May 2, 2022 **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.
Public Utilities Rates Analyst

AD/ja
Attachment

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COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

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 October 14, 2021, the Commission issued its Order approving the March 1, 2021 filings by Northern States Power Company doing business as Xcel Energy (Xcel), Minnesota Power, an operating division of ALLETE, Inc. (Minnesota Power or MP) and Otter Tail Power Company (Otter Tail or OTP) covering January 1, 2020 to December 31, 2020. The Commission also included the following additional order points:

2. Direct Xcel Energy to include in their next annual report in this docket to update the Commission and stakeholders when milestones in the Sherburne County Generating Station auxiliary boiler project are reached, including completion of boiler construction; approval, denial, or delay of the Air Emission Permit Amendment; decisions made by Xcel Energy and/or Liberty Paper, Inc. relating to the sources of steam used by Liberty Paper Inc.; and updates to the feasibility and use of economic commitment at Sherburne County Generating Station Unit I.
5. Direct Minnesota Power to make a compliance filing within 10 days of the order in this matter to provide more information about the system strength study that Minnesota Power has commissioned a consultant to complete; this filing should include, at minimum, the request for proposal or solicitation used to select a consultant and the scope of work for the study.
6. Direct Minnesota Power to file the system strength study in this docket when completed
8. Carry forward all the requirements from prior orders in Docket Nos. E-999/AA-18-373 and E-999/CI-19-704 and requires inclusion of the following in future reports:
    a. Information on annual carbon dioxide emissions;
    b. Reasons for unavoidable self-commit status designations;
    c. Plant startup conditions (e.g. cold, warm, or hot);
    d. Equivalent Forced Outage Rate (EFOR) information to be tracked over time; and
    e. Descriptions of changes to operating procedures and physical modifications to units to ensure plants are becoming more flexible to meet upcoming challenges as applicable.
9. Direct Minnesota Power, Otter Tail Power, and Xcel Energy to develop a methodology, that is consistent to the extent possible, for splitting fuel costs such that one part depends on the MWh production (i.e. variable cost) and the other part is independent of the MWh generated (i.e. fixed cost) and update the reporting template accordingly.
10. Require the utilities to work together to develop a consistent method for estimating the best-case and worst-case potential for economic commitment for each plant.

On March 1, 2022, Xcel, Otter Tail and Minnesota Power filed their third Annual Compliance filing covering January 1,2021 to December 31, 2021. 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)

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[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.

units 3 and 4.[2] Otter Tail's report provided data regarding the Big Stone Plant (Big Stone) and Coyote Station (Coyote).[3]

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

Table 1. OTP Unit Ownership Arrangements

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 MISO's energy market stage 2 of the market process. As clarified by Otter Tail in a prior year, 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:

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[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.

[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.

> 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 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.

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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

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.

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 and 33% in 2022. 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 8 coal and 3 nuclear units that are part of this proceeding.

Table 2. Distribution of Commitment Status across Power Plants in 2021

	Economic (hours)	Economic %	Must Run (hours)	Must Run %	Outage (hours)	Outage %	Other (hours)	Total (hours)
[TRADE SECRET DATA HAS BEEN EXCISED]								

[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

MISO's presentation slides from their March 2022 MISO Monthly Operations Report[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 between March 2021 and March 2022 and this shows between 93% and 87% was economically dispatched. 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.

Table 3. Uneconomic DA Dispatch by Unit

	(a)	(b)	(c)	(d) = (c)/(a)	(e) = (b)-(c)	(f) = (e)/(a)	(g) = (d)+(f)
Unit	**Total DA Dispatch**	**Total Uneconomic DA Dispatch**	**Uneconomic DA Dispatch Minimum**	**Percent Uneconomic DA Minimum**	**Uneconomic DA Dispatch Above Minimum**	**Percent Uneconomic DA Above Minimum**	**Percent Uneconomic DA Dispatch**
[TRADE SECRET DATA HAS BEEN EXCISED							
TOTAL	15,974,270	3,075,470	2,260,695	14%	814,774	5%	19%

[6] https://cdn.misoenergy.org/202203%20Market%20and%20Operations%20Report624194.pdf (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, 2021 - Dec 31, 2021 reporting period.

Considering all the coal units in this proceeding, the result was that the uneconomic DA dispatch minimum equaled 14 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 5 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 Department comments[9]. The percentage of uneconomic dispatch at the aggregate level has fallen considerably since 2020. Minnesota Power has been able to achieve the largest reduction in uneconomic dispatch followed by OTP and then Xcel. Two of Xcel's coal units, King and Sherco 3 are the only two that saw an increase in percentage of uneconomic day ahead dispatch compared to 2020.

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...

[8] The two percentages are additive. Meaning 19 percent of the total hourly cleared DA capacity was not economic.
[9] Table 3 from the Department's comments filed on April 30, 2021 in Docket 19-704

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 the 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 6*** 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.

A. *COST REPORTING*

As part of this docket Utilities came up with a consistent way of reporting their costs. As these comments 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

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

Equation 2. Total Production cost components

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

At this stage it is important to note that both costs, in their current reported format, depend on the MWh generated by the plants as the component costs were allocated across the MWh output of the plants. So, if MWh is zero because the plant is not being dispatched, both these costs are zero. Traditionally, 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

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

generated. Thus, in the subsequent analysis, the Department shows both these costs when they are significantly different.

B. *VARIABLE COST$_{GEN}$ > LMP$_{GEN}$ – MINNESOTA POWER*

1. *Preliminary Analysis*

The Department started the analysis of each utility's data by determining the number of hours each month where 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. Based on the figures, we can see 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 benefit was a common phenomenon at both units throughout 2021; over 70 percent of the hours on average were operated at a net benefits.

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

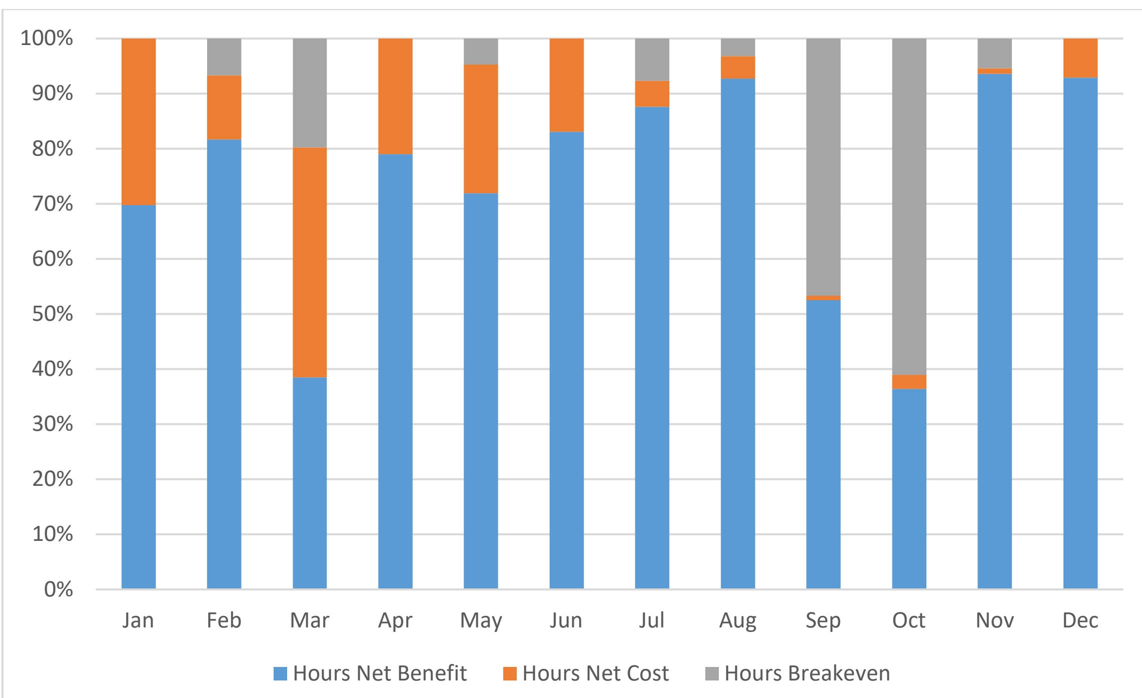
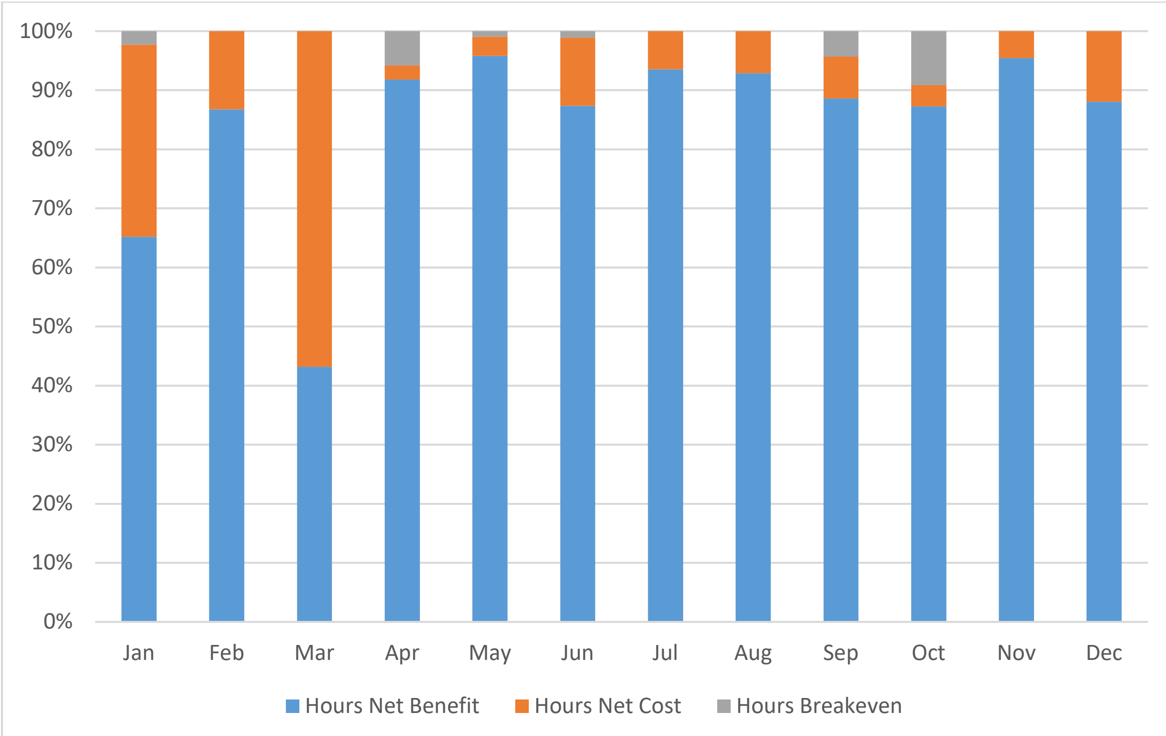


Figure 2. Boswell Unit 4 Hourly Net Benefit/Breakeven/Net Cost



One thing to note here, for Minnesota Power, the Production Cost and the Total Production Costs including Remaining Unit Fuel Costs were identical. This is not the case for other utilities. ***Table 4*** shows the breakdown of the net benefit / (cost) of both units by hours and in percentages.

Table 4. Hours at Net Benefit/Breakeven/Net Cost for MP

Unit	Net Benefit	Breakeven	Net Cost	TOTAL
Boswell Unit 3	6,413 73%	1,137 13%	1,210 14%	8,760 100%
Boswell Unit 4	7,409 85%	173 2%	1,178 13%	8,784 100%

The Department concludes that the preliminary data indicates that a more detailed analysis of both Boswell unit 3 and Boswell unit 4 is not warranted.

2. Conclusion

2021 has been a favorable year with relatively high electricity wholesale prices. This meant that the plants at Boswell produced higher output compared to 2020. Boswell 3 was able to transition to economic dispatch during the second half of 2021 and the lessons learnt should provide valuable insights to Minnesota Power as it works to move Boswell 4 to greater economic dispatch in the coming years. The Department recommends that the Commission take no action regarding MP's commitment and dispatch status decisions regarding the two Boswell units.

C. *VARIABLE COST$_{GEN}$ > LMP$_{GEN}$ – OTTER TAIL*

1. Preliminary Analysis

Big Stone and Coyote 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 3*** and ***Figure 4*** plots the monthly aggregated values of these two costs for each power plant. 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 3. Big Stone Monthly Costs

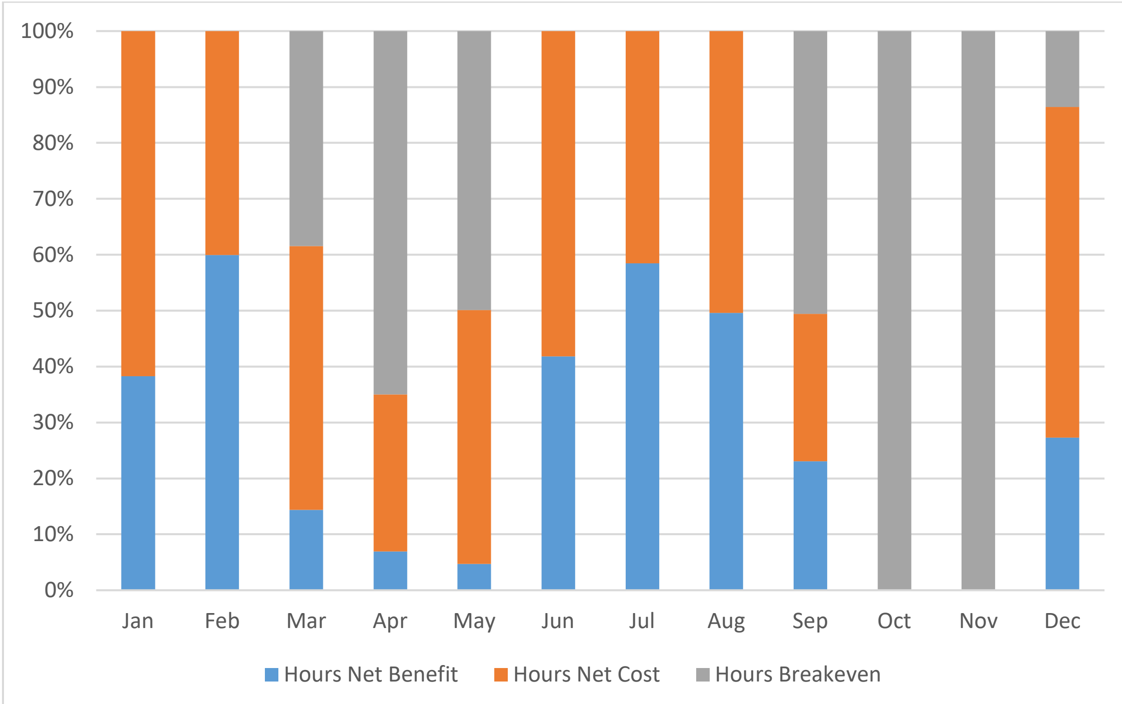
[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 4. Coyote Monthly Costs

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 5 and ***Figure 6*** 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 5***, the months of March, April and May have some of the lowest net benefits compared to other months. We will explore this in the next section when we look at the monthly distribution of commitment status.

Figure 5. Big Stone Hourly Net Benefit/Breakeven/Net Cost



Also, ***Figure 6*** shows Coyote has a much higher proportion of hours compared to Big Stone when the plant is running at Net Benefit. This apparent difference is arising because of how we are counting costs. As was shown in the comparison between ***Figure 3*** and ***Figure 4***, there are differences in the way Otter Tail reported costs for these two plants. If we are to consider total production cost including remaining unit fuel costs for the Coyote plant while calculating Net Benefit, we get much fewer number of hours when the plant was running at net benefit. ***Figure 7*** shows this.

Figure 6. Coyote Hourly Net Benefit/Breakeven/Net Cost (with Production Cost)

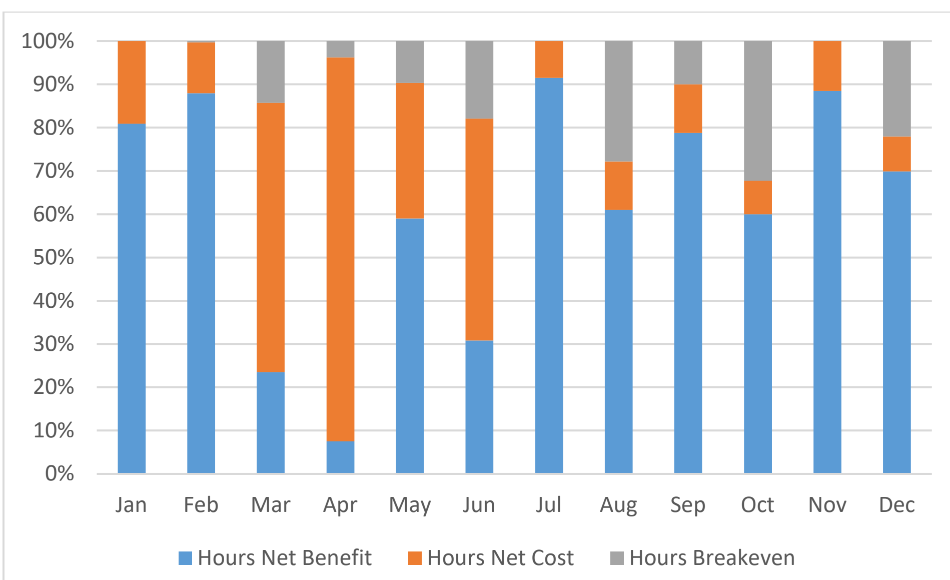
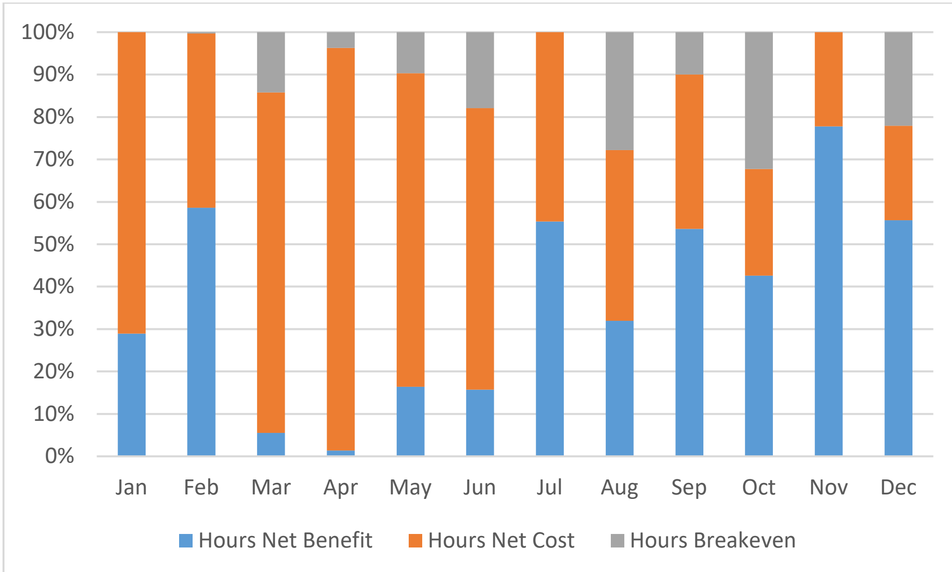


Figure 7. Coyote Hourly Net Benefit/Breakeven/Net Cost (with Total Production Cost)



Overall, for 2020, ***Table 5*** 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 5. Hours at Net Benefit/Breakeven/Net Cost for OTP

Unit	Net Benefit	Breakeven	Net Cost	TOTAL
Big Stone	2,354 27%	3,054 35%	3,352 38%	8,760 100%
Coyote (with Production Cost)	5,388 62%	1,019 12%	2,353 27%	8,760 100%
Coyote (with Total Production Cost)	3,222 37%	1,019 12%	4,519 52%	8,760 100%

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 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[11], 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.
- "System wide 2021 prices increased significantly as compared to pricing in 2020. This increase is believed to be driven by the impacts of winter storm Uri and significantly increased natural gas pricing."
    - Higher electricity prices would lead to higher net benefits. However, the option for greater economic dispatch can reduce risk if LMPs are lower.
- "The largest driver in forced self-commitment was higher LMP pricing in the SPP market and corresponding commitment requests from co-owners."
    - Operating in both SPP and MISO markets can be challenging, especially if these markets produce significantly different LMPs.
- "Implementation of economic offer capability is a relatively new process for both Big Stone Plant and Coyote Station."
    - Economic dispatch at OTP's coal plants is relatively low compared to most other coal plants analyzed in this docket. Lessons learnt from this transition should help OTP operate its units more flexibly.

b. Analysis

Large coal units require a minimum downtime, start up 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. As previously noted, the utilities' analyses all demonstrate the cost effectiveness of the units' operations

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

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 8, ***Figure 9***, ***Figure 11*** and ***Figure 12*** 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 8***, ***Figure 9***, ***Figure 11*** and ***Figure 12*** 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.

During the extreme weather event in February 2021, electricity wholesale prices went up significantly causing all power plants in the state to earn significantly higher revenues. This led to a large spike in net benefits during February 2021. Plotting the data for all twelve months in one graph made it difficult to decipher the variation in net benefits during most of the year. To enable a clear visual representation, the Department included two graphs. One for all days of the year and a second one that excluded February 1 to February 25, 2021.

As can be seen in ***Figure 9***, between March and April, Big Stone was running with an Economic commitment status and breaking even. Both before and after this period, the plant switched to Must Run status and was running at a net cost. Extending the period of economic dispatch beyond this short period would have reduced net costs further leading to higher ratepayer benefits.

Figure 8. Big Stone Rolling Week Total Benefit / (Cost)

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 9. Big Stone Rolling Week Total Benefit / (Cost) excluding Feb 1-25

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 10 helps us understand Big Stone's monthly net benefits along with dispatch patterns. Much of the economic commitment decisions are concentrated between March and April. Almost 70 percent of the must run hours for the Big Stone unit was due to requests from co-owners. The Department recommends OTP explain in reply comments what steps are being taken by OTP to better align the financial incentives of the co-owners regarding Big Stone's operation.

Figure 10. Big Stone Monthly Total Benefits / (Cost) vs Commitment Status

[TRADE SECRET DATA HAS BEEN EXCISED]

The following two figures show the weekly rolling total net benefits for Coyote plant. Coyote plant is a mine to mouth plant and costs are allocated in a specific way to reflect the contract OTP has with the mine. A significant part of the fuel costs is categorized as fixed costs and thus not included in the Production cost. Total cost includes all fuel related costs. The Department calculated net benefits using both costs separately and plotted then in ***Figure 11***, ***Figure 12*** and ***Figure 13***. Coyote experienced a large spike in net benefits during the February extreme weather event.

Figure 11. Coyote Rolling Week Total Benefit / (Cost)

[TRADE SECRET DATA HAS BEEN EXCISED]

Considering the period excluding February 1 to 25, as depicted in **Figure 12** shows that the plant was operating with positive net benefits for much of the later half of 2021. There are extended periods in the first half of the year when the plant was running at net costs.

Figure 12. Coyote Rolling Week Total Benefit / (Cost) excluding Feb 1-25

TRADE SECRET DATA HAS BEEN EXCISED]

Figure 13 shows commitment status by month and plots the Net Benefit / (Cost) calculated using production cost and total production cost. Requests from plant co-owners was the most frequent reason (almost 50 percent) cited by OTP for must run commitment status of the plant. The Department recommends OTP explore the potential of more flexible arrangements with other co-owners of the plant that can be in the interest of OTP's ratepayers. The Department also recommends OTP explain in reply comments what steps are being taken by OTP to better align the financial incentives of the co-owners regarding Coyote's operation to help maximize benefits to the ratepayers of all the co-owners of the plant.

Figure 13. Coyote Monthly Total Benefits / (Cost) vs Commitment Status

[TRADE SECRET DATA HAS BEEN EXCISED]

Otter Tail included additional analysis pointing to how the two plants would have been dispatched following Otter Tail's requests. While the analysis was helpful, it showed there are significant differences in how different co-owners want to run the unit. Otter Tail calculated the net benefit / (cost) every hour if Big Stone and Coyote followed OTP's recommended commitment status. The Department recommends OTP explain in reply comments how much of the disagreements between its units' (Big Stone and Coyote) commitment among the plant co-owners is due to divergent financial incentives.

As can be seen in ***Figure 14***, following Otter Tail's endorsement would lead to lower net cost hours for the plant compared to what was actually observed between March and December 2021. Otter Tail compares these scenarios in Table 6 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 14. Big Stone Actual vs OTP Endorsed Self Commitment effects March - Dec 2021

[TRADE SECRET DATA HAS BEEN EXCISED]

OTP explained the largest driver of forced self-commitment at Coyote was higher prices in SPP compared to MISO. On average, at the Coyote node, SPP market pricing was nearly 140 percent higher than pricing in the MISO market. To demonstrate the impacts of the higher SPP market and forced self-commitment obligations, Otter Tail completed additional analysis for 2021. ***Figure 15*** shows a comparison between actual 2021 Otter Tail share performance and what performance might have been if Otter Tail was not called to self-commit. ***Figure 15*** reflects actual 2021 Otter Tail performance against the hours OTP would have endorsed self-commitment based solely on MISO market conditions. The Department appreciates the analysis and recommends OTP include similar analysis in future filings, a third scenario where OTP endorsed self-commitment is based on both MISO and SPP market conditions.

Figure 15. Coyote vs OTP Endorsed Self Commitment effects May - Dec 2020

[TRADE SECRET DATA HAS BEEN EXCISED]

3. Conclusion

In conclusion, Otter Tail's units performed better in 2021 compared to 2020 due to higher electricity prices. OTP has started offering both its units with economic commitment. It seems like co-owners of Big Stone and Coyote need to better align their financial incentives to allow more flexible operations of the unit in the future.

PUBLIC DOCUMENT

D. *VARIABLE COST$_{GEN}$ > LMP$_{GEN}$ – XCEL NUCLEAR*

1. Preliminary Analysis

Figure 16 to **Figure 18** 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.

Figure 16. Prairie Island Unit 1 Hourly Net Benefit/Breakeven/Net Cost

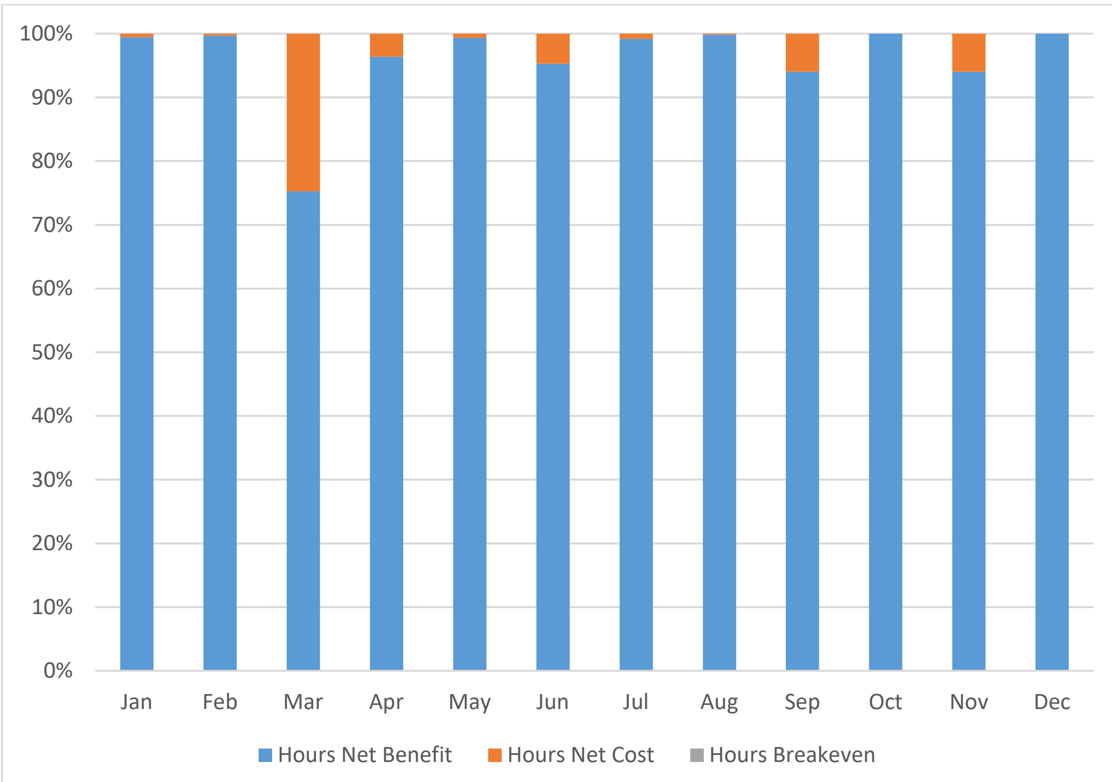


Figure 17. Prairie Island Unit 2 Hourly Net Benefit/Breakeven/Net Cost

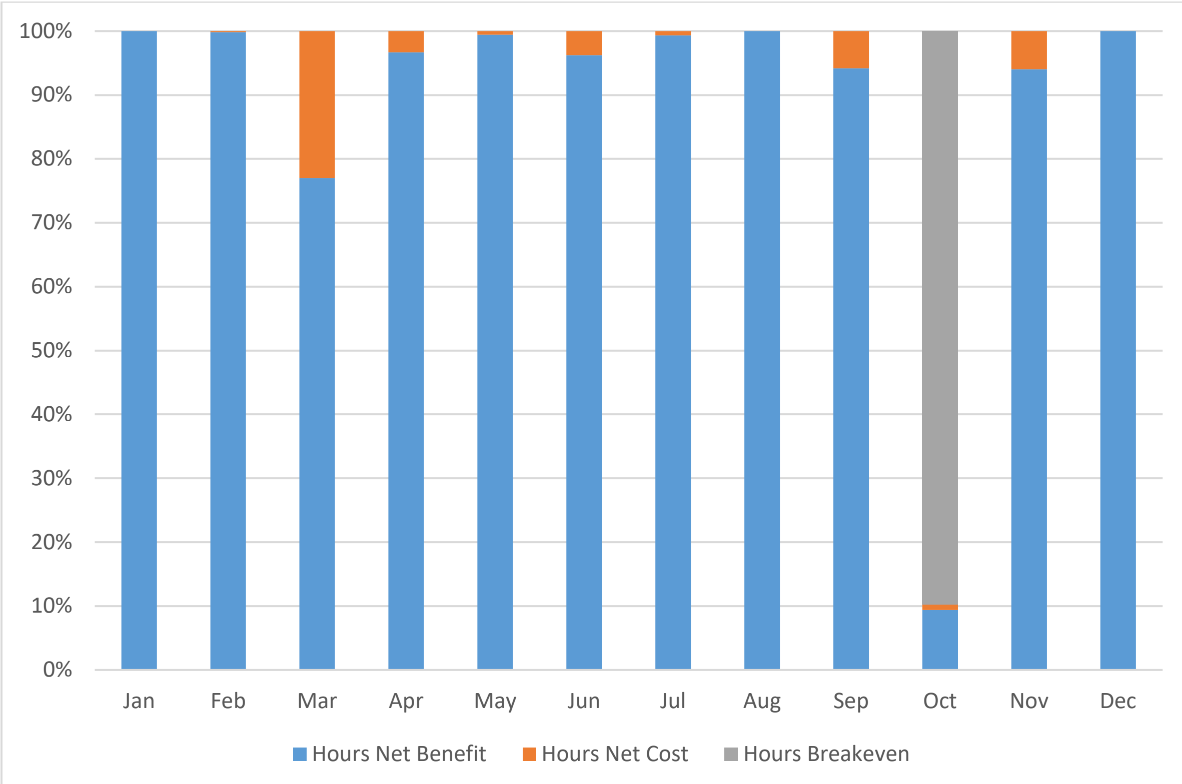
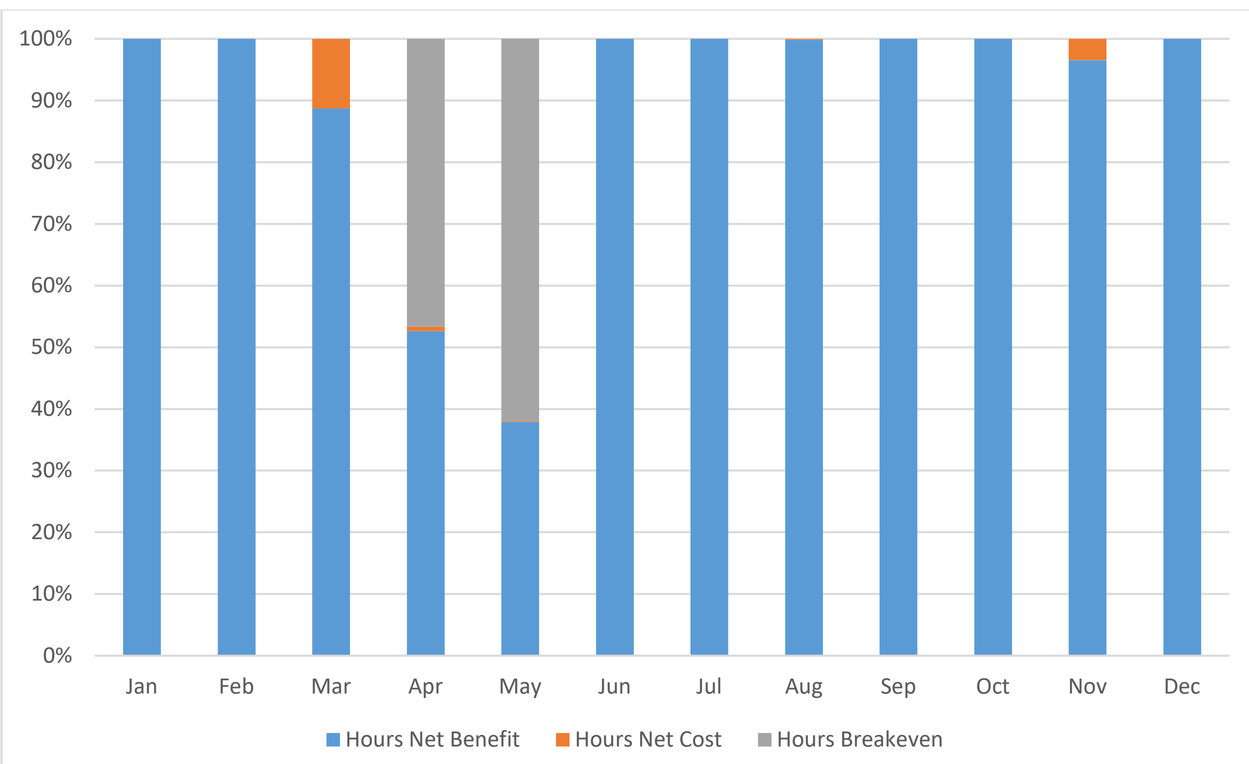


Figure 18. Monticello Hourly Net Benefit/Breakeven/Net Cost



Overall, for the 12-month period ***Table 6*** shows the breakdown of the net benefit / (cost) of all three units by hours and in percentages.

Table 6. Hours at Net Benefit/Breakeven/Net Cost for Xcel's Nuclear Plants

Unit	Net Benefit	Breakeven	Net Cost	TOTAL
Prairie Island Unit 1	8,412 96%	0 0%	348 4%	8,760 100%
Prairie Island Unit 2	7,769 89%	668 8%	323 4%	8,760 100%
Monticello	7,847 90%	797 9%	116 1%	8,760 100%

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.

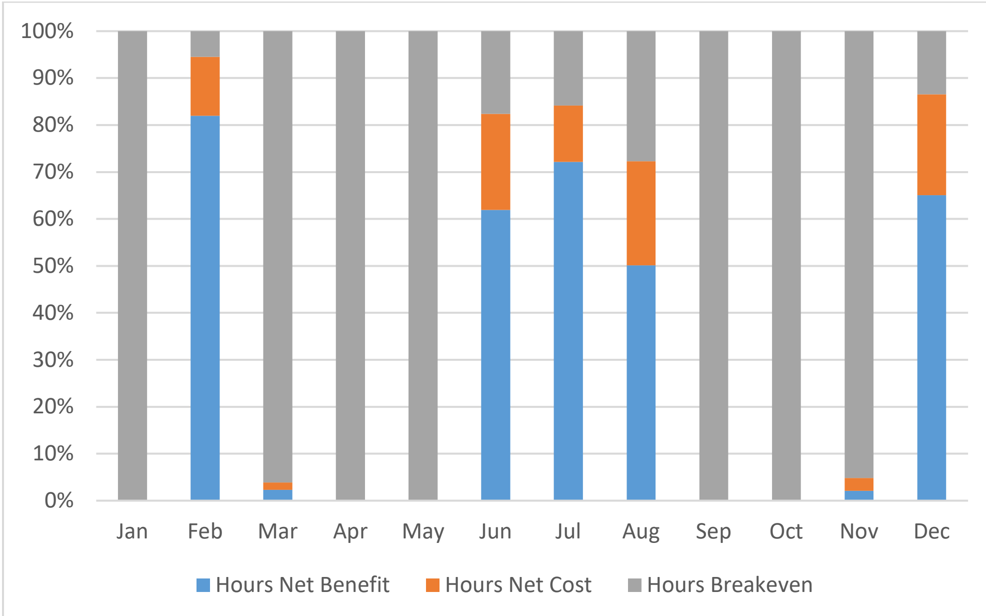
E. *VARIABLE COST$_{GEN}$ > LMP$_{GEN}$ – XCEL COAL*

1. Preliminary Analysis

Figure 19 through ***Figure 22*** show the results of the preliminary analysis for Xcel's King and Sherco units. King was operating under economic commitment for a large part of the year and this meant the plant was not producing output when market prices were low, which lead to multiple hours when the plant was breaking even. Similar patterns were also observed at the Sherco units.

PUBLIC DOCUMENT

Figure 19. King Hourly Net Benefit/Breakeven/Net Cost



King was also on a seasonal shutdown strategy mostly during **[TRADE SECRET DATA HAS BEEN EXCISED]**. During this same period, DA LMPs were fairly high, which raises the following question: Is it possible that the seasonal shutdown strategy at King caused lower net benefits for Xcel compared to an Economic commitment strategy? Xcel answered this question as explained in the section titled Additional analysis by Xcel on Page 30 of these comments.

Figure 20. Sherco 1 Hourly Net Benefit/Breakeven/Net Cost

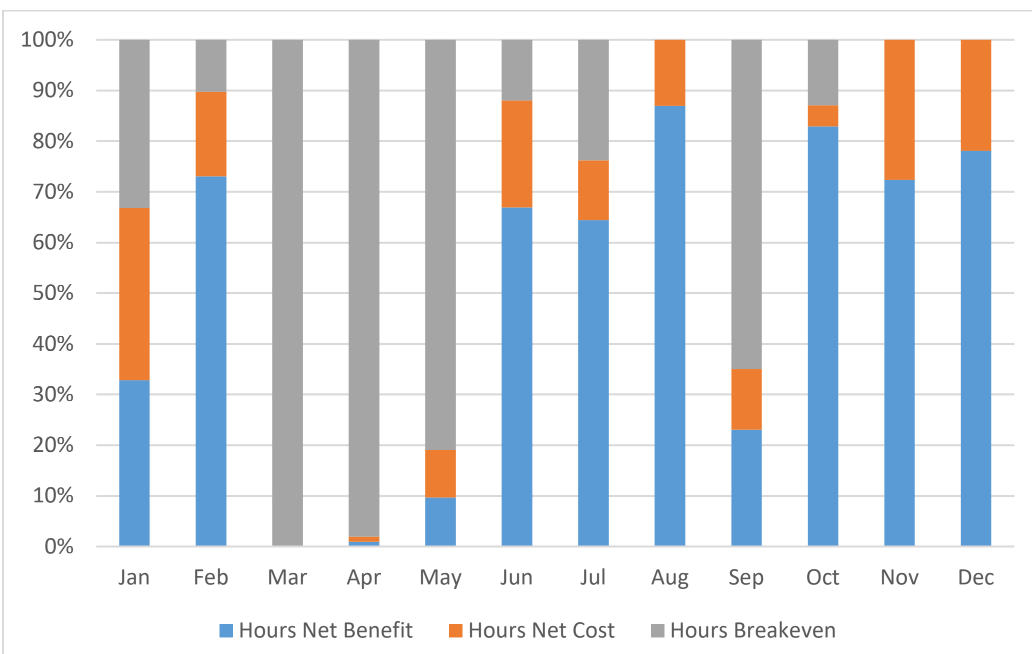


Figure 21. Sherco 2 Hourly Net Benefit/Breakeven/Net Cost

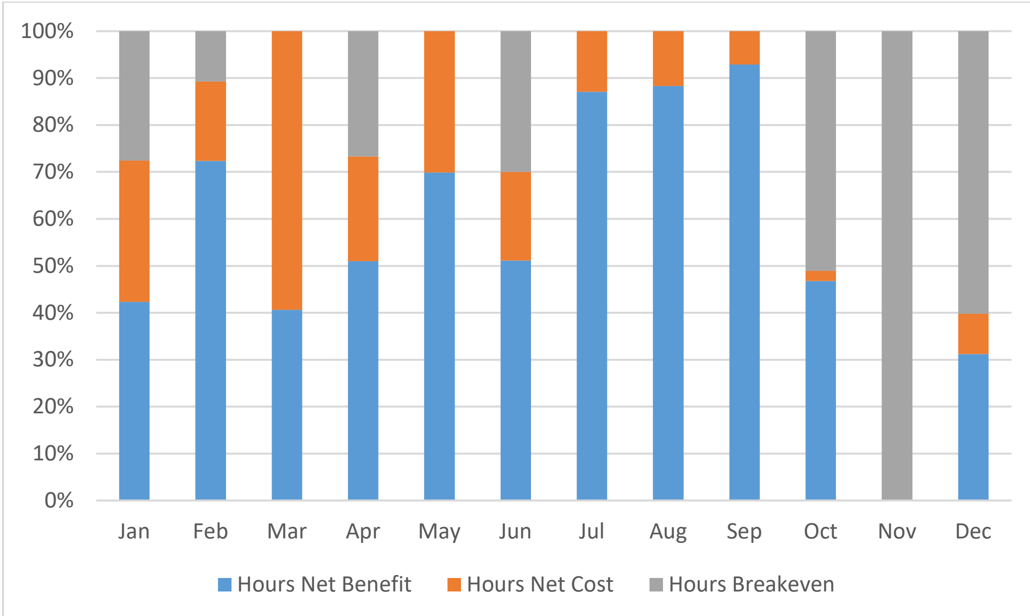
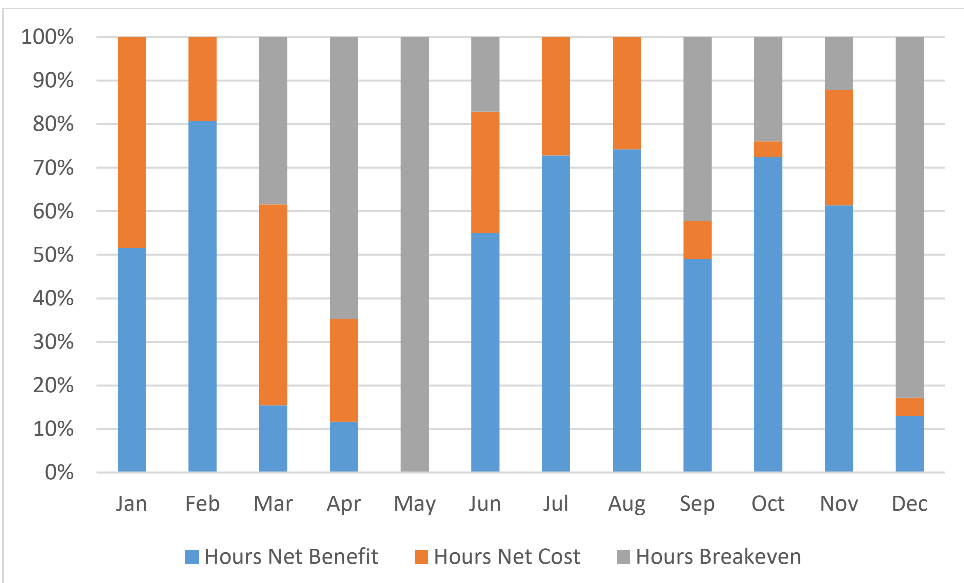


Figure 22. Sherco 3 Hourly Net Benefit/Breakeven/Net Cost



Overall, for 2020, **Table 7** shows the breakdown of the net benefit / (cost) of the units by hours and in percentages.

Table 7. Hours at Net Benefit/Breakeven/Net Cost for Xcel's Coal Plants

Unit	Net Benefit	Breakeven	Net Cost	TOTAL
King	2,423 28%	5,660 65%	677 8%	8,760 100%
Sherco 1	4,307 49%	3,195 36%	1,258 14%	8,760 100%
Sherco 2	4,912 56%	2,233 25%	1,615 18%	8,760 100%
Sherco 3	4,044 46%	2,804 32%	1,912 22%	8,760 100%

The Department concludes that the preliminary data indicates that a more detailed analysis of the Sherco units 2 and 3 is warranted. However, a detailed review of King and Sherco 1 is not warranted.

2. Detailed Analysis

a. Background

Xcel made the following points in the Xcel Report that were distinct from the points made by Minnesota Power and Otter Tail:

- "NSP has worked to reduce the minimum required loading at Sherco 1 and Sherco 2 from 260 MW to 215 MW. This increased "turndown capability" produced an estimated $236,000 in customer benefits in 2021."
  - Thus, reducing minimum required loading can help coal units operate more flexibly and generate savings.
- "King which was the first unit assigned to Seasonal Dispatch, created a Seasonal Dispatch Best Practices document to address maintenance, layup, and equipment management during extended shutdowns."
  - Thus, lessons learnt from flexible operation on one plant can be transferred to other plants to generate similar benefits.
- "Xcel Energy and SMMPA signed a Sherco 3 MISO Coordination Agreement, effective March 1, 2021, to combine each company's share of the plant into a single asset to be offered to MISO."
  - This shows greater coordination is possible at co-owned plants to make them operate more flexibly when the owners participate in the same market (MISO).
- "As a result of this agreement, Sherco 3 was first offered economically to MISO on March 19, 2021. The result of this strategy versus self-committing the unit for the balance of 2021 was a loss of $4.0 million in margins at the unit, meaning that the unit's margins could have been $4.0 million higher if we had self-committed the unit in 2021… The economic strategy did result in a

reduction of an estimated 1.9 billion pounds of carbon dioxide (CO_2) emissions due to lower generation."

- Thus, utilities need to structure their cost flexibly to realize the full potential of economic commitment.

- "In the interim, since Sherco 2 is already being offered into the market on a seasonal basis, and we began to offer Sherco 3 on an economic commitment basis beginning in March 2021, we plan to keep Sherco 1 available to provide auxiliary stream, until the new ABs (Auxiliary Boilers) are available for firing on natural gas."
  - Once the auxiliary boilers become operational, we should see an increase in economic commitment of the Sherco units as they can provide a reliable source of steam supply for the units.

b. Analysis

Large coal units require a minimum downtime, start up 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. 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 23, ***Figure 24***, ***Figure 26*** and ***Figure 27*** below show a rolling sum of Xcel's King and Sherco 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 23***, ***Figure 24***, ***Figure 26*** and ***Figure 27*** 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.

During the extreme weather event in February 2021, electricity wholesale prices went up significantly causing all power plants in the state to earn significantly higher revenues. This led to a large spike in net benefits during February 2021. Plotting the data for all twelve months in one graph made it difficult to decipher the variation in net benefits during most of the year. To enable a clear visual representation, the Department included two graphs. One for all days of the year and a second one that excluded February 1 to February 25, 2021.

Sherco 2 was running with economic commitment during multiple months of the year. The broad trend emerging from ***Figure 23*** and ***Figure 24*** is that Sherco 2 was generating net benefits from May onwards while generating some net costs during March and April of 2021. The plant was operating under Must Run status during the March-April period due to the Steam Contract[12]. The need to run the unit to meet the steam contract commitment should decrease once the auxiliary boilers become operational.

Figure 23. Sherco Unit 2 Rolling Week Total Benefit / (Cost)

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 24. Sherco Unit 2 Rolling Week Total Benefit / (Cost) excluding Feb 1-25

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 25 and ***Figure 28*** shows the monthly breakdown of the plants 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 25 shows Sherco 2 still has a large number of hours when the plants were running with must run commitment. Relatively higher electricity wholesale prices during 2021 lead to positive net benefits for most of the year. If the auxiliary boilers come online in 2022, it should allow greater economic commitment at the Sherco units.

Figure 25. Sherco Unit 2 Monthly Total Benefits / (Cost) vs Commitment Status

[TRADE SECRET DATA HAS BEEN EXCISED]

This was the first year when Sherco 3 was economically committed. **Figure 26** and **Figure 27** shows that economic dispatch was able to reduce the number of hours when the plant might have operated under net-cost conditions, like periods in April, May, June and December. There are periods in these months

[12] Revenues from the steam contract are not regulated. Thus, the costs due to must run commitment should not be allocated to ratepayers.

where net costs were reduced since the plant stopped operations due to its economic commitment. Xcel stated in their filing that economic commitment of Sherco 3 led to a loss of $4.0 million in margins at the unit, meaning that the unit's margins could have been $4.0 million higher if Xcel had self-committed the unit in 2021. Xcel also stated that the economic strategy did result in a reduction of an estimated 1.9 billion pounds of carbon dioxide (CO_2) emissions due to lower generation. The Department recommends Xcel to explain in reply comments how it weighs the lost revenue with the environmental benefits of lower emissions in this context.

Figure 26. Sherco Unit 3 Rolling Week Total Benefit / (Cost)

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 27. Sherco Unit 3 Rolling Week Total Benefit / (Cost) excluding Feb 1-25

[TRADE SECET DATA HAS BEEN EXCISED]

Figure 28 shows when aggregated at a monthly level, Sherco 3 was economically committed for a significant time during 2021. This is significant shift for this unit compared to previous years. The unit was running with positive net benefits at the monthly level throughout 2021.

Figure 28. Sherco Unit 3 Monthly Total Benefits / (Cost) vs Commitment Status

[TRADE SECRET DATA HAS BEEN EXCISED]

c. Additional analysis by Xcel

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. They defined three scenarios: base, must run and economic. The base case modeled the actual commitment of the King and Sherco 2 (or 1) units 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 29**. (Figure 2 of Xcel's filing).

Based on the analysis, we can see the current commitment status at these plants saved them significant amount of dollars and carbon emissions compared to must run commitment. 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 commitment, 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 MP and OTP conduct a similar analysis to understand this tradeoff and determine an optimal pattern of commitment status and move towards the same in subsequent annual filings.

Figure 29. Comparison of Econ and Must Run to Seasonal Operations

		MR Less BASE									ECON less BASE								
		Generation (MWh)	Fuel Cost ($000)	O&M Cost ($000)	Start Costs ($000)	Total Costs ($000)	Revenue ($000)	Profit+/Loss- ($000)	CO2 (000 lb)	run hours	Generation (MWh)	Fuel Cost ($000)	O&M Cost ($000)	Start Costs ($000)	Total Costs ($000)	Revenue ($000)	Profit+/Loss- ($000)	CO2 (000 lb)	run hours
King	Mar-21	233,540	4,387	567	211	5,166	4,429	(736)	521,260	552	-	-	-	-	-	-	-	-	-
	Apr-21	248,365	4,586	608	211	5,405	6,306	901	554,351	513	-	-	-	-	-	-	-	-	-
	May-21	277,965	5,322	8,674	-	13,996	7,001	(6,995)	620,418	744	-	-	-	-	-	-	-	-	-
	Sep-21	34,343	661	1,260	-	1,921	1,308	(613)	76,654	95	-	-	-	-	-	-	-	-	-
	Oct-21	345	7	13	167	186	15	(171)	770	1	-	-	-	-	-	-	-	-	-
	Nov-21	266,592	5,070	9,656	-	14,727	12,480	(2,247)	595,033	685	42,849	813	1,572	167	2,551	2,067	(485)	95,639	108
	Total	1,061,150	20,033	20,778	589	41,400	31,539	**(9,862)**	2,368,486	2,590	42,849	813	1,572	167	2,551	2,067	**(485)**	95,639	108
SHC1	Mar-21	21,140	451	15	-	466	473	7	50,250	48	-	-	-	-	-	-	-	-	-
	Apr-21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	May-21	76,180	1,750	3,032	-	4,781	1,906	(2,876)	181,080	293	-	-	-	-	-	-	-	-	-
	Sep-21	41,004	930	1,461	229	2,620	1,579	(1,042)	97,467	146	-	-	-	-	-	-	-	-	-
	Oct-21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Nov-21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	138,324	3,131	4,508	229	7,867	3,957	**(3,910)**	328,796	487	-	-	-	-	-	-	-	-	-
SHC2	Mar-21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Apr-21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	May-21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Sep-21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Oct-21	74,656	1,604	2,637	-	4,242	3,778	(464)	175,740	200	-	-	-	-	-	-	-	-	-
	Nov-21	189,242	4,123	6,520	186	10,829	8,565	(2,264)	445,474	551	-	-	-	-	-	-	-	-	-
	Total	263,898	5,727	9,157	186	15,071	12,343	**(2,728)**	621,215	751	-	-	-	-	-	-	-	-	-

Based on the analysis Xcel presented for King and Sherco 1 and 2, the Department notes that it would be helpful to explore different mix of commitment status and compare them to understand the mix of must run and economic commitment that would be optimal for Sherco 3.

3. Conclusion

Overall, King, Sherco 1, 2 and 3 implemented a mix of economic and must run commitment status and the results should provide insights into determining an optimal mix of these to maximize the benefits for rate payers. The Department recommends Xcel keep operating these unit flexibly and identify opportunities to further reduce costs and operating minimums. The construction of the auxiliary boilers should help incorporate greater flexibility at the Sherco units.

F. *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, 2022 filings in

Docket No. E015/AA-20-463 (for Minnesota Power), Docket No. E017/AA-20-462 (for Otter Tail Power) and Docket No. E002/AA-20-417 (for Xcel Energy) for their Annual True-up Compliance Reports. The utilities reported curtailment data for 2021 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 compared to 2020. Otter Tail's curtailment roughly stayed the same compared to 2020. Minnesota Power saw a slight increase in their wind curtailment compared to 2020. The Department recommends Xcel explain in reply comments the reasons behind the large increase in curtailment compared to 2020 both for company owned and contracted wind facilities, and the contribution of must run status of its coal and nuclear power plants towards that curtailment.

Given the rise in wind curtailment that was observed, the Department recommends utilities include energy (MWh) produced and curtailed from utility owned and contracted wind facilities on a monthly basis for each wind facility in subsequent filings in this docket.

G. *CARBON DIOXIDE EMISSIONS*

In accordance with Order Point 8.a of the December 2021 Order, utilities reported their Carbon Dioxide emissions for each plant which are summarized below in ***Table 8***.

Table 8. Carbon Dioxide Emissions

Unit	Emissions (short tons) in 2021
Boswell Unit 3	2,543,828
Boswell Unit 4	2,636,159
Big Stone	2,066,415
Coyote	3,058,364
King	1,545,215
Sherco Unit 1	3,051,380
Sherco Unit 2	3,898,059
Sherco Unit 3[13]	2,224,536

The data provided by utilities is helpful and will allow the Commission to track changes in emissions from these units over time. To calculate the avoided emissions from economic commitment, the Department recommends the following methodology:

1. Identify hours when a unit was operating under Economic commitment and producing 0 MWh.
2. For each hour identified in previous step, calculate emissions if the unit produced output equal to its operating minimum.

[13] Emissions for Sherco 3 reflect Xcel Energy's share.

3. Add up the emissions calculated in step 2 to obtain avoided emissions due to economic commitment.

The Department recommends the Commission require the utilities to include avoided carbon dioxide emissions due to economic commitment along with plant level carbon dioxide emissions in subsequent filings, using the Department's recommended method.

H. *BEST- AND WORST-CASE SCENARIO ANALYSIS*

In accordance with Order Point 8.a of the December 2021 Order, utilities came up with the best-case and worst-case potential for economic commitment for each plant. The Department had proposed this requirement to track the progress that utilities make as they transition their units to greater economic commitment over time.

Otter Tail calculated net benefits for three scenarios:
1. Self-Commitment: OTP assumed its share of the plant was self-committed whenever the unit was not in an outage. The Department would categorize this as Benchmark 1 (worst case).
2. Economic one– Otter Tail share is assumed to be independently committable and dispatchable: OTP assumed it can independently dispatch its generation share economically. The Department would categorize this as Benchmark 2 (best scenario).
3. Economic two– Otter Tail share constrained by unavoidable self-commitment: OTP assumed it can dispatch its generation share economically unless it is forced to self-commit. The Department would categorize this as Benchmark 3.

MP considered two operational scenarios for Boswell 4:
1. A worst-case scenario where Boswell 4 was set to must run all year.
2. A best-case scenario where Boswell 4 was set to Economic Dispatch from April to October and Must run for the remaining months.

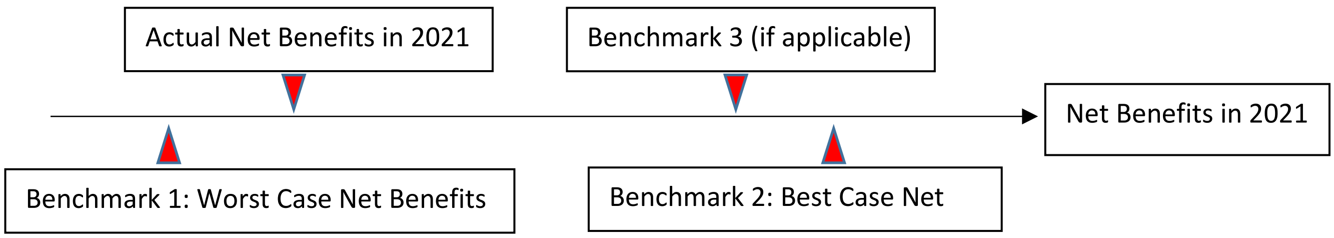
Such scenarios were not calculated for Boswell 3. The Department recommends MP include a similar analysis for Boswell 3.

Xcel considered two scenarios for its plants:
1. Worst Case Scenario: Assume the unit runs with Must Run commitment outside of historic outages
2. Best Case Scenario: Assume all existing constraints, such as outages and nondiscretionary must-runs of the units but allow the units to be economically committed all other hours.

Xcel noted an unexpected result for Sherco 3 where the net benefits in the worst case was higher than the best case due to high start-up costs of the unit. The Department proposes Xcel come up with a third benchmark for Sherco 3 that maximizes the net benefits generated for ratepayers by Sherco 3.

The Department appreciated the effort put in by utilities to create these benchmark scenarios. In order to visually represent these scenarios and provide a comparison with the actual outcome during 2021, the Department recommends the utilities include plant specific graphs similar to ***Figure 30*** to allow an easier comparison of the results. When computing Net Benefits, the same categories of cost and benefits should be considered for each plant to allow a direct comparison. The graphs should be drawn to scale so that the distance between the red triangles reflect the difference in net benefits.

Figure 30. Comparison with Worst- and Best-Case Scenarios



I. *EQUIVALENT FORCED OUTAGE RATE*

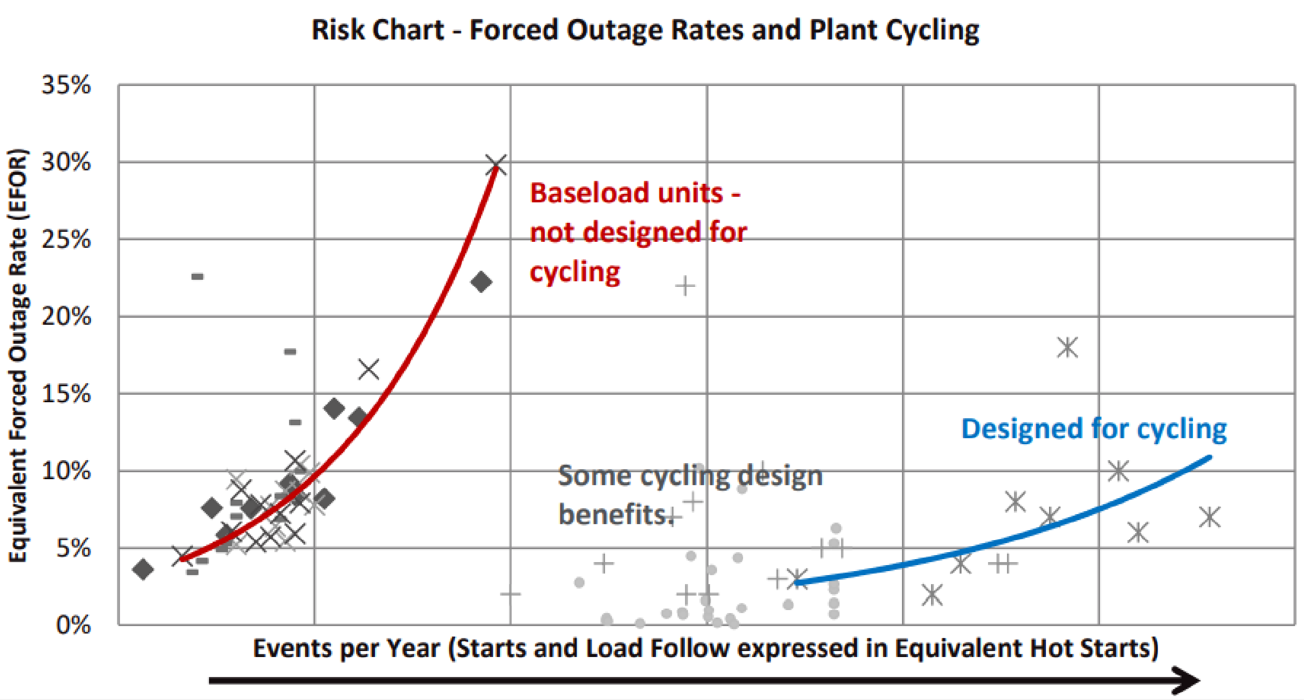
In accordance with Order Point 8.d of the December 2021 Order, utilities provided their equivalent forced outage rates (EFOR) for each unit. The Department had proposed this requirement to track the operating conditions of the units and identify impacts of additional wear and tear of the units as they move towards greater economic commitment.

MP provided one value for 2021 for their two Boswell units. OTP provided annual values for their Big Stone and Coyote Plants over the last ten years. Xcel provided monthly values for its coal and nuclear units for 2021. The monthly values provided by Xcel showed significant variation that is lost when considering annual averages. The ten-year values provided by OTP helped provide a better sense of historic EFOR values to better contextualize the present values. Based upon this year's filings, the Department concludes there should be additional coordination between utilities to develop a consistent way of reporting this metric and providing supporting analysis to help the Commission track impact of greater economic commitment on unit performance. The Department recommends that the utilities agree upon a common template for this metric and report it in future filings.

To help understand the importance of tracking this metric, the Department includes ***Figure 31***. The figure is from a recent report[14] that analyzes reliability and cost impacts of moving coal plants to more flexible generation. Baseload units that are not designed for cycling would see a steep rise in their EFOR as the unit ramps up more frequently. However, plant owners can implement design changes to transition these units to operate with lower EFOR with frequent cycling. This is crucial as forced outages can significantly lower the ability of these units to provide reliable power. While this aspect might not be a significant issue initially, it will become more important as economic commitment becomes more widespread. Since forced outages are high impact low probability events, they have significant risk implications. Tracking this metric is the first step to quantifying the risks involved in a transparent way.

[14] Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators for Western Electricity Coordinating Council published on May 12, 2020. (https://www.wecc.org/Reliability/1r10726%20WECC%20Update%20of%20Reliability%20and%20Cost%20Impacts%20of%20Flexible%20Generation%20on%20Fossil.pdf, Accessed on April 25, 2022)

Figure 31. Flexible Generation and Reliability Impacts



The Department recommends utilities meet and come up with a reporting template that will help track EFOR and hot/warm start events plant wise at a monthly level over a sufficient period of time to perform a meaningful risk analysis from greater economic commitment and include it in subsequent annual filings.

III. CONCLUSION AND RECOMMENDATIONS

A. RECOMMENDATIONS FOR REPLY COMMENTS

The Department would like utilities include plant specific figures similar to ***Figure 30*** to allow an easier comparison of the actual net benefits achieved with the benchmark scenarios (best- and worst-case scenarios).

The Department recommends MP provide a best- and worst-case scenario analysis for Boswell 3.

The Department recommends OTP explain how much of the disagreements between its units' (Big Stone and Coyote) commitment among the plant co-owners is due to divergent financial incentives where each co-owner is maximizing their own profit and not the collective profit of all co-owners.

The Department recommends OTP explain in reply comments what steps are being taken by OTP to better align the financial incentives of the co-owners regarding its unit's (Big Stone and Coyote) operation to help maximize benefits to the ratepayers of all the co-owners of the plant.

The Department recommends Xcel to explain in reply comments how it weighs the lost revenue with the environmental benefits of lower emissions at Serco 3.

The Department recommends Xcel explain reasons behind the large increase in wind curtailment compared to 2020 (both for its owned and contracted wind facilities) and the contribution of must run power plants for the same.

B. RECOMMENDATIONS FOR NEXT YEAR'S FILING

The Department recommends the Commission require the utilities to include avoided carbon dioxide emissions due to economic commitment along with plant level carbon dioxide emissions in subsequent filings, using the Department's recommended method.

The Department recommends OTP include MISO and SPP market conditions in determining its self-commitment endorsement and show Net Benefit results in addition to the analysis provided by OTP in Tables 6 and 8 of their filing.

The Department recommends the utilities point out if there were instances when greater economic commitment led to lost revenue. If there were such instances, the utilities should describe the utility's strategy to weigh those lost revenues with the environmental benefits of lower emissions.

The Department recommends utilities meet and come up with a reporting template that will help track EFOR and hot/warm start events plant wise at a monthly level over a sufficient period of time to perform a meaningful risk analysis from greater economic commitment and include it in subsequent annual filings.

The Department recommends the utilities include energy (MWh) produced and curtailed from utility owned and contracted wind facilities on a monthly basis for each facility in subsequent filings in this docket.

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 3*** 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 3. Customer Bill Components

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

From ***Equation 3*** it can be seen that if ***Equation 4*** is true:

Equation 4. LMPs are equal

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

*Then **Equation 5** must be true as well:*

Equation 5. 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.[15] 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

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[15] 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.

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.

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 6*** below.

Equation 6. 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, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Public Comments

Docket No. E999/CI-19-704

Dated this **2nd** day of **May 2022**

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_19-704_Official
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
Brooke	Cooper	bcooper@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_19-704_Official
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Kristin	Henry	kristin.henry@sierraclub.org	Sierra Club	2101 Webster St Ste 1300 Oakland, CA 94612	Electronic Service	No	OFF_SL_19-704_Official
Holly	Lahd	holly.lahd@target.com	Target Corporation	33 South 6th St CC-28662 Minneapolis, MN 55402	Electronic Service	No	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
Isabel	Ricker	ricker@fresh-energy.org	Fresh Energy	408 Saint Peter Street Suite 220 Saint Paul, MN 55102	Electronic Service	Yes	OFF_SL_19-704_Official
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