additional Information is taken from *Level 200 - Energy and Operating Reserves Market Pricing*, available at:
https://miso.csod.com/clientimg/miso/MaterialSource/f1be778a-f7ff-4458-88a0- 1bc589d03451_Level_200 Energy_and_Operating_Reserves_Market_Pricing.pdf

[5] MISO's presentation, which is the basis for this discussion, is available at:
https://cdn.misoenergy.org/20200305%20MSC%20Item%2009b%20Forward%20Market%20Mechanism%20(IR085)433003.pdf

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In addition to providing a framework for potential changes, MISO's presentation provided overall market data that might be informative for this proceeding. Overall, MISO's data indicates that economic commitment in the market has increased, reflecting both coal-to-gas switching and reduced coal must-run designations. Overall, the percentage of annual energy in the DA market from coal has decreased from 64 percent in 2009 to 50 percent in 2014 to about 36 percent in 2019. Thus, coal energy has dramatically declined as a part of the overall market. Some coal units in Minnesota that are part of this proceeding have also been moving towards economic dispatch. **Table *2*** provides a distribution of Commitment status across the eight coal and three nuclear units that are part of this proceeding.

Table 2. Distribution of Commitment Status Across Power Plants in 2020

[TRADE SECRET DATA HAS BEEN EXCISED]

MISO's presentation slides from their Information Forum on January 19, 2021[6] shows that most coal energy is either from economic commitments or capacity economically dispatched above the economic minimum.[7] MISO plotted the self-commitment and dispatch of coal power plants in its territory in 2020 and this shows between 91% and 78% was economically dispatched. In fact, apart from June, economic dispatch was 80% or above. Thus, in the market as a whole, uneconomic dispatch of must run coal energy holds a relatively small share of coal's overall energy output.

[6] https://www.misoenergy.org/events/informational-forum-if---january-19-2021/ (Slide 53)

[7] Economic minimum refers to the minimum capacity level for each resource; if a resource is dispatched at all, it must be dispatched at least to the minimum capacity level.

The Department notes that LMPs at the Minnesota hub are consistently lower than other hubs across MISO. Therefore, the Department expects that the percentage of DA coal energy from economically dispatched sources would be lower for the units in this proceeding than for MISO as a whole. The Department attempted to calculate the percentage of uneconomically dispatched DA coal energy from the data provided by the utilities in this proceeding. For each unit, the Department summed the hourly DA dispatch minimum in hours where the DA LMP was less than variable costs per MWh. The Department also summed the hourly cleared DA capacity and divided the two totals. Data on uneconomic DA dispatch for the individual coal units subject to this proceeding is available in **Table *3*** below. Note that in **Table *3*** all data covers the January 1, 2020 - Dec 31, 2020 reporting period.

Table 3. Uneconomic DA Dispatch by Unit

[TRADE SECRET DATA HAS BEEN EXCISED]

Considering all the coal units in this proceeding, the result was that the uneconomic DA dispatch minimum equaled 31 percent of the total hourly cleared DA capacity. Thus, if the Department's and MISO's calculations are comparable, the units involved in this proceeding produce more uneconomic "must run" energy than those in MISO as a whole, on average, which was expected given the relatively low LMPs at the Minnesota hub. Finally, the Department notes that a further 7.9 percent of the total hourly cleared DA capacity was from capacity that was not economic and was dispatched above the DA dispatch minimum.[8]

While looking at Table 3, a point of comparison is the same table in last year's filing.[9] The Department recognizes the comparison is not exact because the filings cover different time periods. While the percentage of uneconomic dispatch at the aggregate level has not changed much, there is a significant

[8] The two percentages are additive. Meaning 39 percent of the total hourly cleared DA capacity was not economic.
[9] Table 2 from the Department's comments filed on June 8, 2020 in Docket 19-704

difference across utilities. Xcel's power plants have been able to decrease the proportion of uneconomic dispatch while uneconomic dispatch increased significantly for Minnesota Power and Otter Tail. This is expected as with the exception of Sherco unit 3, Xcel's coal power plants were running on Economic commitment status a larger number of hours compared to Minnesota Power or Otter Tail as shown in Table 2. In the subsequent sections, the Department will dig deeper to understand reasons behind these movements.

C. COMMISSION CONCERNS

The Commission's February 7, 2019 *Order Accepting 2016-2017 Reports and Setting Additional Requirements* (Feb. 7 Order) in Docket Nos. E999/AA-17-492 and E999/AA-18-373 provided the following concern regarding how utilities were using MISO's unit commitment and scheduling processes:

> Renewable sources of generation have the advantage of incurring no fuel costs, which tends to reduce their operating costs and make them attractive options for MISO dispatch. However, self-committed and self-scheduled generators may displace these resources—even if, at any given moment, the renewable resource had lower operating costs.
>
> To further explore this matter, the Commission will direct Minnesota Power, Otter Tail Power, and Xcel to make compliance filings containing an initial analysis of the impacts of self-commitment and self-scheduling of their generators, including the annual difference between production costs and corresponding prevailing market prices...

Below is the Department's analysis of the economics of the participation of the baseload units of Minnesota Power, Otter Tail, and Xcel in MISO's energy markets.

II. DEPARTMENT ANALYSIS

The Commission's concerns to be addressed in this proceeding, as cited above, are the utilities' actions in the situation where a generator's variable cost was greater than the generator's LMP. This is a concern both because it raises the customer's bill (as demonstrated in the discussion of **Equation *7*** in Attachment 1) and because the uneconomic operation may displace lower cost renewable resources—even if the renewable resource had lower variable costs.[10]

The Department's comments below will focus on the reasonableness of the utilities' actions in, and adaption to, circumstances where the generator's variable cost was greater than the generator's LMP since this situation can result both in unnecessary cost increases and unnecessary displacement of lower cost renewable resources.

[10] See Attachment 1 for a simplified discussion about the relationship between LMPs, Variable generation costs and impact on Utility bills.

A. COST REPORTING

As part of this docket, the utilities agreed upon a consistent for reporting their costs. As parties will analyze the reported costs, it is useful to understand how the reported costs are calculated. Two different costs were reported, as explained in the following equations:

Equation 1. Production Cost Components

$$\begin{aligned}&Production\ Cost\\&\quad = Actual\ MWh\\&\quad \times (Unit\ Fuel\ Cost + Unit\ Variable\ O\&M\ Cost\\&\quad + Preventative\ Maintenance\ O\&M\ Cost)\end{aligned}$$

Equation 2. Total Production Cost Components

$$\begin{aligned}&Total\ Production\ Cost\ including\ Remaining\ Unit\ Fuel\ Costs\\&\quad = Actual\ MWh\\&\quad \times\ (Unit\ Fuel\ Cost + Unit\ Variable\ O\&M\ Cost\\&\quad + Preventative\ Maintenance\ O\&M\ Cost + Remaining\ Unit\ Fuel\ Cost)\end{aligned}$$

Currently we do not have a clear definition of Remaining Unit Fuel Costs. Xcel said in their filing "For purposes of this report, the estimated nuclear fuel costs are treated as fixed costs, and are included as “Remaining Fuel Costs” in the reporting as of June 27, 2020. So, fixed fuel costs seems to be what it (remaining) is capturing. At this stage it is important to note that both Production Cost and Total Production Cost, in their current reported format, depend on the MWh generated by the plants as some of the component costs were allocated across the MWh output of the plants. So, if Actual MWh is zero (because the plant is not being dispatched) both Production Cost and Total Production Cost are zero. Traditionally, some units’ fuel costs have a fixed component and a variable component. Fixed fuel costs refer to costs that the plant has to incur irrespective of level of output (hence the name fixed cost). In the current filing, this distinction is not possible as all the costs have been allocated across MWh generated. Thus, in the subsequent analysis, the Department shows both Production Cost and Total Production Cost when they are significantly different.

The Department realizes there may be fixed fuel costs (costs which have to be incurred by the plant irrespective of MWh generation and depends on the terms and structure of fuel contracts) at the power plants considered in this docket. The Department recommends that the companies explain in their reply comments how to determine variable fuel costs versus fixed fuel costs (what costs they would incur on fuel if they produced 0 MWh) based on the data reported.

Department Information Request No. 40 asked Otter Tail about this particular issue. Otter Tail’s reply stated that the difference between the above two reported costs represents fixed costs. **Equation 3** shows that this difference varies with MWh.

Equation 3. Difference Between the Two Costs

$$Total\ Production\ Cost\ including\ Remaining\ Unit\ Fuel\ Costs - Production\ Cost = Actual\ MWh \times Remaining\ Unit\ Fuel\ Cost$$

If the current reporting template is unable to differentiate between fixed fuel costs (costs independent of MWh generated by a plant) and variable fuel costs (costs which depend on MWh generated by the plant), it is important to make this distinction clear in subsequent filings. It is important to split fuel costs in this way to understand what costs can be avoided if the plant did not operate during particular intervals due to economic dispatch. To this end, the Department recommends that the companies modify the reporting template for future filings to split fuel costs in a way that makes this distinction clear.

To help understand these different cost components better, the Department summarized these variables for each plant in **Table *4***. As expected, on a per MWh basis, the nuclear plants are the cheapest. But within the coal plants, there is significant variation. **Table 4** provides an idea about the relative weights of different components in the calculation of costs that will be explored in the subsequent analysis.

Table 4. Average Component Cost per MWh by Unit

[TRADE SECRET DATA HAS BEEN EXCISED]

Based on the above table, the average cost per MWh appears to be very high for Sherco units 1 and 2. The Department recommends Xcel explain in reply comments why these costs are so high for Sherco units 1 and 2. Note that the averages are calculated excluding all zeros to count only those hours when fuel costs were incurred.

A. VARIABLE COST– MINNESOTA POWER

1. Preliminary Analysis

The Department started the analysis of each utility's data by determining the number of hours each month in which a unit operated at a net cost, the number of hours at a net benefit, and the number of hours at the break-even point (presumably shut down). The purpose of this preliminary review was to determine if a more detailed analysis of the unit was merited. **Figure *1*** and **Figure *2*** show the results of the preliminary analysis for Boswell unit 3 and Boswell unit 4. Net Benefits are calculated as the difference between Net MISO Payment, including ASM and Make Whole Payments, and production costs for each plant. The figures show that the percentage of time that these two units were operating at a net cost is very similar. This is not surprising since the units are adjacent to each other. Also, operating at a net cost is a common phenomenon at both units and occurs year-round; almost 60 percent of the hours on average are operated at a net cost for all months other than those with a lengthy outage.

Looking at **Figure *1*** and **Figure *2***, two months seem to be exceptions. During May 2020, Boswell unit 3 was running with a Commitment status of Economic. This resulted in the plant not being dispatched most of the time resulting in mostly breakeven hours. During April 2020, Boswell unit 4 was out of service giving rise to the large number of breakeven hours. Apart from these two months, both these plants were running at net cost most of the time.

Figure 1. Boswell Unit 3 Hourly Net Benefit/Breakeven/Net Cost

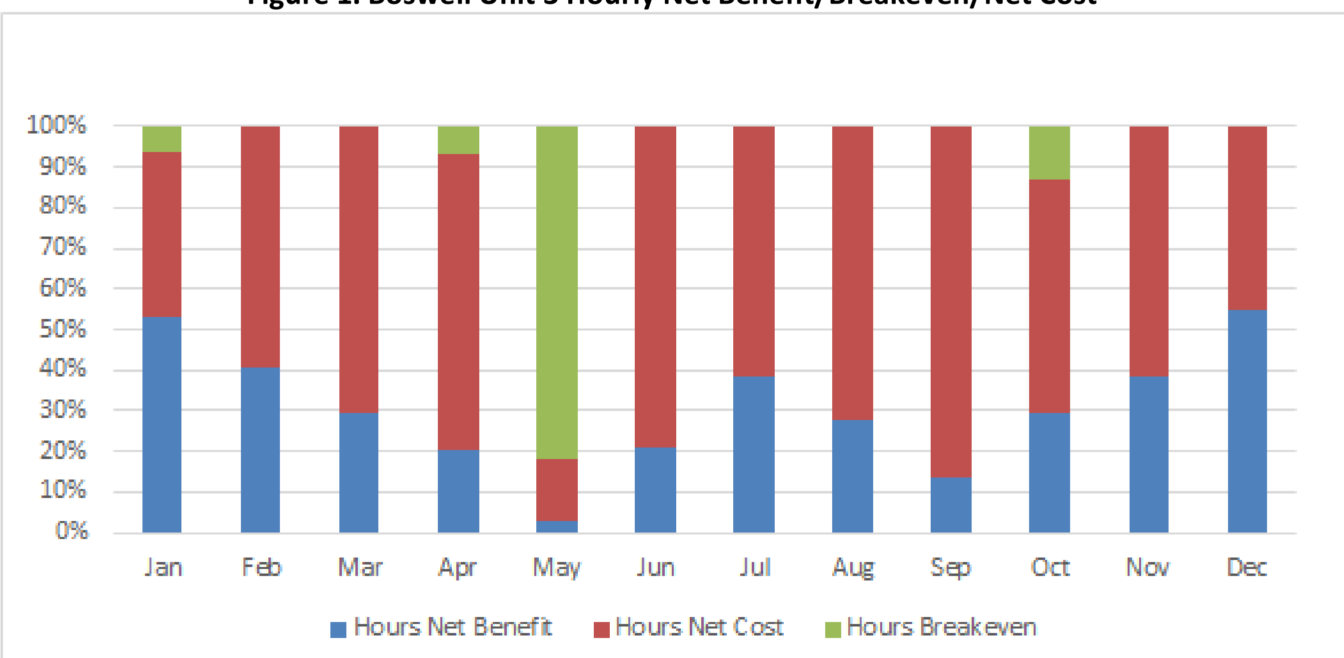
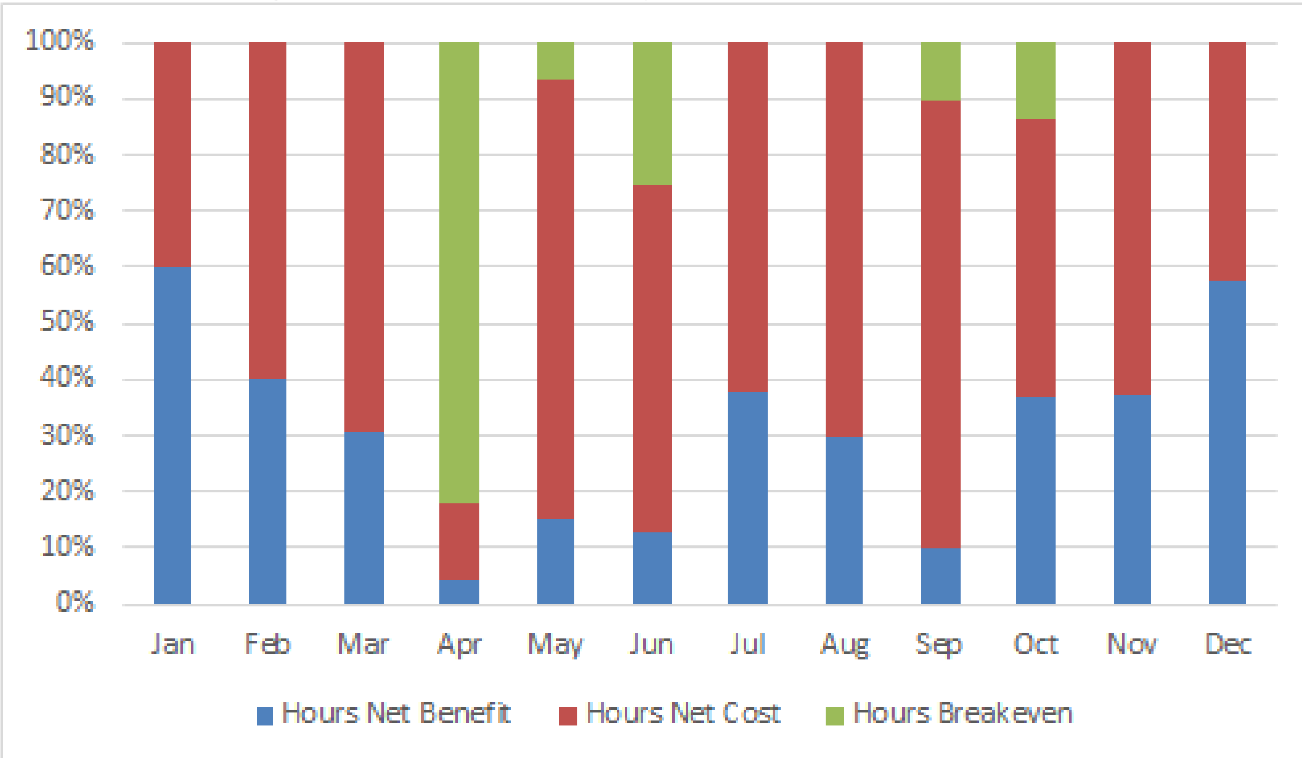


Figure 2. Boswell Unit 4 Hourly Net Benefit/Breakeven/Net Cost



The Department notes that the Production Costs and Total Production Costs including Remaining Unit Fuel Costs were identical for Boswell units 3 and 4. This is not the case for other utilities. **Table *5*** shows the breakdown of the net benefit / (cost) of both units by hours and in percentages.

Table 5. Hours at Net Benefit/Breakeven/Net Cost for Minnesota Power

Unit	Net Benefit	Breakeven	Net Cost	TOTAL
Boswell Unit 3	2,702 30.8%	804 9.2%	5,278 60.1%	8,784 100%
Boswell Unit 4	2,733 31.1%	995 11.3%	5,056 57.6%	8,784 100%

The Department concludes that the preliminary data, specifically the high percentage of hours operating at net cost, indicates that a more detailed analysis of both Boswell unit 3 and Boswell unit 4 is merited.

2. Detailed Analysis

a. Background

In its March 1, 2020 Compliance Filing, Minnesota Power made the following points:

- "2020 was an unprecedented year ... Minnesota Power experienced a customer load loss of about 13 percent ... Although generation levels at Boswell Units 3 and 4 were lower than planned, the Company successfully avoided incurring any liquidated damages. The Company expected to receive additional liquidated damage costs if further reduction in generation occurred."
  - The pandemic lead to a large demand shock in 2020 that affected all utilities. While this shock was unexpected, there are lessons to be learnt regarding how to deal with uncertainty.
- "Minnesota Power is currently targeting July 1, 2021, for Boswell Unit 3 to transition to economic dispatch."
  - Since economic dispatch of Boswell unit 3 during May 2020 provided savings, the earlier this transition can be made, the better.
- "Transitioning Boswell Unit 4 to economic dispatch is more complex; however, Minnesota Power has identified the core milestones that need to be addressed and is diligently working with its co-owners, WPPI, to address options for each..."
  - Joint ownership structures place additional constraints that prevent companies from responding to market incentives.
- "Procuring competitively priced coal becomes challenging under conditions of economic/seasonal operations"
  - Cost of operation depends on operating conditions as contracts might have to be renegotiated if, for example, the unit starts running seasonally as opposed to year long. This is a limitation of the current exercise as we assume costs remain at current levels and hence we might be overestimating the benefits of moving to economic dispatch.
- "Minnesota Power continues to advocate as a MISO stakeholder for operating alternatives within the current market construct such as a multi-day commitment mechanism that is financially binding for long lead time generators"
  - Changes in the market structure might help reduce uneconomic dispatch of large baseload units.
- "Currently Boswell provides essential reliability services that give the operational flexibility needed to ensure continuous reliable operations of the power system and energy supply to a unique geographic area"
  - Taking units off-line is more complicated than might appear at first glance from a purely economic perspective.
- "Minnesota Power intends to invest approximately $3.0 million into Boswell Unit 3 to reduce the operational minimums of the unit from 175 MW to 75 MW by January 2022... In 2018 Minnesota Power reduced the operational minimums for Boswell Unit 4 from approximately 300 MW to 210 MW."

- Lower operating minimums are essential in the current market. Transitioning both units to lower operating minimums can help increase profitability.

The Department acknowledges the reality of the issues raised here. The Department recommends that Minnesota Power discuss in detail, their experience of putting Boswell 3 on Economic dispatch during May 2020, especially with regard to challenges that came up during this month. Please include additional costs that the unit had to incur to operate more flexibly, periods of losses that were prevented due to economic commitment status and any reliability constraints that the company faced.

b. Analysis

Large coal units require a minimum downtime, startup time, and a cool down time when they operate. Furthermore, these time periods depend on starting conditions (warm/cold) and vary by units. The minimum time frame arrived at by adding these durations appears to be about a week or less for the units involved in this proceeding. Therefore, the Department used a week as the minimum duration to consider.

Figure 3. Monthly Production and Total Production Cost for Minnesota Power

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 3 shows that for Minnesota Power, monthly Production Costs and monthly Total Production Costs are identical. This implies that all the costs the company incurred are included in the following Net Benefit calculations. This is important to note as other plants considered in this proceeding count these costs differently.

Figure *4* and **Figure *5*** below show a rolling sum of Minnesota Power's calculated, actual hourly benefit / (cost) effectiveness for 1 week (168 hours). When the line is below zero, that indicates the unit operated at a net cost over the preceding week. When the line is above zero that indicates the unit operated at a net benefit over the preceding week. Note that, **Figure *4*** and **Figure *5*** also include a line indicating the unit's commitment status (must run, outage, economic etc.). When comparing the line indicating net benefit / (cost) to the line indicating commitment status, it is important to keep in mind that the net benefit / (cost) line at any one point represents a sum of the previous seven days while the commitment status line represents only that particular hour.

Figure 4. Boswell Unit 3 Rolling Week Total Benefit / (Cost)

[TRADE SECRET DATA HAS BEEN EXCISED

Figure 5. Boswell Unit 4 Rolling Week Total Benefit / (Cost)

[TRADE SECRET DATA HAS BEEN EXCISED]

As shown in **Figure *4*** and **Figure *5***, Minnesota Power's units were often operating at a sizable net cost over a 1 week duration. Sometimes the rolling total was negative for multiple months at a stretch. For Boswell unit 3, the decision to run the plant under Economic commitment status helped reduce the period of losses temporarily during May but it went back to large losses as soon as the plant switched to a must run status. A similar trend is observable at Boswell unit 4 when losses decrease temporarily when the plant switches to an "Out" status but starts incurring losses consistently as it switches back to must run status. During June to July and again September to late October, Boswell unit 3 continues to incur large loses over a seven-day period. Boswell unit 4 displays a similar pattern between May to July and again September through late October. During these extended periods, sometimes lasting multiple months, operational duration is not a major challenge. This points to an urgent need to address the challenges to moving towards economic/seasonal dispatch at Boswell and the burden ratepayers have to bear until then.

Figure 6. Boswell Unit 3 Monthly Total Benefit / (Cost) vs Commitment Status

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 7. Boswell Unit 4 Monthly Total Benefit / (Cost) vs Commitment Status

[TRADE SECRET DATA HAS BEEN EXCISED]

Another way to look at this problem is to aggregate at a monthly level. In **Figure *6*** and **Figure *7***, the blue line, plotted on the left vertical axis, shows the total benefit / cost over a month. The bars, plotted on the right vertical axis, shows the proportion of different commitment status in each month. This representation shows how profitability of these units vary over different months. It also shows how profitability changed when commitment status changed. Minnesota Power provides very little explanation for unavoidable self-commitment at Boswell unit 3. If there was no specific reason for unavoidable self-commitment of the unit, the question that arises is why did the unit not run more with economic commitment? The only reason for unavoidable self-commitment at Boswell unit 4 is co-ownership status. Other companies provided more detailed reasons behind unavoidable self-commitment. As other co-owned plants are able to run under economic commitment, greater explanation is warranted here. Experimenting with economic dispatch on multiple months and at Boswell unit 4 can provide useful data to plan a transition path moving forward.

c. Additional Analysis by Minnesota Power

Minnesota Power reported the minimum downtime for Boswell units 3 and 4 is **[TRADE SECRET DATA HAS BEEN EXCISED].** Given this time duration, they calculated the number of occurrences when the plant was making losses continuously for a duration longer than the units' minimum downtime and the associated cost. Only those instances are counted when the plant was making losses for a duration greater than its minimum downtime. In **Figure *8*** and ***Figure 9*** the blue bars indicate the number of occurrences of such events while the red dots indicate the associated loss. The sum of the values corresponding to all the red dots is an upper bound to net cost savings that economic dispatch might achieve. While this can be difficult to achieve practically, it is important to try to reduce the occurrence of long periods of time when the plant is running at a loss (eliminate the red dots on the right end of the horizontal axis). Remember the net cost plotted on the right vertical axis depends on both the consecutive hours of loss and the prevailing prices during that period.

Figure 8. Occurrence of Loss Over Consecutive Hours at Boswell Unit 3

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 9. Occurrence of Loss Over Consecutive Hours at Boswell Unit 4

[TRADE SECRET DATA HAS BEEN EXCISED]

Table 6 summarizes the number of occurrences during which Boswell units 3 and 4 experienced consecutive hours of loss above the plant's minimum downtime. It also adds up the cost incurred during each of these events. This calculation ignores that initial conditions[11] during these loss events and minimum runtime for each plant. The Department recommends the utilities standardize this part of the reporting template to ensure the analysis reflects operating conditions better.

Table 6. Summary of events of consecutive hours of loss for Minnesota Power

[TRADE SECRET DATA HAS BEEN EXCISED]

The MP Report also included a net (cost) / benefit analysis that incorporated operational dynamics. The intent of the exercise was to improve the net (cost) / benefit calculation by continuing to include costs that "hypothetically" could have been avoided if Boswell units 3 and 4 were economically dispatched in 2020. The improvement to the calculation is the exclusion of costs that could not have been avoided because of operating dynamics. The MP Report's Table 3 shows the associated cost savings for each plant. This analysis points towards significantly lower production at these plants and the as the utilities describe in their filing, this would require adjustments to fuel procurement strategy, to better align with economic dispatch operations going forward. Changes in the fuel procurement strategy would possibly involve renegotiating fuel contracts with suppliers in light of reduced demand for coal in these scenarios.

3. *Conclusion*

2020 has been a difficult year overall with a significant demand shock. This meant that the units at Boswell produced less energy compared to previous years. With the trends in LMP and greater economic dispatch, 2020 can help Minnesota Power understand how to operate its units less which will be more common as the plant transitions to greater economic dispatch in the upcoming years.

A. *VARIABLE COST– OTTER TAIL*

1. *Preliminary Analysis*

Otter Tail's Big Stone and Coyote plants have different cost structures due to different contracts with the coal mines. Otter Tail reported production costs and total production cost including remaining unit fuel costs (total production cost) for each plant. While the two costs were very similar for Big Stone, they are different for Coyote. **Figure *10*** and **Figure *11*** plot the monthly aggregated values of these two

[11] Initial conditions can be cold, warm and hot and the start time depends on the initial condition.

costs for each power plant. **Figure *11*** appears to show a fixed difference between these two costs. However, when the Department disaggregated this further, the difference in cost varies significantly. **Figure *18*** shows how the total difference over a week varies. Otter Tail reports that fixed fuel costs for Coyote includes the fixed component of the mine fuel invoice for delivered lignite which accounts for approximately **[TRADE SECRET DATA HAS BEEN EXCISED]**. While for accounting purposes this distinction between fixed and variable parts of the contract can make sense, a large part of the fuel cost is paid through a fixed contract. As the two costs are similar for Big Stone, the Department considered only production costs in its analysis for Big Stone. For Coyote, we present calculations using both of these costs separately.

Figure 10. Big Stone Monthly Costs

Figure 11. Coyote Monthly Costs

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure *12* and **Figure *13*** below show the results of the preliminary analysis for Big Stone and Coyote. For these two figures, Net Benefits are calculated as the difference between Net MISO Payment including ASM and Make Whole Payments and production costs for each plant. Looking at **Figure *12***, the months of May, June, September and October seem to have much lower net cost hours than other months. The Department will explore this in the next section when analyzing at the monthly distribution of commitment status.

Figure 12. Big Stone Hourly Net Benefit/Breakeven/Net Cost

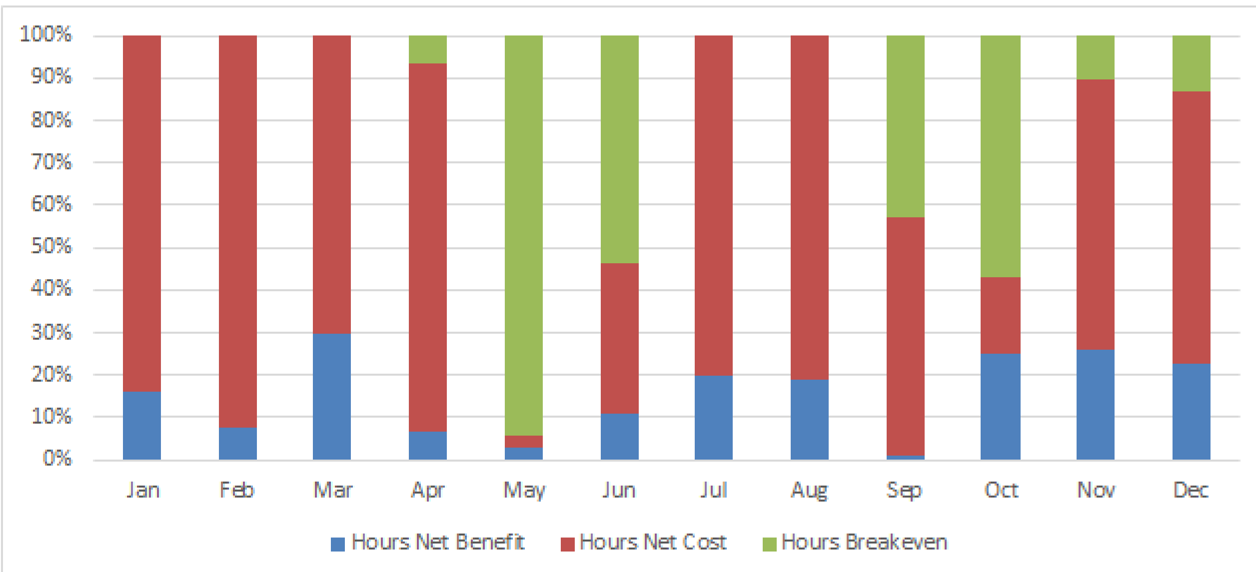


Figure *13* shows Coyote has a much higher proportion of hours when the plant is running at Net Benefit compared to Big Stone. This apparent difference is arising because of how Otter Tail counts costs. As was shown in the comparison between **Figure *10*** and **Figure *11***, there are differences in the way Otter Tail reported costs for these two plants. If total production cost including remaining unit fuel costs are considered for the Coyote plant when calculating Net Benefit, the result is fewer hours when the plant was running at net benefit. **Figure *14*** shows this.

Figure 13. Coyote Hourly Net Benefit/Breakeven/Net Cost (with Production Cost)

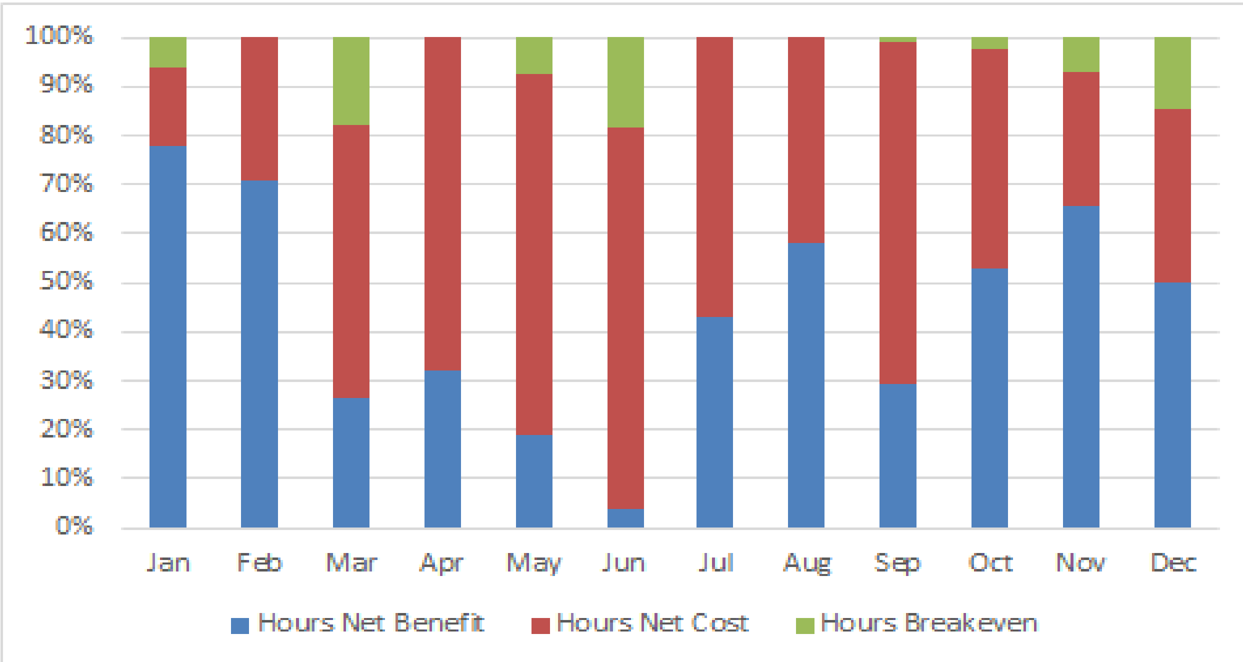
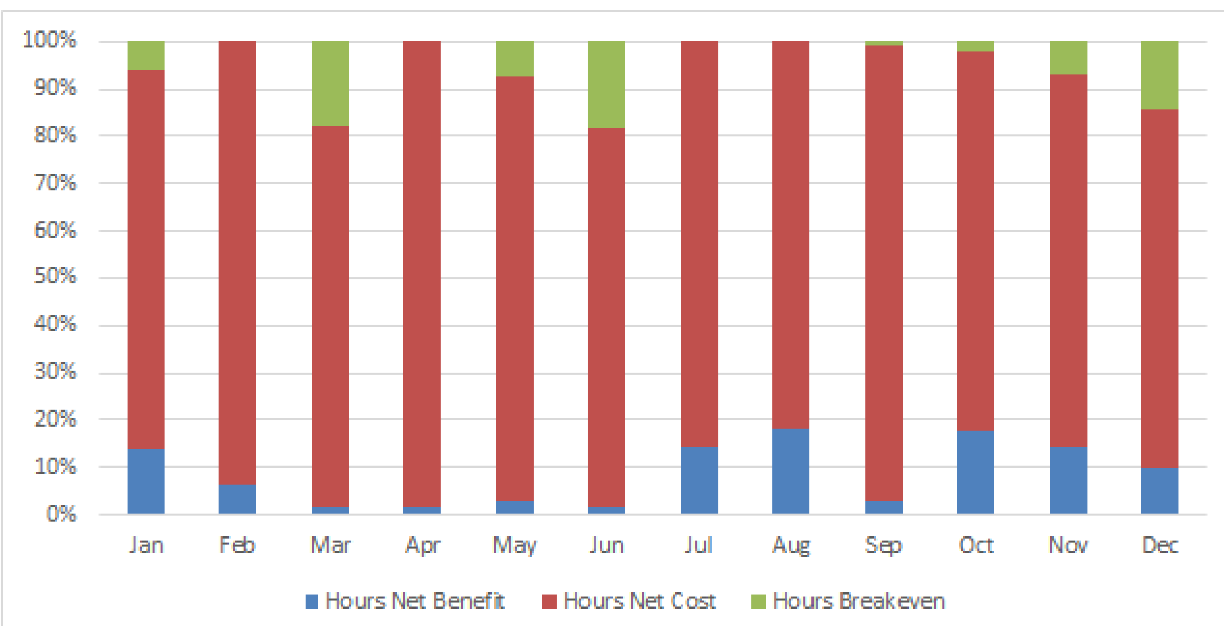


Figure 14. Coyote Hourly Net Benefit/Breakeven/Net Cost (with Total Production Cost)



Overall, for 2020, **Table *7*** shows the breakdown of the net benefit / (cost) of both units by hours and percentages. The two rows for the Coyote plant show how the results vary depending on how costs are considered.

Table 7. Hours at Net Benefit/Breakeven/Net Cost for Otter Tail

Unit	Net Benefit	Breakeven	Net Cost	TOTAL
Big Stone	1,374 15.6%	2,035 23.2%	5,375 61.2%	8,784 100%
Coyote (with Production Cost)	3,865 44.0%	545 6.2%	4,374 49.8%	8,784 100%
Coyote (with Total Production Cost)	772 8.8%	545 6.2%	7,467 85.0%	8,784 100%

The Department concludes that the preliminary data indicates that a more detailed analysis of Big Stone and Coyote is warranted.

2. Detailed Analysis

a. Background

In its March 1, 2020 Compliance Filing, Otter Tail made the following points:

- "In the event Otter Tail were to forego capacity accreditation of the Big Stone or Coyote generators, Otter Tail would need to procure additional capacity resources to meet the MISO Module E capacity requirements"
    - Thus, only a utility with substantial surplus capacity could de-commit (remove from the PRA and then potentially remove from the energy market) a unit without incurring costs to replace the accredited capacity.
- "Coyote is a co-owned by Otter Tail (35 percent), Minnkota Power Cooperative (30 percent), Montana Dakota Utilities (25 percent), and Northwestern Energy (10 percent). Otter Tail, Minnkota Power Cooperative[12], and Montana Dakota Utilities operate within the MISO market, while Northwestern Energy operates within the SPP market."
    - Thus, there may be complications in determining a commitment strategy caused by the interaction of multiple RTO markets.
- "The single day commitment and dispatch process does not consider the economics of running a baseload plant across multiple days. MISO has explored the possibility of a multi-day commitment process but does not currently have plans for development or implementation in the foreseeable future."
    - Changes in the market structure might help reduce uneconomic dispatch of large baseload units.

[12] Northern Municipal Power Agency owns a 30% share of the plant. Minnkota serves as operating agent for NMPA.

- "The 2020 calendar year maintained historically low LMP pricing throughout the MISO footprint ... The drastic change in 2020 LMP pricing greatly impacts Big Stone Plant and Coyote Station revenues as compared to previous years."
    - On average, Otter Tail's LMPs were lower this year compared to previous years. They were also lower compared to LMPs at other plants considered in this docket. While this shows it is harder for Otter Tail to make profits, it also shows market incentives to reduce must run status are greater for Otter Tail's power plants.
- "The largest driver in forced self-commitment was higher LMP pricing in the SPP market."
    - Market conditions in SPP were responsible for Otter Tail's Must Run commitment in MISO almost a quarter of the year at Big Stone. However, SPP market conditions did not cause unavoidable self commitment at Coyote. The Department would like Otter Tail to explain in reply comments why Coyote was not committed because of SPP market conditions.
- "Implementation of economic offer capability resulted in a considerable number of hours of economic decommitment when both MISO and SPP market pricing was low. This resulted in substantial savings for Otter Tail customers compared to what might have been under a continued 100% self-commitment practice."
    - The above statement is for Big Stone. As shown in ***Table 2***, Big Stone had economic commitment slightly over one fifth of the year. It is likely that such savings can also be generated from Coyote.

b. Analysis

Large coal units require a minimum downtime, startup time, and a cool down time when they operate. Furthermore, these time periods depend on starting conditions (warm/cold) and vary by units. The minimum time frame arrived at by adding these durations appears to be about a week or less for the units involved in this proceeding. Therefore, the Department used a week as the minimum duration to consider.

The Department uses the minimum duration in this analysis, not because it is necessarily the appropriate duration, but to provide a second bookend to the analysis used by the utilities. The utilities used different durations in their analysis of the overall benefits and costs, but a long duration was typically selected. As previously noted, the utilities' analyses all demonstrate the cost effectiveness of the units' operations when long durations are considered. The two bookends will demonstrate to the Commission the importance (or lack of importance) of the duration to the results of the analysis.

Figure *15* and **Figure *17*** below show a rolling sum of OTP's Big Stone and Coyote units hourly benefit / (cost) effectiveness for 1 week (168 hours). When the line is below zero, that indicates the unit operated at a net cost over the preceding week. When the line is above zero that indicates the unit operated at a net benefit over the preceding week.

Note that, **Figure *15*** and **Figure *17*** also include a line indicating the unit's commitment status (must run, outage, economic etc.). When comparing the line indicating net benefit / (cost) to the line indicating commitment status, it is important to keep in mind that the net benefit / (cost) line at any one point represents a sum of the previous seven days while the commitment status line represents only that particular hour.

As can be seen in **Figure *15***, between January and April, Big Stone was running with a Must Run commitment status and running at net cost. During May, Big Stone switched to Economic commitment status and this helped to reduce loses. For the second half of the year, the plant fluctuated between economic and must run commitment status. **Figure *16*** provides a detailed explanation of what was going on during the second half of the year.

Figure 15. Big Stone Rolling Week Total Benefit / (Cost)

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure *16* helps explain why Big Stone was running with a must run commitment status. The relatively high LMPs in the SPP market caused the co-owners to self commit the unit during the second half of the year multiple times. Also, Otter Tail provided specific reasons for putting the plant on a must run status during the second half of the year. However, no specific reason was provided for the must run status during the first four months of 2020 that resulted in significant net cost for the customers. The Department recommends Otter Tail provide in reply comments a reason for the must run commitment status throughout the year.

Figure 16. Big Stone Monthly Total Benefits / (Cost) vs Commitment Status

[TRADE SECRET DATA HAS BEEN EXCISED]

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Figure 17. Coyote Rolling Week Total Benefit / (Cost)

[TRADE SECRET DATA HAS BEEN EXCISED]

The Department notes that Otter Tail explained the reason to split costs in this way as shown in **Figure *17*** for the Coyote plant. Otter Tail explained in their filing:

> As a result of this fuel source, and the contract structure described above, much of the fuel costs for Coyote Station are fixed. This means Otter Tail is obligated to pay for these costs whether or not the fuel is consumed to generate electricity. These fixed costs equate to sunk costs and do not play a role in appropriately developing market offers on a day-to-day basis. As such, Otter Tail maintains it is appropriate to judge Coyote Station's commitment and dispatch decisions based on variable costs, not variable costs plus fixed fuel costs.

The Department notes that it is still important to see how the results change depending on which costs we consider. Such calculations also help explain the strength of market signals to the plant. Otter Tail commented "Coyote Station's annual performance still resulted in a substantial net benefit for Otter Tail customers, as compared against the unit's variable operating costs." **Figure *17*** shows the importance of the qualifier "unit's variable operating cost" in the previous sentence. Otter Tail discussed challenges they are facing at Coyote and their Lignite Sales Agreement (LSA) with Coyote Creek Mining Company, L.L.C (CCMC), a subsidiary of North American Coal on page 10 of their filing. Given that Coyote Station's co-owners and CCMC entered into the LSA in 2012 with a term through the end of 2040, the long-term impacts of the LSA on ratepayers may be significant. The Department recommends Otter Tail outline in reply comments strategies it can use to mitigate ratepayer impacts if the fixed costs continue to generate overall net losses for the unit.

Figure 18. Weekly Difference Between Total Production Cost and Production Cost at Coyote

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure *18* shows the 7-day rolling total difference between total production cost and production cost as reported by Otter Tail. Although this is categorized as "fixed fuel costs", it varies quiet a lot ranging from **[TRADE SECRET DATA HAS BEEN EXCISED]**. The Department asked Otter Tail in IR 40, to explain why fixed fuel costs vary so much for Coyote station. Otter Tail explained fixed fuel costs are calculated as a product of remaining unit fuel costs and the actual MWh generated by the plant. Coyote's coal contract is such that the remaining unit fuel costs are high. As the MWh produced by the unit is a large number with significant variation, it produces large swings in the calculated fixed costs over a week.

Figure 19 reports commitment status by month and plots the Net Benefit / (Cost) calculate using production cost and total production cost. Unlike Big Stone, Otter Tail does not provide good reasons for unavoidable self-commitment of Coyote for the bulk of the hours. Unlike Big Stone, high LMPs in the SPP market did not cause the Coyote plant to be on Must Run commitment. Although both Big Stone and Coyote are jointly owned, unlike Big Stone, Coyote has not been able to run on Economic commitment status for a single hour in 2020. Given the Coyote plant generated significant net costs on a Total Production Cost basis for the ratepayers every single month of 2020, significant ratepayer savings can be realized through changes in its fuel contract and commitment status for the plant.

Figure 19. Coyote Monthly Total Benefits / (Cost) vs Commitment Status

[TRADE SECRET DATA HAS BEEN EXCISED]

The Department saw that the results of the analysis are sensitive to the way costs were being counted by Otter Tail. So, to understand more about costs, the Department analyzed the data in the filing and saw the two major components of cost are Unit Fuel Cost (UFC) and Remaining Unit fuel Cost (RUFC).

The following table shows the monthly average values of these two components for Big Stone and Coyote.

Table 8. Monthly Average Fuel Cost Components for Otter Tail

[TRADE SECRET DATA HAS BEEN EXCISED]

Looking at the above table, a few observations can be made:

1. The greater profitability for Coyote on a production cost basis was arising as its monthly average unit fuel costs are lower than Big Stone's during all 12 months.
2. This, however, does not mean Coyote is paying less than Big Stone for its fuel. Coyote splits its cost in a way such that one component is less than the corresponding component at Big Stone.
3. Adding the monthly average components of fuel cost, we see Coyote's fuel costs per MWh are higher than Big Stone's in 11 out of 12 months.

Otter Tail's own analysis showed that the company a saved significant amount of money by moving its Big Stone plant to economic dispatch. Otter Tail's data also shows the cost of producing 1 MWh at Coyote was **[TRADE SECRET DATA HAS BEEN EXCISED]** than the cost at Big Stone. The Department recommends Otter Tail explain in reply comments why it pays a higher price for coal per MWh of generation at Coyote compared to Big Stone. In addition, the Department recommends Otter Tail discuss whether there are any financial benefits to ratepayers from splitting the costs with a much higher fixed fuel cost component.

c. Additional Analysis by Otter Tail

Otter Tail reported the minimum downtime for Big Stone and Coyote is **[TRADE SECRET DATA HAS BEEN EXCISED].** Given this time duration, Otter Tail calculated the number of occurrences when the plant was making losses continuously for a duration longer that the plants' minimum downtime. In the next three figures, the blue bars indicate the number of occurrences of such events for a given duration, while the red dots indicate the associated net cost. The sum of the values corresponding to all the red dots is an upper bound to net cost savings that economic dispatch might achieve. While this can be difficult to achieve practically, it is important to try to reduce the occurrence of long periods of time when the plant is running at a loss (eliminate the red dots on the right end of the horizontal axis). Remember the cost plotted on the right vertical axis depends on both the consecutive hours of loss and the prevailing prices during that period.

Figure 20. Occurrence of Loss Over Consecutive Hours at Big Stone

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 21. Occurrence of Loss Over Consecutive Hours at Coyote on a Variable Cost Basis

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 22. Occurrence of Loss Over Consecutive Hours at Coyote on a Total Cost Basis

[TRADE SECRET DATA HAS BEEN EXCISED]

Table 9 summarizes the above three figures. For each plant, it shows the total number of occurrences of consecutive hours of loss above the plant's minimum downtime. It also adds up the cost incurred on a variable cost and total cost basis during each of these events. This calculation ignores that initial conditions during these loss events and minimum runtime for each plant. The Department recommends the utilities standardize this part of the reporting template to ensure the analysis reflects operating conditions better.

Table 9. Summary of Events of Consecutive Hours of Loss for Otter Tail

[TRADE SECRET DATA HAS BEEN EXCISED]

For Big Stone, Otter Tail included additional analysis pointing to how the plant would have been dispatched following Otter Tail's requests. As this is a co-owned facility, the unit was often running with a must run status even though Otter Tail wanted it to be on economic commitment. Out of the total number of hours that Big Stone was running with a must run commitment status during 2020, Otter Tail endorsed the must run commitment status for 66.6% of the hours. From May to December 2020, Otter Tail endorsed must run status in only 35% of the hours that the plant was actually committed as must run. Otter Tail calculated the net benefit / (cost) every hour if Big Stone followed their recommended commitment status.

As shown in **Figure 23**, following Otter Tail's endorsement would have lead to lower net cost hours for the plant compared to what was actually observed between May and December 2020. Otter Tail compares these scenarios in Table 4 of their filing. This shows that there is still opportunity to reduce the number of hours Big Stone is being committed to run on a must run status and instead offer the plant under economic commitment.

Figure 23. Big Stone Actual vs OTP Endorsed Self Commitment effects May - Dec 2020

[TRADE SECRET DATA HAS BEEN EXCISED]

Otter Tail did not provide any similar analysis for Coyote. Further analysis is essential to understand and plan future economic commitment for the plant. The Department recommends Otter Tail provide simulations for Coyote and report net benefit/(cost) calculations for economic dispatch scenarios for the Coyote Plant.

3. Conclusion

In conclusion, Otter Tail faced significant challenges during 2020. Due to the demand shock, the company faced historically low LMPs. Low LMPs with inflexible operations meant large net costs for ratepayers. Otter Tail provided more detailed explanation for unavoidable self-commitment at Big Stone during the second half of the year. Given the Lignite Sales Agreement (LSA) Coyote has, and the cost burden it is putting on ratepayers, the Department recommends Otter Tail discuss their ability to renegotiate the contract and move the plant to economic self-commitment in next year's filing.

A. VARIABLE COST – XCEL NUCLEAR

1. Preliminary Analysis

Figure 24 to **Figure 26** show the results of the preliminary analysis for Xcel's Monticello and Prairie Island nuclear units. For Xcel's nuclear units, the percentage of the time operating at a net cost is very similar for all three units; operating at a net benefit most of the time every month. It is important to

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note that compared to the previous filing, the proportion of time the three nuclear units were running at net costs have gone up significantly.

Figure 24. Prairie Island Unit 1 Hourly Net Benefit/Breakeven/Net Cost

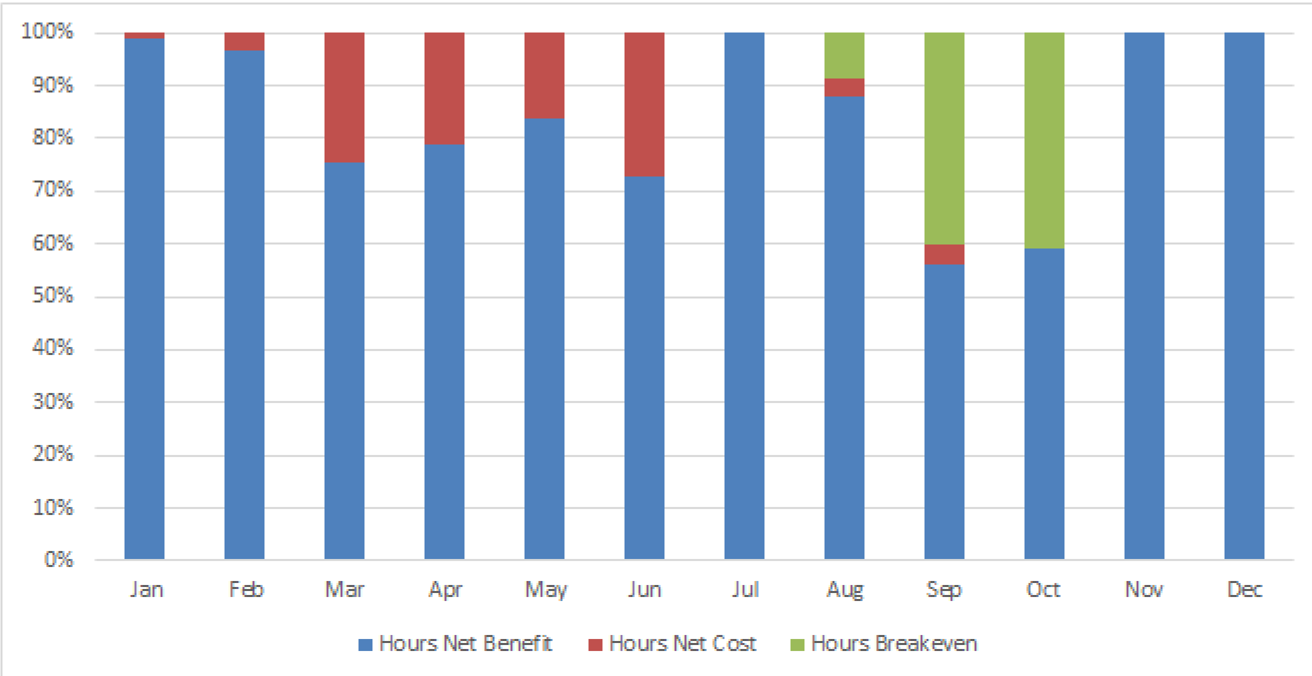


Figure 25. Prairie Island Unit 2 Hourly Net Benefit/Breakeven/Net Cost

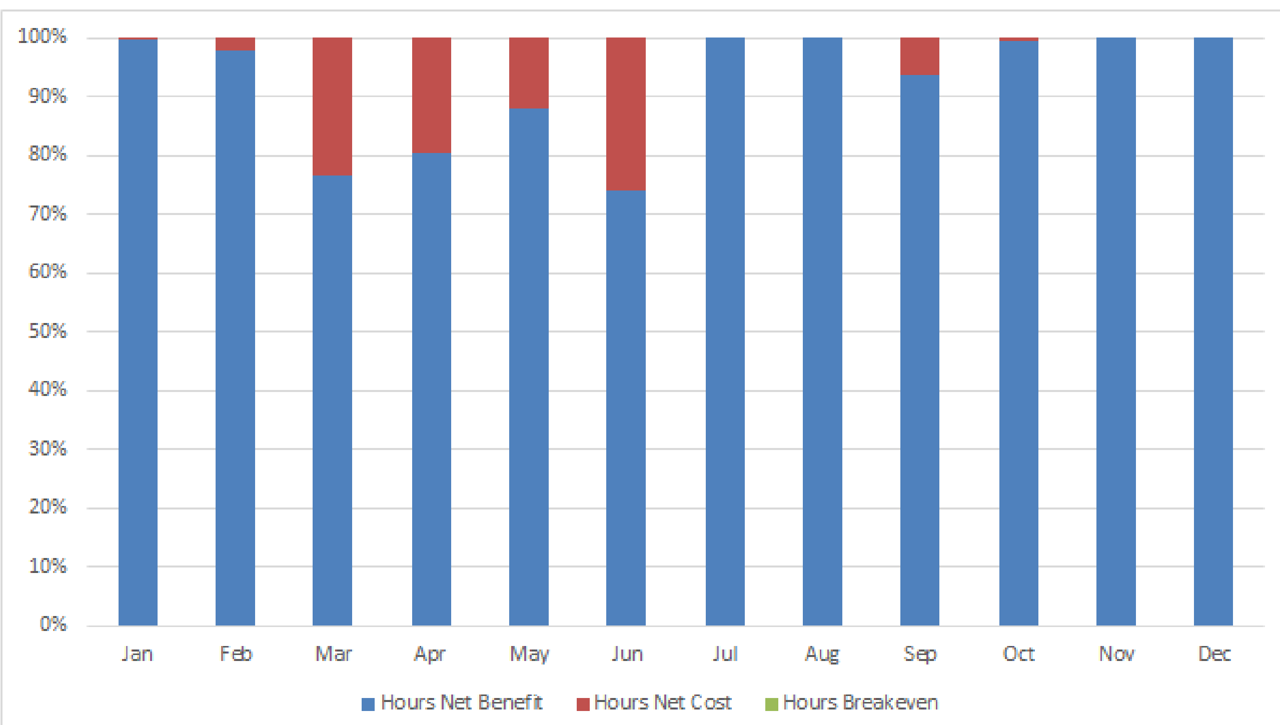
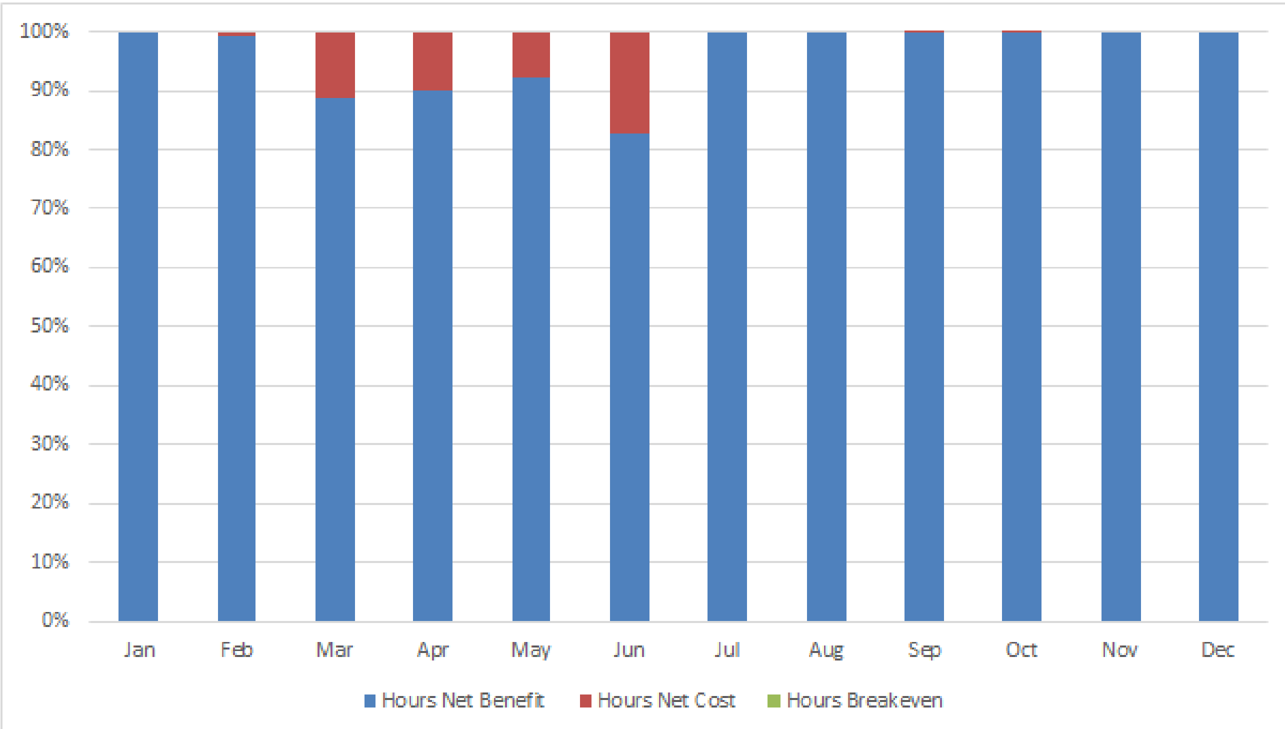


Figure 26. Monticello Hourly Net Benefit/Breakeven/Net Cost



Overall, for the 12-month period **Table *10*** shows the breakdown of the net benefit / (cost) of all three units by hours and in percentages.

Table 10. Hours at Net Benefit/Breakeven/Net Cost for Xcel's Nuclear Plants

Unit	Net Benefit	Breakeven	Net Cost	TOTAL
Prairie Island Unit 1	7,394 84.2%	655 7.5%	735 8.4%	8,784 100%
Prairie Island Unit 2	8,128 92.5%	0 0.0%	656 7.5%	8,784 100%
Monticello	8,439 96.1%	0 0.0%	345 3.9%	8,784 100%

The Department concludes that the preliminary data indicates that a more detailed analysis of Xcel's nuclear units is not warranted.

2. Conclusion

The Department recommends that the Commission take no action regarding Xcel's commitment and dispatch status decisions regarding Monticello, Prairie Island unit 1, and Prairie Island unit 2.

A. VARIABLE COST – XCEL COAL

1. Preliminary Analysis

Figure *27* through **Figure *30*** show the results of the preliminary analysis for Xcel's King and Sherco units. **Figure *27*** can appear to be an outlier with a very high number of net cost hours. However, this appears to be due to King not producing any output for much of the year. Even though the plant was not generating output, it incurred small cost leading to net cost hours. This is explored in greater detail below. For the Sherco units, observe that hours when the units generated profits go up from July. The first half of the year shows mixed results and we will examine each of them in greater detail in the next section.

Figure 27. **King Hourly Net Benefit/Breakeven/Net Cost**

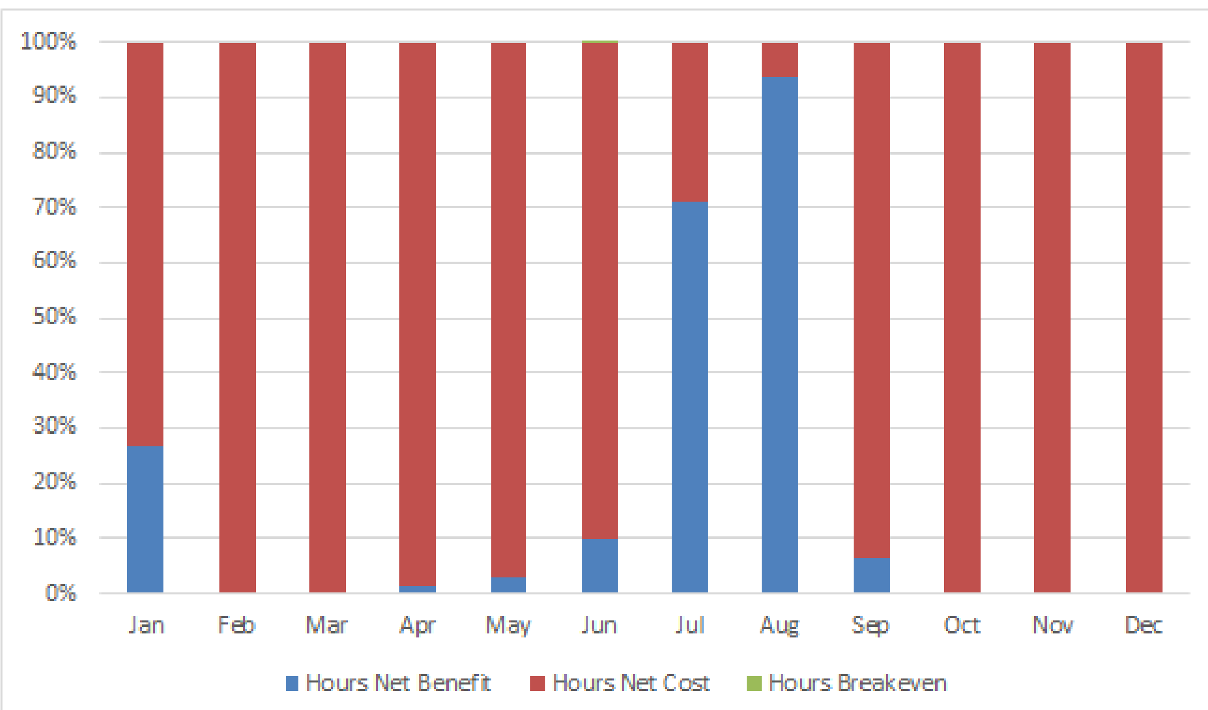


Figure 28. Sherco 1 Hourly Net Benefit/Breakeven/Net Cost

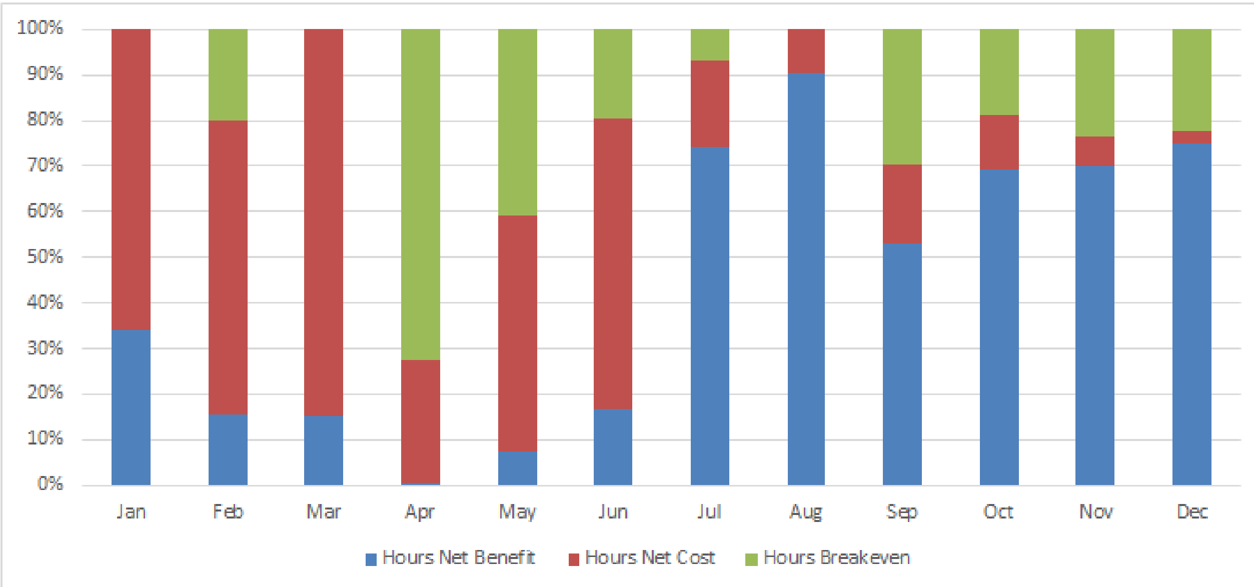


Figure 29. Sherco 2 Hourly Net Benefit/Breakeven/Net Cost

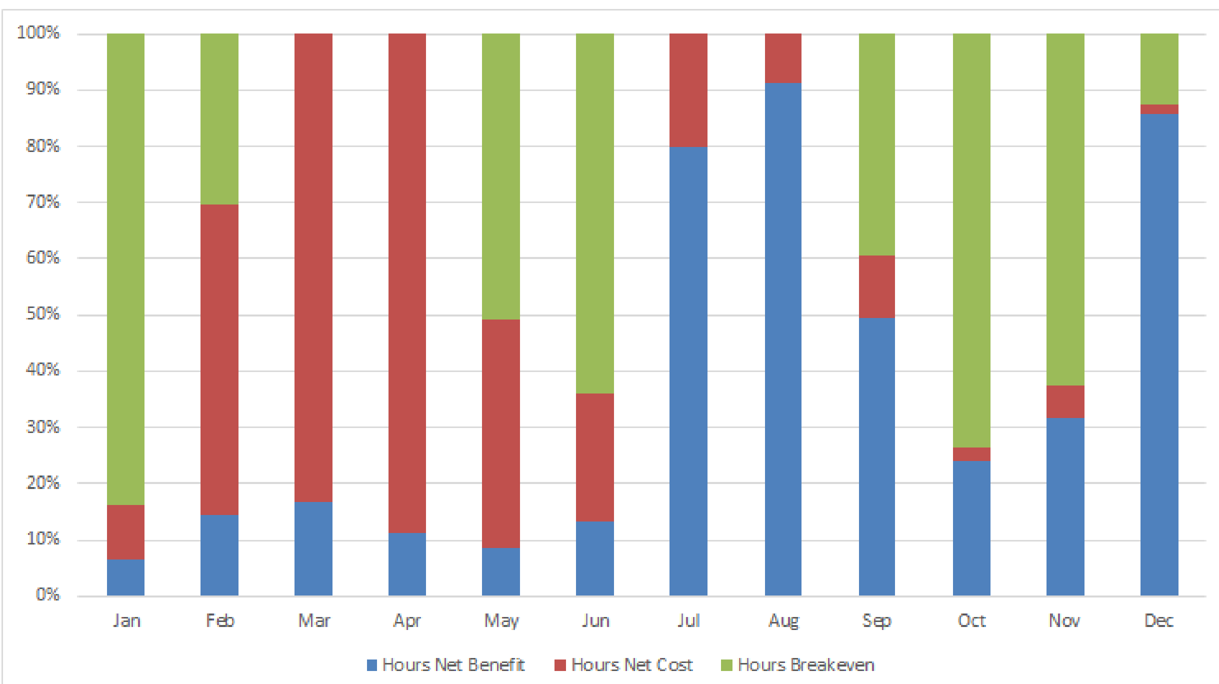
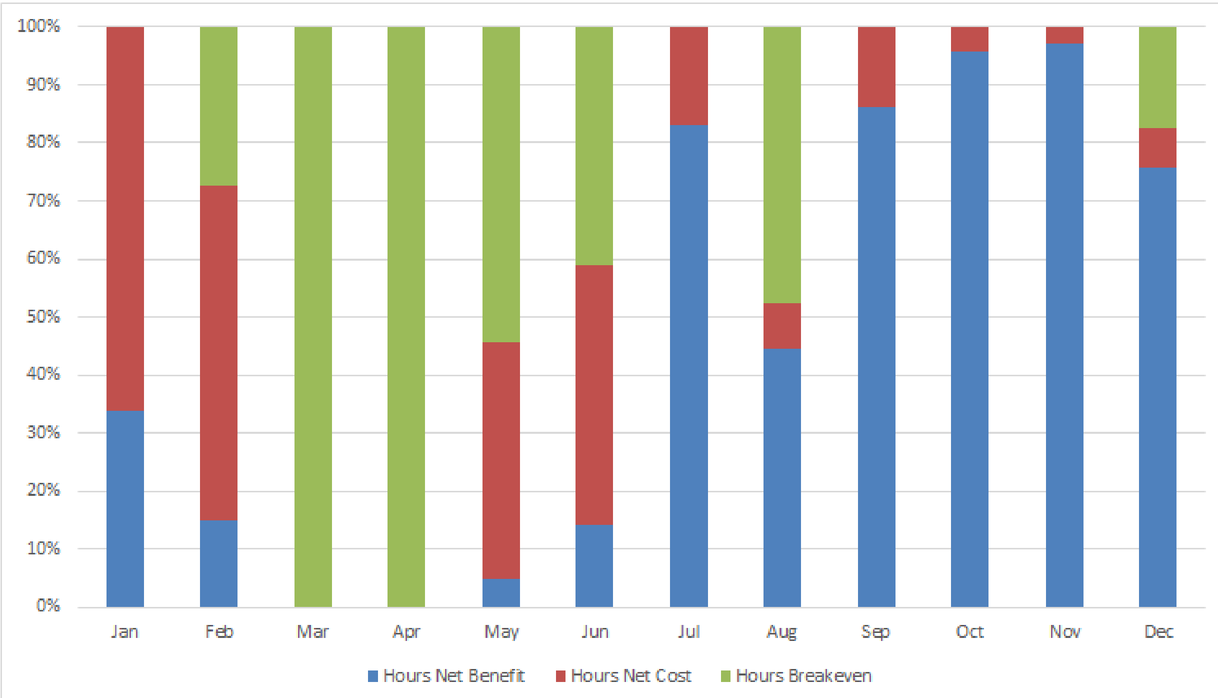


Figure 30. Sherco 3 Hourly Net Benefit/Breakeven/Net Cost



Overall, for 2020, **Table 11** shows the breakdown of the net benefit / (cost) of the units by hours and in percentages.

Table 11. Hours at Net Benefit/Breakeven/Net Cost for Xcel's Coal Plants

Unit	Net Benefit	Breakeven	Net Cost	TOTAL
King	1,580 18.0%	1 0.0%	7,203 82.0%	8,784 100%
Sherco 1	3,831 43.6%	1,841 21.0%	3,112 35.4%	8,784 100%
Sherco 2	3,187 36.3%	3,049 34.7%	2,548 29.0%	8,784 100%
Sherco 3	4,038 46.0%	2,836 32.3%	1,910 21.7%	8,784 100%

The Department concludes that the preliminary data indicates that a more detailed analysis of King and the Sherco units is warranted.

2. *Detailed Analysis*

a. *Background*

In its March 1, 20201 Compliance Filing, Xcel made the following points that were distinct from the points made by Minnesota Power and Otter Tail:

- "Since 2019, the Company's practice is to offer our coal facilities with an economic commit status – as opposed to self-commit – as much as possible. The Company began in fall 2020 to suspend normal operations at King Plant and Sherco 2 during non-peak seasons, as discussed in Docket No. E002/M-19-809."
  - Thus, Xcel already has been trying to move some of its units towards economic commitment. However, Sherco unit 3 is yet to start its transition.
- "In evaluating instances of self-commit of these units, we also excluded hours when Xcel's self-commit action in the MISO market was unavoidable (e.g., mandatory generating resource testing, fuel and steam offtake contract requirements, and generating resource maintenance outages)."
  - Thus, Xcel performed additional economic analysis with more detailed data than was required by the Commission.
- "Both Xcel Energy and SMMPA recognize that there are opportunities to offering Sherco 3 economically to MISO; therefore, both parties have come to an agreement on how to offer economically to the market."
  - Thus, there should be a much greater number of hours when Sherco unit 3 is dispatched with economic commitment during 2021.
- "The Company modeled the impacts of transitioning from a must-commit status on Sherco 3 to a fully economic commitment strategy." Table 1 in Xcel's filing shows expected reduction in fuel costs from this move.
  - Thus, Xcel performed additional analysis to study impacts of moving towards economic commitment at Sherco unit 3. The results show a large reduction in fuel costs and CO_2 emissions at the unit as a result of this transition.
- "…we do not typically exclude sunk contractual costs from unit offers, as we did during 2020 because our contracting for coal in 2020 was complete before plans for seasonal operations were developed and approved. This transitional issue occurred as we moved toward more aggressive cycling and economic operation of our coal fleet. We returned to our standard practice of including the total cost of coal in our offers as of January 1, 2021."
  - Based on **Figure *31***, between June and December, 2020, Xcel did not count sunk contractual costs while submitting offers for its coal plants. The vertical gap between the red and blue lines in **Figure *31*** then represents the monthly contractual cost.

Figure 31. Monthly Production cost and Total Production cost for Xcel's power plants

[TRADE SECRET DATA HAS BEEN EXCISED]

b. Analysis

Large coal units require a minimum downtime, startup time, and a cool down time when they operate. Furthermore, these time periods depend on starting conditions (warm/cold) and vary by units. The minimum time frame arrived at by adding these durations appears to be about a week or less for the units involved in this proceeding. Therefore, the Department used a week as the minimum duration to consider.

The Department uses the minimum duration in this analysis, not because it is necessarily the appropriate duration, but to provide a second bookend to the analysis used by the utilities. The utilities used different durations in their analysis of the overall benefits and costs, but a long duration was typically selected. As previously noted, the utilities' analyses all demonstrate the cost effectiveness of the units' operations when long durations are considered. The two bookends will demonstrate to the Commission the importance (or lack of importance) of the duration to the results of the analysis.

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Figure 32. King Rolling Week Total Benefit / (Cost)

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 32*,* **Figure 34***,* **Figure 36** and **Figure 38** below shows two rolling sums of the hourly benefit / (cost) effectiveness for 1 week (168 hours) for King and the Sherco units, once calculated with production cost and once with total production cost. While these two costs were different during a part of 2020, Xcel will be using total production cost 2021 onwards. When the line is below zero, that indicates the unit operated at a net cost over the preceding week. When the line is above zero that indicates the unit operated at a net benefit over the preceding week. The figures also include a horizontal line indicating the unit's commitment status (must run, outage, economic etc.). When comparing the line indicating net benefit/ (cost) to the line indicating commitment status, it is important to keep in mind that the net benefit/ (cost) line at any one point represents a sum of the previous seven days while the commitment status line represents only that particular hour.

Figure 33, ***Figure 35***, ***Figure 37*** and ***Figure 39*** show the monthly breakdown of the units commitment status and combines it with two plots of the total monthly net benefit / (cost) once considering only production cost and then considering total production cost. This provides a different lens to look at the data and make a clearer comparison across months. As each plant might be different, a comparison across months can provide insights as to the relationship between commitment status and profitability.

Figure 33. King Monthly Total Benefits / (Cost) vs Commitment Status

[TRADE SECRET DATA HAS BEEN EXCISED]

As shown in ***Figure 32*** and ***Figure 33***, King was running on economic commitment most of 2020. Xcel provided specific reasons whenever the plant had to go on a must run commitment. Economic commitment ensured the plant was not producing output most of the months which prevented the plant from incurring large losses. It is worth mentioning that economic commitment for this plant meant not only zero variable cost of operation but also zero fixed costs. The Department recommends Xcel explain in reply comments why the plant did not have to pay any fixed costs for most of the months. In addition, the Department recommends Xcel explain if this can also be achieved at other units that Xcel owns. This makes it important to analyze net benefits both from a variable cost and a total cost perspective.

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Figure 34. Sherco Unit 1 Rolling Week Total Benefit / (Cost)

[TRADE SECRET DATA HAS BEEN EXCISED]

Sherco 1 was in and out of economic commitment during 2020 which provides multiple points of comparison. In general, the plant was making money sometimes during the second half of the year. During the months of April and May, economic dispatch prevented the plant from incurring losses. Both before and after this period, the plant was in must run status and operating at a net cost. Also, note that economic dispatch during the months of July and August coincided with some of the highest net benefits the plant generated on a Production Cost basis; during the same months, the plant was making losses on a Total Cost basis. Since between July and December 2020, Xcel was making offers on the basis of Production Cost, the plant may have been running at a net cost on a Total Production cost basis. For 2021 and onwards Xcel will continue to use its Total Production Cost curve to make offers at MISO. The above figure shows that results can vary significantly depending on how a utility calculates costs for the offer curve. The net benefits using the total cost of production is comparable to the previous and subsequent years.

Figure 35. Sherco Unit 1 Monthly Total Benefits / (Cost) vs Commitment Status

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure *35* provides additional insights. Sherco 1 was often running on a must run commitment status due to a steam contract. The Department recommends Xcel address in reply comments if this Steam Contract is with Liberty Paper and to provide the requirements and term for this Steam Contract. During 2020, 62.6% of the hourly must run designations were due to steam contracts for Sherco 1. The Department would also like Xcel to address in reply comments if this is a non-regulated steam sales contract and explain if any revenues are shared with customers and if not, why not. **Table *12*** summarizes net benefit / (cost) of the steam contract. On a monthly basis, based on Total Cost of Production, Sherco 1 generated losses 10 out of 12 months during 2020.

Sherco unit 2, like Sherco unit 1, was offered with an economic commitment during multiple months of the year. The broad trend emerging from **Figure *36*** is that Sherco unit 2 was generating net benefits during the second half of the year while generating net costs for most of the first half of the year. During the first half of the year, we can see as the unit moves from economic to must run status, net costs increase. Subsequently, as it moves back from must run to economic, net costs decline. Thus, keeping the plant at economic commitment makes sense economically. The net benefit results are sensitive to the way we consider costs for Sherco unit 2. On a Total Production Cost basis, Sherco unit 2 only made much higher losses. On a monthly basis, based on Total Production Cost, Sherco 2 generated losses 9 out of 12 months during 2020.

Figure 36. Sherco Unit 2 Rolling Week Total Benefit / (Cost)

[TRADE SECRET DATA HAS BEEN EXCISED]

As we explore reasons for the must run designation, the steam contracts are again the major reason for Sherco unit 2. 60.7% of the must run hours were arising due to the steam contract. The Department recommends Xcel confirm in rely comments that this Steam Contract is with Liberty Paper. The Department also recommends Xcel confirm in reply comments that this is a non-regulated steam sales contract. **Table *12*** summarizes net benefit / (cost) impact of the steam contract. The Department also recommends Xcel report the specific reasons for all hours of must run commitment for all its units in the next annual filing.

Figure *35* and **Figure *37*** contain large number of hours when the units were running with Must Run commitment but Xcel did not provide a reason for the unavoidable commitment. These hours are marked as “Must Run due to unspecified reason” in the graphs.

Figure 37. Sherco Unit 2 Monthly Total Benefits / (Cost) vs Commitment Status

[TRADE SECRET DATA HAS BEEN EXCISED]

Table *12* summarizes the net costs (difference between Net MISO payment and Total Production Cost) due to the Steam Contract during specific months at Sherco units 1 and 2. The Department recommends Xcel explain in reply comments how the ratepayers will be affected by these losses.

Table 12. Net Cost from Steam Contract at Sherco 1 and 2

[TRADE SECRET DATA HAS BEEN EXCISED]

Sherco unit 3 shows the same pattern of running at net cost for the first half of the year and net benefit for most of the second half of the year. Unlike Xcel's other coal units, Sherco unit 3's performance is not sensitive to how we count costs. Both the 7-day rolling total net benefit curves follow each other closely during 2020. During the first half, the plant was out of service for a long period. The Department looks forward to reviewing the results of implementing economic commitment at this unit during 2021. Based on Xcel's modeling, the company expects a large reduction in fuel costs and carbon emissions as a result. The only reason for unavoidable commitment for this unit that was provided is co-ownership of the plant. While co-ownership can create challenges, further explanation is required. Other co-owned plants investigated in this docket have provided more detailed reasons for their must run commitment status. The Department recommends Xcel explain the reasons for the must run designation at Sherco unit 3 in future annual filings.

Figure 38. Sherco Unit 3 Rolling Week Total Benefit / (Cost)

[TRADE SECRET DATA HAS BEEN EXCISED]

When aggregated at a monthly level, the patterns remain fairly similar. This was the only coal unit that was able to consistently generate profits on a Total Production Cost basis between July and December, 2020. It is important to note that sunk costs from coal contracts are counted differently across Xcel's units. Because of Xcel's accounting practices, the calculations using Total Production Cost are comparable with previous and subsequent years.

Figure 39. Sherco Unit 3 Monthly Total Benefits / (Cost) vs Commitment Status

[TRADE SECRET DATA HAS BEEN EXCISED]

c. Additional analysis by Xcel

Xcel reported the minimum downtime for King is **[TRADE SECRET DATA HAS BEEN EXCISED],** for Sherco units 1 and 2 is **[TRADE SECRET DATA HAS BEEN EXCISED]** and for Sherco unit 3 is **[TRADE SECRET DATA HAS BEEN EXCISED]**. Given these time durations, Xcel calculated the number of occurrences when each plant was making losses continuously for a duration longer than its minimum downtime and the associated cost. Only those instances are counted when the plant was making losses for a duration greater than its minimum downtime. In the following seven figures (**Figure *40*** to **Figure *46***), the blue bars indicate the number of occurrences of such events while the red dots indicates the associated cost. The sum of the values corresponding to all the red dots is an upper bound to net cost savings that economic dispatch might achieve. While this can be difficult to achieve practically, it is important to try to reduce the occurrence of long periods of time when the plant is running at a loss (eliminate the red dots on the right end of the horizontal axis). Remember the cost plotted on the right vertical axis depends on both the consecutive hours of loss and the prevailing prices during that period.

Figure 40. Occurrence of Loss Over Consecutive Hours at King

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 41. Occurrence of Loss Over Consecutive Hours at Sherco Unit 1 on a Variable Cost Basis

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 42. Occurrence of Loss Over Consecutive Hours at Sherco Unit 1 on a Total Cost Basis

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 43. Occurrence of Loss Over Consecutive Hours at Sherco Unit 2 on a Variable Cost Basis

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 44. Occurrence of Loss Over Consecutive Hours at Sherco Unit 2 on a Total Cost Basis

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 45. Occurrence of Loss Over Consecutive Hours at Sherco Unit 3 on a Variable Cost Basis

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 46. Occurrence of Loss Over Consecutive Hours at Sherco Unit 3 on a Total Cost Basis

[TRADE SECRET DATA HAS BEEN EXCISED]

Table *13* summarizes the above 7 figures. For each plant, it shows the total number of occurrences of consecutive hours of loss above the plant's minimum downtime. It also adds up the cost incurred on a variable cost and total cost basis during each of these events. This calculation ignores that initial conditions during these loss events and minimum runtime for each plant. The Department recommends the utilities standardize this part of the reporting template to ensure the analysis reflects operating conditions better.

Table 13. Summary of Events of Consecutive Hours of Loss for Xcel

[TRADE SECRET DATA HAS BEEN EXCISED]

Xcel performed some additional analysis that the Department found useful to understand the effect of moving towards greater economic commitment status of its power plants. Xcel defined three scenarios: base case, must run and economic. The base case modeled the actual commitment of King and Sherco unit 2 during seasonal dispatch. The must run and economic cases enforce the operating parameters used during the base case but alter the commit status to create a what-if scenario. For the must run case, the seasonal dispatch units are forced online in the model during the seasonal operations timeframe. For the economic case, the model is free to commit and decommit the seasonal operations units, respecting the unit parameters included in the model. Finally, the must run and economic cases are compared to the base case, as shown in **Figure 47**.

Based on Xcel's analysis, we can see the current commitment status at these plants saved a significant amount of money and carbon dioxide emissions at the site compared to must run commitment. Note that if King ramps down, its carbon dioxide emissions go down. But the marginal unit ramps up to replace the missing energy, increasing its emissions. The global carbon dioxide impact is the difference between King and marginal emissions. Moving to a fully economic commitment status on the other hand would result in a slightly higher profit that would be offset by operation and maintenance costs and would also result in higher carbon dioxide emissions. Thus, as we increase economic status, profits and carbon dioxide emission savings go up to a certain point, after which they both decline. The results point to the non-linear relationships between profits or emissions and output levels. The Department found this analysis helpful and recommends the other utilities to conduct a similar analysis in the next annual filing to understand this tradeoff and determine an optimal pattern of commitment status and move towards the same.

Figure 47. Comparison of Economic and Must Run to Seasonal Operations

		MR less BASE				ECON less BASE			
		MWh	Profit (+) / Loss (-)	CO2 (000 lb)	run hours	MWh	Profit (+) / Loss (-)	CO2 (000 lb)	run hours
KING	9/4/20 - 9/30/20	258,647	(1,049,650)	567,989	288	-	-	-	-
	Oct-20	320,869	294,169	704,629	744	104,350	580,816	229,153	213
	Nov-20	301,555	(515,327)	662,215	720	-	-	-	-
	Total	881,072	(1,270,808)	1,934,834	1,752	104,350	580,816	229,153	213
SHC2	9/20/20 - 9/30/20	68,056	(760,142)	158,707	205	-	-	-	-
	Oct-20	151,977	(668,035)	354,409	408	-	-	-	-
	Nov-20	215,913	(82,162)	503,509	456	20,996	55,370	48,963	35
	Total	435,946	(1,510,339)	1,016,625	1,069	20,996	55,370	48,963	35

Xcel mentioned their efforts at trying to get Sherco unit 3 to economic commitment beginning March 1, 2021. They presented their analysis on potential fuel clause impacts and carbon dioxide emissions (in Table 1 and 2 of their filing) for Sherco unit 3. Based on the analysis Xcel presented for King and Sherco unit 2, it would be helpful to explore different mix of commitment statuses and compare them to understand the optimal mix of must run and economic commitment that would be optimal for Sherco unit 3.

3. *Conclusion*

Overall, King and Sherco units 1 and 2 implemented a mix of economic and must run commitment status and the results provide insights into determining an optimal mix of these commitment statuses to maximize the benefits for ratepayers. The Department recommends Xcel perform additional analysis for Sherco unit 3 to determine the optimal way to offer the plant to the MISO market. The Department also recommends Xcel provide a more complete description of reasons for unavoidable must run commitment status. Lastly, the Department recommends Xcel explain the implications of the must run status due to the steam contract with Sherco 1 and 2 on ratepayers.

A. *RENEWABLE IMPACT*

As discussed above, the Commission's Feb. 7 Order expressed concern that renewable resources typically have no fuel costs but self-committed and self-scheduled generators may displace renewable resources—even if, at any given moment, the renewable resource has lower operating costs. To obtain basic data on renewable curtailment, the Department referred to the utilities' March 1, 2021 filings in Docket No. E015/AA-19-302 (for Minnesota Power), Docket No. E017/AA-19-297 (for Otter Tail) and Docket No. E002/AA-19-293 (for Xcel) for their Annual True-up Compliance Reports. The utilities reported curtailment data for 2020 as follows:

- Minnesota Power—**[TRADE SECRET DATA HAS BEEN EXCISED]**
- Otter Tail—**[TRADE SECRET DATA HAS BEEN EXCISED]**
- Xcel—**[TRADE SECRET DATA HAS BEEN EXCISED]**

Overall, the largest increase in curtailment was seen by Xcel, where curtailment went up by 765% compared to 2019. Otter Tail's curtailment went up by 200% compared to 2019. Minnesota Power saw a decrease, their 2020 number was 50.8% of their 2019 curtailment. The Department would recommends Xcel and Otter Tail explain in reply comments the reasons behind the large increase in curtailment compared to 2019 and the contribution of must run power plants for the same.

B. MOVING TOWARDS FLEXIBLE OPERATIONS

The coal plants studied in this docket were at different levels of economic commitment in 2020. While each company has unique challenges, based on the compliance filings, it is clear that all plants are moving towards greater economic commitment of their units. As companies transition their facilities into more flexible generation resources, new operational procedures have to be created to minimize costs. NREL, in a 2013 study titled "Flexible Coal: Evolution from Baseload to Peaking Plant"[13] discusses multiple changes in operating procedures that help control the rise in temperature during startup and fall in temperature during shutdowns, as well as rigorous inspection to limit the damage from cycling that enable large savings for the plants. In subsequent filings, the Department recommends the utilities describe changes to their operating procedures and physical modifications to the boilers, pulverizes, turbines, condensers etc., to ensure these plants are becoming more flexible to meet the upcoming challenges.

As the companies implement greater economic dispatch, the Department recommends benchmarks be developed to track the progress being made. These benchmarks need to recognize unique characteristics of each unit. To this end, the Department recommends the creation of two benchmark scenarios based on the data utilities submit as part of this docket.

1. A worst case scenario of no economic dispatch: In this scenario, the plants operate with must run designation all the time with at least the minimum capacity for all 8,760 hours.
2. A best case scenario where commitment status ensures maximum net benefits for the plant after satisfying transmission and reliability constraints.

The Department recommends that the utilities meet to determine a consistent methodology to calculate the best case scenario results. The methodology would use the data utilities are already filing as part of this docket. This exercise is a refinement of Order Point 5.g from the Commission's January 11, 2021 Order. This scenario would quantify the loss events that are avoidable given startup, minimum run time, and cool down time of the plants, transmission and reliability constraints, etc.

As units operate more flexibly, they will have to ramp up and down more frequently than before. This can lead to a deterioration of the equipment leading to reliability concerns. The Department recommends the utilities include the equivalent forced outage rate (EFOR) for each plant and track this over time. This will help us track increased wear and tear of the plants as they move towards greater economic dispatch.

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[13] https://www.nrel.gov/docs/fy14osti/60575.pdf

III. CONCLUSION AND RECOMMENDATIONS

A. RECOMMENDATIONS FOR REPLY COMMENTS

Table *12* shows Steam Contracts were responsible for millions of dollars of losses during specific months of 2020 at Sherco units 1 and 2. The Department recommends Xcel address in reply comments if this Steam Contract is with Liberty Paper and to provide the requirements and terms for this Steam Contract. The Department would also like Xcel to address in reply comments if this is a non-regulated steam sales contract and explain if any revenues are shared with customers and if not, why not. If Xcel's ratepayers are paying for the losses generated due to the steam contract, the Department recommends Xcel explain how will they change the contract going forward.

The Department would like Xcel to explain why the average cost per MWh was so high for Sherco units 1 and 2 (See ***Table 4***). Also, explain why Remaining Unit Fuel costs for Sherco unit 1 was so high between August and December 2020.

Economic commitment for the King plant meant not only zero variable cost of operation but also zero fixed fuel costs for Xcel. The Department recommends Xcel explain how it achieved this and if the Company can achieve this at Sherco units as well.

The Department recommends the companies explain in their reply comments how to determine variable fuel costs vs fixed fuel costs (what costs they would incur on fuel if they produced 0 MWh) based on the data reported.

Otter Tail's Big Stone and Coyote plants have very different ways of splitting their fuel costs between fixed and variable components. The Department recommends that Otter Tail explain any financial benefits to splitting the fuel cost with a much higher fixed component at Coyote for the ratepayers and the company.

The Department recommends Otter Tail explain in reply comments why it pays a higher price for its coal per MWh of generation at Coyote compared to Big Stone. The Department recommends Otter Tail outline in reply comments strategies it can use to mitigate ratepayer impacts if the fixed costs continue to generate overall net losses for the unit.

The Department recommends Otter Tail provide simulations for Coyote and report net benefit/(cost) calculations for economic dispatch scenarios for the Coyote Plant.

The Department recommends Otter Tail explain in reply comments why Coyote was not committed because of SPP market conditions during 2020 despite the fact that this was the biggest reason for must run commitment at Big Stone.

Otter Tail discussed customer savings it was able to generate by committing Big Stone to economic commitment for 22% of the time during 2020. ***Table 4*** shows the cost per MWh was significantly higher at Coyote compared to Big Stone. In light of this, The Department recommends Otter tail explain the company's best estimate of customer savings that can be generated from economic commitment of the company's Coyote unit.

The Department recommends Minnesota Power discuss in detail, their experience of putting Boswell unit 3 on Economic dispatch during May 2020, especially with regard to challenges that came up during this month.

The Department recommends Xcel and Otter Tail to explain in reply comments reasons behind the large increase in wind curtailment compared to 2019 and the contribution of must run power plants for the same.

B. RECOMMENDATIONS FOR COMPLIANCE FILING

One objective of the filings in the 19-704 docket is to understand what fuel costs can be avoided if commitment decisions are driven by economic considerations. To understand this better, the Department recommends the companies decide on a methodology to split fuel costs in a way that such that one part depends on the MWh produced (variable costs) and the other part is independent of the MWh generated (fixed costs).

To track the progress of utilities as they move towards greater economic commitment of their plants, the Department recommends the creation of two benchmark scenarios. Utilities should meet to come up with a consistent methodology to calculate the best case scenario results based on the data being filed in this docket. This scenario would quantify the loss events that are avoidable given startup, minimum run time and cool down time of the plants, transmission and reliability constraints etc. In addition, utilities should analyze and report on a worst case scenario of no economic dispatch: In this scenario, the plants operate with must run designation all the time with at least the minimum capacity for all 8,760 hours.

C. RECOMMENDATIONS FOR NEXT YEAR'S FILING

Ensuring coal plants are dispatched according to economic commitment has multiple benefits. The Department recommends each utility include in their filing carbon dioxide emission reduction that arise at the site as they move to greater economic commitment.

The Department recommends that the companies provide a complete list of reasons for unavoidable self-commitment of each of their plants. The current filings contain a significant number of must run hours with no explanation for unavoidable commitment status.

The Department recommends the utilities include the starting conditions for each plant (Cold, Warm and Hot) whenever a plant starts operating. This will help parties understand the operational dynamics better for each plant.

The Department recommends the utilities include the equivalent forced outage rate (EFOR) for each plant and track this over time. This will help us track increased wear and tear of the plants as they move towards greater economic dispatch.

The Department recommends Otter Tail discuss their ability to renegotiate their fuel contract for the Coyote plant and move the plant to economic self-commitment in next year's filing.

The Department recommends the utilities describe the changes to their operating procedures and physical modifications to their units to ensure these plants are becoming more flexible to meet the upcoming challenges.

ATTACHMENT- A

STRATEGIES IN MISO MARKETS

A. Background

Analysis of the economics of the operation of baseload units within the MISO market construct requires some knowledge of the MISO market construct and how utilities can use the MISO market construct. The following discussion is intended to provide some of that background knowledge. Start by assuming a simplified situation where a utility has a single customer, the utility owns one dispatchable generator, and the utility participates in MISO's markets. In this scenario, the customer's load is bid into the MISO market and the utility pays the LMP at the load; the utility's generator is also bid into the MISO market and the utility receives the LMP at the generator—if the generator is selected by MISO and generates electricity. In this scenario **Equation *4*** provides a simple explanation of how the bill is determined; for now assume that the generator is always selected by MISO and produces energy equal to load. This assumption will be relaxed later in the analysis.

Equation 4. Customer Bill Components

$$Variable\ Cost_{Gen} - LMP_{Gen} + LMP_{Load} = Utility\ Bill$$

From **Equation *4*** it can be seen that if **Equation *5*** is true:

Equation 5. LMPs are equal

$$LMP_{Gen} = LMP_{Load}$$

Then **Equation *6*** *must be true as well:*

Equation 6. Determining the Bill

$$Variable\ Cost_{Gen} = Utility\ Bill$$

This analysis implies that, all else equal, one strategy for a utility to follow is to site new generation close to load under the assumption that the closer generation is to load the closer the two LMPs will be to each other.[14] In such a circumstance, the variable cost of the utility-owned generator determines the customer's bill and the utility and customer are effectively insulated from MISO market LMP spikes and locational LMP differentials.

B. Variable Cost and Generator LMP

If a utility does not own any generation or the generator is not selected by MISO, then the generation LMP and generation variable cost are zero. From Equation 1 it can be seen that, in this situation, the customer's bill is equal to the load LMP. This represents a second strategy that could be followed, not building generation and simply paying the market price. The focus of the remaining discussion is how ownership of generation can increase or decrease the customer's bill.

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[14] For examples of this strategy being used by utilities see the January 19, 2018 Direct Testimony and Attachments of Dr. Steve Rakow at page 29 in Docket No. E015/AI-17-568 (regarding Minnesota Power's Nemadji Trail Energy Center) and the January 8, 2020 comments of the Department at page 4 in Docket No. E002/M-19-268 (regarding Xcel's Deuel Harvest North Wind project) both referencing locational requirements for bids offered in request for proposals (RFP) processes.

At any one time the generator's variable cost can be less than, equal to, or greater than the generator's LMP. The analysis above dealt with the situation where the generator's variable cost is equal to the generator's LMP (both net to zero). In a situation where the generator's variable cost is less than the generator's LMP, then Equation 1 can be re-arranged to better show the consequences; see **Equation *7*** below.

Equation 7. Customer Bill Components Rearranged

$$LMP_{Load} - (LMP_{Gen} - Variable\ Cost_{Gen}) = Utility\ Bill$$

If the generator's variable costs are less than the generator's LMP, then the difference between generation LMP and variable cost becomes a subtraction from the load LMP, decreasing the bill. In this circumstance, ownership of generation is an advantage. However, if the generator's variable costs are greater than the generator's LMP, then the generator should not operate. However, if the generator does operate despite the price signal, the difference between generation LMP and variable cost becomes an addition to the load LMP, increasing the bill. In this circumstance, ownership of generation is a disadvantage.

CERTIFICATE OF SERVICE

I, Marcella Emeott, 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 – COMMENTS

Docket No. E999/CI-19-704

Dated this 30th day of April 2021

/s/Marcella Emeott

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Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-704_Official
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Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_19-704_Official
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