COMMERCE DEPARTMENT

June 8, 2020 **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 Department of Commerce, Division of Energy Resources**
Docket No. E999/CI-19-704

Dear Mr. Seuffert:

Attached are the **PUBLIC** Comments of the Minnesota Department of Commerce, 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/ Steve Rakow
Analyst Coordinator

SR/ar
Attachment

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
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[8] 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.

<u>Hourly data for all units:</u>

a) Date and hour
b) Commit status (Null / Economic / Emergency / Must Run / Outage / Not Participating)
c) Dispatch Status for Energy (Null / Economic / Self Schedule)
d) Cleared MW
e) Day ahead locational marginal price at unit node
f) Real time MW adjustment
g) Real time locational marginal price at unit node

h) Day ahead dispatch minimum
i) Real time dispatch minimum
j) Fuel cost ($/MWh)
k) Variable operations and maintenance costs ($/MWh)
l) Day ahead locational marginal price representative of utility load zone
m) Real time locational marginal price representative of utility load zone
n) Whether Day Ahead Cleared = Day Ahead Dispatch Minimum (0 or 1)
o) Actual production in MWh (for all 8,760 hours of the year)
p) Day ahead MISO payment
q) Real time MISO payment
r) Net MISO energy payment
s) Production costs ((J+K) * O)
t) Net cost or benefit (R-S)

<u>Monthly or annual data for all units:</u>

u) Revenue from ancillary services (Monthly)
v) Fixed operations and maintenance costs (preferably monthly) or reasonable estimates in approximation thereof
w) Capital revenue requirements (annual) or reasonable estimates in approximation thereof
x) Average heat rate at economic minimum
y) Average heat rate at economic maximum

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[8] *In the Matter of an Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities*, Docket No. E-999/DI-19-704.

On December 13, 2019, the Commission issued its *Notice of Comment Period* (Notice). The Notice established comment periods regarding procedural issues.

In response to the Notice, on January 13, 2020, procedural comments were filed by:

- city of Minneapolis;
- Fresh Energy;
- Minnesota Department of Commerce, Division of Energy Resources (Department);
- Minnesota Office of the Attorney General—Residential Utilities Division;
- Minnesota Power, a public utility operating division of ALLETE, Inc. (Minnesota Power);
- Northern States Power Company, doing business as Xcel Energy (Xcel);
- Otter Tail Power Company (Otter Tail); and
- Sierra Club.

On January 28, 2020, reply comments were filed by Minnesota Power, Otter Tail, and Xcel.

On February 28, 2020 Xcel filed Xcel's *Annual Report* (Xcel Report). The Xcel 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]

On March 2, 2020 Minnesota Power filed its *Annual Compliance Filing* (MP Report). The MP Report provided data regarding Boswell Energy Center (Boswell) units 3 and 4.[2] Also, Otter Tail filed its *Annual Compliance Filing* (OTP Report) as well. The OTP 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

On May 5, 2020 Sierra Club requested a one week extension to the comment deadline, to June 8, 2020.

On May 11, 2020 the Commission granted Sierra Club's request.

B. MISO MARKET BACKGROUND

[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.

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, 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. 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. Thus, coal energy has dramatically declined as a part of the overall market.

In addition, MISO's presentation shows that most coal energy is either from economic commitments or capacity economically dispatched above the economic minimum.[6] MISO stated that, of cleared coal energy in the DA market (January 1, 2017 through November 13, 2019), 12.2 percent was from economically committed capacity and 75.8 percent was economically dispatched above the economic

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[4] The following information summarizing the MISO markets impacting this proceeding are taken from MISO's *Level 100 - Energy and Operating Reserves Markets* training materials. These materials are available at: https://miso.csod.com/clientimg/miso/MaterialSource/adda678c-bb1d-4ff4-8374-2e3c37905bfc_Level_100___Energy_and_Operating_Reserves_Markets.pdf
Additional Information is taken from *Level 200 - Energy and Operating Reserves Market Pricing*, available at: https://miso.csod.com/clientimg/miso/MaterialSource/f1be778a-f7ff-4458-88a0-1bc589d03451_Level_200___Energy_and_Operating_Reserves_Market_Pricing.pdf
[5] MISO's presentation which is the basis for this discussion is available at: https://cdn.misoenergy.org/20200305%20MSC%20Item%2009b%20Forward%20Market%20Mechanism%20(IR085)433003.pdf
[6] 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.

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minimum.[7] Thus, in the market as a whole uneconomic or must run coal energy holds a relatively small share of coal's overall energy output.

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 2 below. Note that in Table 2 all data covers the July 1, 2018 - Dec 31, 2019 reporting period.

Table 2: 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 **Boswell 4**	**[TRADE SECRET DATA HAS BEEN EXCISED]**						
Big Stone **Coyote**	**[TRADE SECRET DATA HAS BEEN EXCISED]**						
King **Sherco 1** **Sherco 2** **Sherco 3**	**[TRADE SECRET DATA HAS BEEN EXCISED]**						
							]
TOTAL	**[TRADE SECRET DATA HAS BEEN EXCISED]**						

Considering all the coal units in this proceeding, the result was that the uneconomic DA dispatch minimum equaled 28.9 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

[7] Regarding natural gas, the same presentation shows that 66.8 percent of natural gas DA cleared energy was from economically committed capacity and 24.7 percent was economically dispatched above the economic minimum.

low LMPs at the Minnesota hub. Finally, the Department notes that a further 10.4 percent of the total hourly cleared DA capacity was from capacity that was not economic and was dispatched above the DA dispatch minimum.[8] This phenomenon of dispatching above the minimum even when a unit was not economic appeared in the data for all units to varying degrees. The Department recommends that the utilities explain this phenomenon in reply comments.

C. COMMISSION CONCERN

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

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

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

II. DEPARTMENT ANALYSIS

A. STRATEGIES IN MISO MARKETS

1. 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 1 provides a simple explanation of how

[8] The two percentages are additive. Meaning nearly 40 percent of the total hourly cleared DA capacity was not economic.

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 1: Customer Bill Components

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

From Equation 1 it can be seen that if Equation 2 is true:

Equation 2: LMPs are Equal

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

then Equation 3 must be true as well:

Equation 3: 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.[9] 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.

2. 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 4 below.

Equation 4: Customer Bill Components Rearranged

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

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[9] 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.

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.

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 4) and because the uneconomic operation may displace lower cost renewable resources—even if the renewable resource had lower variable costs.

Finally, it is interesting to note that the utilities' responses to the Commission's concern focused on longer durations where, on average, the generator's variable cost was less than the generator's LMP, rather than on shorter time periods. The notable exception was the MP Report which analyzed shorter durations in detail. The utilities all demonstrated that, over long durations, the economic impact of the times when the generator's variable cost has been less than the generator's LMP is greater than the economic impact of the times when the generator's variable cost has been greater than the generator's LMP and the unit operated nonetheless. However, while this analysis is useful, it does not cover all circumstances that need to be addressed in this proceeding. In this regard the analysis of MP regarding shorter durations was most instructive.

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.

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. One observation is that, not counting months where a unit had 100 or more hours on maintenance, the percentage of the time operating at a net cost is very similar for the two units; different by less than five percentage points in nine of ten months. This is not surprising since the units are adjacent to each other. A second observation is that operating at a net cost is a common phenomenon at both units and occurs year round; over 30 percent of the hours are operated at a net cost for all months other than those with a lengthy outage.

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

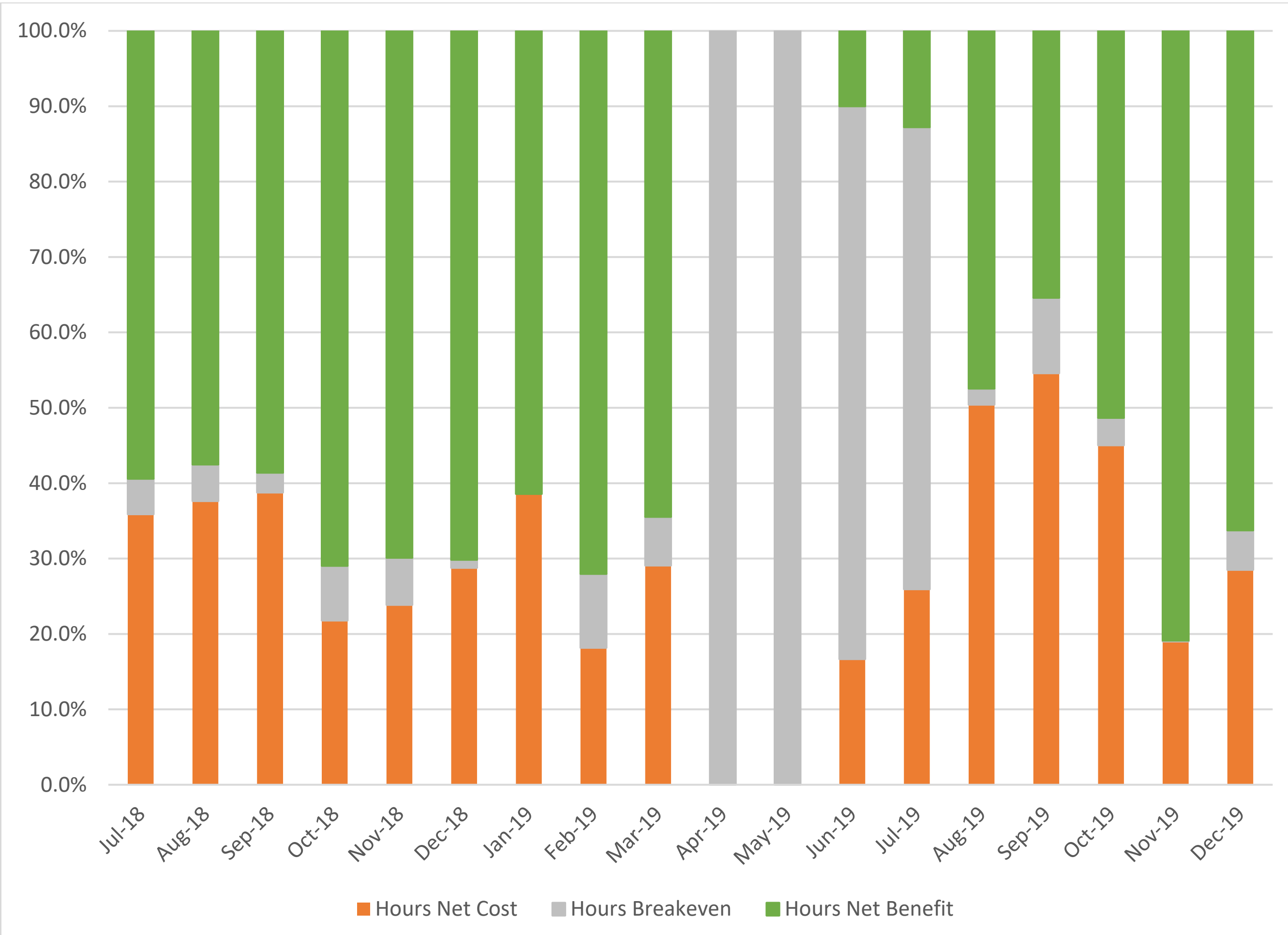

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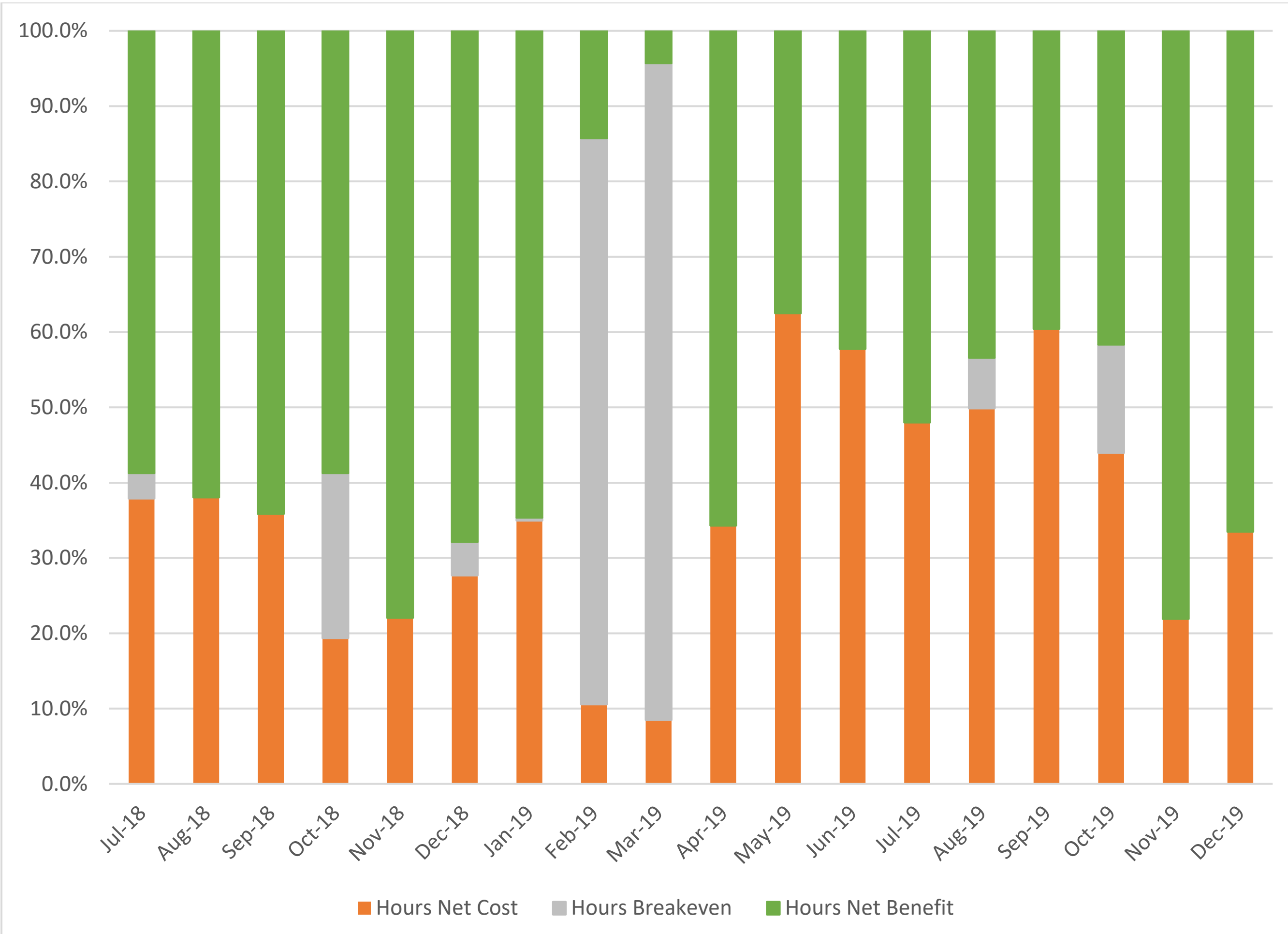
Figure 2: Boswell Unit 4 Hourly Net Benefit/Breakeven/Net Cost



Overall, for the 18-month period, Table 3 shows the breakdown of the net benefit / (cost) of both units by hours and in percentages.

Table 3: Hours at Net Benefit/Breakeven/Net Cost[10]

Unit	Net Benefit	Breakeven	Net Cost	TOTAL
Boswell Unit 3	6,499 49.3%	2,914 22.1%	3,764 28.6%	13,177 100%
Boswell Unit 4	6,892 52.3%	1,534 11.6%	4,751 36.1%	13,177 100%

The Department concludes that the preliminary data indicates that a more detailed analysis of both Boswell unit 3 and Boswell unit 4 is merited.

[10] Note that Minnesota Power has an extra hour compared to the other utilities because the Minnesota Power's data adds one hour in November and subtracts one hour in March to account for daylight savings time. The data has 2 Novembers but 1 March. The other utilities did not make this adjustment.

2. Detailed Analysis

a.) Background

Minnesota Power made the following points in the MP Report:

- "On an annual basis, the Boswell facility realized a net positive benefit for customers when operating in both the on-peak and off-peak hours."
    - Thus, when considering a long duration rather than individual hours, the Boswell units provide a net benefit. The question for this proceeding is the appropriate duration.
- "customers benefited from the flexible operations at Boswell that includes backing down during lower market conditions, but being available to increase generation to avoid purchasing higher cost energy in the market" and "To rely significantly on importing energy from the MISO market into the region at an unknown energy cost creates additional risk for customers…"
    - Thus, the limits to the units' ramp rates, down times, and other factors limit the ability to adjust to price spikes if a unit is not already operating. Further, the lack of operational flexibility creates risk when the units are off-line or otherwise unable to respond.
- "Minnesota Power's wind generation, although not part of the analysis, experiences an immaterial level of curtailment."
    - The Commission's concern regarding must-run designations reducing renewable energy have not been realized to a significant degree at this point.
- "Today, having these units on-line provides … essential reliability services that come along with energy production. Examples of essential reliability services include voltage regulation, frequency response, system strength, local power delivery, and redundancy."
    - Taking units off-line is more complicated than might appear at first glance from a purely economic perspective.
- "Given these are the two largest and remaining baseload generators in the [northeast Minnesota] region, there will be increases in market prices within the region when the generation is offline."
    - Thus, changes in the operation of any one generator in this proceeding would impact the LMPs for all other generators and loads.

The Department also notes that the MP Report states that:

> Minnesota Power has initiated an investigation into the alternative for economic dispatch to determine the potential operating conditions that exist at each Boswell unit and to identify potential solutions. At this time, it is too early in the investigative phase to report on conditions and potential solutions with any certainty. Minnesota Power will continue to consider this topic in its Integrated Resource Plan which will be filed on October 1, 2020, and next year's Self-Commitment filing.

The Department looks forward to reviewing the results of Minnesota Power's study of dispatch and commitment alternatives for Boswell unit 3 and Boswell unit 4.

b.) Analysis

The Department began the detailed analysis of Minnesota Power's units by requesting information regarding the minimum downtime, the time required to come on-line, and the minimum time on-line. The purpose of this request was to estimate the overall minimum timeframe required for decision making. Minnesota Power's response to Department Information Request No. 10 was that "for Boswell unit 3 and Boswell unit 4, Minnesota Power is currently investigating what these parameters need to be for economic dispatch in the MISO market." While Minnesota Power is determining the parameters, based upon the data provided by other utilities the Department concludes that the minimum time frame arrived at by adding the minimum downtime, the time required to come on-line, and the minimum time on-line appears to be about a week or less for the units involved in this proceeding. Therefore, the Department used a week as the minimum duration to consider.

The Department uses the minimum duration in this analysis, not because it is necessarily the appropriate duration, but to provide a second bookend to the analysis used by the utilities. The utilities used different durations in their analysis of the overall benefits and costs, but a long duration was typically selected. For example, the reporting period of July 1, 2018 through December 31, 2019 was reported by both Minnesota Power and Xcel. 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 3 and Figure 4 below show a rolling sum of Minnesota Power's 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.

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

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

As shown in Figure 3 and Figure 4, Minnesota Power's units typically were not operating at a sizable net cost over a 1 week duration. However, at times the rolling week total benefit / (cost) hovered near zero for an extended duration. Therefore, the Department agrees with Minnesota Power that a more detailed consideration of the overall benefits and costs of alternatives such as economic or seasonal dispatch at Boswell unit 3 and Boswell unit 4 is warranted. The Department recommends that the Commission require Minnesota Power to provide an analysis of the overall benefits and costs of alternatives such as economic or seasonal dispatch at Boswell unit 3 and Boswell unit 4 in the Company's next annual filing in this proceeding.

c.) Other Issues

The MP Report evaluated the data to see which consecutive hour segments resulted in a net cost to customers due to the self-commitment process. The results of the analysis are shown in the MP Report's Figure 1. The MP Report's Figure 1 shows that most of the net costs are incurred during periods of less than 12 consecutive hours. From this, the MP Report concluded that "With the cost occurring in short blocks of time, it would be difficult and not cost effective for the coal units to try to capture these savings by starting-up and shutting down multiple times in a week to try to capture these short time periods." In general, given the minimum downtime, the time required to come on-line, and the minimum time on-line, the Department agrees with Minnesota Power's conclusion that net costs incurred during a short time frame cannot be avoided due to the limits of the technology installed at Boswell.

3. Conclusion

The Department recommends the Commission require Minnesota Power to provide an analysis of the overall benefits and costs of alternatives such as economic or seasonal dispatch at Boswell unit 3 and Boswell unit 4 in the Company's next annual filing in this proceeding.

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

1. Preliminary Analysis

Figure 5 and Figure 6 below show the results of the preliminary analysis for Big Stone and Coyote. Note that Otter Tail's filing included a column for ancillary services revenues in the overall calculation of hourly net (cost) or benefit. No other utility include such a column. There were other differences such as reporting a net benefit in an hour as a positive number for some utilities and a negative number for others. Therefore, to create an easier comparison between utilities the Department recalculated Otter Tail's net (cost) or benefit excluding ancillary services revenues. The Department recommends that the Commission determine if ancillary services revenues should be included in the overall calculation of hourly net (cost) or benefit in future filings.

A second data issue is that Otter Tail reported only a "unit cost" not the breakdown into Unit Fuel Cost and Unit Variable O&M Cost as directed by the Commission. The Department did not request the data broken down because only the total cost was necessary for the Department's analysis. The Department recommends that the Commission determine if a breakdown into Unit Fuel Cost and Unit Variable O&M Cost is necessary or if only a total variable cost is necessary. In addition, to remedy the differences in calculations and data reporting among utilities, the Department recommends that the Commission require the utilities to make a compliance filing within 30 days of the Commission's order containing an Excel spreadsheet of the required data, with formulas intact, and that all utilities provide an updated spreadsheet for each unit in future annual compliance filings. The spreadsheet should have clear definitions for the inputs so that the data is more comparable across utilities. Hopefully a standard form with standard formulas will make cross-utility comparisons easier.

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

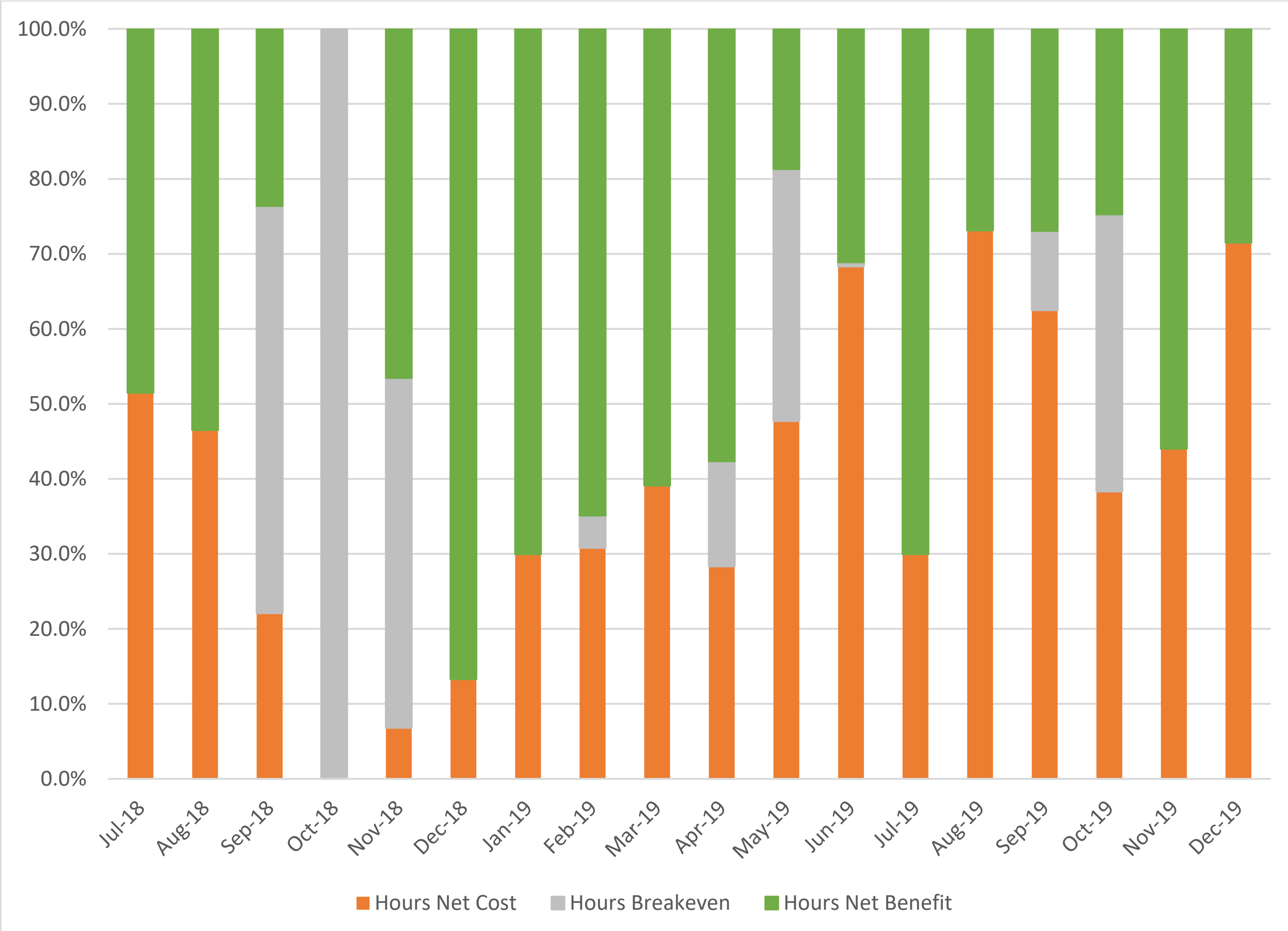

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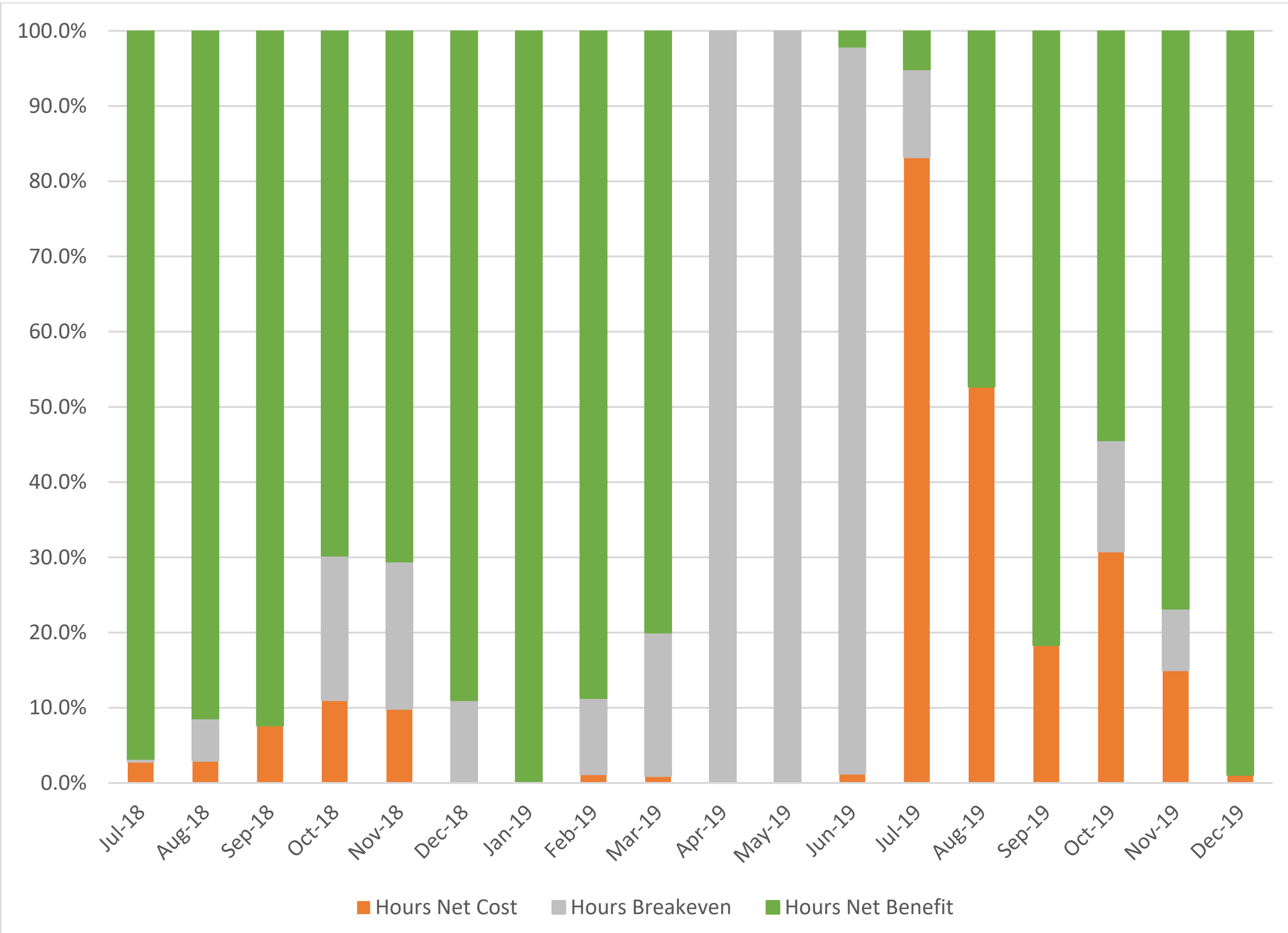
Figure 6: Coyote Hourly Net Benefit/Breakeven/Net Cost



One observation regarding Otter Tail's data is that, not counting months where a unit had 100 or more hours on maintenance, the percentage of the time operating at a net cost is very different for the two units; different by at least 25 percentage points in two-thirds of the months. A second observation is that, as with the Boswell units, operating at a net cost is a common phenomenon at Big Stone and occurs year round; over 30 percent of the hours are operated at a net cost for all but two months (not counting months with a lengthy outage). However for Coyote, consistently operating at a net cost is a rare phenomenon; being over 30 percent of the hours in only two months.

Overall, for the 18-month period, 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

Unit	Net Benefit	Breakeven	Net Cost	TOTAL
Coyote	8,375	3,037	1,764	13,176
	63.6%	23.0%	13.4%	100%
Big Stone	5,811	2,206	5,159	13,176
	44.1%	16.7%	39.2%	100%

The Department concludes that the preliminary data indicates that a more detailed analysis of Big Stone is warranted. However, a detailed review of Coyote is not warranted.

2. Detailed Analysis

a.) Background

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

- "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 joint owned unit … Otter Tail, Minnkota Power Cooperative, and Montana Dakota Utilities operate within the MISO market, while Northwestern Energy operates within the SPP market."[11]
  - Thus, there may be complications in determining a commitment strategy caused by the interaction of multiple RTO markets.
- "Partial dispatch would result in under recovery of startup and make whole payments to the partners whose shares were not dispatched."
  - Thus, the multiple-ownership structure creates the potential for economic losses for one partner to make the other partners whole.
- "from a co-owner contractual standpoint, if one owner calls on their share of the plant, all owners are required to take their share's minimum output."
  - The multiple-ownership structure results in limits to Otter Tail's commitment and dispatch options.
- "It should also be noted that MISO utilizes a single day dispatch process… The single day dispatch process does not consider the economics of running a baseload plant across multiple days."
  - Thus, until MISO creates a comprehensive multi-day dispatch process, operating large baseload units involves forecasting MISO's LMPs for several days.

The Department also notes that Otter Tail's response to Department Information Request No. 20 states that "The Big Stone owners are currently investigating the viability and logistics of moving to an economic offer at Big Stone during seasonally low market pricing periods."

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[11] Note that Otter Tail makes many of the same points regarding joint ownership, multiple RTO markets, and so forth for Big Stone.

As discussed below, the Department looks forward to reviewing the results of the Big Stone owners' study of dispatch and commitment alternatives for Big Stone.

b.) Analysis

As with Minnesota Power, the Department began detailed analysis of Otter Tail's Big Stone unit by requesting information regarding the minimum downtime, the time required to come on-line, and the minimum time on-line. The purpose of this request was to estimate the overall minimum timeframe required for decision making. Otter Tail's response to Department Information Request No. 18 provided the requested data. Based upon the data provided by Otter Tail and Xcel (discussed below) the Department concludes that the minimum time frame for coal unit operations—arrived at by adding the minimum downtime, the time required to come on-line, and the minimum time on-line—appears to be a week or less. Therefore, the Department used a week as the minimum duration to consider.

The Department uses the minimum duration in this analysis, not because it is necessarily the appropriate duration, but to provide a second bookend to the analysis used by the utilities. The utilities used different durations in their analysis of the overall benefits and costs, but a long duration was typically selected. For example, the reporting period of July 1, 2018 through December 31, 2019 was reported by both Minnesota Power and Xcel.[12] 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 7 below shows a rolling sum of Big Stone's hourly benefit / (cost) effectiveness for 1 week (168 hours). When the line is below zero that indicates Big Stone operated at a net cost over the preceding week. When the line is above zero that indicates Big Stone operated at a net benefit over the preceding week.

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[12] Again, as discussed above Minnesota Power also discussed short durations in detail.

Figure 7: Big Stone Rolling Week Total Benefit / (Cost)

As shown in Figure 7, Big Stone typically was not operating at a sizable net cost over a 1-week duration. However, at times the rolling week total benefit / (cost) hovered near zero for an extended duration. Therefore, the Department agrees with Otter Tail that a more detailed consideration of the overall benefits and costs of alternatives, such as economic or seasonal dispatch, at Big Stone is warranted. The Department recommends the Commission require Otter Tail to provide an analysis of the overall benefits and costs of alternatives, such as economic or seasonal dispatch, at Big Stone in the Company's next annual filing in this proceeding.

3. Conclusion

The Department recommends that the Commission take no action regarding Otter Tail's commitment and dispatch status decisions regarding Coyote. The Department also recommends that the Commission require Otter Tail to provide an analysis of the overall benefits and costs of alternatives, such as economic or seasonal dispatch, at Big Stone in the Company's next annual filing in this proceeding.

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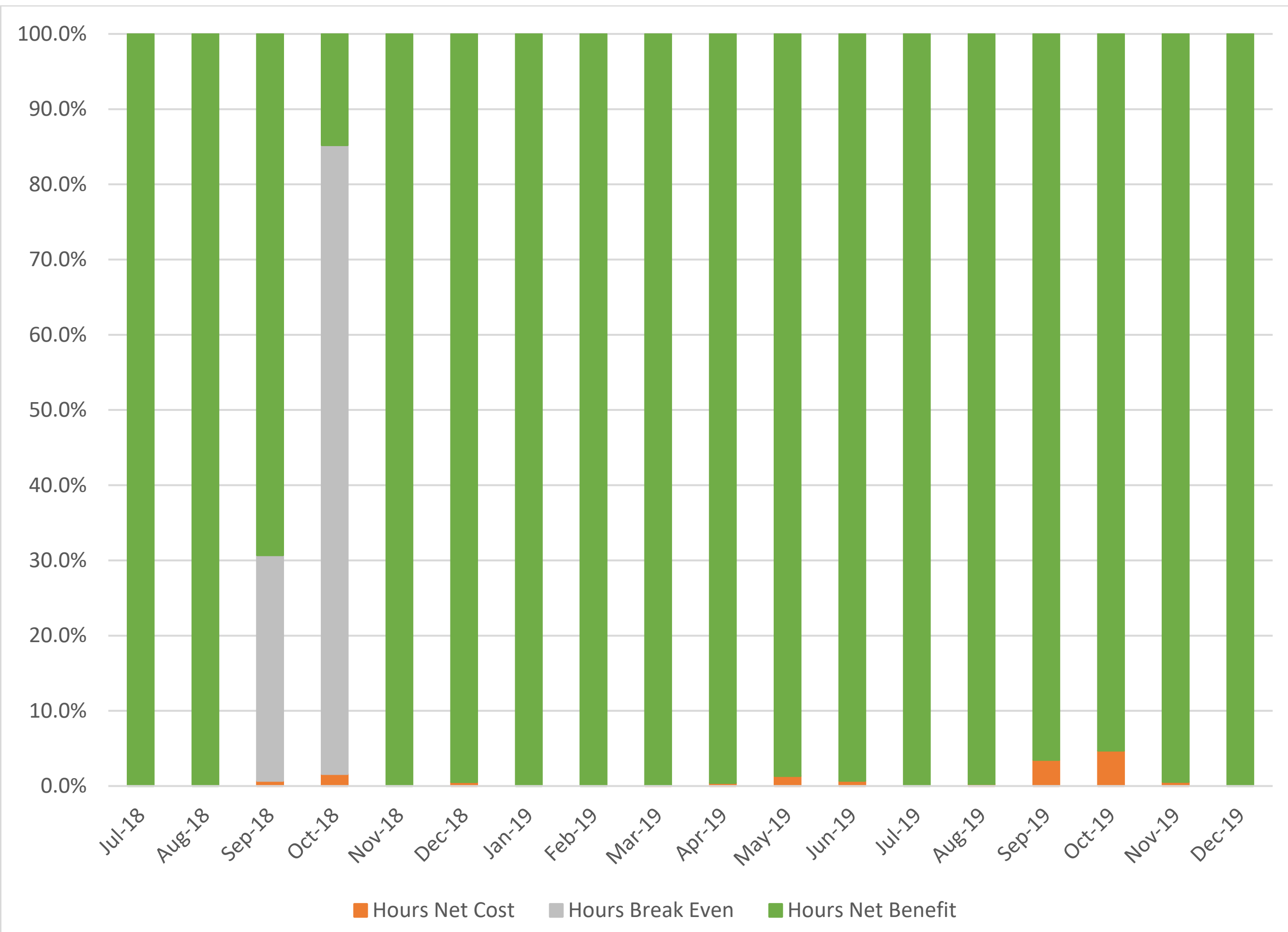
D. VARIABLE $COST_{GEN}$ > LMP_{GEN}—XCEL NUCLEAR

1. Preliminary Analysis

Figures 8 to Figure 10 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 cost rarely exceeds even 1 percent of the hours in a month.

Figure 8: Prairie Island Unit 1 Hourly Net Benefit/Breakeven/Net Cost



 PUBLIC DOCUMENT

Figure 9: Prairie Island Unit 2 Hourly Net Benefit/Breakeven/Net Cost

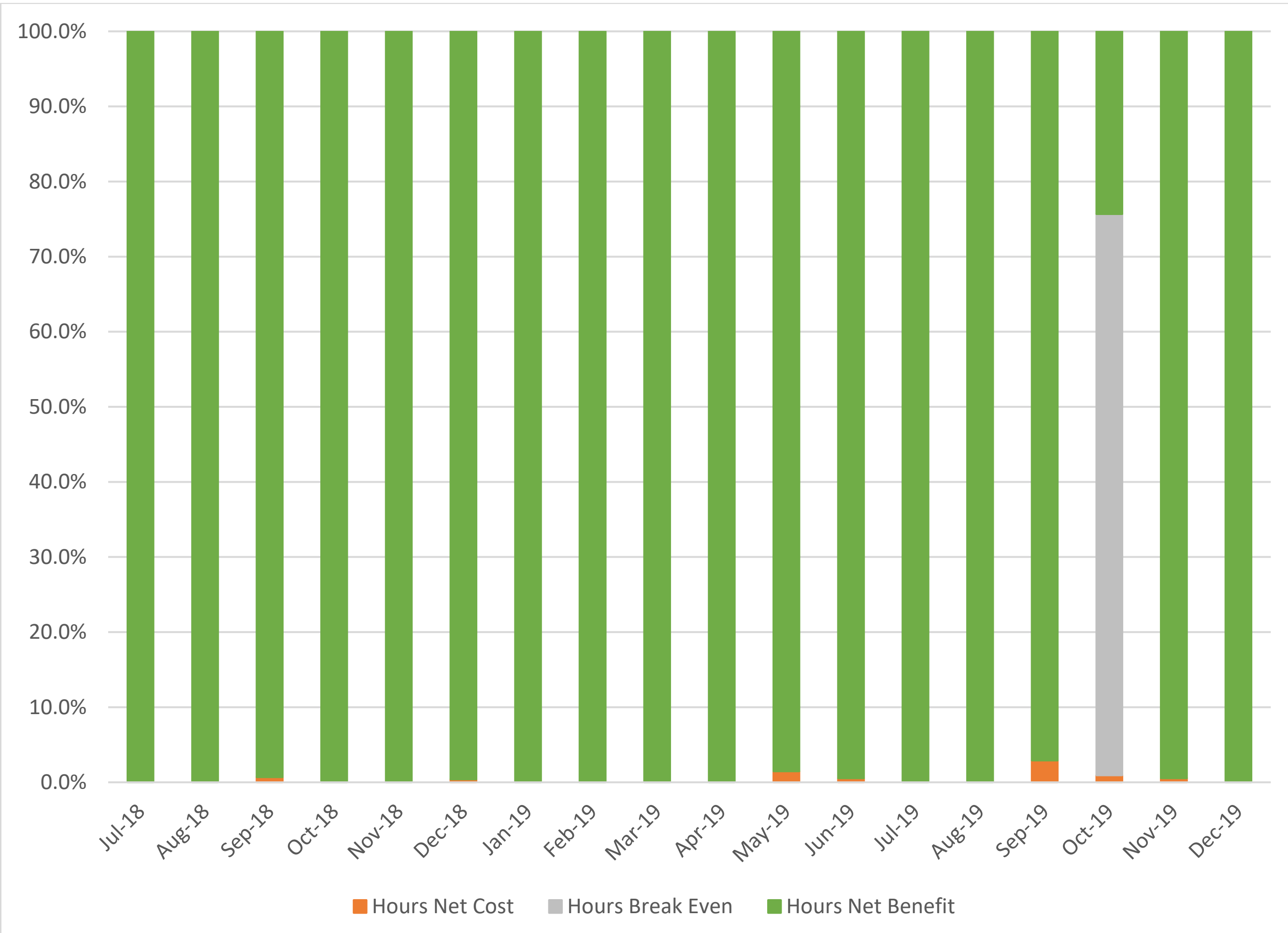
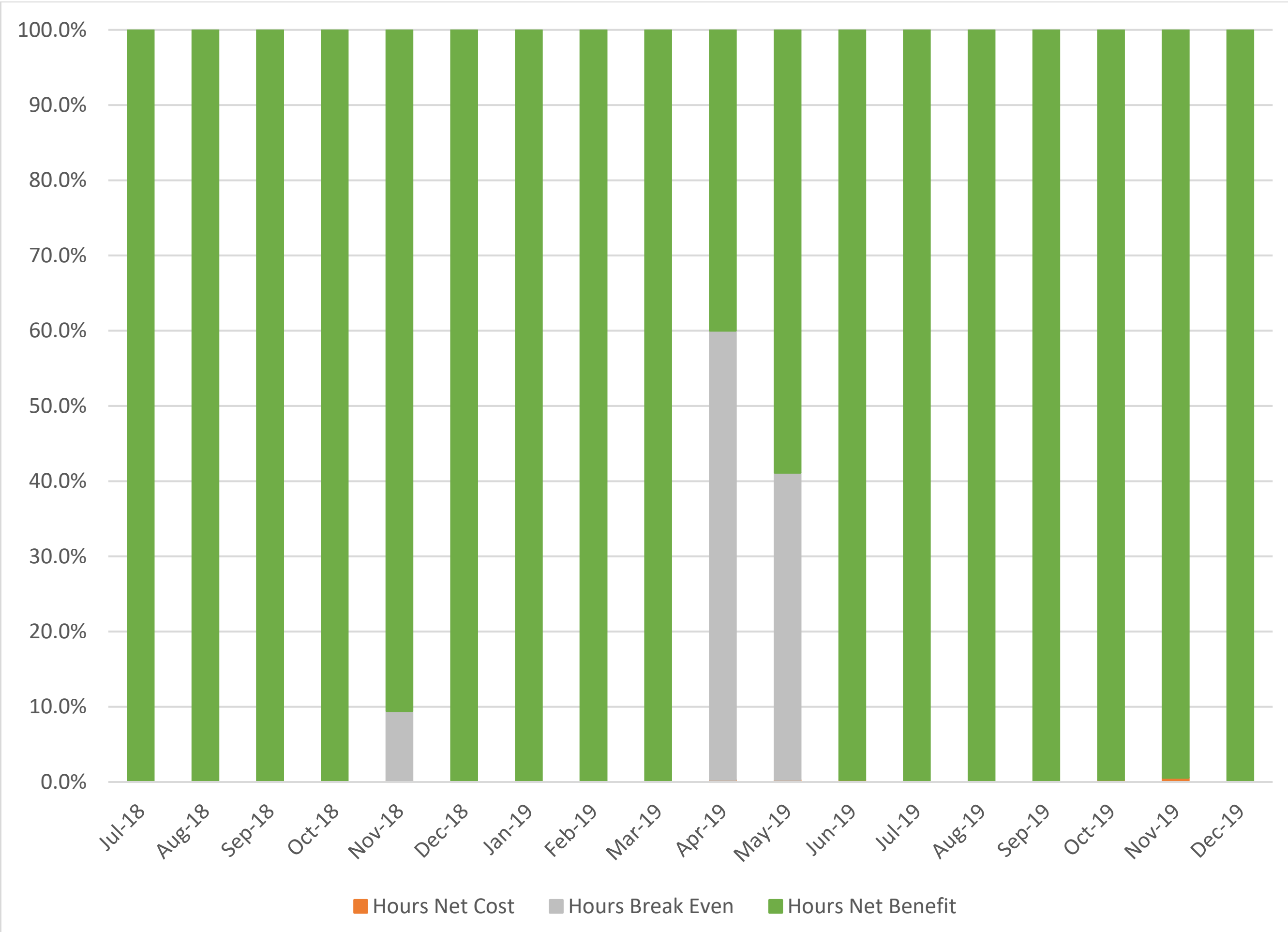


Figure 10: Monticello Hourly Net Benefit/Breakeven/Net Cost



Overall, for the 18-month period Table 5 shows the breakdown of the net benefit / (cost) of all three units by hours and in percentages.

Table 5: Hours at Net Benefit/Breakeven/Net Cost

Unit	Net Benefit	Breakeven	Net Cost	TOTAL
Prairie Island Unit 1	12,232	838	106	13,176
	92.8%	6.4%	0.8%	100.0%
Prairie Island Unit 2	12,565	556	55	13,176
	95.4%	4.2%	0.4%	100.0%
Monticello	12,362	801	13	13,176
	93.8%	6.1%	0.1%	100.0%

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 11 through Figure 14 show the results of the preliminary analysis for Xcel's King and Sherco units. While working with Xcel's data the Department discovered that Xcel's reported fuel cost for King for 5/7/2019 at hour ending 13 displayed "#DIV/0!" Xcel's reply to Department Information Request No. 29 stated that the hours that display "#DIV/0!" are equal to $0 fuel cost. The Department remedied the error by entering zero.

One observation is that, unlike all other units in this proceeding, King does not show many hours at breakeven. This may be due to King **[TRADE SECRET DATA HAS BEEN EXCISED]**

Second, not counting months where a unit had 100 or more hours on maintenance, the percentage of the time operating at a net cost is very similar for the three Sherco units; the difference between highest and lowest averages about six percentage points for the 18-month reporting period. Third, as with the Boswell and Big Stone units, operating at a net cost is a common phenomenon at King and Sherco and occurs year round; over 30 percent of the hours are operated at a net cost for all but two months for King and Sherco unit 1 and four months for Sherco unit 2 and Sherco unit 3.

 PUBLIC DOCUMENT

Figure 11: King Hourly Net Benefit/Breakeven/Net Cost

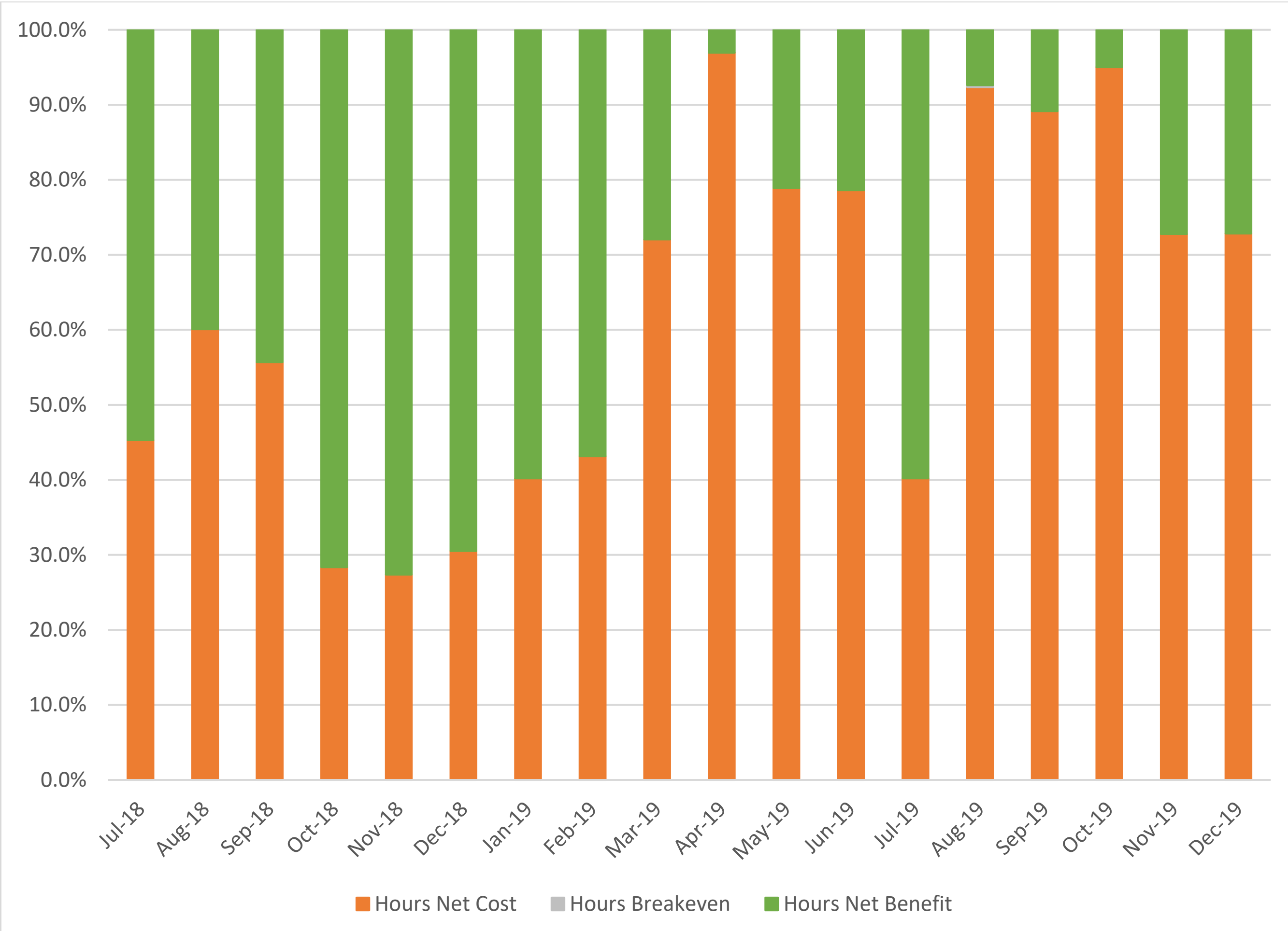


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Figure 12: Sherco Unit 1 Hourly Net Benefit/Breakeven/Net Cost

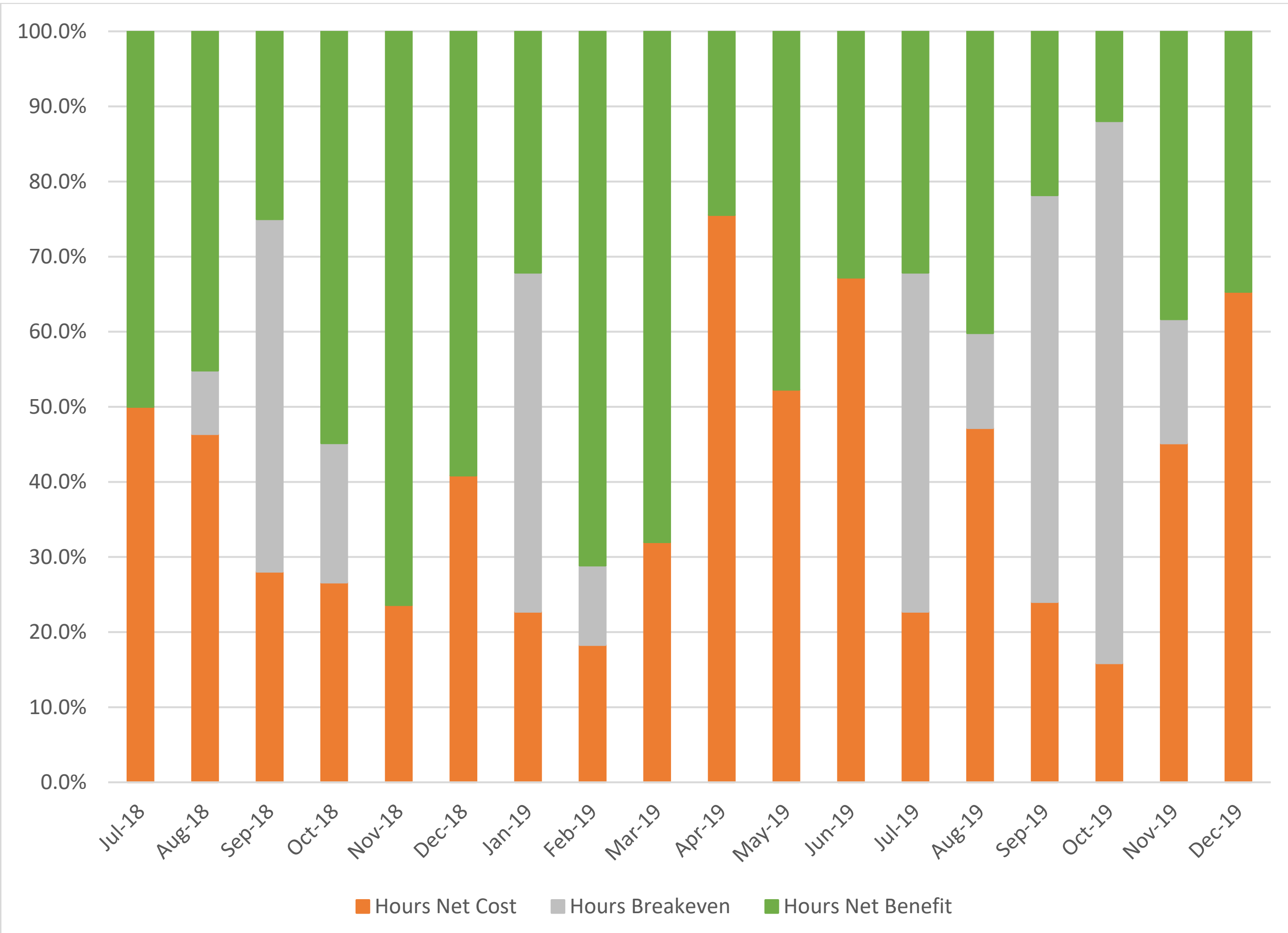

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Figure 13: Sherco Unit 2 Hourly Net Benefit/Breakeven/Net Cost

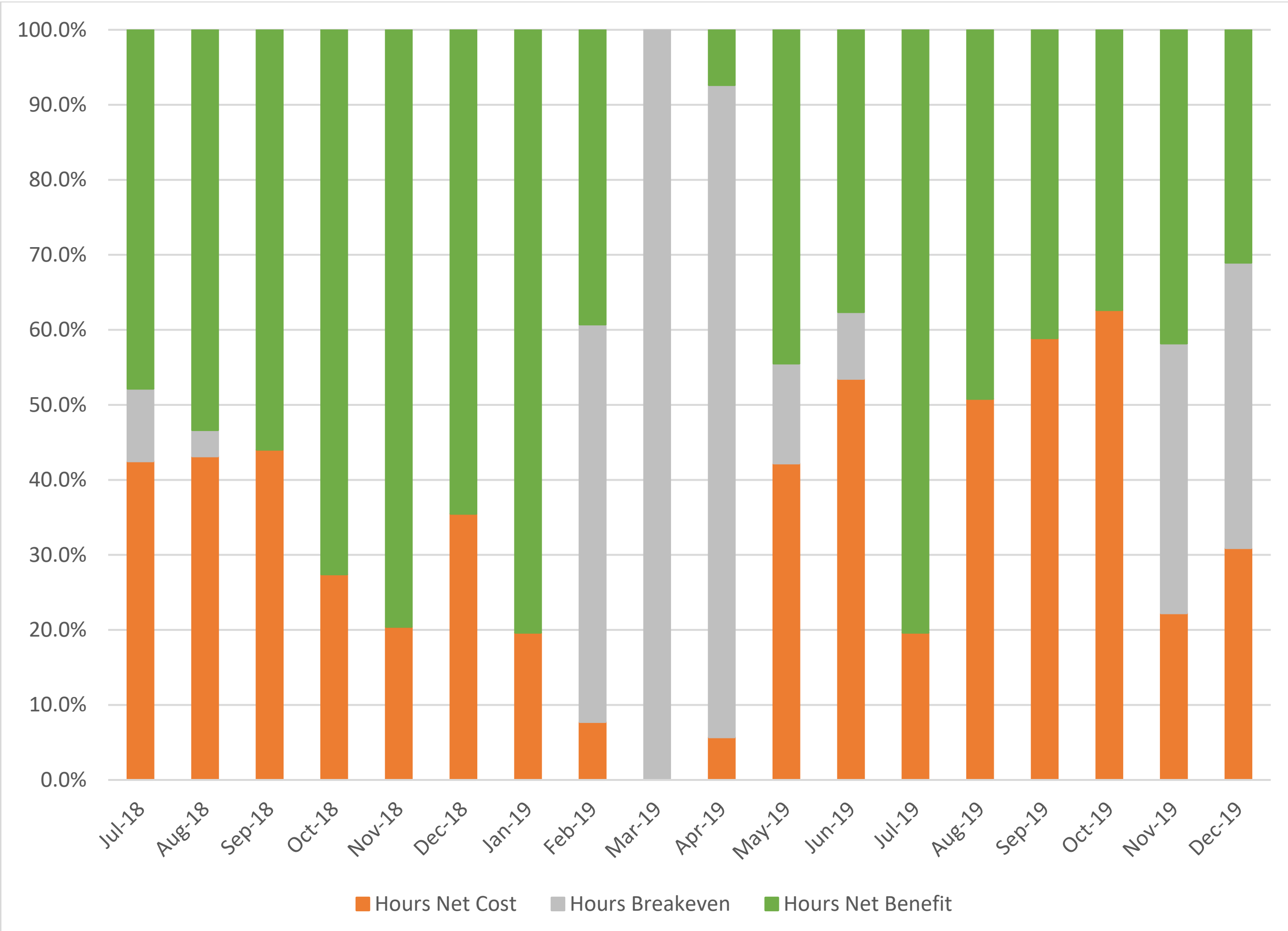

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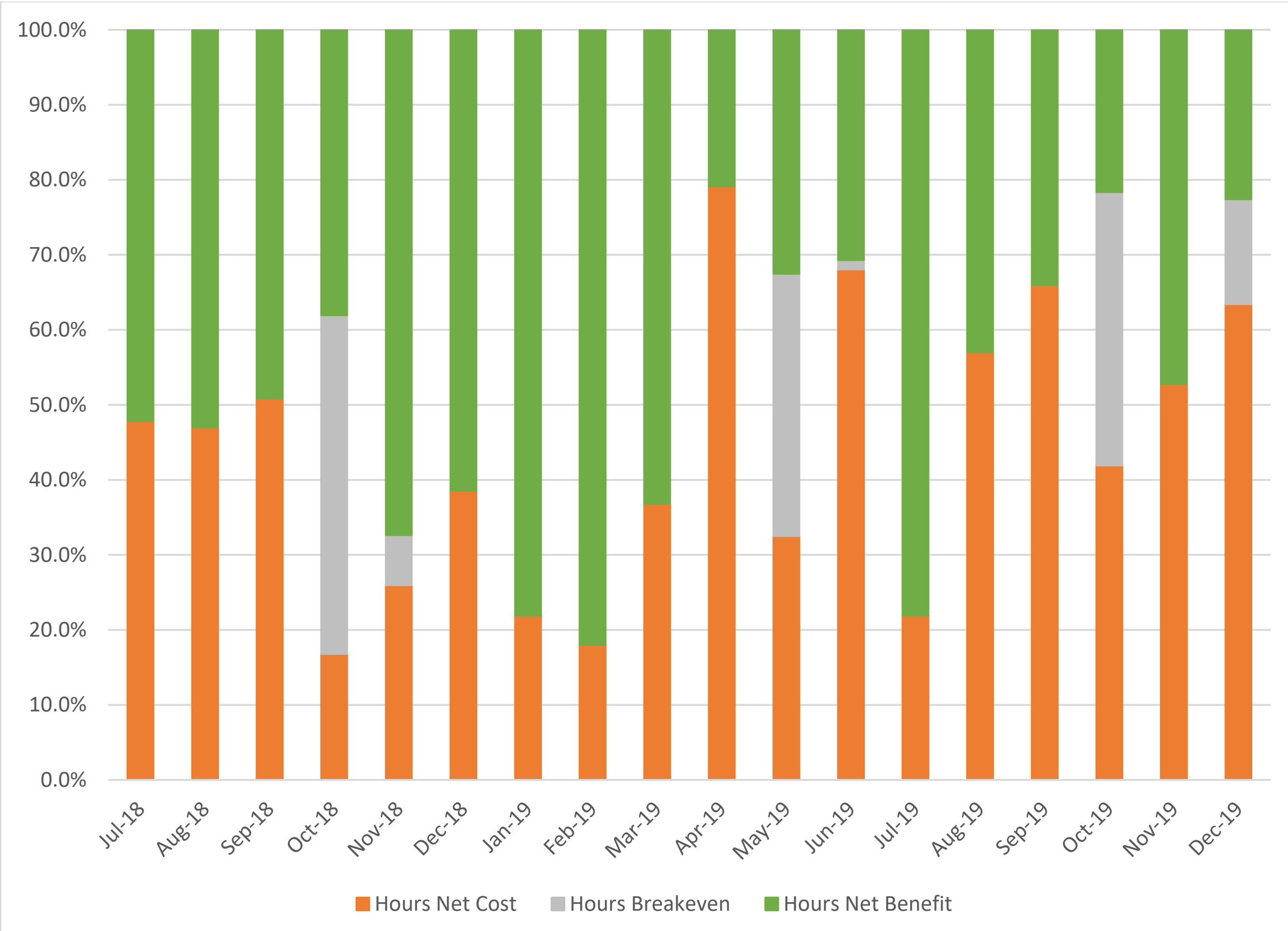
Figure 14: Sherco Unit 3 Hourly Net Benefit/Breakeven/Net Cost



Overall, for the 18-month period, Table 6 shows the breakdown of the net benefit / (cost) of the units by hours and in percentages.

Table 6: Hours at Net Benefit/Breakeven/Net Cost

Units	Net Benefit	Breakeven	Net Cost	TOTAL
King	4,977	2	8,197	13,176
	37.8%	0.0%	62.2%	100.0%
Sherco Unit 1	5,594	2,422	5,160	13,176
	42.5%	18.4%	39.2%	100.0%
Sherco Unit 2	6,336	2,529	4,311	13,176
	48.1%	19.2%	32.7%	100.0%
Sherco Unit 3	6,391	1,028	5,757	13,176
	48.5%	7.8%	43.7%	100.0%

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

2. Detailed Analysis

a.) Background

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

- "Since 2019, the Company's practice is to offer our coal facilities with an economic commit status – as opposed to self-commit – as much as possible." And "The Company has also proposed to suspend normal operations at King Plant and Sherco 2 during nonpeak seasons, as discussed in Docket No. E002/M-19-809."
  - Thus, Xcel already has developed alternatives and selected a preferred plan to adapt to the data regarding the number of hours Xcel's units are operating at a net cost. However, Xcel has also proposed to modify the preferred plan.
- "In evaluating instances of self-commit of these units, we also excluded hours when Xcel Energy's self-commit action in the MISO market was unavoidable (e.g., mandatory generating resource testing, fuel and steam offtake contract requirements, and generating resource maintenance outages)."
  - Thus, Xcel performed additional economic analysis with more detailed data than was required by the Commission.

b.) Analysis

As with Minnesota Power, the Department began detailed analysis of Xcel's King and Sherco units by requesting information regarding the minimum downtime, the time required to come on-line, and the minimum time on-line. The purpose of this request was to estimate the overall minimum timeframe required for decision making. Xcel's response to Department Information Request No. 4 provided the requested data. Based upon the data provided by Otter Tail and Xcel the Department concludes that the minimum time frame for coal unit operations—arrived at by adding the minimum downtime, the time required to come on-line, and the minimum time on-line—appears to be a week or less. Therefore, the Department used a week as the minimum duration to consider.

The Department uses the minimum duration in this analysis, not because it is necessarily the appropriate duration, but to provide a second bookend to the analysis used by the utilities. The utilities used different durations in their analysis of the overall benefits and costs, but a long duration was always selected. For example, the reporting period of July 1, 2018 through December 31, 2019 was reported by both Minnesota Power and Xcel. 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 duration to the results of the analysis.

Figures 15 to Figure 18 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, as discussed in the Xcel Report, since 2019, Xcel's practice is to offer coal facilities with an economic commit status – as opposed to self-commit – as much as possible. Therefore, Figure 15 to Figure 18 also include a line indicating the unit's commitment status (must run, outage, or economic). When comparing the line indicating net benefit/ (cost) to the line indicating commitment status, it is important to keep in mind that the net benefit/ (cost) line at any one point represents a sum of the previous seven days while the commitment status line represents only that particular hour.

Figure 15: King Rolling Week Total Benefit / (Cost)

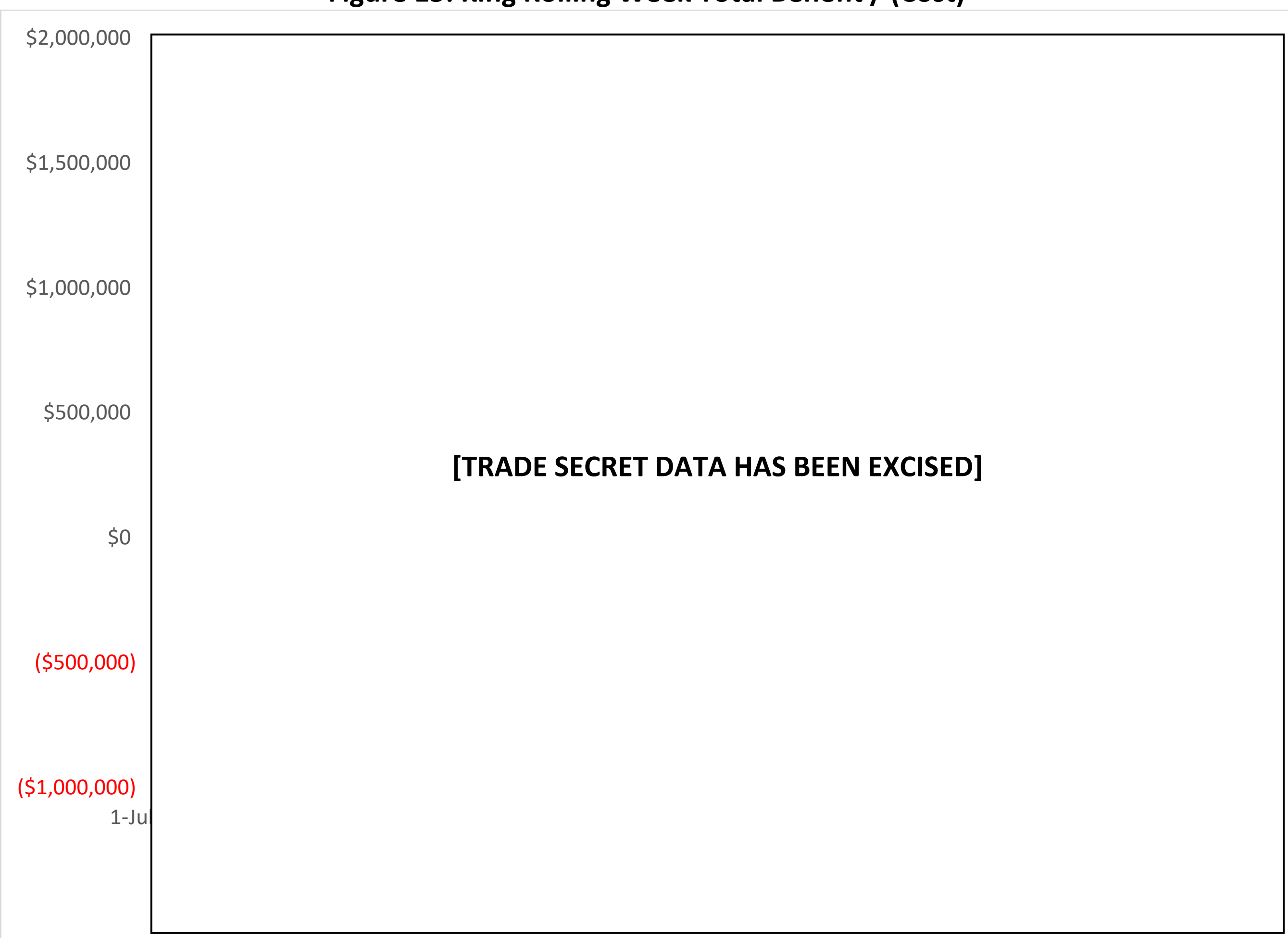


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Figure 16: Sherco Unit 1 Rolling Week Total Benefit / (Cost)

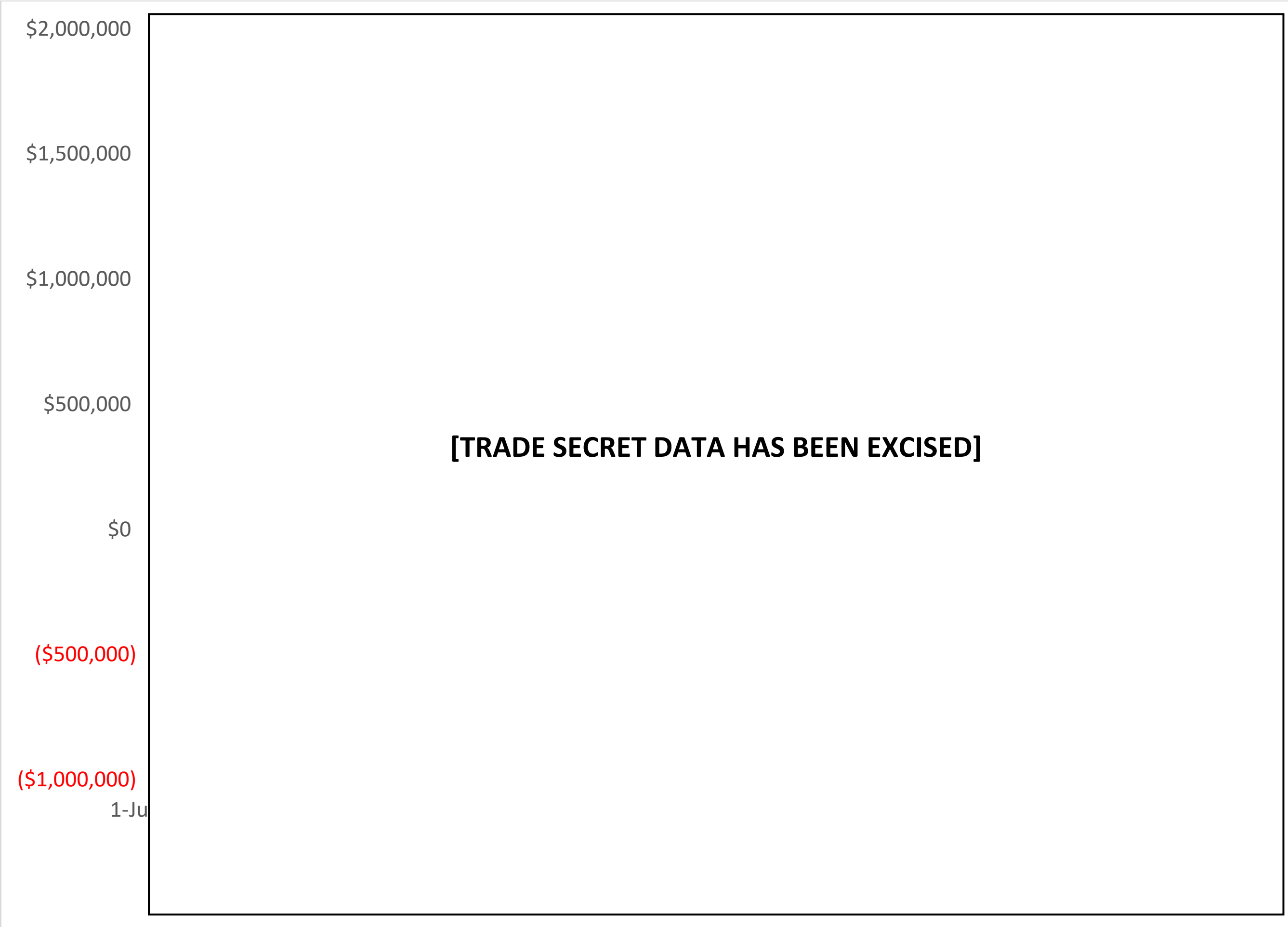

Figure 17: Sherco Unit 2 Rolling Week Total Benefit / (Cost)

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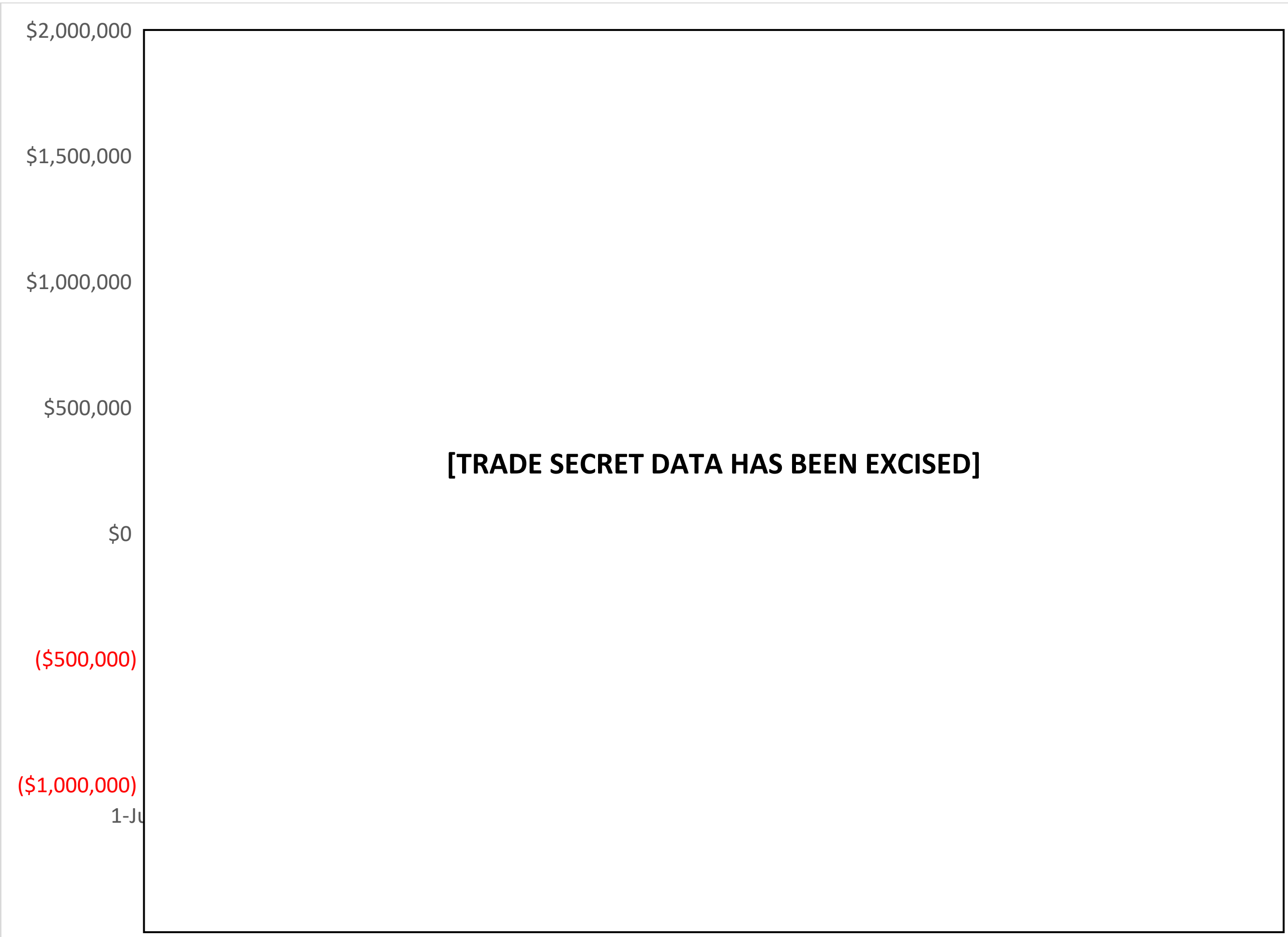
Figure 18: Sherco Unit 3 Rolling Week Total Benefit / (Cost)



As shown in Figure 15 to Figure 18, occasionally the King and Sherco units operated at a sizable net cost over a 1 week duration. Furthermore, at times the rolling week total benefit / (cost) hovered near zero for an extended duration. It appears that Xcel reacted to this situation through the practice of offering some of the units with an economic commitment status. The Department agrees with Xcel that a detailed consideration of the overall benefits and costs of alternatives such as economic or seasonal dispatch at King and Sherco unit 2 is warranted since those units are being addressed in another proceeding (Docket No. E002/M-19-809).

c.) Unavoidable Must Run

The Xcel Report also provided analysis of the data set that calculated costs and benefits excluding hours when Xcel's self-commit action in the MISO market was unavoidable. The Xcel Report cites "mandatory generating resource testing, fuel and steam offtake contract requirements, and generating resource maintenance outages" as examples of unavoidable must run designations. The results of this additional analysis are included in the Xcel Report's Figure 1. The Department recommends that the Commission consider whether data regarding unavoidable self-commitment should be added to the utilities' filings in the future.

d.) Commitments and Results

Since Xcel implemented an economic commitment strategy in varying degrees for King, Sherco unit 1, and Sherco unit 2 the Department developed data showing how often a unit was given a commitment status of economic, outage, or must run and the result in terms of the real-time cleared MW being equal to zero (off-line) or above zero (on-line).[13] This data is shown below in Table 7 to Table 9.

Table 7: King RT Commitment and RT Result (2019 Data, percent of hours each month)

Commitment →	Economic		Outage		Must Run		Total
Result →	Off-line	On-line	Off-line	On-line	Off-line	On-line	
January	0%	0%	0%	0%	0%	100%	100%
February	1%	7%	19%	1%	0%	71%	100%
March	27%	15%	45%	0%	0%	13%	100%
April	0%	0%	100%	0%	0%	0%	100%
May	0%	1%	21%	1%	0%	77%	100%
June	0%	0%	0%	0%	0%	100%	100%
July	25%	7%	0%	0%	0%	68%	100%
August	63%	4%	22%	0%	0%	11%	100%
September	58%	3%	6%	0%	0%	32%	100%
October	90%	7%	0%	0%	0%	3%	100%
November	64%	28%	0%	0%	0%	7%	100%
December	64%	1%	0%	0%	0%	35%	100%

Table 8: Sherco Unit 1 RT Commitment and RT Result (2019 Data, percent of hours each month)

Commitment →	Economic		Outage		Must Run		Total
Result →	Off-line	On-line	Off-line	On-line	Off-line	On-line	
January	0%	0%	47%	0%	0%	53%	100%
February	0%	0%	11%	1%	0%	88%	100%
March	0%	0%	0%	0%	0%	100%	100%
April	0%	0%	0%	0%	0%	100%	100%
May	0%	0%	0%	0%	0%	100%	100%
June	0%	0%	1%	0%	0%	99%	100%
July	0%	0%	0%	0%	0%	100%	100%
August	13%	2%	0%	0%	0%	85%	100%
September	54%	17%	0%	0%	0%	29%	100%
October	59%	5%	13%	0%	0%	22%	100%
November	11%	0%	6%	1%	0%	82%	100%
December	0%	0%	0%	0%	0%	100%	100%

[13] Again, as noted above for King**[TRADE SECRET DATA HAS BEEN EXCISED]**

Table 9: Sherco Unit 2 RT Commitment and RT Result
(2019 Data, percent of hours each month)

Commitment →	Economic		Outage		Must Run		Total
Result →	Off-line	On-line	Off-line	On-line	Off-line	On-line	
January	0%	0%	0%	0%	0%	100%	100%
February	3%	3%	50%	2%	0%	42%	100%
March	0%	0%	100%	0%	0%	0%	100%
April	0%	0%	87%	3%	0%	10%	100%
May	8%	11%	5%	2%	0%	74%	100%
June	9%	7%	0%	0%	0%	83%	100%
July	0%	0%	0%	0%	0%	100%	100%
August	0%	0%	0%	0%	0%	100%	100%
September	0%	0%	0%	0%	0%	100%	100%
October	0%	0%	0%	0%	0%	100%	100%
November	36%	14%	1%	0%	0%	49%	100%
December	38%	12%	0%	0%	0%	50%	100%

Table 7 through Table 9 generally show that, in the first half of 2019, when units were given economic commitment the result was mixed. The result was that for roughly half of the hours the unit was off-line and for half of the hours the unit was on-line for both King and Sherco unit 2.

In the second half of 2019 an economic commitment status most often ended with a result that the unit was off-line. Overall, the ratio of the off-line to on-line percentages was about 7:1 for King, 6:1 for Sherco unit 1, and 3:1 for Sherco unit 2. Thus, the success of economic commitment in terms of resulting in avoiding uneconomic generation is dependent upon the circumstances of both the MISO market in general and the unit in particular.

3. Conclusion

The Department recommends that the Commission take no action regarding Xcel's commitment and dispatch status decisions regarding King and Sherco unit 2. The Department also recommends that the Commission order Xcel to provide an analysis of the overall benefits and costs of alternatives, such as economic or seasonal dispatch, at Sherco unit 1 and Sherco unit 3 in the Company's next annual filing in this proceeding.

F. OVERALL PROFITABILITY

The data ordered by the Commission include fixed operations and maintenance costs (fixed O&M), capital-related revenue requirements, and ancillary services revenues. When combined with the market margin data discussed above, this data potentially enables a partial review of unit profitability. However, the Department notes that the data do not provide the information required for an overall determination of whether a unit should be shut down or continue operating in a rate regulated environment. Such determinations are made in the utilities' resource plans. The data missing includes, for example, cost of transmission fixes required if a unit shuts down, a review of the socioeconomic impacts of a shutdown on the local areas, a capacity expansion analysis of how a unit might be replaced, and so forth. All of this data is available in a resource plan. Since the goal of this proceeding is to determine if utilities' decisions regarding unit commitment are reasonable, the Department did not pursue detailed analysis of this topic. However, the Department did attempt to assemble the available data into two tables, one for each year, to show the information available.

Table 10: Unit Profitability for July 1 to December 31, 2018

Unit	Capital Revenue Requirement	Fixed O&M Revenue Requirement	Ancillary Services Revenues	Operating Margin	TOTAL BENEFIT (COST)	Actual Generation (MWh)	Total Benefit (Cost) per MWh
	(a)	(b)	(c)	(d)	(e) = (a) + (b) + (c) +(d)	(f)	(g) = (e) / (f)
Boswell 3	[TRADE SECRET DATA HAS BEEN EXCISED]						
Boswell 4							
King							
Monticello							
Prairie Isl 1							
Prairie Isl 2							
Sherco 1							
Sherco 2							
Sherco 3							
Big Stone							
Coyote							

Table 11: Unit Profitability for 2019

<table>
<tr><th>Unit</th><th>Capital Revenue Requirement</th><th>Fixed O&M Revenue Requirement</th><th>Ancillary Services Revenues</th><th>Operating Margin</th><th>TOTAL BENEFIT (COST)</th><th>Actual Generation</th><th>Total Benefit (Cost) per MWh</th></tr>
<tr><th></th><th>(a)</th><th>(b)</th><th>(c)</th><th>(d)</th><th>(e) = (a) + (b) + (c) +(d)</th><th>(f)</th><th>(g) = (e) / (f)</th></tr>
<tr><td>Boswell 3</td><td rowspan="11" colspan="7">[TRADE SECRET DATA HAS BEEN EXCISED]</td></tr>
<tr><td>Boswell 4</td></tr>
<tr><td>King</td></tr>
<tr><td>Monticello</td></tr>
<tr><td>Prairie Isl 1</td></tr>
<tr><td>Prairie Isl 2</td></tr>
<tr><td>Sherco 1</td></tr>
<tr><td>Sherco 2</td></tr>
<tr><td>Sherco 3</td></tr>
<tr><td>Big Stone</td></tr>
<tr><td>Coyote</td></tr>
</table>

Regarding resource planning, the Commission's January 11, 2017 *Order Approving Plan with Modifications and Establishing Requirements for Future Resource Plan Filings* in Docket No. E002/RP-15-21 required Xcel to "describe its plans and possible scenarios for cost-effective and orderly retirement of its aging base load fleet, including Sherco, King, Monticello, and Prairie Island." These scenarios are currently being evaluated in Docket No. E002/RP-19-368.

Also, the Commission's January 24, 2019 *Order Approving Affiliated-interest Agreements with Conditions* in Docket No. E015/AI-17-568 required Minnesota Power to provide "A baseload retirement analysis that thoroughly evaluates and includes a plan for the early retirement of Minnesota Power's two remaining coal plants, Boswell 3 and 4, individually and in combination." This plan is currently due October 1, 2020.

Finally, the Commission's December 30, 2019 *Order Extending Deadline for Filing Resource Plan, Requiring Supplemental Filing, and Completing Competitive Bidding Process* in Docket No. E017/RP-16-386 required Otter Tail to "make a supplemental filing by December 31, 2020 which must include a Base case with low, mid, and high scenarios for Regional Haze compliance options, as well as a Coyote Station 2028 retirement scenario."

Therefore, the Commission has required retirement studies for all of the units covered in this proceeding except Otter Tail's Big Stone unit. Thus, the Department concludes that a detailed economic analysis regarding potential retirement of the units is unnecessary in this proceeding.

F. REGULATORY RESPONSE

The analysis above demonstrates that the duration considered is an important factor in the ultimate determination of the reasonableness of the utilities actions regarding unit commitments. If the Commission is concerned about the reasonableness of the actions, it appears that the Commission has three different approaches to consider as tools to improve decision-making and ensure reasonable rates for ratepayers. The three options available to the Commission are:

1. agreement by the utility to greater market commitment of their units;
2. changes to the fuel clause adjustment to create a mechanism to share the costs and benefits; and/or
3. disallowance of cost recovery due to unreasonable actions.[14]

All three utilities are actively pursuing the first alternative, use of economic or seasonal commitment for various units. Also, the fuel clause recently underwent significant revisions, intended in part to provide a stronger incentive for the utility to make reasonable and prudent decisions impacting fuel costs; the Department concludes that further fuel clause revisions should wait until the success of the most recent revisions can be determined. Given that all three utilities are pursuing the first alternative, the Department did not explore in detail the disallowance alternative.

As indicated above, the Department recommends that the Commission require the utilities to finish and provide studies of greater economic commitment before taking further action.

G. 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 2, 2020 filings in Docket No. E999/AA-20-171, the Annual Automatic Adjustment of Charges Reports. The utilities reported curtailment data for July 2018 to December 2019 as follows:

- Minnesota Power - **[TRADE SECRET DATA HAS BEEN EXCISED]**
- Otter Tail—**[TRADE SECRET DATA HAS BEEN EXCISED]**
- Xcel—72,117 MWh, or 1.0 percent of total energy.

Overall, the available data indicate that curtailment is minimal in the recent past for all three utilities.

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[14] The options are taken from a Union of Concerned Scientists presentation to the Organization of MISO States (OMS), apparently originally presented to United States Association for Energy Economists Annual Conference 2018.

III. DEPARTMENT RECOMMENDATIONS

A. RECOMMENDATION FOR REPLY COMMENTS

The phenomenon of dispatching above the minimum even when a unit was not economic appeared in the data for all units to varying degrees. The Department recommends that the utilities explain in reply comments the phenomenon of dispatching above the minimum even when a unit was not economic.

B. RECOMMENDATION FOR COMPLIANCE FILING

To remedy various differences still present in the calculations and data reporting, the Department recommends that the Commission require the utilities to file a compliance filing within 60 days of the Commission's order containing an Excel spreadsheet of the required data, with formulas intact, that the utilities will fill out for each unit in future filings, including clear definitions of the inputs. As part of developing this spreadsheet, the Department recommends that the Commission determine if:

- a breakdown into unit fuel cost and unit variable O&M cost is necessary or if only a total variable cost is necessary;
- ancillary services revenues should be included in the overall calculation of hourly net benefit / (cost); and
- data regarding unavoidable self-commitment should be added to the utilities' filings in the future.

C. RECOMMENDATIONS FOR NEXT YEAR'S FILINGS

Regarding Minnesota Power, the Department recommends that the Commission require Minnesota Power to provide an analysis of the overall benefits and costs of alternatives, such as economic or seasonal dispatch, at Boswell unit 3 and Boswell unit 4 in the Company's next annual filing in this proceeding.

Regarding Otter Tail, the Department recommends that the Commission require Otter Tail to provide an analysis of the overall benefits and costs of alternatives, such as economic or seasonal dispatch, at Big Stone in the Company's next annual filing in this proceeding.

Regarding Xcel, the Department recommends that the Commission require Xcel to provide an analysis of the overall benefits and costs of alternatives, such as economic or seasonal dispatch, at Sherco unit 1 and Sherco unit 3 in the Company's next annual filing in this proceeding.

/ar

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 **8th** day of **June 2020**

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_19-704_Official
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
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 220 Saint Paul, Minnesota 55102	Electronic Service	No	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
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_19-704_Official
Leann	Oehlerking Boes	lboes@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_19-704_Official
Randy	Olson	rolson@dakotaelectric.com	Dakota Electric Association	4300 220th Street W. Farmington, MN 55024-9583	Electronic Service	No	OFF_SL_19-704_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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	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
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	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