COMMERCE DEPARTMENT

May 31, 2023 **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/ar
Attachment

Contents

List of Tables

List of Figures

Before the Minnesota Public Utilities Commission

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 November 17, 2022, the Commission issued its Order approving the March 1, 2022 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, 2021 to December 31, 2021. The Commission also included the following additional order points:

2. Required Xcel to provide, in future reports, instances when greater economic commitment led to lost revenue. If there were such instances, the utility should describe its strategy to weigh those lost revenues with the environmental benefits of lower emissions.
5. Required Otter Tail to include Midcontinent Independent System Operator, Inc. (MISO) and Southwest Power Pool (SPP) market conditions in determining its self-commitment endorsement and show Net Benefit results in addition to the analysis provided by Otter Tail in Tables 6 and 8 of its 2021 filing.
6. Required that Otter Tail include in its 2023 and 2024 annual reports an update on its progress toward implementing the Total Plant Offer Optimization Plan and Combined Modeling of MISO Co-Owner Generation Shares Plan at Big Stone Plant and Coyote Station.
7. Required that utilities provide the following in future reports:
    a. Avoided carbon dioxide emissions due to economic commitment along with plant level carbon dioxide emissions in subsequent filings, using the Department's recommended method.
    b. Equivalent Forced Outage Rate (EFOR) information to be tracked over time.
    c. Energy (MWh) produced and curtailed from utility owned and contracted wind facilities monthly for each facility in subsequent filings in this docket.

On March 1, 2023, Xcel, Otter Tail and Minnesota Power filed their fourth Annual Compliance filing covering January 1,2022 to December 31, 2022. 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] Otter Tail's report provided data regarding the Big Stone Plant (Big Stone) and Coyote Station (Coyote).[3]

---

[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.
[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.

 PUBLIC DOCUMENT

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, which is 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:

> 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.

3. MISO 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, MISO is pursuing capacity market changes, referred to as a downward-sloped or reliability-based demand curve. The capacity market changes also have the potential to impact 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

---

[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

decreased from 64 percent in 2009 to 50 percent in 2014 to about 36 percent in 2019 and 33 percent 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)
Big Stone	**[TRADE SECRET DATA HAS BEEN EXCISED]**							
Coyote								
Boswell 3	**[TRADE SECRET DATA HAS BEEN EXCISED]**							
Boswell 4								
King	**[TRADE SECRET DATA HAS BEEN EXCISED]**							
Sherco 1								
Sherco 2								
Sherco 3								
Monticello								
Prairie Island 1								
Prairie Island 2								

MISO's presentation slides from their February 2023 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

[6]https://cdn.misoenergy.org/202302%20Market%20and%20Operations%20Report628415.pdf (Slide 33)
[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.

territory between February 2022 and February 2023 and this shows between 93% and 77% 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**
Boswell 3	**[TRADE SECRET DATA HAS BEEN EXCISED]**						
Boswell 4							
Big Stone	**[TRADE SECRET DATA HAS BEEN EXCISED]**						
Coyote							
King	**[TRADE SECRET DATA HAS BEEN EXCISED]**						
Sherco 1							
Sherco 2							
Sherco 3							
TOTAL	16,975,300	2,788,773	1,956,519	11.5%	832,254	4.9%	16.4%

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** above. Note that in **Table 3** all data covers the January 1, 2022 - Dec 31, 2022 reporting period.

Considering all the coal units in this proceeding, the result was that the uneconomic DA dispatch minimum equaled 16.4 percent of the total hourly cleared DA capacity. Thus, the Department's and MISO's calculations are comparable. Finally, the Department notes that a further 4.9 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 Department comments[9]. The percentage of uneconomic dispatch at the aggregate level has fallen from 19 percent in 2021 to 16.4 percent in 2022. Each utility had some units whose uneconomic dispatch increased and some units whose uneconomic dispatch decreased compared to 2021.

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.

[8] The two percentages are additive. Meaning 16.4 percent of the total hourly cleared DA capacity was not economic.
[9] Table 3 from the Department's comments filed on May 2, 2022 in Docket 19-704

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

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

Equation 2. Total Production cost components

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

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

---

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

PUBLIC DOCUMENT

B. *UNECONOMIC DISPATCH – 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 based on the proportion of time the unit was running at net cost. **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 2022; less than 15 percent of the hours on average were operated at a net cost.

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

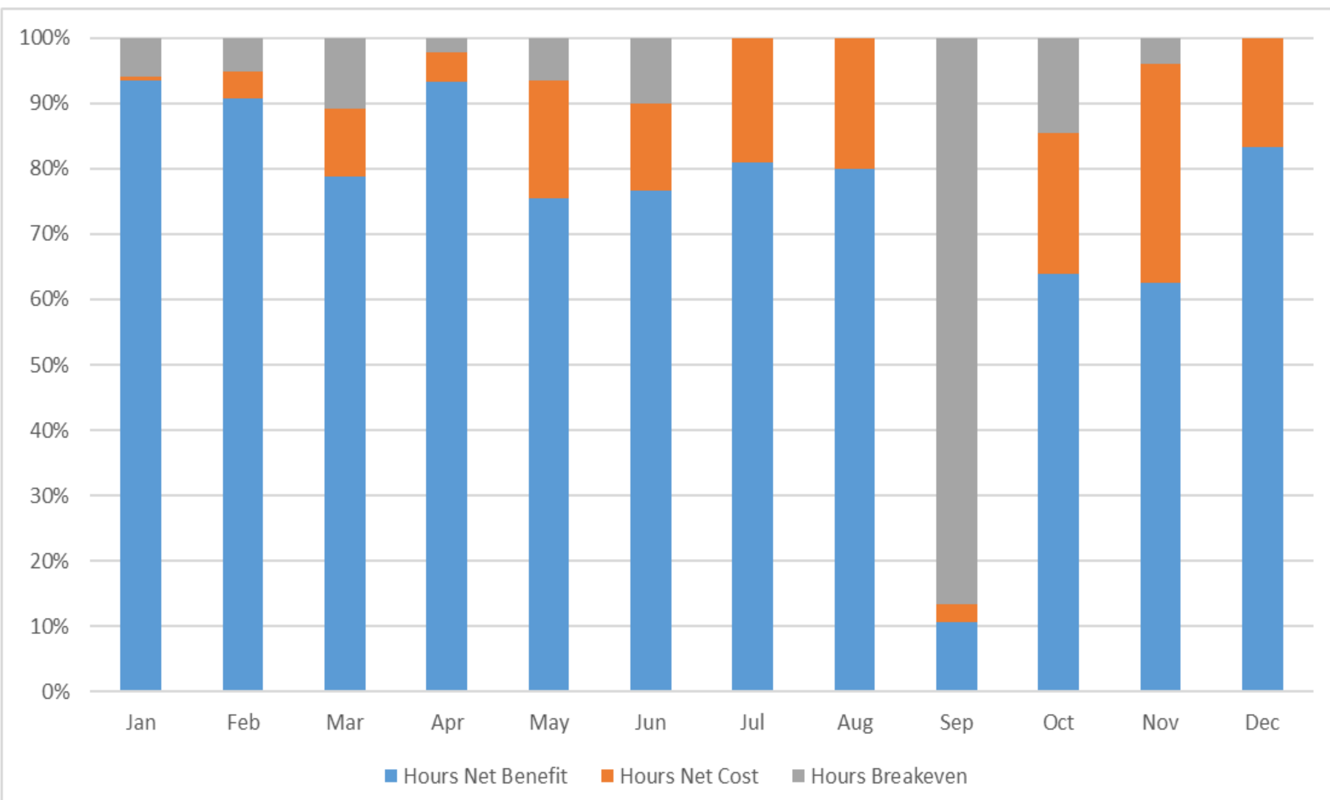
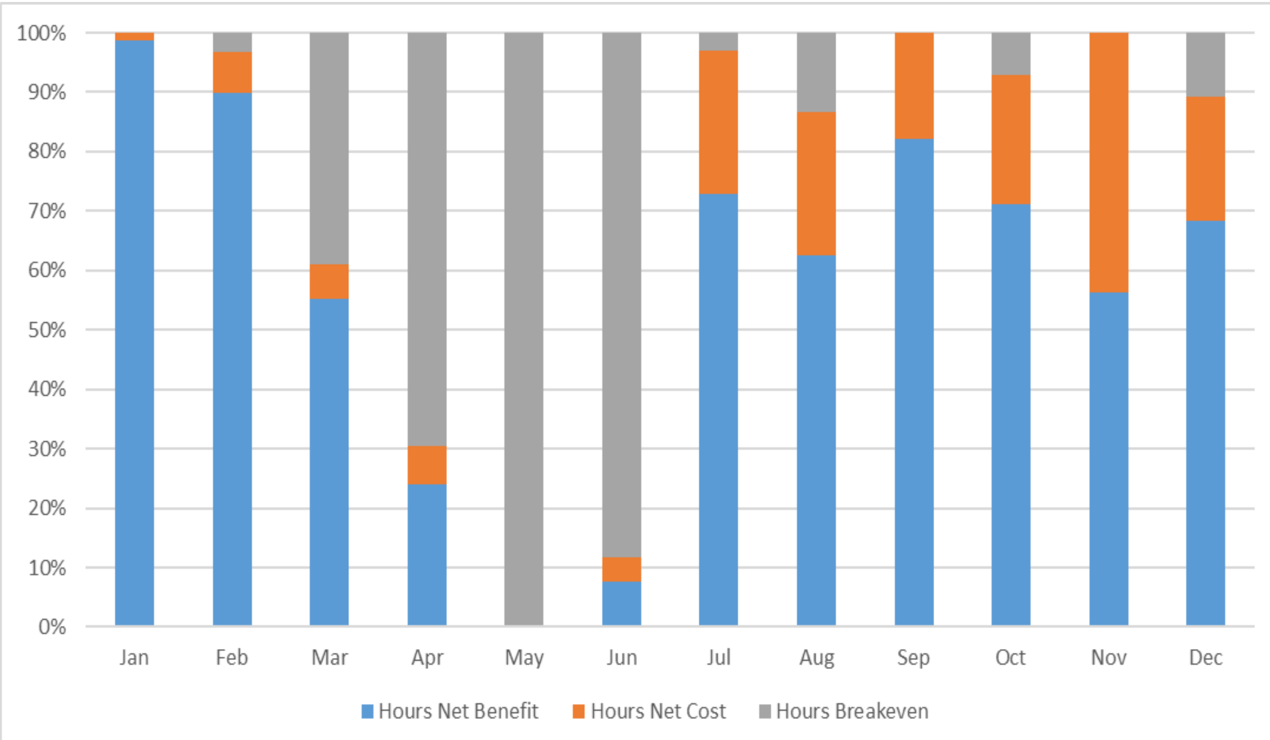


Figure 2. Boswell Unit 4 Hourly Net Benefit/Breakeven/Net Cost



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	6,493 74%	1,058 12%	1,209 14%	8,760 100%
Boswell Unit 4	5,021 57%	2,445 28%	1,294 15%	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

2022 has been a favorable year with relatively high electricity wholesale prices. This meant that the plants at Boswell were producing at net cost for a smaller fraction of time. Boswell 3 was operating under Economic commitment during 2022 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. *UNECONOMIC DISPATCH – 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*** plot 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]**. **Figure *3*** shows that the two costs are similar for Big Stone. Therefore, the Department considered only production costs in its analysis for Big Stone. For Coyote, **Figure *4*** shows that the two costs are different. Therefore, the Department presents calculations using both of these costs separately.

Figure 3. Big Stone Monthly Costs

[TRADE SECRET DATA HAS BEEN EXCISED]

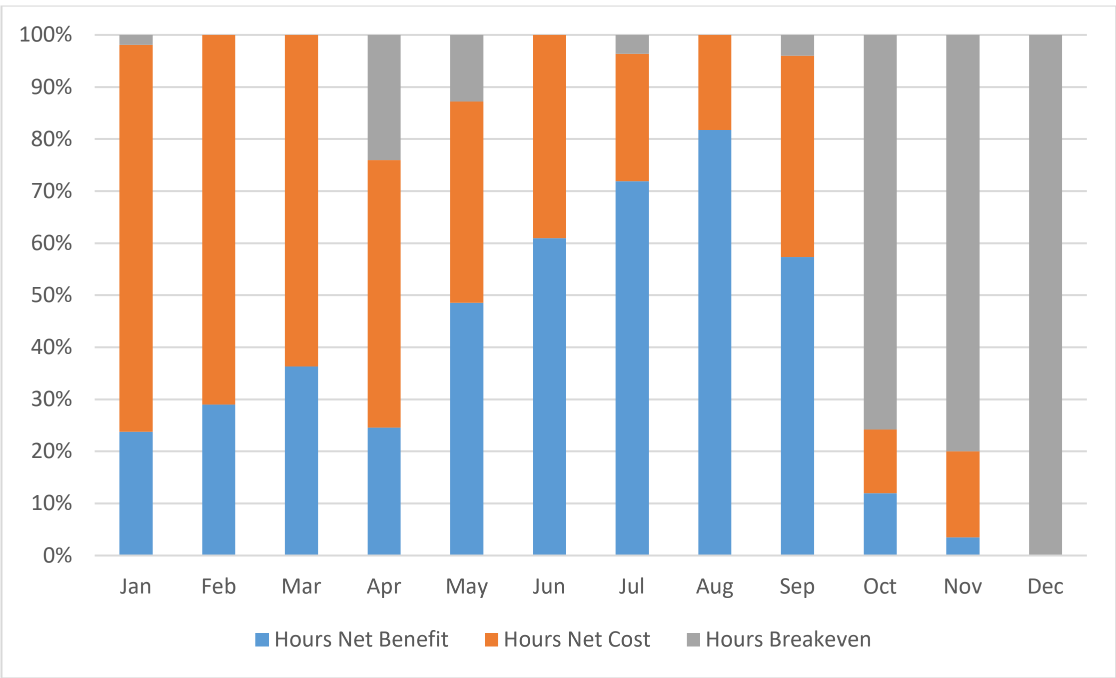
 PUBLIC DOCUMENT

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 January, February and March have some of the highest hours at net cost 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 as can be seen in **Figure 7**.

 PUBLIC DOCUMENT

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

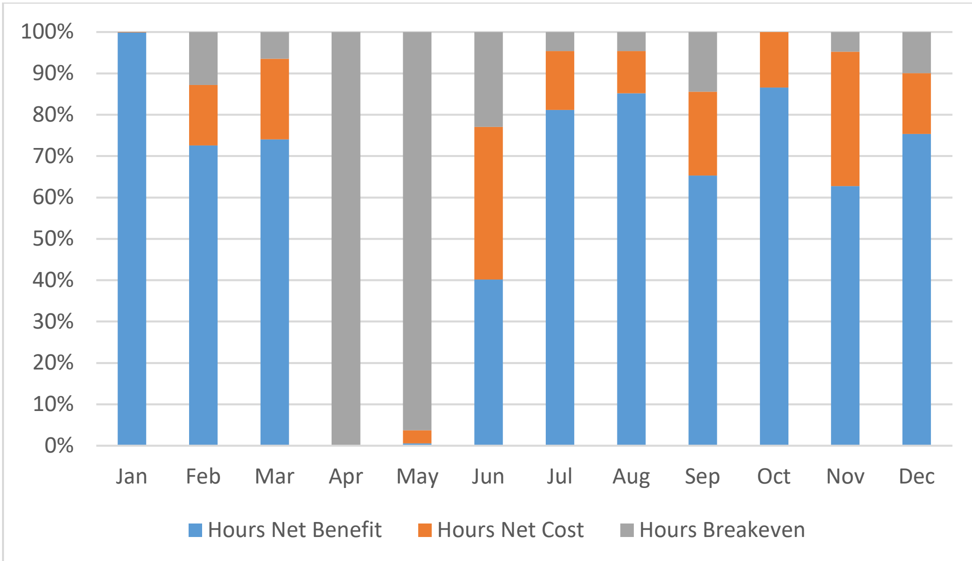
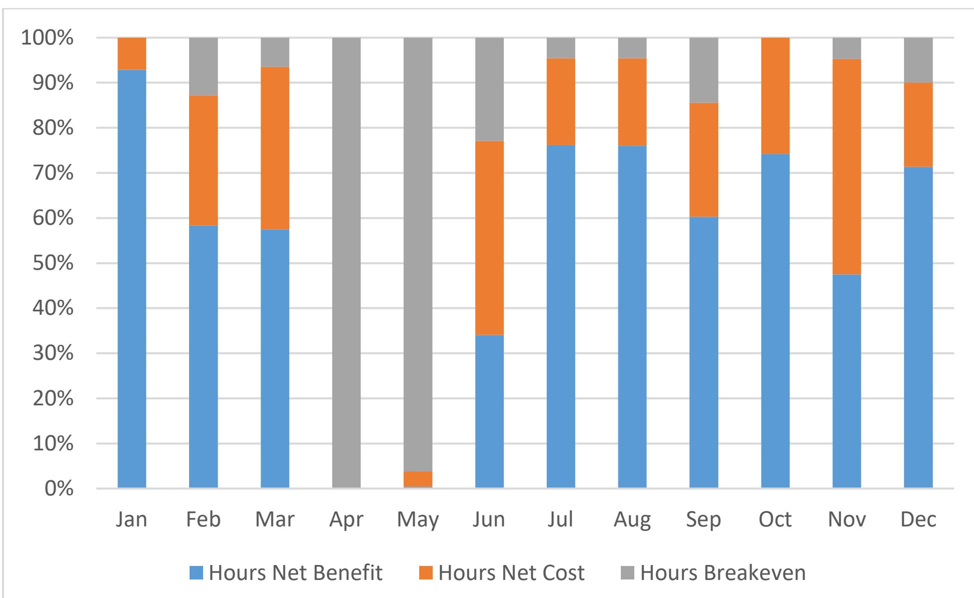


Figure 7. Coyote Hourly Net Benefit/Breakeven/Net Cost (with Total Production Cost)



Overall, for 2022, ***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.

 PUBLIC DOCUMENT

Table 5. Hours at Net Benefit/Breakeven/Net Cost for OTP

Unit	Net Benefit	Breakeven	Net Cost	TOTAL
Big Stone	3,289 38%	2,222 25%	3,249 37%	8,760 100%
Coyote (with Production Cost)	5,440 62%	2,015 23%	1,305 15%	8,760 100%
Coyote (with Total Production Cost)	4,751 54%	1,994 23%	2,015 23%	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

The following quotes are from Ottar Tail's compliance filing for the current reporting period which provide helpful 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.

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

- "In summary, improved periods of LMP pricing driven by increased natural gas markets resulted in substantial 2022 net benefits (market revenues less production costs)."
  - 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 due to co-owner requests to commit. These requests were often driven by higher LMP pricing in the SPP market."
  - 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."
  - 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. 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 8 and **Figure 11** 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** and **Figure 11** 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 8**, between January and May, Big Stone was running with a Must Run commitment status and operating at net cost. The unit was operating on Economic commitment for a small fraction of time during 2022 spread out during the year. It does seem OTP could have reduced its net costs by reducing operations during the first few months of the year.

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

[TRADE SECRET DATA HAS BEEN EXCISED]

One of the reasons provided by OTP for committing Big Stone as Must Run is requests from co-owners. In order to understand the prevalence of such co-owner requests, **Figure *9*** shows the percentage of must run hours that were triggered by co-owner requests every month. We can see that even though co-owner requests are common, the unit was running with must run commitment for a large amount of time without co-owner requests.

Figure 9. Percentage of Must Run commitment at Big Stone due to Co-owner requests

[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 January and April. Almost 70 percent of the must run hours for the Big Stone unit was due to requests from co-owners but the percentage was much lower later in the year (August to October). The Department recommends OTP explain in reply comments if it can reduce must run commitment during periods when there are no co-owner requests and the associated cost savings that those might generate.

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

[TRADE SECRET DATA HAS BEEN EXCISED]

The following figure shows 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*** and **Figure *13***.

PUBLIC DOCUMENT

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

[TRADE SECRET DATA HAS BEEN EXCISED]

During 2022, as depicted in **Figure 11**, the unit was operating with positive net benefits for much of the year. While there are periods in the second half of the year when the plant was running at net costs, these were relatively short. One of the reasons provided by OTP for committing Coyote as Must Run is requests from co-owners. In order to understand the prevalence of such co-owner requests, **Figure 12** shows the percentage of must run hours that were triggered by co-owner requests every month. We can see that even though co-owner requests are common, the unit was running with must run commitment for a large amount of time without co-owner requests.

Figure 12. Percentage of Must Run commitment at Coyote due to Co-owner requests

[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 57 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 recommends OTP explain in reply comments if it can reduce must run commitment during periods when there is no co-owner requests and the associated cost savings that those might generate.

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 January and April 2022. Otter Tail compares these scenarios in Attachment 1 of their filing. Between May and October 2022, following OTP's recommendation would have led to lower net benefits compared to actual operation of the unit.

Figure 14. Big Stone Actual vs OTP Endorsed Self Commitment effects March - Dec 2021

[TRADE SECRET DATA HAS BEEN EXCISED]

OTP explained another 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 5 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 2022. **Figure 15** shows a comparison between actual 2022 Otter Tail share performance and what performance might have been if Otter Tail was not called to self-commit. **Figure 15** reflects actual 2022 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.

 PUBLIC DOCUMENT

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 2022 compared to 2021 due to higher electricity prices. OTP has offered its Big Stone unit with economic commitment for short periods in 2022. The analysis shows that the co-owners of Big Stone and Coyote would benefit from better aligning their financial incentives to allow more flexible operations of the unit in the future.

D. *UNECONOMIC DISPATCH – 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.

PUBLIC DOCUMENT

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

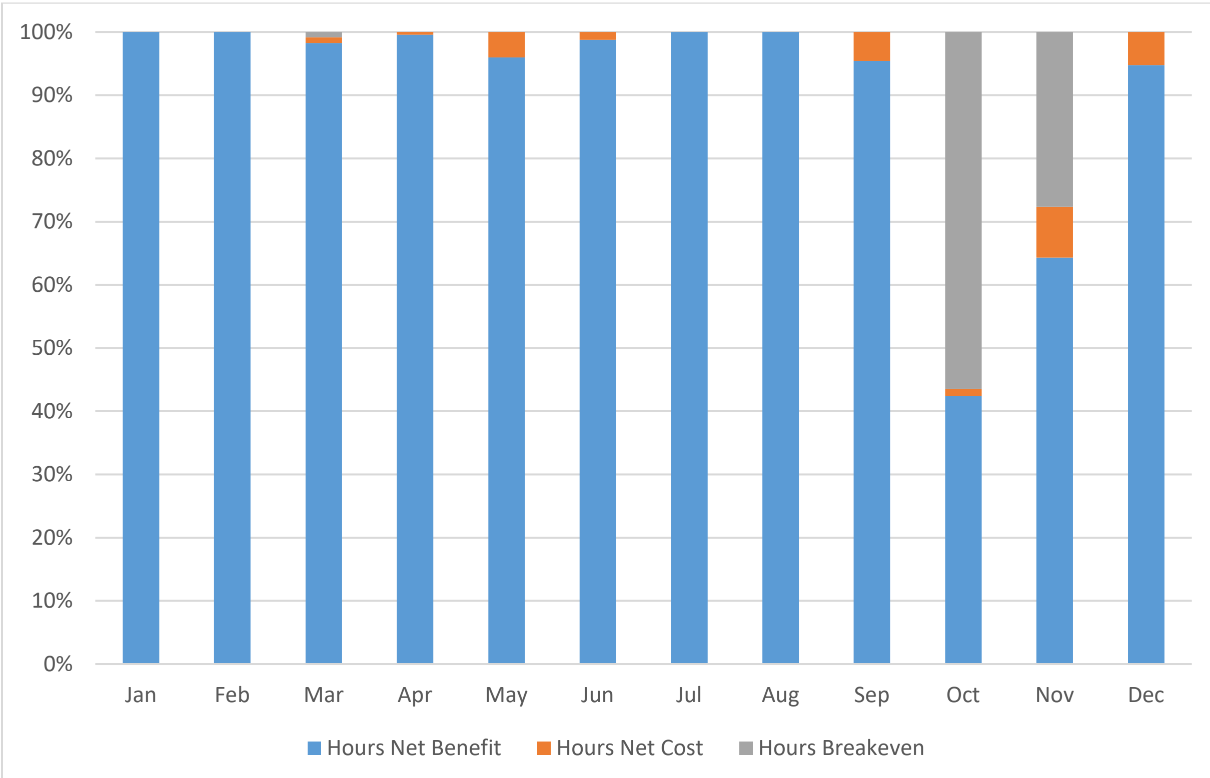


Figure 17. Prairie Island Unit 2 Hourly Net Benefit/Breakeven/Net Cost

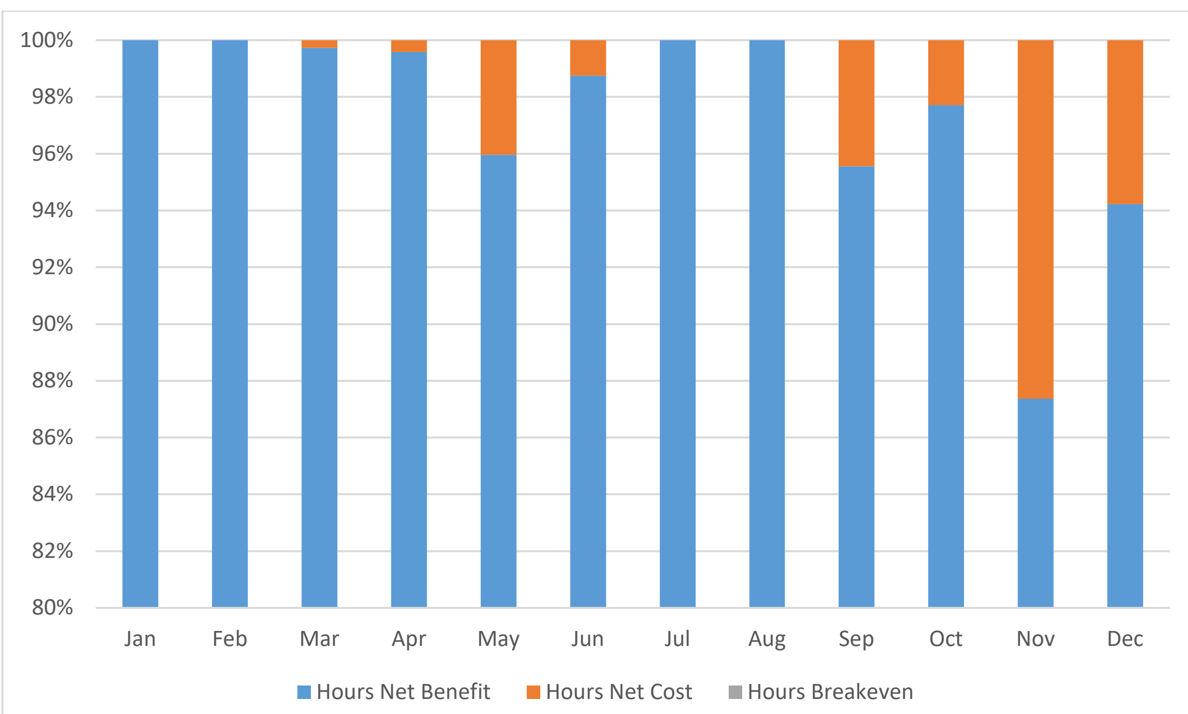
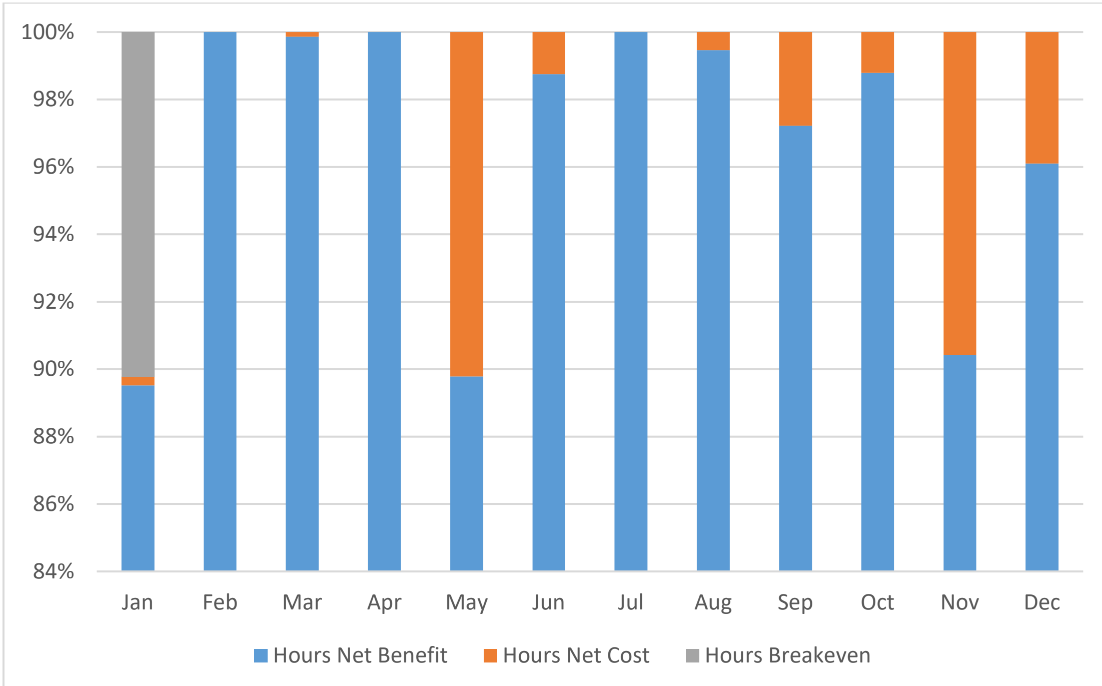


Figure 18. Monticello Hourly Net Benefit/Breakeven/Net Cost



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	7,948 91%	187 2%	625 7%	8,760 100%
Prairie Island Unit 2	8,533 97%	0 0%	227 3%	8,760 100%
Monticello	8,465 97%	76 1%	219 3%	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.

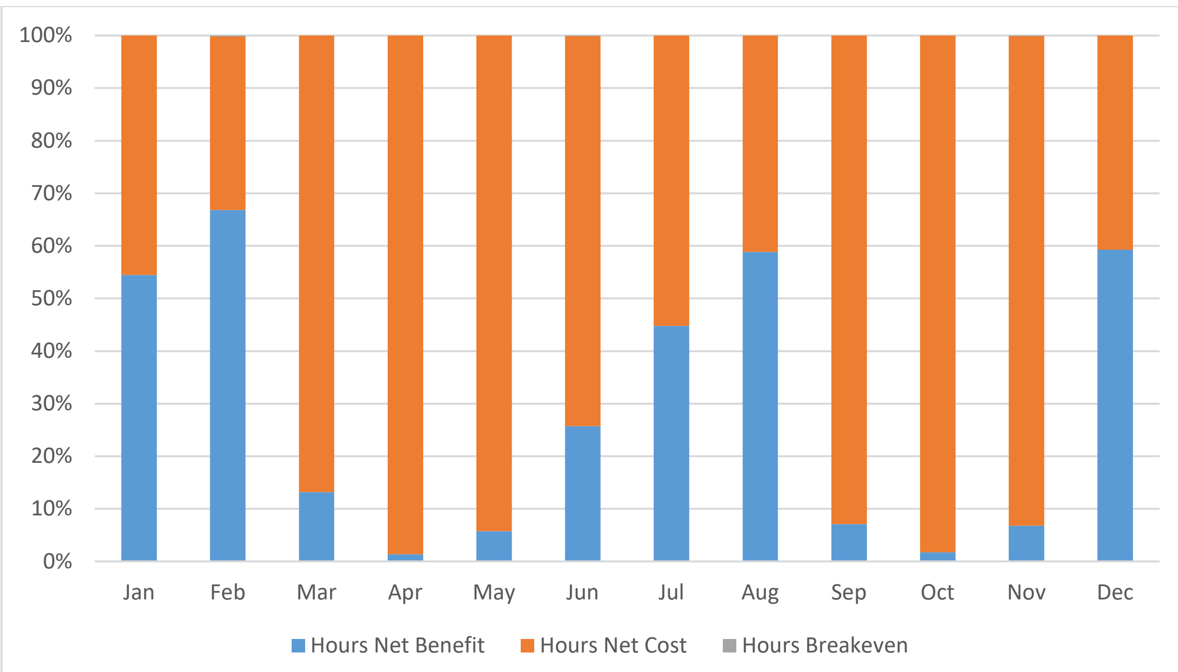
 PUBLIC DOCUMENT

E. *UNECONOMIC DISPATCH – 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 at net cost because Xcel reports costs for King even for hours when there is no energy output. Similar patterns were also observed at the Sherco units.

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



Actual coal generation in 2022 was greater than forecast. This was due to higher gas prices that led to stronger LMP and greater market sales making coal more economical for generation. Also, the 2022 Xcel's forecast assumed seasonal operations of two coal units, that could not occur following a ruling by MISO's Independent Market Monitor (IMM), which further contributed to greater generation from coal than forecast. The increase in coal generation was the primary driver to higher coal costs than forecasted. A secondary driver was higher cost for coal fuel delivered to the plants. Coal prices were higher in response to natural gas prices that had already begun to rise by the Fall of 2021.

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

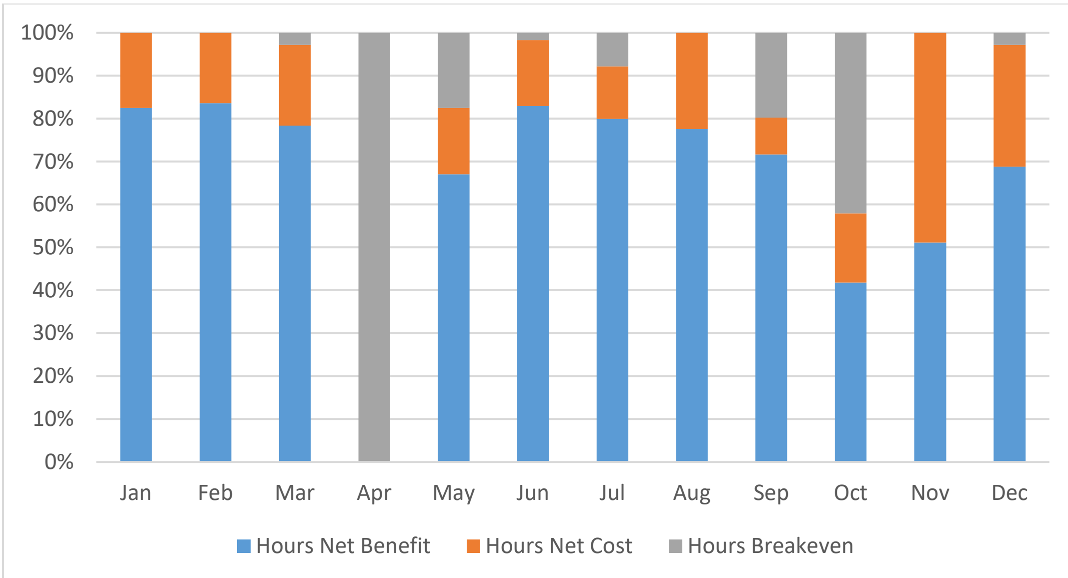
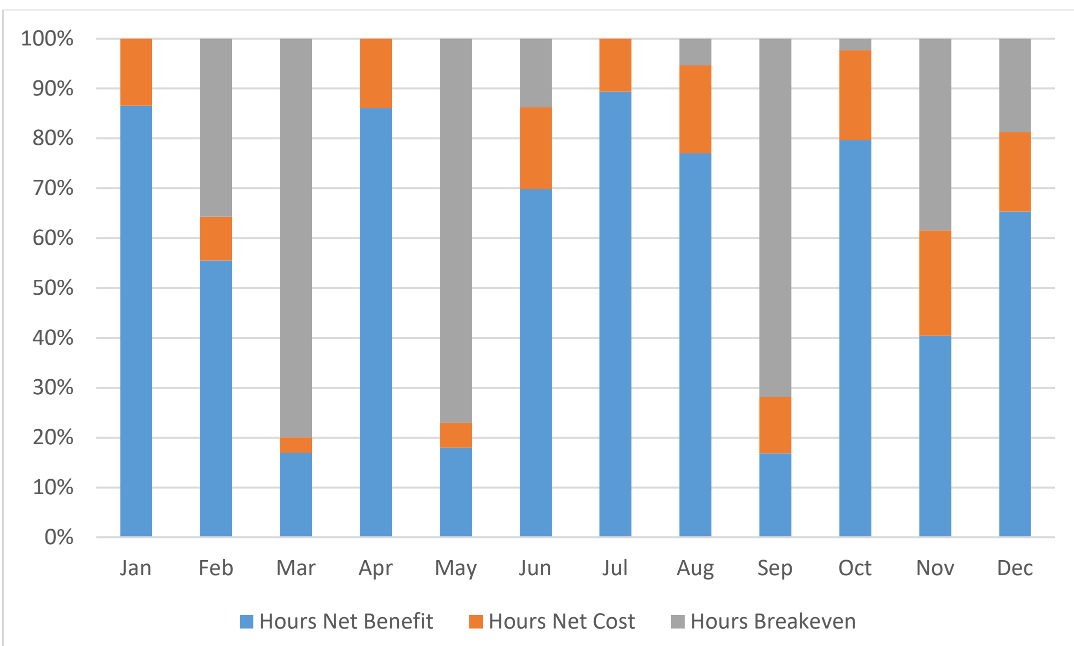
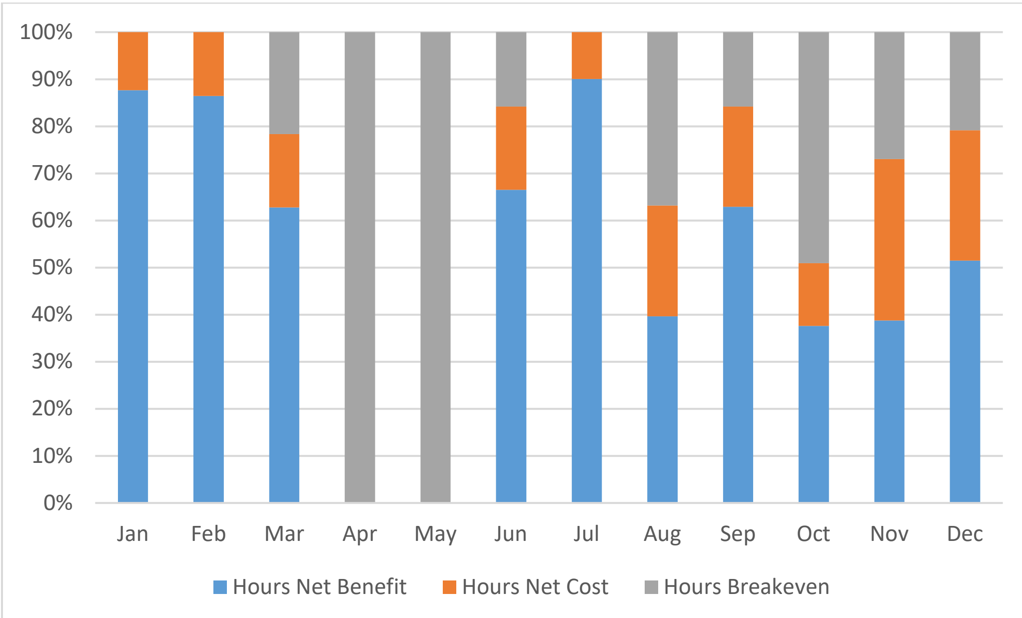


Figure 21. Sherco 2 Hourly Net Benefit/Breakeven/Net Cost



PUBLIC DOCUMENT

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



Overall, for 2022, **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	2,515 29%	3 0%	6,242 71%	8,760 100%
Sherco 1	5,734 65%	1,417 16%	1,609 18%	8,760 100%
Sherco 2	5,129 59%	2,497 29%	1,134 13%	8,760 100%
Sherco 3	4,539 52%	2,841 32%	1,380 16%	8,760 100%

The Department concludes that the preliminary data indicates that a more detailed analysis of the King and Sherco unit 1 is warranted. However, a detailed review of Sherco units 2 and 3 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 $261,000 in customer benefits in 2022."
    - Thus, reducing minimum required loading can help coal units operate more flexibly and generate savings.
- "MISO's Independent Market Monitor (IMM) raised new concerns regarding the reasonableness of our plans to idle King and Sherco 2 during the Spring 2022 season and both units cleared in the 2022-2023 MISO Planning Reserve Auction (PRA). As a result, King and Sherco 2 have been offered since last March."
    - Thus, as the combined MISO North and Central Regions had insufficient capacity resources to meet the planning reserve requirements of the region, the clearing price for capacity was set to the Cost of New Entry (CONE) and both King and Sherco 2 cleared the PRA.
- "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 2022 was a gain of $17.7 million in margins at the unit, meaning that the unit's margins could have been $17.7 million lower if we had self-committed the unit in 2022."
    - Thus, economic commitment can result in significant cost savings.
- "Construction of natural gas capability for the Auxiliary Boilers (ABs) was completed on schedule by the end of 2022. Performance testing and tuning has been completed to achieve smooth and stable combustion over the load range… We plan to keep Sherco 1 available to provide auxiliary stream until the new ABs are available for firing on natural gas under our approved air permit amendment in the third quarter of 2023."
    - 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 and **Figure 25** 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** and **Figure 25** 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.

King was running with economic commitment during multiple months of the year. The broad trend emerging from **Figure 23** is that King was generating net benefits February through March, July through September and then the last half of December. The unit did not run at net costs for significantly long periods. The unit's economic commitment helped save money during large periods of time throughout the year.

PUBLIC DOCUMENT

Figure 23. King Rolling Week Total Benefit / (Cost)

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 24 and **Figure 26** shows the monthly breakdown of the plants commitment status and combines it with two plots of the total monthly net benefit / (cost) considering only 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 24 shows King was running on economic commitment for majority of 2022. That along with relatively higher electricity wholesale prices during 2022 lead to positive net benefits overall. The large number of net cost hours were primarily due to hours when the plant was not producing energy.

PUBLIC DOCUMENT

Figure 24. King Monthly Total Benefits / (Cost) vs Commitment Status

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 25 shows Sherco unit 1 did not have any prolonged periods when it was running at net costs. The unit was generating net benefits most of the time it was operating. Even though the unit was committed as must run, there are multiple periods when MISO did not dispatch the unit.

Figure 25. Sherco Unit 1 Rolling Week Total Benefit / (Cost)

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 26 shows when aggregated at a monthly level, Sherco 1 was committed as must run for a significant time during 2022. The unit was running with positive net benefits at the monthly level throughout 2022. The highest monthly net benefits were produced during June to September.

PUBLIC DOCUMENT

Figure 26. Sherco Unit *1* Monthly Total Benefits / (Cost) vs Commitment Status

[TRADE SECRET DATA HAS BEEN EXCISED]

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. Pursuant of the Commissions order point 7.c in its November 17, 2022 order in the instant docket, all three electric utilities included the following data in their filings. The utilities reported curtailment data for 2022 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 Minnesota Power compared to 2021. Otter Tail's curtailment grew by a large amount compared to what was reported by the Department in this docket in 2021. Xcel's wind curtailment slightly decreased compared to 2021 but is still at a relatively high level. The Department recommends all three utilities explain in reply comments the reasons behind the large amounts of curtailment both for company owned and contracted wind facilities, and the contribution of must run units towards that curtailment.

PUBLIC DOCUMENT

G. *CARBON DIOXIDE EMISSIONS*

In accordance with Order Point 7.a of the November 2022 Order, utilities reported their Carbon Dioxide emissions for each unit which are summarized below in **Table 8**. Utilities also reported avoided emissions during 2022.

Table 8. Carbon Dioxide Emissions

Unit	Emissions (short tons) in 2022	Avoided Emissions (short tons) in 2022
Boswell Unit 3	2,604,917	2,087
Boswell Unit 4	2,618,437	0
Big Stone	2,390,422	24,033[12]
Coyote	2,787,970	0[13]
King	1,385,510	476,869
Sherco Unit 1	3,955,004	69,911
Sherco Unit 2	3,416,090	66,640
Sherco Unit 3[14]	2,423,237	119,360
Total	21,581,587	758,900

Based on the above table, 3.5 percent of actual emissions from these coal plants were avoided due to flexible operations.

[12] OTP did not report this value in their March 1, 2023 filing. The Department calculated this value following the methodology approved by the Commission.

[13] *Id.*

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

 PUBLIC DOCUMENT

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.

Figure 27 show the results of OTP's analysis of the best- and worst-case scenarios. The figure indicates there is potential to increase net benefits by moving Big Stone and Coyote to greater flexible operation through economic commitment. The Department recommends OTP explain in reply comments why the actual net benefits for both its unit is outside the range of self-commitment and economic scenarios.

Figure 27 Net Benefits in 2022 from Worst- and Best-Case Scenarios for OTP

[TRADE SECRET DATA HAS BEEN EXCISED]

MP considered two operational scenarios for its units:

1. A worst-case scenario where its units were set to must run all year.
2. A best-case scenario where its units were set to Economic Dispatch all year. Due to the need for supplemental heat Boswell 4 was set to must run during the winter months and economic for all other months.

However, MP did not provide the net benefits for the best- and worst-case scenarios for 2022 in their compliance filing. The Department reached out to MP to obtain this information, but MP was unable to resolve its internal questions with the model and could not provide the information by the end of May. The Department requests MP to provide net benefits for the best- and worst-case scenarios for 2022 along with actual net benefits for Boswell 3 and 4 in its reply comments.

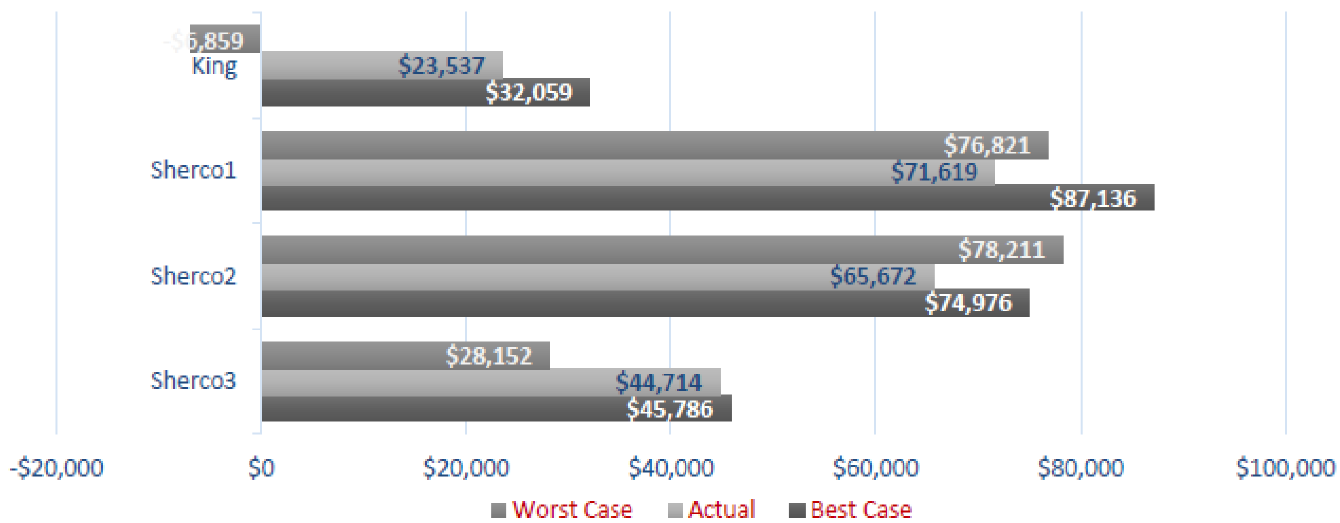
Xcel considered two scenarios for its plants:

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.

The results of Xcel's analysis are depicted in **Figure 29** below. In 2022, the Economic case resulted in higher margins than the Must Run case at three of the four coal units. For King, Sherco 1, and Sherco 3, the Economic case resulted in higher net benefits than the Must Run case, whereas the Must Run case resulted in higher benefits for Sherco 2. During March through May, coal prices were significantly high. These higher costs are reflected in all the units, but most acutely at King, Sherco 1, and Sherco 3, which the Must Run case highlights. Xcel explained that in the Economic case for these units, the Plexos model decommitted them as it was uneconomic for them to operate at market prices during this period. The difference between the two cases shows that the cost savings was enormous relative to the lost revenue. Most of the benefits of the Economic case over the Must Run case for the year was during this period.

Sherco 2 was offered as Must Run for most of the period of coal mitigation. For this reason, the two cases at Sherco 2 ran relatively closely from March-April. Also, there were periods during the remainder of the year where Sherco 2 was decommitted by Plexos for its minimum downtime only to bring the unit back online soon after and incurring a high start cost. Xcel explained that there were also instances where the model only considered the units' costs in the next 24-hours to determine the benefits of operating them, rather than considering the benefits of operating the units over multiple days. The results of these instances can be seen where the Must Run case results in higher net benefits than the Economic case. Xcel also explained that there are differences in how Plexos dispatches its units vs how MISO dispatches the same. The Department recommends Xcel explain reasons behind dispatch differences between the Plexos model and actual MISO day ahead awards and ways to generate more realistic comparison benchmarks from its modeling.

Figure 28. Net Benefits in 2022 ($000) from Worst- and Best-Case Scenarios for Xcel



I. *EQUIVALENT FORCED OUTAGE RATE*

In accordance with Order Point 7.a of the November 2022 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. Flexible operations put more stress on steam piping; headers; and superheater, reheating, and waterwall tubing. The calculation of EFOR is defined in the North American Electric Reliability Corporation (NERC) GADS Data Reporting Instructions[15] as follows:

---

[15] NERC Generating Availability Data System (GADS) Data Reporting Instructions, Effective January 1, 2023 Appendix F at F-9. Accessed at: https://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/GADS_DRI_2023.pdf

PUBLIC DOCUMENT

$$\mathbf{EFOR} = \frac{\mathbf{FOH + EFDH}}{\mathbf{FOH + SH + Synchronous\ Condensing\ Hours + Pumping\ Hours + EFDHRS}} \mathbf{\ x\ 100\%}$$

Where: FOH – Forced outage hours
EFDH – Equivalent forced derated hours
SH – Service hours
EFDHRS - Equivalent forced derated hours during reserve shutdowns

Every time a power plant is turned off and on, the boiler, steam lines, turbine, and auxiliary components go through unavoidably large thermal and pressure stresses, which may cause damage. To track this, the Department calculated the number of plant start up events in each month for each coal unit and plotted that against the relevant monthly EFOR. **Figure 29**, **Figure 30** and **Figure 31** shows the relationship between the number of monthly plant startup events and EFOR across utilities. In each figure, the individual units are color coded. Months with no start up events were omitted along with months where the unit was in outage for a significant period of time. Overall, the data shows higher plant start up events in a month were associated with higher EFOR.

Figure 29. EFOR vs Plant Start up events for Minnesota Power

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 30 EFOR vs Plant Start up events for OTP

[TRADE SECRET DATA HAS BEEN EXCISED]

Figure 31 EFOR vs Plant Start up events for Xcel

[TRADE SECRET DATA HAS BEEN EXCISED]

The Department recommends Xcel explain in reply comments why its units have relatively high EFOR and if these numbers have increased in the recent years.

III. CONCLUSION AND RECOMMENDATIONS

A. RECOMMENDATIONS FOR REPLY COMMENTS

The Department recommends Xcel explain in reply comments why its units have relatively high EFOR and if these numbers have increased in the recent years.

The Department recommends Xcel explain reasons behind dispatch differences between the Plexos model and actual MISO day ahead awards and ways to generate more realistic comparison benchmarks from its modeling for the best and worst case analysis.

The Department recommends OTP explain in reply comments if it can reduce must run commitment during periods when there is no co-owner requests and the associated cost savings that those might generate.

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.

The Department recommends OTP explain in reply comments why the actual net benefits for both its unit is outside the range of self-commitment and economic scenarios.

The Department recommends all three utilities explain in reply comments the reasons behind the large amounts of curtailment both for company owned and contracted wind facilities, and the contribution of must run units towards that curtailment.

The Department recommends MP to provide net benefits for the best- and worst-case scenarios for 2022 along with actual net benefits for Boswell 3 and 4 in its reply comments.

B. RECOMMENDATIONS FOR NEXT YEAR'S FILING

The Department recommends the Commission keep all existing reporting requirements unchanged for next year.

ATTACHMENT- A

 PUBLIC DOCUMENT

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.[16] 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.

---

[16] 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.

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.

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 **31st** day of **May 2023**

/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
Hillary	Creurer	hcreurer@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_19-704_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_19-704_Official
Bruce	Gerhardson	bgerhardson@otpco.com	Otter Tail Power Company	PO Box 496 215 S Cascade St Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_19-704_Official
Allen	Gleckner	gleckner@fresh-energy.org	Fresh Energy	408 St. Peter Street Ste 350 Saint Paul, Minnesota 55102	Electronic Service	Yes	OFF_SL_19-704_Official
Kim	Havey	kim.havey@minneapolismn.gov	City of Minneapolis	350 South 5th Street, Suite 315M Minneapolis, MN 55415	Electronic Service	No	OFF_SL_19-704_Official
Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_19-704_Official
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

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Leann	Oehlerking Boes	lboes@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_19-704_Official
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
Christine	Schwartz	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_19-704_Official
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-704_Official
Shane	Stennes	stennes@umn.edu	University of Minnesota	319 15th Avenue SE Minneapolis, MN 55455	Electronic Service	No	OFF_SL_19-704_Official
Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company	215 S Cascade St PO Box 496 Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_19-704_Official
Brian	Tulloh	btulloh@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121-2498	Electronic Service	No	OFF_SL_19-704_Official
Laurie	Williams	laurie.williams@sierraclub.org	Sierra Club	Environmental Law Program 1536 Wynkoop St Ste 200 Denver, CO 80202	Electronic Service	No	OFF_SL_19-704_Official