April 29, 2022

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

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E015/RP-21-33

Dear Mr. Seuffert:

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

Minnesota Power's Application for Approval of its 2021-2035 Integrated Resource Plan.

The Petition was filed on February 1, 2021 by:

Jennifer J. Peterson
Manager, Regulatory Strategy and Policy
30 West Superior Street
Duluth, MN 55802

The Department recommends **approval with modifications**. The Department's team of Craig Addonizio, Danielle Winner, and myself is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ STEVE RAKOW
Analyst Coordinator

SR/ja
Attachment

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Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. E015/RP-21-33

I. EXECUTIVE SUMMARY

Minnesota Power (MP) is a member of Midcontinent Independent System Operator, Inc. (MISO). For members of MISO, all of the powerplants in MISO are stacked up and are dispatched to serve all of the load in MISO in a MISO-wide market. Thus, MP's power plants do not directly serve MP's customers. Instead, MP's power plants function as a hedge against MISO capacity and energy market prices. Therefore, to the extent possible, the Department's analysis of an IRP is structured to evaluate MP's generation fleet as a hedge against market prices.

The first step in the analysis is to review MP's forecast of demand and energy requirements. For 2015 to 2019 MP experienced a significant drop in demand and energy requirements due to shutdowns among MP's taconite and paper customers. As a result, MP forecasts a 93 MW load loss by 2025 when compared to current customer's full requirements.

If the forecast MP uses is too high, MP becomes a net seller in MISO's capacity and energy markets and vice versa. The economic risks of the surplus/shortfall are symmetric and confined to MP. While the financial implications are confined to MP and its ratepayers, the reliability implications are not confined to MP. Reliability issues created by MP may be experienced by other members of MISO and vice versa. Thus, the reliability benefits of over building and the reliability costs of underbuilding MP's system are not confined to that util MP; instead, they are shared across MISO. The Department ran the capacity expansion model (EnCompass) both with MP's base case forecast (the forecast with 93 MW of lost load) and with MP's high forecast (which assumes the lost load returns) to see how much the different forecasts mattered.

The second step is to review MP's capacity expansion modeling (EnCompass). MP's modeling looked at five different scenarios for the timing of retiring its two remaining Boswell units. The scenarios were:

- retire Boswell 3 in 2025 and take no action on Boswell 4;
- retire Boswell 3 in 2029 and take no action on Boswell 4;
- take no action on Boswell 3 and retire Boswell 4 in 2030;
- retire Boswell 3 in 2025 and Boswell 4 in 2030, and
- take no action on either unit.

MP also looked at the cost impacts of 38 different contingencies (e.g., higher or lower fuel costs, restricted bulk market access, etc.), and per Commission directive, MP incorporated different levels of externality and hypothetical carbon tax costs into its results. Under MP's preferred scenario, EnCompass tended to prefer transmission upgrades (to fix system issues after unit retirements), wind, and solar.

The Department looked at the same five retirement scenarios, the same externality and hypothetical carbon tax costs, and 34 of MP's 38 contingencies. However, the Department made two major changes to MP's scenario structure. First, the Department looked at both the base (permanent lost load) and higher (lost load returns) sales forecasts for every run. Second, the Department varied the ownership percentage of the Nemadji Trail Energy Center (NTEC), a combined cycle natural gas plant in Superior, Wisconsin scheduled to be on-line in 2027. The Commission has approved a 50 percent MP ownership share of NTEC. However, MP has stated that the Company will seek approval for agreement that would reduce its ownership share to 20 percent. The Department ran half of its runs at a 50 percent ownership of NTEC and half at a 20 percent ownership. Because of the sales forecast and NTEC ownership considerations the Department performed about 7,660 runs compared to MP's 1,260.

The Department's modeling shows the least cost runs tend to be where both Boswell units are retired early. In these scenarios, EnCompass selects multiple large natural gas plants to replace the retiring units. MP encountered the same result for this scenario. If EnCompass were not permitted to select gas expansion units, it is unclear whether retiring both units early would continue to be the least cost scenario. A further complication comes from the fact that large transmission projects near the Boswell site are currently being studied in a separate transmission planning process. These transmission projects may impact the necessity of additional transmission or generation at the Boswell site in the retirement scenarios.

Based upon the overall results, the Department recommends the Commission modify MP's proposed resource plan to approve the retirement dates of the FastExit scenario for the Boswell units. The Department also recommends the Commission order MP to begin a resource acquisition process for up to 300 MW of new wind resources, to be on-line in the 2024 to 2025 time frame.

The third step is to review MP's proposed energy conservation levels. The Department concludes that MP's proposed level of energy efficiency is a reasonable proxy for the decision that will be made within Minnesota's conservation improvement program (CIP) process and the energy efficiency ultimately achieved by MP. In addition, the Commission required MP to investigate the potential for an energy-efficiency competitive bidding process to supplement its existing conservation improvement program—particularly targeted at CIP-exempt customers. The Department concludes that programs to acquire conservation resources should be contained within the CIP process and multiple processes to achieve the same goal is not warranted.

The fourth step is to review MP's compliance with various Minnesota statutes and policies.

- Minnesota requires a utility to include a plan for meeting 50 and 75 percent of all energy needs from both new and refurbished generating facilities through a combination of conservation and renewable energy resources.
    - MP's proposed plan recommends meeting all new energy needs with 100 percent new renewable resources and maintaining existing conservation programs.
- MP has a renewable energy standard (RES) of 20 percent now, increasing to 25 percent starting in 2025 along with a solar energy standard (SES) of 1.5 percent.

  - The Department's 2021 legislative report stated that MP can comply with the RES through 2053 and the three public utilities subject to the SES appear on track to comply with the first-year requirement in 2020.
- Minnesota has a goal to reduce statewide greenhouse gas emissions across all sectors to 15 percent below 2005 levels by 2015, 30 percent below 2005 levels by 2025, and to 80 percent below 2005 levels by 2050.
  - The results of the Department's calculations were that the CO_2 emissions reduction percentage, starting in 2025, varied between 72 and 78 percent. Thus, under the Department's calculations arrive at a result that is similar to MP's and show that MP is nearly able to meet the state's 2050 CO_2 emissions reduction goal by 2025.

The fifth step is to review MP's resource acquisition process; a proposal for a bidding process was required as part of Commission approval of MP's share of NTEC. The process was largely worked out during the NTEC proceeding. The Department recommends the Commission require MP to use a bidding process for supply-side acquisitions of 100 MW or more lasting longer than five years; minor modifications are proposed by the Department.

The final step is to review MP's securitization discussion. The Department agrees with MP that securitization would likely be a feasible option for MP were it permitted by Minnesota law and an analysis that more specifically contemplates MP's unique characteristics would be helpful in assessing the potential benefits of securitization and believes that the Phase 1 and 2 Reports demonstrate that this further evaluation would be worthwhile.

II. INTRODUCTION

A. DOCKET HISTORY

On February 1, 2021, February 3, 2021, February 5, 2021, and April 1, 2021, Minnesota Power, a division of ALLETE, Inc., (MP or the Company) filed the Company's *Application for Approval of its 2021-2035 Integrated Resource Plan* (Petition). The Petition was filed in compliance with the Commission's July 18, 2016 *Order Approving Resource Plan with Modifications* (July 18 Order) in Docket No. E015/RP-15-690[1] which required:

> 8. Minnesota Power's next resource plan shall include a full analysis of all alternatives, including renewables, energy efficiency, distributed generation, and demand response, for providing energy and capacity sufficient to meet its needs.

[1] The original due date in the July 18 Order of February 1, 2018 was subsequently extended by the January 24 Order later by a Commission order issued September 25, 2020 in Docket Nos. E015/RP-15-690, E015/AI-17-568, and E015/GR-16-664. Numerous other Commission orders affect parts of the Petition, see the Petition's Appendix N for a summary.

> …
>
> 14. Minnesota Power shall investigate the potential for an energy-efficiency competitive bidding process to supplement its existing conservation-improvement program, open to both CIP-exempt and non-CIP-exempt customers, and shall summarize its investigation and findings in its next resource plan.

The Petition was also filed in compliance with the Commission's January 24, 2019 *Order Approving Affiliated-interest Agreements with Conditions* (January 24 Order) in Docket No. E015/AI-17-568 which required:

> 6. Minnesota Power shall include the following in its next resource plan:
>   a. 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;
>   b. A securitization plan that could be used to mitigate potential ratepayer impacts associated with any early retirement of one or both of the Boswell 3 and 4 facilities; and
>   c. A proposed bidding process for supply-side acquisitions of 100 MW or more lasting longer than five years, as set forth in Attachment A, for Commission consideration and potential approval.
> 7. In developing the modeling analysis to be used in its next resource plan, Minnesota Power shall consult with stakeholders, including but not limited to the Department of Commerce and the Clean Energy Organizations, regarding the Company's modeling inputs and parameters.

On February 3, 2021 the Commission issued its *Notice of Comment Period* (Notice). The Notice stated that topics open for comment are as follows:

1. Should the Commission approve, modify, or reject Minnesota Power's 2021 Integrated Resource Plan (IRP)?
2. When should Minnesota Power file its next IRP? What additional information should the Commission require Minnesota Power to provide as part of its next IRP?
3. Are there other issues or concerns related to this matter?

On February 19, 2021 the Clean Energy Organizations (Fresh Energy, Clean Grid Alliance, Sierra Club, and Minnesota Center for Environmental Advocacy) filed a letter supporting Commission staff's proposal to refer the Petition to the Minnesota Office of Administrative Hearings (OAH) to conduct public meetings.

On March 9, 2021 the Commission issued its *Order Requiring Bill Insert and Referring Matter to OAH for Public Meetings* (Process Order). The Process Order required MP to provide notice to customers and governmental bodies and create a general advertising plan regarding the IRP. The Process Order also referred the matter to the OAH for the purpose of conducting public meetings.

On August 13, 2021 OAH filed its *Summary of Public Testimony*, providing an overview of the public meetings.

On November 2, 2021 the Institute for Local Self-Reliance and Vote Solar filed a letter requesting the Commission:

- order public utilities subject to the Commission's resource planning requirements to acquire EnCompass modeling licenses for intervening organizations in resource plan dockets, beginning with MP; and
- consider requiring utilities to provide, without a data request, modeling inputs, including settings, and outputs, assumptions, any post-processing spreadsheets, and the model manual.

The letter is being addressed in a separate proceeding. Below are the Department's comments regarding MP's Petition.

B. COMPANY BACKGROUND

According to the Petition, MP serves about 145,000 retail electric customers and 15 municipal electric utilities across a 26,000-square-mile service area in central and northeastern Minnesota. In 2019, 61 percent of MP's energy sales were to a small number of large industrial customers.

The Company planned to meet an estimated coincident peak demand of about 1,370 MW after energy efficiency in 2021. In addition, the Company must have about 120 MW of resources above peak demand to meet reliability requirements. MP had a 2,400 MW portfolio of supply-side resources used to meet this peak demand and reliability requirements in 2021 including:

- 920 MW of coal;[2]
- 100 MW of natural gas steam turbines;
- 370 MW of hydro;
- 870 MW of wind;[3]
- 10 MW of solar;[4]
- 10 MW of distributed generation—wind and solar qualifying facilities;

[2] Load and capability data was taken from MP's response to Office of Attorney General (OAG) Information Request No. 28, the Petition's Appendix C, and other sources.
[3] Wind resources are typically measured using a discount factor for reliability purposes of about 80 percent discount for reliability purposes as calculated by MISO.
[4] Solar resources are typically measured using a discount factor for reliability purposes of about 50 percent as calculated by MISO.

- 50 MW of biomass;
- 130 MW of energy only purchases;
- (30) MW of capacity and energy sales; and
- (50) MW of capacity only sales.

C. RESOURCE NEEDS AND ACTION PLAN

Table 1 below, taken from Figure 1 in MP's Petition, shows the Company's projected resource needs over the planning period. These are the needs before any new actions but after already approved actions. Note that the Company's data included the Commission-approved purchase of 50 percent of the output from the Nemadji Trail Energy Center (NTEC) starting in 2025. To illustrate the effect of the potential change in MP's share of NTEC, the Department added an adjustment to reduce the NTEC purchase from 50 percent to 20 percent.[5]

Table 1: MP's Resource Needs 2021-2035 (MW)

Year	Surplus / (Deficit)	NTEC Adjustment	Net Surplus After Adjustment
2021	28	-	28
2022	74	-	74
2023	35	-	35
2024	19	-	19
2025	244	(150)	94
2026	219	(150)	69
2027	219	(150)	69
2028	220	(150)	70
2029	221	(150)	71
2030	224	(150)	74
2031	226	(150)	76
2032	232	(150)	82
2033	240	(150)	90
2034	249	(150)	99
2035	248	(150)	98

Table 1 shows that MP does not expect a need to acquire new capacity resources for the duration of the IRP before any new actions are taken regardless of what happens to NTEC.

[5] The adjustment is based upon an assumed 250 MW original share of NTEC and assumes a 2025 in-service date, as noted above the in-service date is now expected to be 2027.

In the Petition, MP proposed the following five-year (2021 to 2025) action plan:

1. Retire the currently idled Taconite Harbor Energy Center (THEC) facility in September 2021.[6]
2. Construct three solar projects totaling approximately 20 MW in the Company's service territory in 2021 to both meet MP's requirements under the SES mandate and assist in the local economic recovery from the COVID-19 pandemic.
3. Move Boswell Energy Center unit 3 (BEC3) to economic dispatch in 2021.
4. Investigate and prepare Boswell Energy Center unit 4 (BEC4) to transition to economic dispatch in the future.
5. Continue the Company's conservation efforts via Minnesota's CIP.
6. Implement the Product C Demand Response Program for industrial customers in 2022.
7. Add 200 MW of new wind resources to the Company's power supply portfolio by 2025.

The remainder of the action plan (2026 to 2035) is as follows:

1. Retire BEC3 by December 31, 2029.
2. Add 200 MW of solar at the Boswell site or other MP facilities by 2030.
3. Pursue up to 50 MW of long-term demand response by 2030.
4. Develop and implement transmission solutions to address reliability issues related to the early retirement of BEC3.
5. Investigate options for refuel or remission BEC4 and associated reliability transmission as coal operations cease by 2035.

III. GENERAL ANALYSIS

A. APPLICABLE STATUTES AND RULES

The Commission's IRP process is governed by Minnesota Statutes § 216B.2422 which states in part:

> subd. 2. Resource plan filing and approval. (a) A utility shall file a resource plan with the Commission periodically in accordance with rules adopted by the Commission. The Commission shall approve, reject, or modify the plan of a public utility, as defined in section 216B.02, subdivision 4, consistent with the public interest.
>
> …
>
> (c) As a part of its resource plan filing, a utility shall include the least cost plan for meeting 50 and 75 percent of all energy needs from both new and refurbished

[6] THEC unit 1 (75 MW) was retired in 2015 and the remaining two units (75 MW each) were idled in 2016.

generating facilities through a combination of conservation and renewable energy resources.

subd. 2a. Historical data and advance forecast. Each utility required to file a resource plan under this section shall include in the filing all applicable annual information required by section 216C.17, subdivision 2, and the rules adopted under that section. To the extent that a utility complies with this subdivision, it is not required to file annual advance forecasts with the department under section 216C.17, subdivision 2.

…

subd. 2c. Long-range emission reduction planning. Each utility required to file a resource plan under subdivision 2 shall include in the filing a narrative identifying and describing the costs, opportunities, and technical barriers to the utility continuing to make progress on its system toward achieving the state greenhouse gas emission reduction goals established in section 216H.02, subdivision 1, and the technologies, alternatives, and steps the utility is considering to address those opportunities and barriers.

subd. 3. Environmental costs. (a) The Commission shall, to the extent practicable, quantify and establish a range of environmental costs associated with each method of electricity generation. A utility shall use the values established by the Commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the Commission, including resource plan and certificate of need proceedings.

…

subd. 4. Preference for renewable energy facility. The Commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the Commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest. When making the public interest determination, the Commission must consider:

1) whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, subdivision 2f;
2) impacts on local and regional grid reliability;
3) utility and ratepayer impacts resulting from the intermittent nature of renewable energy facilities, including but not limited to the costs of

purchasing wholesale electricity in the market and the costs of providing ancillary services; and

4) utility and ratepayer impacts resulting from reduced exposure to fuel price volatility, changes in transmission costs, portfolio diversification, and environmental compliance costs.

…

subd. 7. Energy storage systems assessment. (a) Each public utility required to file a resource plan under subdivision 2 must include in the filing an assessment of energy storage systems that analyzes how the deployment of energy storage systems contributes to:

1) meeting identified generation and capacity needs; and
2) evaluating ancillary services.

(b) The assessment must employ appropriate modeling methods to enable the analysis required in paragraph (a).

The Commission's IRP process is also governed by Minnesota Rules parts 7843.0100 to 7843.0600 which states, in part:

subp. 3. Factors to consider. In issuing its findings of fact and conclusions, the Commission shall consider the characteristics of the available resource options and of the proposed plan as a whole. Resource options and resource plans must be evaluated on their ability to:

A. maintain or improve the adequacy and reliability of utility service;
B. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;
C. minimize adverse socioeconomic effects and adverse effects upon the environment;
D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and
E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

In summary, the Commission evaluates a proposed IRP based upon its ability to create a reliable, low cost, low environmental and socioeconomic impact system that manages risk. In weighing these factors, the Commission considers the statutory preference for renewable energy facilities. As indicated in the Petition's Appendix N there are numerous other statutes, rules, and Commission orders which impact this proceeding.

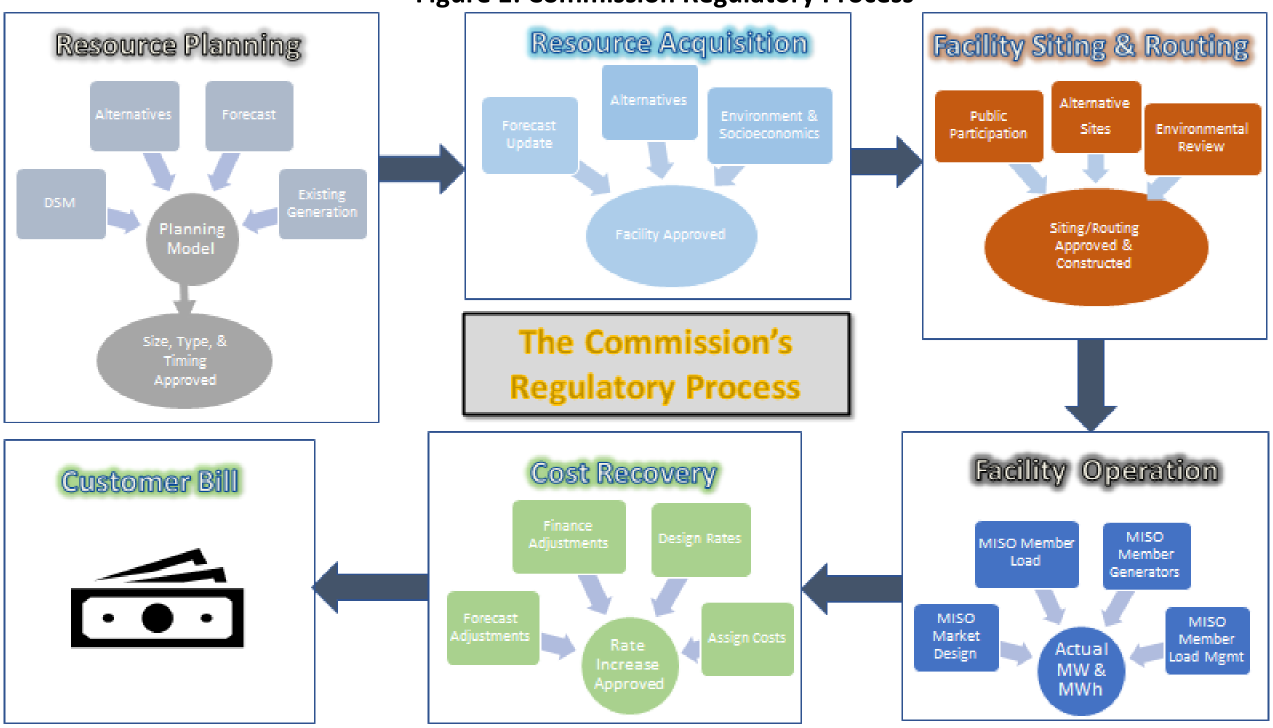
Regarding the proposal to shut down the coal plants early, the Department notes that Minnesota Statutes § 216B.16, subd. 6 states:

> If the Commission orders a generating facility to terminate its operations before the end of the facility's physical life in order to comply with a specific state or federal energy statute or policy, the Commission may allow the public utility to recover any positive net book value of the facility as determined by the Commission.

B. OVERVIEW OF DEPARTMENT ANALYSIS

An IRP is the first step in the Commission's overall regulatory process. The Commission's regulatory process as applied to generation units is illustrated in Figure 1 below.

Figure 1: Commission Regulatory Process



For MP's IRP, the Department:

- reviewed the accuracy of the Company's 15-year energy and demand forecast process;[7]
- reviewed the Company's proposed BEC3 and BEC4 retirement scenarios;
- produced a Department reference case for EnCompass based on changes to MP's modeling;

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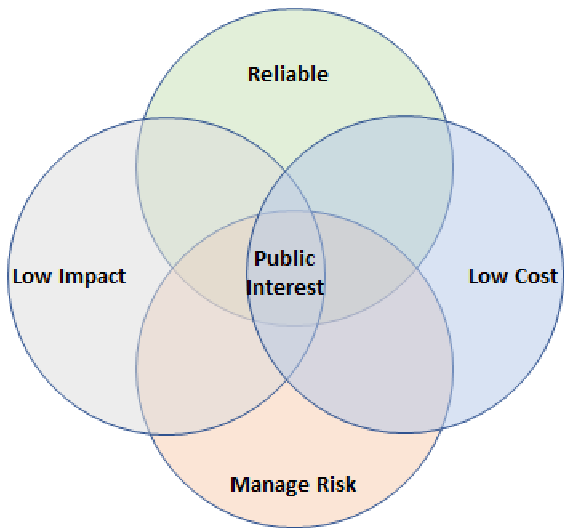
[7] As discussed further below, this means the Department did not review the technical details of MP's forecast. Instead, the Department reviewed the overall accuracy of MP's forecast process over the past 15 years.

- assessed different scenarios, including various shutdown dates for BEC3 and BEC4;
- chose a preferred plan;
- reviewed MP's information regarding securitization; and
- reviewed MP's proposed competitive bidding process to acquire supply-side resources.

The Department's recommendation for a preferred plan is based upon the overall resource planning goals of maintaining a reliable, low cost, low impact system that manages risk; this balancing of goals is illustrated in Figure 2 below.

Figure 2: Balancing the Four IRP Goals[8]



[8] Each of the four goal is embedded in numerous Minnesota Statutes and Minnesota Rules. For further details see the Direct Testimony and Attachments of Dr. Steven Rakow at Department Ex. __ SRR-2 (Docket No. E015/AI-17-568). Examples of each goal from the Commission's resource planning decision criteria:

- reliability—7843.0500 subp. 3 A—ability to maintain or improve the adequacy and reliability of utility service;
- cost—7843.0500 subp. 3 B—keep the customers' bills and the utility's rates as low as practicable;
- risk—7843.0500 subp. 3 E—risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control; and
- impact—7843.0500 subp. 3 C—minimize adverse socioeconomic effects and adverse effects upon the environment.

Under Minnesota Rules 7843.0600, subp. 2 the consequences of the Commission's order in this proceeding are clear:

> the findings of fact and conclusions from the Commission's decision in a resource plan proceeding may be officially noticed or introduced into evidence in related Commission proceedings … In those proceedings, the Commission's resource plan decision constitutes prima facie evidence of the facts stated in the decision.

C. SPOT MARKET TREATMENT IN IRP

1. Historical Approach

Traditionally, in IRPs the Department has treated the Midcontinent Independent System Operator, Inc. (MISO) energy and capacity markets (Spot Markets) as an alternative. In other words, the Spot Markets are another option for a utility to consider in meeting its demand and energy requirements. Using a well-defined Spot Market construct allows the Spot Markets to contribute towards meeting the four objectives of low cost, reliable, low socioeconomic/environmental impact system that manages risk. For example:

- allowing Spot Market energy to be consumed allows MISO's energy market to help minimize system costs;
- CO_2 emissions are accounted for in the Spot Market energy price inputs, thus directly putting emissions into the cost minimizing routine (thus addressing impact);[9]
- allowing only minimal capacity purchases means the capacity expansion model[10] (CEM) plans to build a system to meets reliability needs with minimal reliance on other parties;[11] and
- regarding risk, the discussion below is a lengthy discussion of how the Spot Markets impact risks in an IRP.

In general, Spot Market locational marginal prices (LMP) can be somewhat volatile. For example, Spot Market LMPs at the Minnesota Hub for 2008 averaged $46.16 per MWh and the LMP was over $100 per MWh for 813 hours. The next year (2009) Spot Market LMPs fell about 50 percent, averaging $23.70 per MWh and exceeded $100 per MWh in only 61 hours—a decrease of over 90 percent. While

[9] See the Petition's Appendix J at page 4.
[10] For this docket MP and the Department use EnCompass as the CEM.
[11] For this docket MP made available up to a maximum of 100 MW of wholesale market capacity for the CEM during all study years. To mitigate reliance on wholesale market energy, MP applied an increasing price adder based on the level of energy purchased. As the volume of energy purchased from the Spot Markets increased, so did the price adder. See the Petition's Appendix J for details.

Spot Market LMPs remained somewhat stable in the decade since, there is no reason to expect such stability to continue for another 15 years—the duration of an IRP. In fact, there was a steady increase in Spot Market LMPs for most of 2021 and LMPs remained high in 2022.

In addition to the economic risks, MISO's Spot Markets have potential design issues that could lead to reliability problems if they are over-used. Essentially, the Spot Markets do not provide price signals far enough in the future to trigger addition of new capacity in a timely manner. This means reliance on the Spot Markets comes with a reliability risk for MISO market participants that do not have a well-functioning IRP process. This occurred in the recent capacity auction for the 2022-2023 planning year.

From the alternatives perspective, based upon the economic and reliability risks, in the past the Department's IRP goal has been to use Spot Markets as a short-term bridge. For example, to address timing issues regarding when existing resources retire and when replacement resources come on-line. The expectation was that, in most years, Spot Market purchases and sales would generally offset each other over a longer duration. Occasionally there might be a spike in either net purchases or net sales, but such events are expected to be temporary as part of a bridge.

2. *Spot Market Basics*

i. *Capacity Market*

At a simple level, the Spot Market construct involves two-steps. The first step is the capacity market. Broadly speaking, in the capacity market a utility has the choice between two different methods of participation. In the first method a utility may participate in the annual Planning Resource Auction (PRA). Essentially, utilities submit their resources with a bid price and MISO administratively determines the auction clearing price. Resources that participated and were selected by MISO receive the auction price. The utility then pays the auction clearing price for load. Note that there is no requirement that a participant in the PRA have both load and resources.

In the second method a utility may submit a Fixed Resource Adequacy Plan (FRAP). A utility that uses a FRAP designates resources to offset the utility's Planning Reserve Margin Requirement (PRMR)—the total load plus the reserve requirement. Load and resources used in a FRAP do not participate in the PRA.

In summary, under the first method the utility simply purchases generic capacity via MISO's PRA and under the second method the utility purchases capacity outside of the MISO process and demonstrates to MISO that it has purchased sufficient capacity[12]

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[12] The FRAP process is commonly used in Local Resource Zone (LRZ) 1. For the 2021/2022 PRA, LRZ 1 had a PRMR of 18,476 MW with 14,408 MW of FRAP and 3,507 MW of "self-scheduled" resources. Thus, for LRZ 1 about 78 percent of the PRMR was acquired via FRAP and nearly all of the remainder via self-scheduling. For MISO as a whole, the PRMR was 133,902 MW, with 46,757 MW of FRAP and 82,287 MW of self-scheduled resources. Thus, for MISO about 35 percent of the PRMR was acquired via FRAP and nearly all of the remainder via self-scheduling. See: https://cdn.misoenergy.org/PY21-22%20Planning%20Resource%20Auction%20Results541166.pdf

Thus, in investment terms, purchasing capacity outside of MISO's PRA is simply the acquisition of a hedge against the PRA price.[13]

In hedging, one standard of comparison is what is referred to as a perfect hedge. A perfect hedge is a position that eliminates all risk associated with an existing position. In MISO, if a utility acquires capacity equal to its PRMR and submits the capacity and load to MISO in a FRAP, the utility has acquired a perfect hedge because the utility is not subject to the PRA price at all; there is no price risk associated with the utility's load.

Overall, as indicated above, utilities in Local Resource Zone (LRZ) 1 generally FRAP or self-schedule[14] their resources. In economic terms, one fundamental question for an IRP is "what is a reasonable price to pay for capacity as a hedge against price risk associated with merely submitting load to the PRA?" Or in rate recovery terms, is the price paid for a perfect hedge—a FRAP or self-schedule for the full PRMR—reasonable?

When considering this question, one must keep in mind that MISO's PRA process covers only a single year. Meanwhile, it can take several years for a new resource to come on-line. For example, the U.S. Energy Information Administration's *Assumptions to AEO2021* in the Electricity Market Module at table 3 shows a lead time of two or three years for a combustion turbine, a combined cycle unit, a wind unit, and a solar unit. Thus, if a utility does not have sufficient resources to FRAP and prices in the PRA spike, upwards, then the utility may be paying the higher prices for an extended duration unless capacity can be found via a bilateral contract or constructed. However, if Spot Market prices are high, the price of the bilateral contract should also be high.

In this context it is important to note that prices in the PRA cannot go upwards past a certain boundary; PRA prices are limited to the cost of new entry (CONE). CONE is calculated within MISO's process based upon the cost associated with a constructing a new combustion turbine. Thus, the PRA price is capped at approximately the lowest cost of what would have to be done to cover load in any case. This built-in cap limits the financial risk associated with PRA participation and thus limits the hedging value of a FRAP. However, there are reliability consequences to PRA participation. If all utility load participated in the PRA with no utility resources submitted, PRA prices would go to CONE, which is not necessarily a financial problem since CONE is the cost that would be paid to build a new resource. However, there would be reliability issues associated with having insufficient resources in an LRZ and/or MISO as a whole.[15] This is what happened for the PRA held in April 2022.

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[13] Hedging refers to buying one investment to reduce the risk of losses from another investment. Typically, an entity will buy an opposite investment to hedge. In MISO's capacity market process supply units and demand response are the opposite of load. Thus, the purchase of these capacity resources, which receive the PRA price, offsets the risk associated with load which pays the PRA price.

[14] For purposes of this proceeding, self-scheduling is similar to a FRAP, but for an individual resource rather than the utility's entire loads and resources. Technically, a self-schedule involves offering resources at $0.00/MW-day, up to the MW amount needed to meet obligations. A $0.00/MW-day offer ensures that at least the self-scheduled resources will clear in the PRA. Thus, a self-schedule provides a hedge against the cost of purchasing capacity for the load.

[15] It is possible for resources not under contract to be submitted into the PRA process by independent power producers. However, such resources are not large enough to serve all of the load in MISO.

From this discussion it can be observed that, for MISO's capacity market to result in a reliable system, the individual states must engage in appropriate resource planning. This is because if all load decided to take advantage of the PRA prices—which cannot go higher than the cost of capacity that would otherwise be constructed, and most of the time will be lower—then insufficient resources would be available and reliability issues would follow.

ii. Energy Market

The second step in the Spot Market construct involves the energy and ancillary services markets. MISO has both day-ahead and real-time energy markets and also ancillary services markets for functions such as regulation, spinning reserves, and supplemental reserves. For purposes of this discussion, these functions will all be treated as a single "energy" market.

Regarding participation in the Spot Market, the Commission's December 21, 2005 *Order Establishing Second Interim Accounting for MISO Day 2 Costs, Providing for Refunds, and Initiating Investigation* (Docket Nos. E015/M-05-277, et al) required that "Each petitioner shall limit its level of activity in the real-time market to five percent of total purchases for retail customers, or make real-time market activities subject to prudence review on an annual basis in the annual automatic adjustment of charges docket arising pursuant to Minnesota Rules part 7825.2810." Further, the Company's May 3, 2021 *Annual Forecast of Automatic Adjustment Charges for the period of January 2022 through December 2022* (Docket No. E015/AA-21-312) described the operation of MISO's energy market and stated that, in the short-term MP "also looks to buy energy in the short-term bilateral market when there is an energy need and purchases can be made below expected MISO day-ahead costs." Thus, MP has taken steps to reduce short term market exposure.

In the medium term, MP analyzes its forward monthly energy position using a production cost model. When a significant energy deficit is identified:

> the Company monitors the wholesale market for least cost supply opportunities and enters into bilateral purchases to maintain volumetric position limits as outlined in Minnesota Power's Power Marketing Risk Management Policy. If forward energy prices drop below forecasted spot market prices the entire short position could be covered with a bilateral purchase prior to the start of the outage. If lower cost energy is available in the areas that border the MISO north region, Minnesota Power may choose to use bilateral purchases from those border areas to cover a generator outage

In general, each location in MISO has its own LMP. The utility's load is bid into the energy market and the utility pays the LMP at the load's site. The utility's generation, if any, is also bid into the energy market and the utility receives the LMPs at the generator(s) site—if the generator(s) produce electricity. In this scenario, Equation 1 provides a simple explanation of how the utility's overall energy bill is determined. For now, assume that the generator is always selected by MISO and produces energy equal to load.

Equation 1: Customer Bill Components

$$\textit{Variable Cost}_{Gen} - LMP_{Gen} + LMP_{Load} = \textit{Utility Bill}$$

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

$$\textit{Variable Cost}_{Gen} = \textit{Utility Bill}$$

This example shows that, at one extreme, ownership of generation that produces energy equal to load each hour represents a perfect hedge against LMP risk in the Spot Market.

This example also implies that, in the other extreme where a utility does not own any generation, then the LMP_{Gen} and Variable $Cost_{Gen}$ are zero. From Equation 1 it can be seen that, in this scenario, the utility's bill is equal to LMP_{Load}. This represents a strategy that could be followed—not building generation and simply paying the Spot Market price. In essence, the utility would have no hedge.

Thus, acquisition of resources, to the extent they can produce energy that offsets load, represents another hedge, this time against Spot Market LMPs. Thus, *when resources are offsetting load, they represent a decrease in spot market risk.* Note that LMPs are not the same in all locations. The closer LMP_{Gen} is to LMP_{Load} the more successful a hedge the resources should represent. If Equation 2 is true, then the resources represent a form of a perfect hedge. Assuming a successful hedge leads us to Equation 3 and the fact that the Variable $Cost_{Gen}$ determines the utility bill; the utility is insulated from Spot Market LMPs.

Note that in this case the acquisition of resources, while insuring against the risk inherent in LMP_{Load} also creates a risk in that Variable $Cost_{Gen}$ is uncertain for some resources. This is the case, for example, when a power plant is fueled by natural gas. In this example the acquisition of a resource as a hedge against LMP_{Load} leads to a different form of risk and another potential round of hedging—here against natural gas fuel price risk. Finally, while resources such as wind have little to no fuel cost risk, they are not completely dispatchable and thus cannot be assumed to be producing energy when LMPs spike upwards.

Also, when acquiring resources, it is not only the energy prices (expected LMP_{Gen} and LMP_{Load}) that must be considered but also the quantity (MW). The closer the MW of resources acquired is to the MW of load, the more successful a hedge the resources represent. When the MW of resources acquired are less than the MW of load, some of the load is unhedged and will pay LMP_{Load}. When the MW of resources acquired is greater than the MW of load, all of the load is hedged and, in addition, some of the resources represent speculation on LMP_{Gen}. Thus, when resources greater than load are acquired, the resource represents an addition to the pool of spot market risk. Since MP has resources in excess of load (see Table 1 above), unless MP shuts down existing generation resources, resource additions generally are not a hedge decreasing risk. Instead, they represent an increase in risk faced by MP's ratepayers.

There is a fundamental difference in the risk profile associated with resources acquired to offset load versus resources acquired based on expected LMP_{Gen}. When a utility is long (has surplus capacity) the economic risk is capped at the cost of the existing units—the worst that can happen is ratepayers pay the cost of the units but get no offsetting revenue. When a utility is short (does not have enough capacity) the only cap on economic risk is the Spot Market price cap. Thus, risks are not symmetric. This implies that, during IRP and resource acquisition analysis, the reasons for acquiring a resource must be ascertained to enable prudent decisions.

Furthermore, when acquiring resources, the variable cost must be considered. At any point in time Variable $Cost_{Gen}$ can be less than, equal to, or greater than LMP_{Gen}. The analysis above dealt with the situation where Variable $Cost_{Gen}$ is equal to LMP_{Gen}. In a situation where the Variable $Cost_{Gen}$ is not equal to the LMP_{Gen}, then Equation 1 can be re-arranged to better show the consequences; see Equation 4 below.

Equation 4: Customer Bill Components Rearranged

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

If Variable $Cost_{Gen}$ is less than the LMP_{Gen}, then the difference between LMP_{Gen} and Variable $Cost_{Gen}$ becomes a subtraction from LMPLoad, decreasing the utility bill. In this circumstance, ownership of generation is an advantage. If Variable $Cost_{Gen}$ is greater than LMP_{Gen}, then the generator should not operate.[16] In this circumstance, ownership of generation is a disadvantage. Thus, Variable $Cost_{Gen}$ represents a cap on exposure to LMPs because if LMP_{Gen} goes above Variable $Cost_{Gen}$, the utility's resource should provide energy in place of the Spot Market.

Finally, operational availability must be considered. A resource that is perfectly flexible—can be ramped up and down at will—represents the ideal resource from a hedging perspective because it lacks limitations on the ability to provide the hedge. However, no resource is perfectly flexible; for example, resources have a time lag between first being notified of the need to be on-line and operating at full capacity. Some resources, such as combustion turbines, are relatively flexible while others, such as nuclear units, are relatively inflexible. Finally, intermittent resources such as wind have limits in that availability of the fuel (wind) can be uncertain.

3. Spot Market and CEMs

The various factors involved in Spot Markets are considered in the CEM to varying degrees. For example, MP has a Spot Market for capacity built into EnCompass. MP's capacity market construct in EnCompass allows purchases (but not sales) by MP of up to 100 MW.[17] Because purchases are allowed, the structure of MP's inputs does not ensure that the Company plans to have sufficient capacity to meet the PRMR from its own

[16] However, if the generator does operate despite the LMPs the difference between LMP_{Gen} and Variable $Cost_{Gen}$ becomes an addition to LMPLoad, increasing the bill. See Docket No. E999/CI-19-704 for further details.
[17] See the Petition's Appendix J for details.

resources. Instead, the construct assumes that up to 100 MW of capacity will be available in MISO's PRA or via bilateral contracts.[18]

For the last three PRAs LRZ 1 capacity offered (supply of capacity) has been greater than the PRMR (demand for capacity) by an average of 1,850 MW. MISO as a whole has had capacity offered greater than the PRMR by about 6,530 MW, thus nearly 30 percent of the surplus capacity in MISO is located in LRZ1. In summary, for the near term it appears that there is surplus capacity in MISO available as assumed by MP's Spot Market construct. However, a large portion of MISO's surplus is in LRZ1 and scheduled retirements may reduce the surplus to a significant degree relatively soon. While MP's capacity market construct allows only purchases, MP's energy market construct allows both sales and purchases. MP's energy market construct does not have a physical limit. However, the Petition describes an escalating penalty as the Company purchases increasing amounts of energy from the Spot Market. Thus, there are economic limits to how much the Company can rely upon the Spot Market for energy. The policy question is how much reliance is reasonable. The higher the energy market limit the more the market can serve to reduce costs. But the tradeoff is the same higher limit can create risks. For example, risk could be added via adding units to make profitable sales, only to find out later that the energy market pricing was wrong and the unit's costs are incurred, but the offsetting market revenues are not realized.

Finally, the Department notes that all Spot Market constructs in CEMs contain an inherent flaw that must be considered when analyzing and interpreting CEM outputs. In economic terms, CEMs contain barriers to entry that prevent utilities, other than the utility being modeled, from responding to any price signals contained in the CEM. For example, it could be the case that new solar units are priced at $8 per MWh while the Spot Market price is set at $10 per MWh in a CEM. In this circumstance, the CEM would add solar to sell into the Spot Market and reduce overall system revenue requirements by the $2 per MWh gap. However, in the real world, responding to the $2 gap between solar prices and Spot Market prices is not limited to the utility being modeled. Other utilities (such as Great River Energy), independent power producers (such as NextEra Energy, Inc.), and others can also respond to the gap. The resulting competition would eliminate the $2 per MWh gap. Thus, the CEM's expected profits may not be realized in the real world. The consequence of this for MP's IRP is that units that are added by the CEM may only be added due to the difference in their cost versus the expected Spot Market revenue. That difference might not be realized when entities other than MP respond to the price signal.

The same logic applies to existing units, not just new units. For example, assume that that a CEM has a single natural gas price for all units to use and that the CEM's Spot Market prices were designed using that natural gas price and a CT unit (with a heat rate of 10,000 MBTU per MWh) to set the Spot Market price. If the utility being modeled has a CC unit (with a heat rate of 7,000 MBTU per MWh) then that CC unit will be able to take advantage of the heat rate differential (the 3,000 MBTU per MWh gap between the Spot Market's CT and its own heat rate) to sell energy into the Spot Market and reduce overall system revenue requirements by the 3,000 MBTU per MWh gap. Once again, in the real world, responding to the heat rate gap between CC units and Spot Market prices is not limited to the utility being modeled. Other utilities, independent power producers,

[18] The Petition's Appendix J also states that an unidentified bilateral purchase, referred to as a "bridge purchase" was available as an expansion unit starting in 2026. The bridge purchase provides energy and capacity.

and others can also respond to the gap. The resulting competition would eliminate the heat rate gap. Again, the CEM's expected profits may disappear in the real world.

In summary, CEM's are a static model of a dynamic process. As a result, it is not enough to simply get a set of results. It is critical to understand why the model is producing the results and to understand the resulting risks from factors outside the model's consideration. The result for the IRP is that units recommended for MP's expansion plan may differ from CEM outcomes due to the necessity of considering factors beyond the CEM's ability to consider. In particular, units may be removed from the proposed expansion plan if it appears they are cost effective largely due to an assumed gap between the unit's costs and the expected revenues from the Spot Market.

D. RELIABILITY VERSUS ECONOMIC RISKS

At times participants in IRP and resource acquisition dockets have confused economic and reliability risks. In general, the confusion is between the value dispatchable generation provides any one utility system with the value provided to the broader Spot Markets. In essence, regardless of the availability of dispatchable generation on any one utility's system, the utility's load (and customer reliability expectations) can be met. If a utility has insufficient dispatchable generation, it would maintain reliability via participating in the broader MISO market. Thus, lack of dispatchable capacity on any one utility system is not a reliability issue because the load simply would be met by non-utility resources—in other words the utility becomes a net importer in certain hours.[19] Instead, it is an economic risk (a hedging issue). As explained above, to the extent MP is a net importer the Company pays the Spot Market price for energy and thus is exposed to an unhedged economic risk.

In comparison, insufficient dispatchable capacity on MISO's system as a whole—for example, during low wind/solar output hours—could be a reliability issue as it might result in a situation where insufficient capacity was available to MISO to dispatch in order to meet load. This is a system-wide reliability issue. A regional reliability issue could occur if a utility's (or combination of utilities) shortfall exceeded the region's import capability available from the rest of MISO (via the transmission system) and that utility did not have sufficient firm capacity available to make-up for that shortfall. That is, a reliability issue would occur if MP's capacity deficit triggered a regional capacity deficit greater than the region's ability to import power.

Overall, it is important to avoid confusing economic risk (exposure to MISO spot market prices due to being a net importer) with reliability risk (insufficient capacity available system-wide or insufficient import capability to meet load). This is because such confusion creates problems for parties in understanding the consequences of a utility's proposed action plan in an IRP or resource acquisition docket.

All three rate regulated utilities have identified risks related to their proposed expansion plans in the past. For example, see the petition of Northern States Power Company doing business as Xcel Energy (Xcel) in Docket No. E002/RP-19-368 identified a potential risk-related issue: "The addition of several

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[19] An exception is that enough resources must be located in each LRZ to meet a portion of the load in that zone. A utility could reasonably claim that a portion of the quantity resources that must be sited locally need to be on that utility's system for planning purposes.

gigawatts of renewable resources requires that we consider not only our traditional summer peak, but also whether we have sufficient dispatchable resources to meet other peaks, including in winter when solar energy is typically unavailable and wind resources may not be available for long periods of time." Similar statements were made by MP regarding NTEC and by Otter Tail Power Company regarding Astoria Station.

Depending upon the degree to which the Commission determines to rely upon the ability of non-dispatchable resources to mitigate risk, the issue of Spot Market exposure may influence the mix of resources ultimately determined to be necessary to replace resources ordered to be retired as a result of this IRP. As multiple coal units retire, the ability of new dispatchable units to hedge MP's load against market prices (while potentially creating a fuel price risk) may or may not be necessary. In summary, the Department did not make any adjustments to the CEM based upon this reliability versus economic spot market risk.

E. ASSESSMENT OF MISO IMPACTS

a.

1. Introduction

In preparation for the CEM analysis the Department reviewed information regarding the current status of MISO's generation interconnection queue (GIQ). One potential issue regarding MP's (or any utility's) preferred plan is the degree to which the plan can be implemented given that generation projects of any size must move through MISO's GIQ before they can come on-line. Distributed generation (DG) and load management projects can bypass the MISO GIQ. Thus, the GIQ cannot eliminate a preferred plan, but can limit the alternatives available to meet the preferred plan.[20] Both the issue of MISO GIQ status and the potential impact on generation units are explored below.

2. Status of MISO's GIQ

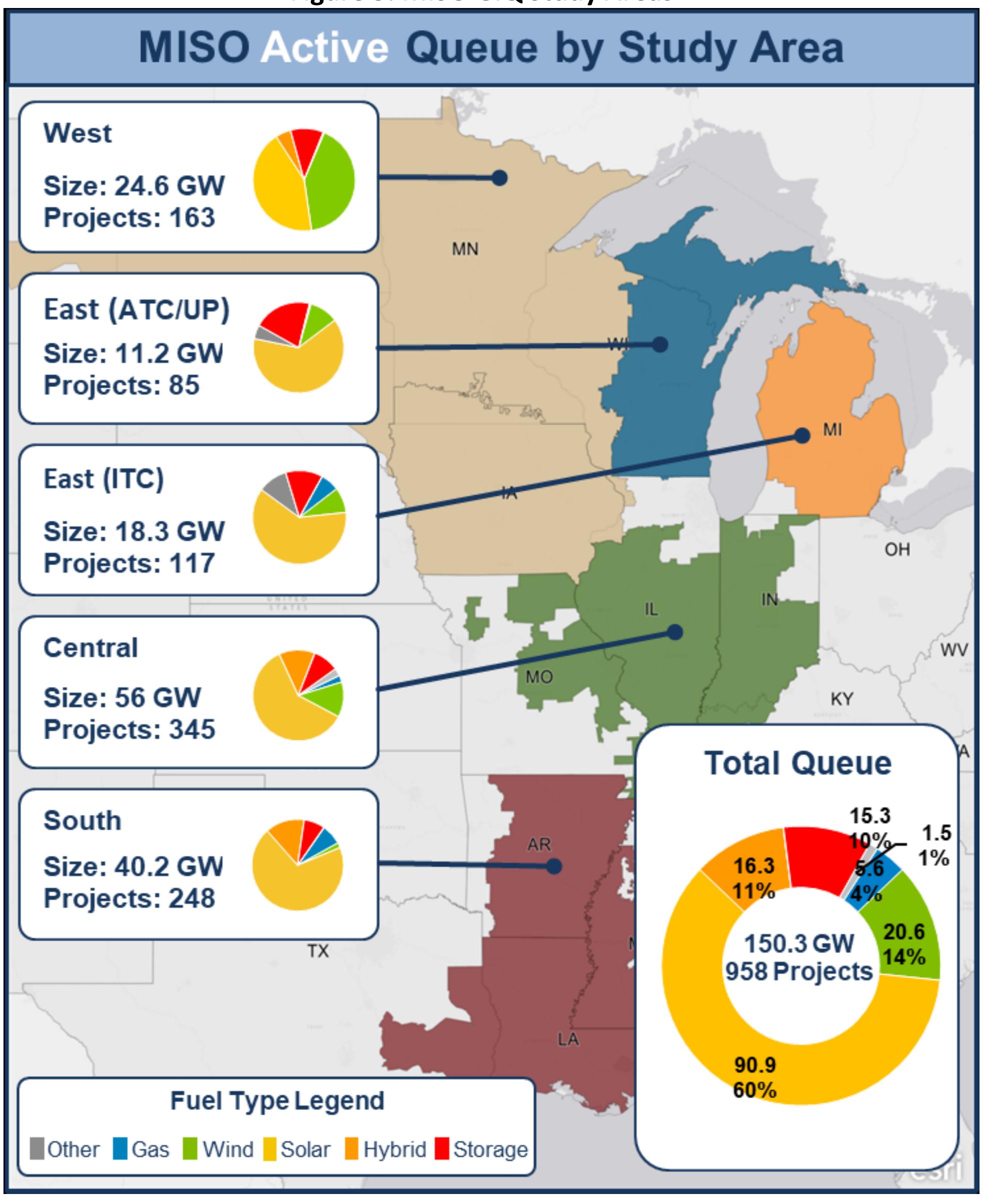
i. Background

The MISO GIQ is divided into several study areas. A picture of the GIQ study areas is provided in Figure 3 below. Figure 3 shows that Minnesota is in the West Study Area. Thus, all subsequent data in this section focuses on the West Study Area. This is because the further a generator is from load presumably the greater the potential for LMP_{Load} to be different than LMP_{Gen}, thus introducing a risk to the system. Also note that Figure 3 shows that, as of October 1, 2021, a total of 150.3 GW in MISO as a whole and 24.6 GW for the West Study Area in the GIQ. For purposes of context, the MISO system peak demand would be approximately 125 GW. The GIQ's West Study Area appears to be similar to the MISO North region reported in MISO's *Daily Regional Forecast and Actual Load* report. For the

[20] For example, a 200 MW solar unit may have to be installed as separate projects too small to require studying in the GIQ process.

years 2015 to 2019 the MISO North region's annual peak demand varied from 24.9 GW and 26.2 GW. Thus, the generation in the GIQ represents a sizable fraction of existing load for both MISO and the West Study Area.

Figure 3: MISO GIQ Study Areas[21]



[21] Taken from the Informational Forum presentation available on MISO's website, dated October 19, 2021: https://cdn.misoenergy.org/20211019%20Informational%20Forum%20Presentation597254.pdf

Based upon this data and other factors MISO has concluded that many interconnection requests in the GIQ will never be built. In response, MISO has recently implemented GIQ reforms, such as increased site control requirements. The reforms are targeted at reducing the number of non-buildable projects in the GIQ. The degree of success realized by MISO's reforms will be determined in the future as the changes are implemented and market participants react to the changes.

ii. Delay Issues

In November 2021 the Department obtained data from MISO's website regarding the initially announced and actual start dates for each Definitive Planning Phases (DPP) group that was currently underway and for the most recently completed DPP group. In obtaining this data the Department focused on the MISO West Study Area and did not go further back than April 2017. Therefore, the "initially announced" dates for some DPP groups are likely not far enough in the past. However, the data obtained is sufficient to illustrate the timing issues encountered by projects in MISO's GIQ process. This data on DPP start dates illustrates the delays encountered by MISO in getting a DPP group started.

The Department also obtained the estimated final date to execute[22] a generation interconnection agreement (GIA) when each DPP group started and the actual final date (or most recent estimate) for executing a GIA. This data on final date to execute a GIA illustrates the delays encountered by MISO in getting a DPP group from the start to the end; in other words, the delay in processing the group. The two sets of data are summarized below in Table 2.

Table 2: MISO West Study Area Group Start and End Dates

West Region Study Groups	DPP Start			GIA Executed			Total Delay
	First Estimate Announced	Actual	Delay Days	Estimate at DPP Start	Actual	Delay Days	
DPP-2016-FEB	27-Jan-17	27-Jan-17	-	16-Jun-18	29-Mar-19	286	286
DPP-2016-AUG	16-Jun-17	12-Sep-17	88	21-Feb-19	01-Mar-20	374	462
DPP-2017-FEB	03-Nov-17	15-Oct-18	346	02-Mar-20	16-Mar-20	14	360
DPP-2017-AUG	23-Mar-18	12-Jun-19	446	05-Nov-20	13-Jan-22†	434	880
DPP-2018-APR	10-Aug-18	09-Sep-19	395	28-Jan-21	11-May-22†	468	863
DPP-2019-Cycle1	20-Dec-19	05-May-20	137	21-Jan-22	19-Sep-22†	241	378
DPP-2020-Cycle1	03-Dec-20	06-Jan-21	34	27-May-22	21-Nov-22†	178	212

† Date in the future at the time the table was prepared.

Table 2 shows that the recent study DPP groups in the West Study Area have all encountered substantial delays. The minimum delay encountered, for DPP-2020-Cycle1, is seven months. This group is not yet completed and may experience further delays. The maximum delay, for DPP-2017-AUG, is nearly 2.5 years. Clearly the reforms

[22] Executing a GIA is the final step in MISO's GIQ process.

implemented by MISO will require a dramatic impact to reduce the delays in processing the West Study Area GIQ to a reasonable level.[23]

According to the schedules shown in Table 2, the actual DPP process was supposed to take a total of approximately 505 days (~17 months). Again, MISO has been working to substantially reduce the time required for the DPP process. Nonetheless, the Department used this data to estimate the lead time to get through MISO GIQ. Considering the minimum overall delay of 9 months results in an estimate of at least two years to get through the MISO GIQ process. Considering the maximum overall delay of two years results in an estimate of about 3.5 years to get through the MISO GIQ process.

Assuming one or two years are needed for final permitting and construction of a project indicates that it would be wise to assume that no new supply units are available in a CEM for the first five years unless it is reasonable to assume that new projects:

- can be acquired in a manner that avoids the MISO GIQ process; or
- currently in the GIQ (or recently completed the GIQ without a buyer) can be obtained at a reasonable cost.

The transmission costs recently incurred by projects in the GIQ are discussed in the next section. Ultimately, the Department did not limit availability of new expansion units in the early years because there is no reason to limit resource planning based on MISO's GIQ since there are other potential paths to obtain projects. In the later years of this IRP the delays are not as important because there will be sufficient time to take the steps necessary to construct a new project and MISO's reforms may have an impact.

iii. *Cost Issues*

Table 3 below shows the capacity studied and the resulting costs from the published studies for all three DPP phases for the five most recently completed DPP groups in the West Study Area. Note that DPP1 results from DPP-17-AUG and DPP-18-APR are not comparable to the data for prior DPP groups due to changes in what is studied in DPP1.[24]

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[23] The Department notes that the initially announced start date for the DPP-2021-Cycle 1 group was October 20, 2021 and the current estimated start (again, as of early November, 2021) is December 1, 2021, a delay of 42 days.
[24] The changes are part of MISO's efforts to speed up the DPP studies.

Table 3: MISO West Study Group Results
Projects Requesting Network Resource Interconnection Service (NRIS)

	NRIS MW			Average NRIS $,000 / MW			Maximum $,000 / MW		
Study Group	**DPP 1**	**DPP 2**	**DPP 3**	**DPP 1**	**DPP 2**	**DPP 3**	**DPP 1**	**DPP 2**	**DPP 3**
DPP-16-FEB	5,387	4,567	3,302	$ 475	$ 135	$ 60	$1,164	$ 240	$ 159
DPP-16-AUG	5,618	2,400	2,302	$ 639	$ 141	$ 93	$1,923	$ 461	$ 134
DPP-17-FEB	3,421	1,394	245	$ 969	$ 1,966	$ 970	$2,089	$ 4,265	$ 1,211
DPP-17-AUG	4,819	3,594	600	$ 181	$ 679	$ 103	$ 609	$ 1,647	$ 247
DPP-18-APR	8,023	4,240	953	$ 134	$ 225	$ 64	$ 606	$ 2,676	$ 226

To provide context for the cost numbers in Table 3, the U.S. Energy Information Administration's (EIA) *Assumptions to AEO2021* publication shows an estimated overnight cost to construct a wind project of about $1.85 million per MW and a cost to construct a solar project of about $1.25 million per MW .

Table 3 shows that the DPP-16-FEB group was largely successful in obtaining NRIS interconnection at a reasonable cost; 61 percent of the NRIS capacity studied in DPP1 was still in active for DPP3 and the maximum cost for a project turned out to be $159,000 per MW or an 8.5 percent cost increase using EIA's overnight wind cost. However, the second group in Table 3, DPP-16-AUG, encountered significant transmission cost issues and was less successful; only 41 percent of the capacity studied in DPP1 was still in active for DPP3 but the maximum cost for a project was similar, about $134,000 per MW or a 7 percent cost increase using EIA's overnight wind cost. Finally, the third group in Table 3, DPP-17-FEB, largely failed; apparently due to transmission cost issues. Only seven percent of the NRIS capacity studied in DPP1 was still active for DPP3 and the maximum cost for a project soared to $1,211,000 per MW. The two most recent groups, DPP-17-AUG and DPP-18-APR have largely failed to get NRIS projects through the GIQ. Only 12 percent of the NRIS capacity of both DPP-17-AUG and DPP-18-APR was still active for DPP3.

From the data in Table 3 it appears that the affordability upper limit for a project is around $150,000 to $200,000 per NRIS MW for transmission costs. Further, the West Study Area appears to be very short of affordable transmission interconnection capability. A preferred plan that involves obtaining interconnection for substantial amounts of new capacity may not be achievable within the MISO GIQ construct until the new transmission projects being studied by MISO are in-service. Furthermore, no amount of GIQ timing reforms can change the lack of transmission; it can only deliver the message that transmission is not available sooner. Since MP's proposed action plan involves acquiring 200 MW of new wind resources by 2025 the issues in the MISO GIQ do not appear to be critical for MP. The amount of capacity MP is seeking should be available via the MISO GIQ or via projects that can avoid the GIQ such distributed generation or re-use of existing interconnection.

iv. *Recommendations Regarding MISO*

The Department notes that under Minnesota Statutes § 216B.2425 all utilities that own or operate electric transmission facilities in Minnesota must file a report by November 1st of each odd numbered year on the status of the transmission system. In the *2019 Biennial Transmission Projects Report* filed by the Minnesota Transmission Owners (Docket No. E999/M-19-205) the Commission required additional information be provided on transmission improvements that may be needed to meet utility clean energy goals and resource plan requirements, and to identify any gaps that may exist. Therefore, the Commission is addressing any potential transmission shortfalls in the biennial transmission planning process.

Based upon the review in this section, it is unlikely that significant amounts of new NRIS resources can be added by MP or other utilities in the near future unless the resources can be obtained outside of the MISO GIQ. In addition, the data indicates that a transmission cost cap of about $150,000 to $200,000 per NRIS MW currently exists. However, the data also show that there is little interconnection capacity with costs below the cap. Therefore, the Department concludes that either the transmission cost cap will increase, the cost of major transmission upgrades that increase interconnection capacity will be distributed beyond the GIQ (for example, as Market Efficiency Projects (MEP) or Multi-Value Projects (MVP)), or generation projects will not get built via the GIQ.

F. DEMAND AND ENERGY FORECASTS

1. Introduction

The Petition was prepared using the Company's Advanced Forecast Report (AFR) for 2020—see the Petition's Appendix A: *Minnesota Power's 2020 Annual Electric Utility Forecast Report*. MP's AFR2020 was filed on July 20, 2020 in Docket No. E999/PR-20-11. According to Appendix A:

> Annual energy sales are projected to decline at a -0.4 percent per year rate (on average) from 2019 through 2034. Summer and Winter peak demands are projected to decline at average annual rates of -0.5 percent and -0.3 percent, respectively. The AFR 2020 load forecast reflects 103 megawatts (MW) of system load loss by 2030. [citation omitted]

The review of the AFR2020 forecast in this docket had two goals. First, to be done quickly. Second, to establish an acceptable base forecast and an acceptable forecast range for long term planning purposes. Given these limits, the forecast review did not address some details that would normally be part of forecast analysis. This means that the Department neither reviewed the technical details of MP's forecasts nor tested all the Company's previous or current statistical models. Instead, the Department examined the potential for bias in MP's forecasting over the past two decades. As described below, the review indicates that the Company's demand and energy forecasts do not have a systematic bias, other than the impact of a significant decrease in load since 2015. Consequently, for this IRP, the Department did not adjust MP's forecast used to evaluate capacity expansion plans.

Note that the Commission's July 18 Order stated the following regarding MP's forecasts in the prior IRP:

> The Commission concurs with the Department that Minnesota Power's range of load forecasting used for its 2015 resource plan is reasonable for planning purposes. However, the Clean Energy Organizations' comments serve to

> highlight the economic trends that have led to lower demand projections in recent forecasts. In light of these trends, Minnesota Power's load forecast scenarios used in its 2015 resource plan may overstate the size or timing of future needs. The Commission bears this fact in mind as it evaluates the Company's preferred plan in the following sections.

Thus, the Commission expressed a concern that MP's IRP forecasts may be too high and adapted the approved plan to that concern.

2. Comparing AFR2020 to AFR 2021

Since the Petition was filed the Company has filed a new forecast (AFR2021)—on June 29, 2021 in Docket No. E999/PR-21-11.[25] To determine if updating the Department's EnCompass inputs to reflect the newer forecast (AFR2021) was warranted the Department compared the base and high energy and demand forecast results for AFR2020 to the base forecast results for AFR2021. The purpose was to determine how different the two forecasts (AFR2020 and AFR2021) were. Also, the Department compared the AFR2021 forecast to the range established by the base and high forecasts in AFR2020. The purpose was to see if AFR2021 was within the range established in AFR2020. The results of the comparison for the demand forecasts are shown below in Figure 3.[26]

[25] Note that OAG IR No. 33 asked MP if the AFR2022 was expected to differ significantly from AFR2021. MP's answer was that "At this time, the Company does not expect its 2022 AFR outlook to differ significantly from the 2021 AFR." The Company then discussed two projects that are expected to add less than 15 MW of total new load. MP concluded that AFR2022 "is expected to be well within the range of load sensitivities" tested in this IRP.

[26] Note that Figure 3 shows the summer forecast results since that is the season used by MISO for reliability purposes. The data was taken from section III C (Expected Scenario Peak Demand and Energy Outlooks) of AFR2021 and section 2 C (Peak Demand and Energy Outlooks) of AFR2020.

Figure 3: AFR2020 Versus AFR2021 Demand Forecasts (MW)

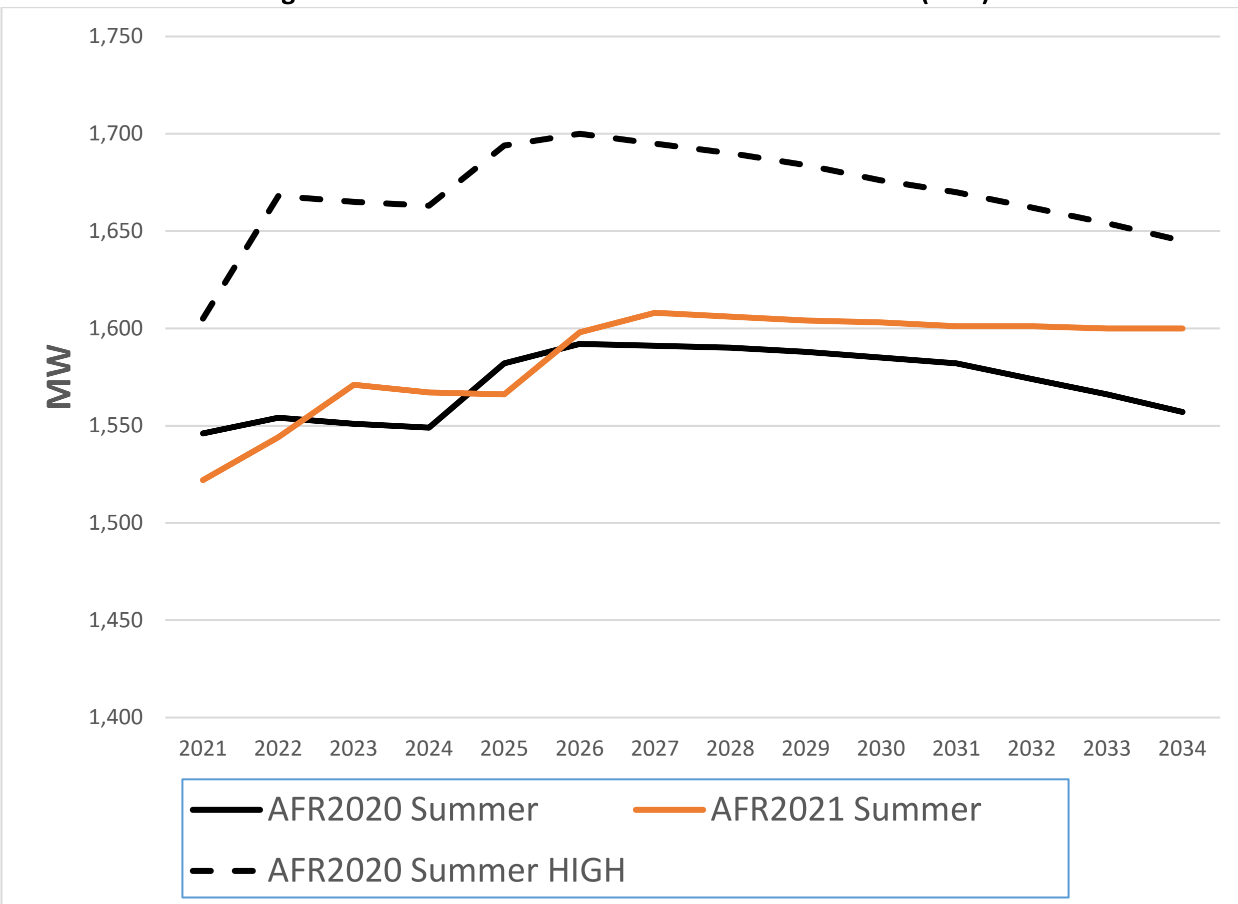

Figure 3 shows that, through 2031 the two demand forecasts are very close to each other, differing between 15 MW and 20 MW each year. For the final 3 years of the comparison (2032 to 2034) AFR2021 begins to diverge from AFR2020, the difference grows to 43 MW in 2034 or about 2.7 percent. However, the AFR2021 demand forecast is well within the high forecast—base forecast range established by AFR2020.

The results of the comparison for the energy forecasts are shown below in Figure 4.

Figure 4: AFR2020 Versus AFR2021 Energy Forecasts (MWh)

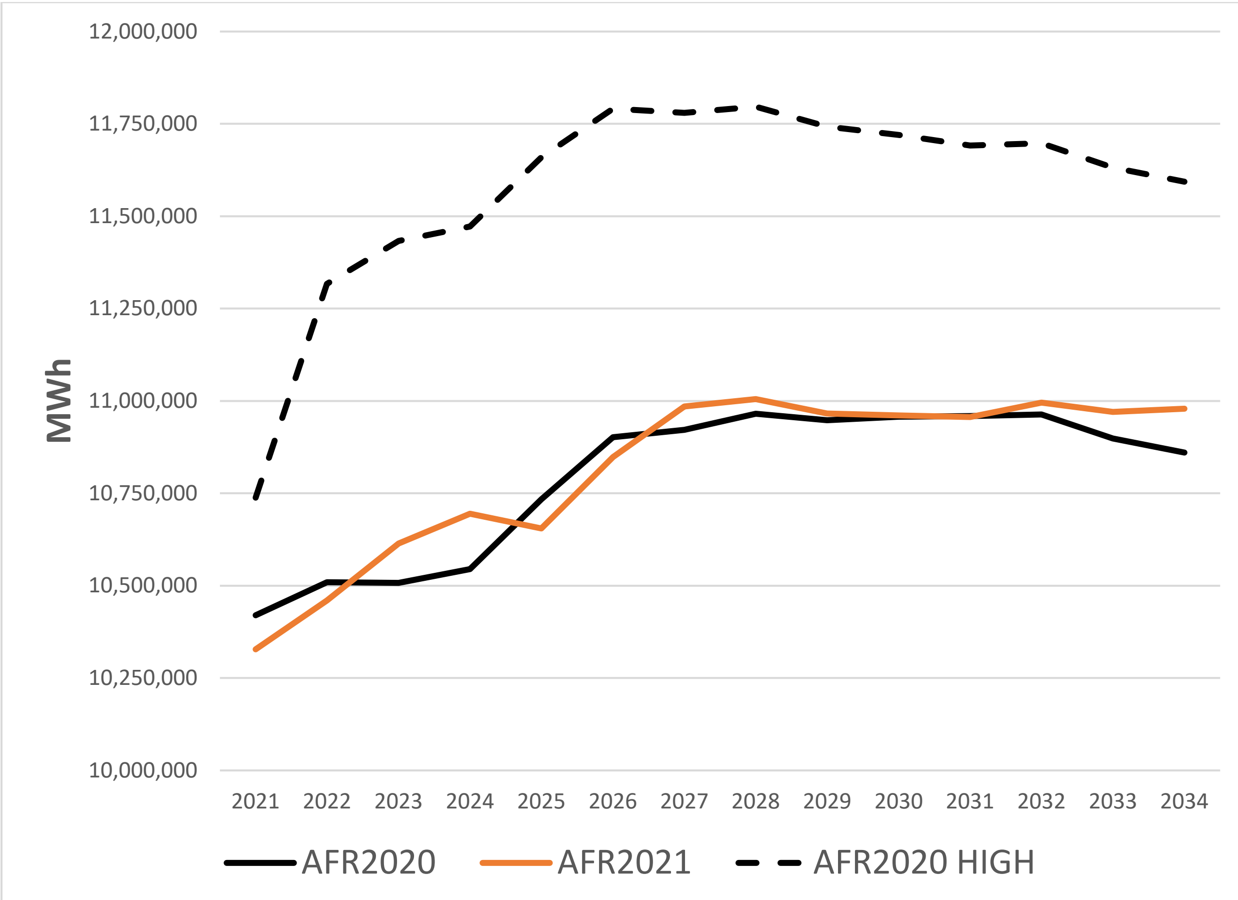

Figure 4 shows that the two demand forecasts are very close to each other for the entire period, differing by between ± 100 GWh most years or about ± 1.0 percent. Again, the AFR2021 energy forecast is well within the high forecast—base forecast range established by AFR2020.

Based upon this analysis the Department concludes that the two forecasts (AFR2020 and AFR2021) are too close for the differences to meaningfully impact the selection of a preferred plan or the associated size, type, and timing of expansion units in this IRP. Therefore, the Department elected to not update the EnCompass database with AFR2021 inputs.

When comparing the two forecasts the Department noted that the historic peak demand shown in Table 1 of AFR2020 and Table 1 of AFR2021 for the years 2017 to 2019 was slightly different (by 10 MW or less). The historic energy did not differ between the two AFRs. Given the small size of the discrepancy and the probable lack of impact on the IRP results, the Department elected to not pursue this issue.

3. *Overview of AFR2020*

The Department notes that MP's forecasting that utilizes its AFR2021 for certain customer classes, will be reviewed in detail for those certain classes in the Company's current rate case (Docket No. E015/GR-21-335). The Department elected to not review AFR2020 in detail for this IRP. As an overview, the Department notes that the scenario from AFR2020 used as the basis for the IRP projects 93 MW of load loss by 2025 when compared to current levels.[27] According to AFR2020 much of the load loss can be attributed to two different customers whose facilities are indefinitely idled in the base forecast. According to Figure 5 of the Petition MP's energy sales in the base case can be broken down by class as follows:

- Industrial—61 percent;
- Resale—16 percent;
- Commercial—12 percent;
- Residential—10 percent; and
- All others—1 percent.[28]

AFR2020 contains three forecast contingencies, high, mine restart, and low. The contingencies are illustrated in the Petition's Figure 6 and Figure 7. The high forecast contingency assumes the full operation of all taconite mining customers and the restart of the Verso Duluth paper mill, capturing about 100 MW of additional load over the Base Case. The mine restart forecast contingency also assumes full operation by taconite mining customers, but the Verso mill remains idled indefinitely. The low forecast contingency is 5 percent (approx. 75 MW) lower than the base forecast to simulate the loss of additional industrial load.

For resource planning purposes, the Company's base forecast shows a significant, long-term drop in energy and demand requirements while the high and mine restart contingencies essentially return demand and energy requirements to the historic levels and do not include significant new requirements. Therefore, the Company's IRP is focused on adapting to a permanent loss of load with the possibility that, at most, load returns to the prior level. Given that MP's customer mix is dominated by the industrial class, the future of the Company's mining and wood-based industrial customers is most important for determining the accuracy of the Company's forecast. Overall, the Department concludes that the forecast range established by MP is acceptable for planning purposes. When evaluating EnCompass results, the Department focused on the base case and the high forecast contingency as showing the most likely range of actual demand and energy requirements for the IRP.

4. *AFR2020 Forecast Bias Analysis*

The Department briefly reviewed the overall results of MP's forecast process as documented in the Petition's *Appendix A: Minnesota Power's 2020 Annual Electric Utility Forecast Report.* The Department's review focused

[27] July 2019 demand was 1,674.5 MW.
[28] All others includes both lighting and public authorities

on Appendix A's Table 8 (Energy Sales Forecast Accuracy) and Table 9 (Summer Peak Demand Forecast Accuracy). Tables 8 and 9 show the forecast errors (difference from actuals) for the forecasts prepared for AFR2000 to AFR2019. Each forecast covers a 15-year period. Table 8 of Appendix A is replicated below in Table 1 and Table 9 of Appendix A is replicated below in Table 2. In Tables 1 and 2 a positive number indicates the forecast turned out to be too high and a negative number indicates that the forecast turned out to be too low. For easy identification, the Department shaded the cells in Tables 1 and 2 that are negative. Finally, Tables 1 and 2 are broken down into sub-sections so as to better enable a comparison of AFR2000 through AFR2015 versus AFR2016 through AFR2019 and the years 2000 through 2014 versus 2015 through 2019.

Overall, as shown in Tables 1 and 2 MP's energy and demand forecasts were too high about two-thirds of the time and too low one-third of the time. This is a significant change from the results for a similar analysis in MP's previous IRP (see the Department's March 4, 2016 Reply Comments in Docket No. E015/RP-15-690, pages 5 to 10). The Department reviewed the data in more detail in order to determine why the number of too high forecasts was so much greater than the number of too low forecasts. What immediately stood out is that, for AFR2000 to AFR2015 during the years 2015 to 2019, the energy and demand forecast errors are positive (meaning the forecast is too high) in every instance. Further, the average error for energy is 15 percent and the average error for peak demand is 13 percent.[29]

The likely explanation for the sudden increase is shown in Table 1 of the Petition's Appendix A, showing historical and forecasted energy and seasonal peak demand. Table 1 shows that, for 2011 to 2014 energy sales averaged about 11 million MWh annually and peak demand averaged about 1,780 MW in both summer and winter. However, for 2015 to 2019 energy sales averaged about 10.3 million MWh annually and peak demand averaged about 1,670 MW in both summer and winter. Thus, MP experienced a sustained drop in both energy and demand during the years 2015 to 2019. One key forecasting question is as follows: "will the lower level of energy and demand be experienced in the future or will the older levels return"?

[29] Again, for AFR 2000 to AFR 2015 covering only the years 2015 to 2019.

Table 1: MP's Energy Forecast Error (percent)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
AFR 2000	-3.9%	1.5%	0.5%	1.9%	-0.6%	-2.2%	-2.9%	-2.7%	-3.7%	29.1%	1.0%	-5.1%	-5.0%	-3.5%	-3.4%					
AFR 2001		-2.0%	0.3%	3.4%	-1.0%	-3.1%	-4.1%	-3.9%	-4.2%	29.0%	0.5%	-4.2%	-4.4%	-3.1%	-3.3%	6.4%				
AFR 2002			-0.9%	3.1%	0.2%	-2.4%	-3.6%	-3.8%	-4.4%	28.2%	-0.4%	-5.4%	-5.9%	-5.0%	-5.5%	3.6%	5.8%			
AFR 2003				3.6%	-1.8%	-2.9%	-2.9%	-2.1%	-2.7%	31.6%	2.8%	-1.3%	-0.6%	2.0%	3.2%	15.2%	19.8%	12.5%		
AFR 2004					0.6%	-0.3%	-0.5%	0.0%	0.6%	36.1%	6.4%	2.4%	3.0%	6.0%	7.5%	20.1%	25.2%	17.7%	20.0%	
AFR 2005						-0.3%	-0.5%	0.6%	4.1%	41.5%	11.0%	6.8%	7.0%	10.2%	11.7%	24.8%	29.9%	21.8%	23.9%	27.7%
AFR 2006							-0.3%	1.4%	1.8%	41.8%	11.1%	7.4%	8.0%	10.0%	10.5%	22.3%	26.2%	17.2%	17.9%	20.9%
AFR 2007								0.0%	-0.5%	37.0%	6.0%	2.8%	3.4%	5.7%	6.0%	17.4%	21.0%	12.3%	12.9%	15.3%
AFR 2008									-2.0%	34.8%	8.9%	5.1%	4.0%	4.8%	4.1%	15.6%	19.3%	11.2%	12.4%	15.2%
AFR 2009										4.8%	-16.8%	-13.9%	-8.1%	-3.1%	-0.9%	11.0%	15.9%	8.5%	10.2%	13.4%
AFR 2010											-0.8%	-1.8%	-1.0%	0.7%	1.1%	11.6%	15.2%	6.9%	7.7%	10.1%
AFR 2011												-0.3%	-1.1%	0.5%	1.0%	11.9%	15.7%	7.5%	8.4%	10.8%
AFR 2012													-1.4%	0.5%	0.7%	11.5%	15.4%	6.9%	7.8%	10.2%
AFR 2013														-0.2%	-0.4%	18.1%	24.6%	18.7%	20.0%	22.6%
AFR 2014															-0.3%	13.9%	24.2%	13.9%	14.9%	17.2%
AFR 2015																2.4%	5.9%	9.9%	11.0%	13.1%
AFR 2016																	-1.4%	-0.6%	0.9%	1.7%
AFR 2017																		1.8%	2.5%	3.6%
AFR 2018																			1.4%	1.7%
AFR 2019																				-1.8%

Table 2: MP's Summer Demand Forecast Error (percent)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
AFR 2000	0.9%	13.7%	-5.6%	-1.3%	-3.1%	-6.8%	-8.5%	-7.5%	-3.1%	23.6%	-2.2%	-1.6%	-2.8%	-0.2%	-0.1%					
AFR 2001		5.2%	-0.5%	4.0%	1.8%	-2.5%	-4.6%	-3.8%	0.5%	28.0%	1.4%	2.4%	1.2%	2.9%	2.6%	17.4%				
AFR 2002			-2.0%	5.0%	3.5%	-0.6%	-2.6%	-1.9%	2.3%	30.7%	2.4%	3.1%	1.4%	2.7%	2.3%	16.7%	16.9%			
AFR 2003				2.4%	-4.4%	-6.4%	-6.9%	-8.2%	-3.1%	24.6%	-2.9%	-1.7%	-2.2%	-1.7%	-2.0%	12.4%	12.0%	7.5%		
AFR 2004					0.0%	0.0%	-3.9%	-3.5%	3.7%	30.8%	1.7%	4.8%	4.1%	5.6%	6.3%	22.5%	22.7%	18.4%	17.2%	
AFR 2005						-5.0%	-6.9%	-6.3%	3.1%	30.7%	2.5%	3.3%	2.0%	4.4%	5.2%	21.3%	22.8%	19.2%	18.8%	25.1%
AFR 2006							-0.2%	-0.7%	4.5%	34.3%	5.9%	7.0%	6.0%	7.5%	7.0%	22.0%	22.0%	17.1%	15.0%	19.5%
AFR 2007								-2.4%	2.2%	31.4%	3.5%	4.8%	3.6%	5.2%	5.0%	19.8%	19.8%	15.1%	13.2%	17.7%
AFR 2008									2.5%	31.0%	3.2%	3.7%	2.4%	3.6%	2.9%	17.3%	17.4%	12.9%	11.3%	15.9%
AFR 2009										0.0%	-21.1%	-15.6%	-11.9%	-8.9%	-8.2%	5.3%	5.7%	1.9%	0.9%	5.7%
AFR 2010											-0.1%	-1.4%	-2.6%	-1.5%	-2.1%	11.3%	11.2%	6.6%	4.9%	8.9%
AFR 2011												-1.5%	-3.5%	-2.4%	-2.8%	10.8%	10.8%	6.3%	4.7%	8.7%
AFR 2012													-3.7%	-3.0%	-4.5%	8.8%	8.9%	4.5%	2.9%	6.9%
AFR 2013														-2.8%	-2.1%	14.7%	17.3%	15.1%	13.2%	17.5%
AFR 2014															-4.3%	13.2%	19.5%	14.9%	13.1%	17.2%
AFR 2015																1.0%	5.4%	10.6%	10.3%	14.5%
AFR 2016																	-1.4%	0.9%	-0.2%	1.2%
AFR 2017																		4.5%	2.0%	3.6%
AFR 2018																			-0.8%	0.5%
AFR 2019																				-1.5%

One test of a forecast process is how quickly the forecast process can recognize a fundamental change and adapt to the changed circumstances. To test this, the Department compared the average forecast errors for AFR2000 to AFR2015 to the average error of AFR2016 to AFR2019 one year out, two years out, and three years out.[30]

For energy, while there are very few observations for AFR2016 to AFR2019, at this time it appears that the forecast process has adapted. The average error for AFR2016 to AFR2019 was slightly closer to zero than that of AFR2000 to AFR2015.

For demand, again while there are very few observations, at this time it appears that the forecast process has also adapted. The average error for AFR2016 to AFR2019 was higher than AFR2000 to AFR2015 two years out and three years out but the average error was relatively small (less than 2.5 percent) and there are very few observations for AFR2016 to AFR2019, making the comparison somewhat suspect to begin with.

A more detailed review of MP's forecasts may or may not find significant issues and more years of data might or might not reveal significant trends in forecast error that are not apparent at this time. However, based upon the preliminary review above, the Department concludes that MP's forecasts are acceptable for resource planning purposes. This is because the forecast process performed well until the extended drop in energy and demand that began in 2015 caused the older forecasts to be consistently too high. However, MP appears to have recognized the issue and the forecasts since 2015 have adapted to what appears to be a new environment.[31] As noted above, the question of whether the lower levels will continue remains outstanding but the answer cannot be known. In summary, the Department did not make any changes to the overall peak demand and energy forecasts used in the modeling process.

5. Comparing AFR2020 to EnCompass Inputs

The final step in the Department's forecast analysis was to review how the Company turned the forecast into modeling inputs. The Company modeled the forecast using three sets of inputs:

- Monthly peak demand forecast—the monthly (non-coincident) peak demand forecast is converted into EnCompass inputs "by applying a Coincidence Factor, which was calculated based on the methodology recommended by MISO."[32]
- Monthly energy forecast—is performed at the customer meter and "is "grossed-up" for line losses to represent total energy requirements, or energy at generator."[33]

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[30] Note, these calculations omit the problematic observations for AFR 2000 to AFR 2015 for years 2015 to 2019.
[31] In a simple way this can be seen by comparing the errors for AFR 2015 to the errors for AFR 2016.
[32] See the Company's response to Department IR No. 5.
[33] See the Company's response to Department IR No. 5.

- Coincident customer net generation—represents "the difference of total accredited Behind the Meter Generation and the customer-owned peak-coincident generation estimated in AFR 2020, and adjusts for any applicable reserve margin."[34]

After reviewing MP's calculations for turning the forecasted values into EnCompass inputs the Department concludes that MP's EnCompass inputs for the forecast are acceptable for planning purposes.

6. Consequences of Forecast Error

When evaluating EnCompass results the Department kept in mind the consequences of forecast error. If an IRP is developed using a forecast that is too high, the primary consequence would be that too many units would be added and the utility would end up selling more capacity and energy into the Spot Markets than expected. In contrast, if an IRP is developed using a forecast that is too low, the primary consequence would be that too few units would be added and the utility would end up buying more capacity and energy into the Spot Markets than expected.

As discussed elsewhere in more detail, economically, being a net seller means that the utility would benefit from higher market prices. Being a net buyer presents the opposite exposure, the utility would benefit from lower market prices. Thus, the risks can be seen as symmetric and the economic consequences are confined to the utility.

In terms of reliability, if an electrical system has more capacity than needed it will be more reliable than required, reducing the standard reliability risks. However, if an electrical system has less capacity than needed it will be less reliable that required, increasing reliability risks above the standard level. In addition, it must be kept in mind that reliability is a phenomenon of the network as a whole and not any one part of the network. For example, a utility such as MP might have ownership or contracts for the required amount of capacity and not experience any generation outages or forecast error. In this example MP could not be said to contribute to reliability problems. However, if the network MP is part of (MISO) experiences a capacity shortfall, MP may be required to shed firm load, depending on the circumstances faced by MISO's system operators. Thus, the reliability benefits of over building and the reliability costs of underbuilding any one utility's system are not confined to that utility, instead they are shared across the network.

7. Forecast Recommendation

The most difficult forecasting question for this IRP is whether MP should plan to the base forecast, which assumes the permanent loss of large power customer load, or plan to the high forecast, which assumes the large power customer load returns to past levels. Given MP's obligation to serve customers in its service territory, the Department concludes that it is not appropriate to plan based on MP's assumption that currently existing customers in AFR 2020 will remain shut down permanently without significant evidence that the customers will in fact, not be able to return. Therefore, when evaluating modeling results the Department focused on the high forecast which assumes currently shut down large power customers will not remain shut down indefinitely.

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[34] See the Company's response to Department IR No. 5.

H. NATURAL GAS TRANSPORTATION RISKS

1. Background

For this IRP the Department further explored the Company's exposure to risks related to natural gas transportation. This review was triggered by the increasing use of natural gas-fueled capacity by Minnesota utilities and events during recent winters. While MP's total usage of natural gas for electric generation might be small, the incremental impact of MP's natural gas usage might be large. Note that risks related to natural gas pricing are explored in the Department's CEM analysis elsewhere in these comments. The focus of this discussion is on the reliability of natural gas delivery to the relevant power plants.
Department IR No. 2 requested MP provide certain data for each power plant that consumed natural gas during 2016 to 2020 along with curtailment data for 2021. MP's response provided data regarding three power plants:

- BEC—Great Lakes Gas Transmission (GLGT) pipeline, 1,000 Dth/day firm and then interruptible transport, not curtailed in 2021;
- Hibbard Renewable Energy Center (HREC)—GLGT and Northern Natural Gas (NNG) pipelines, interruptible transport, curtailed by the local distribution company (LDC) for February 6 to February 8, 2021.
- Laskin Energy Center (LEC)—NNG pipeline, secondary firm transport, plant was curtailed due to lack of pipeline capacity and was placed in fuel outage status from February 11 to February 17, 2021.[35]

Of these three units, only LEC is primarily fueled by natural gas. BEC and HREC are primarily fueled by coal and/or biomass but require natural gas in some circumstances.

Generally, the Department understands that natural gas transportation contracts can be primary firm, secondary firm, or interruptible as follows:[36]

- Primary firm:
    - is the highest priority and the most expensive contract;
    - the customer pays a fixed subscription fee for the transportation capacity that is reserved by the customer; and
    - provides right to transport fuel daily up to the contracted capacity.
- Secondary firm:
    - is second in delivery priority only to primary firm;
    - represents the purchase of unused primary firm capacity on a secondary capacity release market (conducted and usually done on the pipeline's Electronic Bulletin Board); and
    - often bought and sold on a short-term basis and requires no subscription fee.

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[35] MP's explanation in Department IR No. 3 was that "Minnesota Power would have been able to procure natural gas for the Laskin facility, however, there was no available pipeline capacity on Northern Natural Gas ("NNG") to physically get the gas to the Laskin Energy Center."
[36] See the explanation provided by the U.S. Department of Energy: https://www.energy.gov/sites/prod/files/2014/07/f17/qermeeting_denver_backgroundmemo.pdf

- Interruptible:
    - has the lowest delivery priority;
    - is the least expensive of the three main types; and
    - are contracts for pipeline capacity that remains available after all firm contracts are honored.[37]

2. *Analysis of MP's Natural Gas Transportation*

Most important for analysis of MP's natural gas transportation is the fact that the hierarchy for delivery is as follows: primary firm is delivered first, secondary firm is delivered second, and interruptible delivery is delivered last. In discussing these classes of natural gas transportation contracts DOE stated:

> LDCs rely on primary firm capacity to cover the needs of their residential and commercial customers. Many gas-fired power plants rely on short-term interruptible and secondary firm capacity contracts to meet their daily gas shipping needs. ISOs/RTOs that operate regional wholesale electricity markets allow generators to offer only their variable cost into the electricity markets, and short-term capacity contracts can be included in these bids.
>
> Operationally, reliance on short-term interruptible capacity contracts exacerbates constraints that can occur during unexpected reliability events. Natural gas generators can be first to lose their shipping privileges when pipeline capacity is limited. This is problematic, as natural gas constraints often occur during precisely the time when electricity is needed the most; high heating demand for natural gas during extreme cold weather events can prevent the power system from providing the electricity needed to operate residential and institutional heating systems.

During the February 2021 event MP experienced an interruption in gas supply both due to the LDC (at HREC) and due to transportation (at LEC). While MP's explanation regarding the LEC curtailment is somewhat vague, it appears that MP's use of secondary firm transport ultimately led to the curtailment. To gauge the significance of the interruption the Department calculated the maximum possible lost revenue. For the February 11 to February 17 interruption at LEC the maximum possible lost revenue was about $2.9 million.[38] Depending on a number of factors such as MP's cost of natural gas and MISO's dispatch instructions the LEC interruption had the potential to be economically significant.

In reliability terms the Company's choice to use secondary firm transport for LEC appears to be questionable since LEC does not report (in Federal Energy Regulatory Commission Form 1) use of any alternative fuels. To perform as a peaking facility LEC would need to have fuel during the extreme conditions that trigger the need

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[37] In addition to these three primary contracting types, natural gas pipelines offer an array of natural gas transportation options that vary in cost, flexibility, and delivery priority. Most of these other options can be considered sub-classes of the three mentioned here.
[38] Calculated as (average day ahead LMP each day at MP.LASKIN1) * (24 hours) * (99.0 MW) for February 11 to February 17.

for peaking resources. Use of secondary firm transport leaves LEC open to being unable to operate during the very conditions when it is most likely to be needed.

The choice of interruptible transport for HREC is more understandable since HREC reports using both waste wood and coal in addition to natural gas. However, if natural gas is required for operation—for example as a start-up fuel then the choice of interruptible transport again would represent a potential reliability issue.

The Department recommends that MP explain in reply comments the economic and reliability consequences of the Company's natural gas transportation contracts and explain what data and information MP has submitted and provided to MISO in its winter fuel and generator surveys.

Finally, in Northern States Power Company doing business as Xcel Energy's most recent IRP (Docket No. E002/RP-19-368) the Department concluded that the "main risk that remains is that all of Xcel's plants ultimately draw their natural gas supplies using the same interstate pipeline—Northern Natural Gas (NNG)." MP has diversified its natural gas transportation, drawing natural gas supplies from two different pipelines. Overall, it appears that MP's actions have created a diversified portfolio in that MP is not reliant upon a single interstate pipeline.

3. Natural Gas Transportation Recommendations

The Department recommends that MP explain in reply comments the economic and reliability consequences of the Company's natural gas transportation contracts and explain what data and information MP has submitted and provided to MISO in its winter fuel and generator surveys.

III. ENCOMPASS ANALYSIS

A. ENCOMPASS AND CONVERGENCE TOLERANCE

a.

4. Background

EnCompass can be used both as a CEM and as a production cost model. When used as a CEM, EnCompass uses a mathematical method called mixed integer programming (MIP) to determine the least cost expansion plan. At a high level, EnCompass' MIP process involves two basic steps. In the first step EnCompass determines the potential ideal (or lowest possible cost) expansion plan by adding fractions of units. For example, the potential ideal plan may involve adding 30 percent of a wind unit in 2023, 70 percent of a solar unit in 2025, and 20 percent of a combustion turbine unit in 2027. The assumption in this proceeding is that fractions of units are not possible in the real world, and thus a second step is necessary.

In the second step EnCompass experiments by adding whole units and not fractions of units in order to create feasible plans. For example, a feasible plan may involve adding one wind unit in 2023 and one combustion turbine unit in 2027. EnCompass continues to experiment until it finds a feasible plan (using whole units) that falls within an acceptable cost range. EnCompass then ceases experimenting and reports the results of the feasible plan.

The range of acceptable costs is defined by the modeler and is referred to as the "MIP Stop Basis." EnCompass' MIP Stop Basis input is a fraction of the cost of the potential ideal plan. The potential ideal plan still includes fractional units, so that the ideal (using whole units) plan cost must be equal to or (most likely) higher than the potential ideal plan. During the MIP process, the costs of this potential ideal plan will increase as potential feasible plans are evaluated and eliminated from consideration. For example, if the cost of the potential ideal plan is $6.527 billion[39] and the MIP Stop basis input is 80 (which is 0.0080) then the maximum allowed cost would be $6.579 billion.[40] The first feasible plan that EnCompass finds that has a cost between $6.527 billion and $6.579 billion would be reported by EnCompass as the expansion plan.[41]

Note that any changes to EnCompass inputs that change the costs considered in creating the ideal plan (such as fuel costs or the demand and energy forecasts) will change the range of acceptable costs even if the MIP Stop Basis input was not changed. Thus, use of a higher MIP Stop Basis does not necessarily mean a wider range of acceptable costs if other inputs were changed as well. For example, in a first run EnCompass might calculate a potential ideal plan cost of $1.000 billion. If the MIP Stop Basis input is 80, then the range of acceptable costs is from $1.000 billion to $1.008 billion. This creates a gap of $8 million for feasible plans. Second, assume that the modeler runs a contingency with a lower energy and demand forecast, resulting in a potential ideal plan cost of $0.500 billion. If the MIP Stop Basis input remains at 80, then the range of acceptable costs narrows to between $0.500 billion and $0.504 billion. This leaves a gap of only $4 million for feasible plans. Since the cost of expansion units has not changed, the resulting $4 million gap might be too small for EnCompass to fit in whole expansion units (rather than fractions).[42] However, if the MIP Stop Basis input is increased from 80 to 160, then the range of acceptable costs broadens to between $0.500 billion and $0.508 billion (a gap of $8 million again). Thus, the use of a higher MIP Stop Basis in the second (low forecast) EnCompass run creates the same $8 million range of acceptable costs as in the first EnCompass run.

As shown above, everything else held constant, the smaller the MIP Stop Basis input the narrower the range of acceptable costs becomes. However, EnCompass, on average, will require a longer duration to find a feasible plan and may not be able to find a plan at all if computing resources are limiting.

a.

5. Understanding EnCompass Cost Results

When comparing the costs of various plans to each other it is important to keep the convergence tolerance of the EnCompass modeling process in mind. For example, in Chart 1 below the lines represents the range of acceptable costs (from the potential ideal plan's cost to the maximum allowed cost) for three scenarios. The dots represent the cost reported by EnCompass for the feasible plan for the three scenarios. For simplicity, assume the only difference among the three scenarios is that they have different expansion units available to be added. Of the three plans, at first glance "Scenario 1 – I" is clearly reported as least cost, "Scenario 1 – B" has a cost higher by $17 million, and "Scenario 1 – C" has a cost higher than Scenario 1 – I by $27 million.

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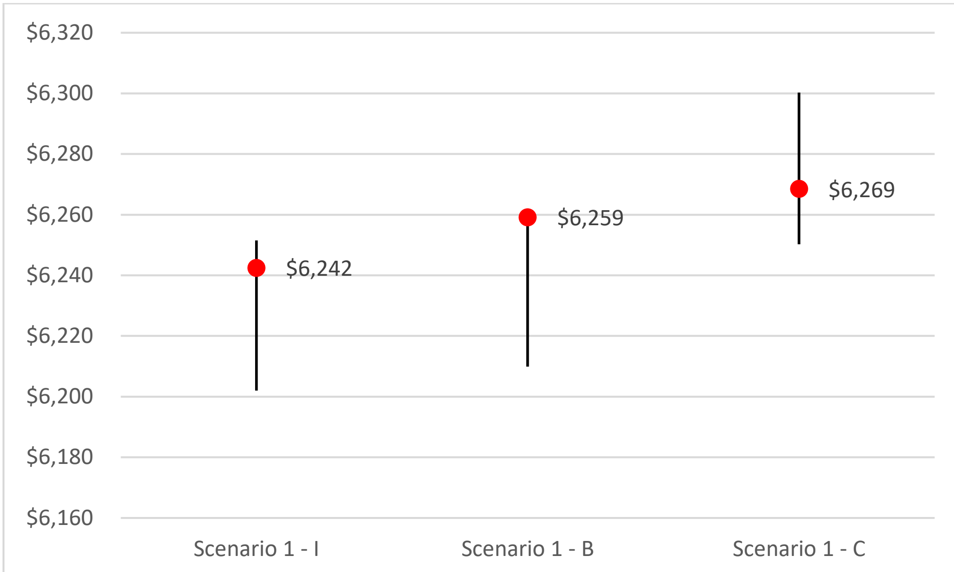
[39] The ideal cost includes only variable costs of existing units and all costs (fixed and variable) for new units. So, the ideal cost excludes fixed costs of existing units.
[40] The equation is $6.527 billion * [1 + (80/10,000)] = $6.579 billion.
[41] It is possible to require EnCompass to find and report on multiple plans but that and other complications are not discussed here.
[42] While the numbers are hypothetical, this situation was encountered by the Department in prior proceedings.

Chart 1: MIP Convergence Example ($ million)



However, when examining the bars in Chart 1, which show the range of acceptable costs, it is possible for both Scenarios 1 – I and 1 – B to have feasible plans with costs lower than the $6,242 million reported for Scenario 1 – I because the bars for both extend below $6,242 million. Likewise, it is not possible for Scenario 1 – C to have a feasible plan with a cost lower than the $6,242 million because the bar (the range of acceptable costs) does not extend far enough. In this example, given the information available in Chart 1 the Department would conclude two things. First, Scenario 1 – C clearly cannot be least cost because Scenario 1 – I has a reported cost lower than the potential ideal (or lowest possible) cost of Scenario 1 – C. Second, the reported costs of Scenarios 1 – I and 1 – B are within the tolerance inherent in the model; meaning one plan cannot be said to be cheaper than the other.[43]

Based upon the clear results of the EnCompass runs (discussed below), the complexity of calculating the range of acceptable costs, and the length of MP's IRP process to date, the Department did not pursue this analysis of the range of acceptable costs for MP's IRP modeling.

a.

6. Understanding EnCompass Expansion Unit Results

The convergence tolerance inherent in EnCompass' cost minimization routine also impacts how to understand the number of expansion units added. For a more detailed discussion see the Department's October 15, 2021 comments in Docket No. E002/RP-19-368 at page 16.

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[43] The existence of a margin of error for a modeling result is not unique to EnCompass and has been discussed by the Department in past resource plan comments regarding Strategist results. For an example, see the Department's July 8, 2016 comments in Docket No. E002/RP-15-21.

The hypothetical cost range discussed above was $6.527 billion to $6.579 billion. In contrast, a 50 MW solar unit added in 2027 might impose a cost increase of about $14 million[44] in net present value. If the actual least cost plan is $6.550 billion the net cost increase of adding another 50 MW of solar results in a plan with a total cost of $6.564 billion, still within the acceptable range. From this it can be seen that the existence of a range of acceptable costs implies that cost changes that are small in magnitude may be within the convergence tolerance of the model. In this example, there are at least two plans (with and without the hypothetical solar unit added in 2027) within the acceptable range and either might be reported by EnCompass.

In this example, 50 MW each expansion units are too small for EnCompass to truly determine if the addition or subtraction of one or two units is cost effective. In future resource plans, if MP determines to use discrete unit sizes, the Department recommends MP consider MIP convergence tolerance as a factor in determining the unit sizes to use in EnCompass.

a.

7. Using EnCompass' Potential Ideal Plan

Another way to run EnCompass is to skip the step where the model determines the best combination of whole units to add and have the model simply report the potential ideal plan. For example, in a given year EnCompass might show 0.4 wind units, which is equivalent to using 40% of the cost and capacity values of a full wind unit. The next year EnCompass might show 0.6 wind units. This is the same as adding another wind unit with 20% of the cost and capacity values of a full unit. This option has the advantage of keeping all costs and constraints intact but bypassing the step in which EnCompass searches for the best way to round the units up or down, and thus reducing runtime. In addition, this approach avoids the variability that is inherent in the MIP acceptable cost range process.

However, use of the potential ideal plan raises the question "does adding a fraction of a unit actually provide meaningful resource planning information?" One response would be that, since the expansion plan is based on long-term forecasts, the IRP process can only determine the approximate size, type, and timing of new units. Thus, the specific values must be interpreted as including a degree of uncertainty and acquiring approximately the capacity selected would be reasonable.

A second response would be that wind turbines and solar panels actually come in very small sizes, less than 10 MW per wind turbine and smaller still for solar panels. Therefore, wind and solar projects could be developed in nearly any size. This means that adding fractions of wind and solar units is reasonable.[45] A more difficult question is how to consider the capacity units (here modeled as CT units). The Department has consistently assumed that the CT units are merely generic capacity. This means that anything that can perform essentially

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[44] Calculated assuming a 50 MW unit, added in 2027, priced at $45 per MWh (escalated at two percent annually), with a 22 percent capacity factor, the ability to recover from the market (or avoid generation from existing units) only 75 percent of its costs—so that 25 percent of its costs represent a net cost increase to MP's ratepayers, all discounted to the starting year.

[45] One limiting factor is that, to actually be acquired, generation projects above a certain size must go through the MISO generation interconnection queue. Projects in MISO's queue tend to come in sizes rounded to 50 MW. But that is not required. Of course, there are ways around the need to go through the MISO generation interconnection queue—such as connecting to the distribution grid.

the same function would be acceptable. Since load management can serve many of the same functions as a CT it would be acceptable. Capacity (in the form of load management) can be acquired in nearly any size as well. In summary, the units being selected in MP's resource plan do not have to be acquired in any one size increment.

Overall, the Department concludes that reporting the potential ideal plan costs is a reasonable way to use EnCompass. The Department recommends MP consider the benefits and costs of reporting fractions of units when running EnCompass for the Company's next IRP.

B. MODELING BACKGROUND

For these comments, the Department used EnCompass to review MP's modeling efforts. This is the second IRP where the Department relied solely on EnCompass. The general process followed by the Department when reviewing CEM data is as follows

1. obtain from the applicant a base case file and the commands necessary to recreate the various scenarios explored by the Company;
2. re-run the applicant's base case file to make sure the outputs match and that the Department is working with the correct files (matching analysis);
3. review the base case's inputs and outputs for reasonableness;
4. create a new base case, which includes any changes deemed necessary to the Company's base case;
5. run scenarios of interest on the new base case to explore various risks and alternative futures;
6. assess the results of the scenarios and establish a new preferred case; and
7. run scenarios of interest on the new preferred case to test the robustness of the preferred case.

The Department's overall goal in reviewing a utility's modeling efforts is to determine if the Company's proposed plan results in a reliable, low cost, low impact system that manages risk, and to recommend modifications if needed. Figure 6 below illustrates how the four overall goals are implemented in EnCompass analysis.

Figure 6: Minnesota Decision Criteria and Modeling

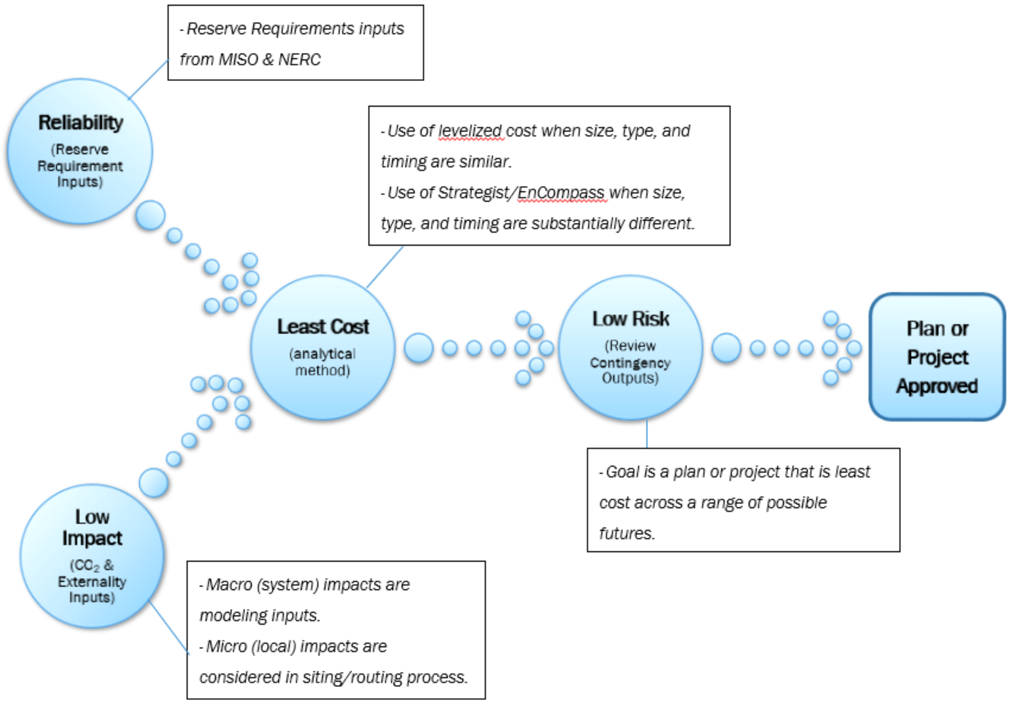

Figure 6 shows that, when evaluating modeling results, the present value of societal costs (PVSC) outputs already include the Commission's reliability and environmental impact criteria. Since EnCompass' function is to minimize cost, that is also included in the modeling results. Thus, when evaluating modeling outputs, the Department's focus is on understanding why the model is producing the results, the risks inherent in the results, and how the plan contributes to other State of Minnesota goals not reflected in the modeling inputs, such as greenhouse gas reduction goals.

C. ENCOMPASS MODELING

a. *The Department begins by noting that MISO's Long Range Transmission Plan (LRTP) is not yet complete but appears to have the potential to impact the choice of retirement scenarios for the Boswell units. MISO's Draft MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report (MTEP Addendum) recommends an Iron Range – Benton – Cassie's Crossing 345kV double circuit transmission line. The Iron Range substation is near the Boswell site. The MTEP Addendum reports that this transmission line would address numerous reliability issues in central and northern Minnesota.*
b.
c. *Given that the Iron Range substation is near Boswell the LRTP may reduce or eliminate the need for and cost of transmission and/or new thermal generation in scenarios that retire the Boswell units. These constraints are discussed further below. Since:*
d.

- MISO's cost recovery proposal for the LRTP projects has not been approved by the Federal Energy Regulatory Commission (FERC);
- the LRTP projects have not been approved by MISO's board of directors; and
- the complicated nature of the EnCompass analysis in this docket;

the Department did not pursue the potential impact of the LRTP in modeling. Instead, the Department recommends that MP discuss the impact of the LRTP on the costs and constraints regarding the various Boswell retirement scenarios in reply comments.

e. 1. Introduction

For this IRP, the Department used EnCompass to review MP's modeling efforts, using the following general process:

1. obtained from the applicant a base case file, and the commands necessary to recreate the various scenarios explored by the Company;
2. re-ran the applicant's base case file to make sure the outputs match and that the Department is working with the correct file;
3. reviewed the base case's inputs and outputs for reasonableness;
4. created a new base case, which includes any changes deemed necessary to the Company's base case;
5. ran scenarios of interest on the new base case to explore various risks and alternative futures;
6. assessed the results of the scenarios and established a new preferred case; and
7. ran scenarios of interest on the new preferred case to test the robustness of the preferred case.

f. 2. Matching MP's Results

Prior to making any changes to the Company's base case, the Department sought to match MP's EnCompass modeling results. The primary purpose of this step is to ensure that the Department is using the same input data as MP. Theoretically, the Department should be able to load MP's input files into EnCompass, run the model without making any changes, and produce the same results shown in MP's output files. Given the complexity of utility databases and the repetitive nature of downloading and saving modeling spreadsheets, is relatively easy for modelers to have mismatched inputs and outputs.[46] When running MP's inputs in EnCompass, if the outputs generated by the Department are different than the outputs MP sent to the Department, the Department would be unable to rely on MP's inputs and outputs until the source of any discrepancy is determined and corrected. Once the Department is able to produce the same outputs as MP using the same inputs that MP used, the Department has confidence that the databases are sound and can be used to evaluate MP's resource plan. If parties use different data than the utility, all subsequent party analysis

[46] For example, a modeler might upload an input spreadsheet into EnCompass (Input 1), run the model and download and save the outputs (Output 1), change the input data within EnCompass without downloading the new input spreadsheet (Input 2), and run the model and download and save the new outputs by overwriting the original outputs (Output 2). In this example, the modeler would have saved the mismatched Input 1 spreadsheets and Output 2 spreadsheets but may believe those datasets correspond to each other.

has the potential to be meaningless. Therefore, the matching process is a critical component of analyzing the utility's model.

The first step in this matching process was to recreate MP's databases in EnCompass from the Company's input files. MP submitted input files for five databases. The following table provides summary information for each of these five databases; for other visual representations of the Company's databases, see Attachments 1A and 1B.

Table 6: MP's Databases and Summary Information

MP Database	Purpose of Database	Number/Type of scenarios	Number of datasets used as inputs
Expansion Planning Runs	Produce optimized expansion plans and costs for five Boswell retirement Scenarios and six regulatory/externality cost futures	• 30 optimized expansion plan scenarios (10 repeat, 20 unique) • 30 production cost scenarios • 60 total scenarios	98
Swim Lane Runs	Produce costs for 38 contingencies applied to locked in expansion plans under each of the five different Boswell retirement scenarios with six regulatory/externality futures	• 30 locked in expansion plan scenarios (10 repeat, 20 unique) • 1,165 production cost scenarios • 1,195 total scenarios	184
Renewable Energy Standard (RES) and Solar Energy Standard (SES) Expansion Planning	Compare incremental costs of RES/SES plans vs. non-RES/SES plans, for purposes of calculating rate impact	• 2 locked in expansion plan scenarios • 2 production cost scenarios • 4 total scenarios	99
RES/SES Swim Lanes	Compare incremental costs of SES plan vs. non-SES plan, for purposes of calculating rate impact	• 4 locked in expansion plan scenarios • 4 production cost scenarios • 8 total scenarios	186
Special IRP2020 Runs	Looks at hourly data for the 2031 year under Contingency 18 (No Market Sales/Purchases) conditions	• 15 locked in expansion plan scenarios • 35 production cost scenarios • 50 total scenarios	51

For the following discussion, “datasets” are model inputs, and results are described as either “results” or “outputs.” There are also two types of runs: expansion plan runs (also called “optimized” runs) and production cost runs (also called “8760” runs). MP’s production cost runs “lock in” the parent expansion plan, and simply re-run the dispatch routine within that predetermined set of resources.

As noted in Table 6, between 51 and 186 datasets were used in each of the five databases. However, many of these datasets were repeated across databases. Throughout each of these databases, MP used and re-used the same datasets across multiple Boswell scenarios and regulatory/environmental cost futures. However, the Department did not need to run each scenario + future run combination in order to validate each dataset; rather, the inputs of a single dataset can be validated from outputs associated with a single run. What this means is that even though the same dataset may be used as a scenario input once in each of the five databases, the Department only needs to run one run in one database in order to validate the data of that dataset. The Department determined that there were only 99 unique datasets that needed to be validated for purposes of the Department’s matching analysis. The following table summarizes information about which datasets were validated by the Department:

Table 7: Number of runs needed to match each unique dataset in MP's Model, by database

MP Database	Unique datasets to validate	Number/type of runs to match
Expansion Planning Runs	98	10
Swim Lane Runs	98	98
RES Expansion Planning	1	1
RES Swim Lanes	2	2
Special IRP2020 Runs	0	0
Totals	199	111

Table 7 shows that to validate the Company’s 199 unique datasets, the Department needed to match 111 specific runs.[47]

After determining which scenarios to match, the Department then assembled each of the databases within EnCompass without any modifications. Once the scenarios identified for matching were run, the Department exported and compared its results to MP’s results.[48]

As background, EnCompass first determines the cost of an ideal expansion plan, adding fractions of units (partial-unit plan). The model then repeatedly tests varying plans that add full units (whole-unit plan). When EnCompass reaches a whole-unit plan whose cost is within a certain fraction of the cost of partial unit plan, the model stops. The fraction is determined by the modeler and is referred to as the “MIP stop basis.” The basis for

[47] The list of runs to be validated can be seen in the Department’s matching results in Attachments 2A-2C.
[48] The Department used MP’s supplemental analysis spreadsheets for its matching analysis, which were provided in response to DOC IR01.

the MIP is the "objective function." The cost that most closely aligned with the objective function in EnCompass is the net present value (NPV) Plan Cost.[49]

For expansion planning runs, the Department compared MP's NPV plan cost to the Department's NPV plan cost for the same run.[50] For production cost runs, the Department compared a proxy value for the objective function, which MP's operating cost plus carrying cost to the Department's operating cost plus carrying cost for the same run.[51] Table 8 shows example results for one production cost run and one expansion plan run.

Table 8: Example Results for Expansion Plan and Production Cost Runs[52]

Expansion Planning Run	MIP Stop Basis	NPV Plan Cost ($000 in $2021)
CHER1S REF (MP Run)	50	$2,793,331.71
DeptMatch DB1 CHER1S REF (Dept Run)	50	$2,783,424.51
Delta		$9,907.20
Percent Difference		0.36%
Production Cost Run	**MIP Stop Basis**	**Operating Cost + Carrying Charge Cost ($000, $2020)**
PrefPlan CHER1S-9_Highest Gas+100% (MP Run)	50	$6,818,692.54
DeptMatch DB2 PrefPlan CHER1S-9_Highest Gas+100% (Dept Run)	50	$6,817,798.54
Delta		$894.01
Percent Difference		0.01%

[49] This is found in the Plan Costs report of an output file. The NPV Plan Cost value from the Plan Costs report is the same as the objective function in the System Annual report.
[50] To match MP's Expansion Plan runs, the Department exported the "Project Plans" report from EnCompass, which exports three distinct sets of data: Plan Costs, Plan Projects, and Reduced Project Costs.
[51] In the case of a production cost run, which locks in the expansion plan of a parent run, the best values to use for purposes of matching are the operating costs plus carrying costs of the Company Capital report. Operating costs represent the total plan costs, less any fixed costs that cannot be avoided. While the total operating cost value is closely aligned with the objective function of the MIP stop basis, it is not the same. The objective function does contain fixed costs; it is equal to the net present value of the total plan cost, which can be found in the "Present Value (PV) Cost ($000)" column in the EnCompass Plan Cost Report. From the Department's perspective, it is logical to include fixed costs when matching an expansion plan run, since incorrect fixed cost data could completely change an expansion plan. However, production cost runs are based on an existing expansion plan; as such, fixed cost data is already validated in the parent expansion plan and doesn't need to be validated again.
[52] Note that the costs reported in this table are not representative of the total plan costs of either run but are instead only the components of the total plan costs necessary for matching purposes. The NPV plan cost is used for the expansion plan runs because it equals value of the objective function, which is the basis for the MIP stop gap; the operating plus carrying cost is used for the production cost runs as a proxy for the objective function.

Table 8 shows that when the Department ran HighReg/HighEnv exactly as MP had submitted it, the Department's plan costs were approximately $9,907,200 less than MP's results, in 2021 dollars. When the Department ran PrefPlan CHER1S-9_Highest Gas+100% exactly as MP had submitted it, the Department's operating + carrying charge costs were $894,010 less than MP's results, in 2021 dollars. For the expansion plan run, the percent difference between MP's and the Department's results was 0.36 percent; and for the production cost run, the difference between MP's and the Department's results was 0.01 percent. In both cases, this is an acceptable level of variation because both percentages fall within the MIP stop basis of 50, which permits for a variation of 0.50 percent. For the results to be unacceptably different, the percent difference between an MP run and a Department run would need to be greater than 0.50 percent. Therefore, the Department would consider both of these scenarios to be "matched."

Attachments 2A-2C show the full results of the Department's matching analysis.[53] These results are summarized in Table 9.

Table 9: Results of Department's matching analysis

	Total Number of Scenarios to Match	Percent Matched
Expansion Planning Runs	98	100%
Swim Lane Runs	98	95%
RES Expansion Planning	1	100%
RES Swim Lanes	2	100%
Special IRP2020 Runs	0	n/a

Table 9 shows that the Department was able to match a majority of runs, and thus was able to validate a majority of datasets used by the Company. The Department was unable to match one dataset, which was the Contingency 18 (No market sales or purchases) dataset. The results of this run are shown below.

Table 10. MP's vs. Department's Matching Results for Contingency 18

Production Cost Run	MIP Stop Basis	Operating Cost + Carrying Charge Cost ($000 in $2021)
PrefPlan CHER1S-18_No Sales and Purchases (MP Run)	50	$7,516,246.47
DepMaDB2 PrefPlan CHER1S-18_No Sales and Purchases (Dept Run)	50	$7,436,714.63
Delta		$79,531.83
Average Percent Change		1.07%

[53] The Department notes that it altered MP's database for one particular contingency, but this was not a material change. For contingency 15, the dataset used referred to data that originated in dataset 14. EnCompass does not let the model perform runs in which this is the case. To rectify the situation, the Department added dataset 14 to scenario 15, but gave it lower priority than dataset 15.

Although the Department used this file in its contingencies, it was not relied upon heavily. If the Department finds that it is necessary for more detailed analysis, the Department will pursue the issues with this file. However, other parties may want to note that results using this dataset may contain errors.

3. Review of MP's Inputs and Outputs

After completing the file verification process, the Department reviewed MP's EnCompass inputs and outputs, as provided to parties in Department IR No. 1. The following section describes MP's model and process, which the Company breaks down as Step 1 (Expansion Plan Analysis) and Step 2 (Swim Lane Analysis). MP used its Expansion Planning Run and Swim Lane databases for these steps.

i. Step 1: Expansion Plan Analysis

a. Inputs

MP's primary analysis focused on the timing of Boswell 3 and 4 retirements. For ease of reference, Table 11 summarizes the retirement dates examined.

Table 11: MP's Boswell retirement scenarios examined for the planning period, no retirement action taken in blank cells[54]

	Boswell 3 Retirement Date	Boswell 4 Retirement Date
Status Quo (Base Case)	-	-
Early3	2025	-
PrefPlan	2029	-
Early4	-	2030
FastExit	2025	2030

Boswell 3 and 4 do not have formal retirement dates under Base Case (StatusQuo) conditions; to represent this, the Department has left blank the retirement dates in the above table.[55] In EnCompass, the Company assumes Base Case retirement dates of December 31, 2050 for both units.

[54] MP used different modeling nomenclature for each of the Boswell retirements in Step 1 versus Step 2, but to reduce confusion, the Department just uses the Step 2 nomenclature here.

[55] In cases where no retirement year is listed, MP notes that the retirement does not occur prior to 2035. The Company also states that although neither unit has a formal retirement date, 2035 is the current end of both units' depreciable lives, and that by 2035, the Company hopes to transition Boswell 4 to non-coal operations. Initially, the Department thought this meant that a 2035 retirement date was assumed for Base Case conditions. In the model, the Company assumes very late retirement dates for both units, unless an early retirement date is specified. The Department found it conceptually easier to ignore the 2035 date when describing Boswell retirement scenarios, and instead think of the scenarios as combinations of "early retirement" or "no action taken" during the planning period.

For each of the five Boswell retirement scenarios, MP then ran six different regulatory and environmental cost futures to comply with the Commission's January 24, 2019 *Order Approving Affiliated-interest Agreements with Conditions* in Docket No. E015/AI-17-568. These futures reflect both a hypothetical carbon tax that begins in 2025 (referred to as "regulatory" costs), as well as the externality costs of effluent emissions (referred to as "environmental" costs). These futures are referred to by the Department in the following terms, with MP's nomenclature in parentheses:

- Mid Reg/Mid Env (CREF1S): Both costs are set at mid-range values, with regulatory costs starting at $15/ton in 2025;
- HighReg/HighEnv (CHER1S): Both costs are set at high-range values, with regulatory costs starting at $25/ton in 2025;
- LowReg/LowEnv (CLER1S): Both costs are set at low-range values, with regulatory costs starting at $5/ton in 2025;
- NoReg/HighEnv(CHE1S): Environmental costs are set at high-range values for each effluent emission rate, with regulatory costs set at $0;
- NoReg/LowEnv (CLE1S): Environmental costs are set at low-range values for each effluent emission rate, with regulatory costs set at $0; and
- NoReg/NoEnv (CCUST1S): Both costs are set at $0.

For each of these thirty combinations (5 Boswell retirement scenarios * 6 regulatory/environmental cost futures), MP first ran a "parent" capacity expansion run (also called an optimized run), then a "child" production cost run (also called an 8760 run), for a total of 60 runs performed in Step 1.[56] The 8760 runs use the capacity expansion plan developed in the "parent" run and perform a more detailed dispatch routine, thus providing more precise outputs.[57] Therefore, aside from the expansion plan selections, any reported data associated with the runs, such as costs or emissions, comes from the 8760 run.

Significantly, regulatory and environmental costs are captured in different ways by the EnCompass model. Per Commission requirements, regulatory cost futures assume that the externality costs of carbon become

[56] For a visual representation of the Company's Expansion Plan database, see Attachment 1A.

[57] By optimizing projects, expansion plan runs produce a capacity expansion plan for a given run. Modelers tend to use simplified scenario settings for these types of runs in an effort to reduce the size of the problem. For example, rather than accounting for every hour of every day of the year when optimizing projects, a modeler might only allow the model to solve to the typical peak and off-peak days (48 hours total) for each month of the full planning period. Both MP and Northern States Power Company d/b/a Xcel Energy employed this simplification for expansion plan runs. These less precise parameters are acceptable for an expansion plan run because, beyond the expansion plan itself, MP does not appear to use any of resulting data. Further, all CEMs have a trade-off between run time and accuracy.
Production cost runs are used to understand all other results of a given expansion plan. These types of runs do not generate their own expansion plans, but simply re-dispatch resources within a parent expansion plan, the 'parent' expansion plan run must be run and completed prior to modeling a 'child' production cost run. To date, the Department's experience is that utility modelers prefer to model production cost runs as "8760" that solve to each hour of the day for every day of the year. This means that production cost runs generate a very large amount of highly detailed information. As a result, the production cost run produces more precise data, but this benefit comes at the cost of assuming as given the expansion plan.

internalized into the cost of a given resource; subsequently, these costs would be passed along as rates reflected in MP's Locational Marginal Prices (LMPs) in the MISO marketplace. As a result, the model's capacity expansion and dispatch routine decisions are based upon costs that reflect the internalization of externality costs. For purposes of this IRP, this means that a theoretical carbon tax is represented in the model in futures that contain regulatory costs (MidReg/MidEnv, HighReg/HighEnv, and LowReg/LowEnv).

Environmental costs, on the other hand, are not adequately captured in the EnCompass model. Since environmental costs represent externality costs that have not been internalized into rates, EnCompass accounts for these costs separately from the "internalized" or realized costs a given resource. This means that environmental costs are not factored into the model's decision-making, either in the capacity expansion or dispatch routines.[58] Instead, after the model has made its capacity expansion or resource decisions, it calculates the externality costs attributable to resources chosen. The modeler can then add the costs of externalities onto the final revenue requirement if they so choose. Since the externality costs do not impact either the expansion plan or the dispatch routine of the model, both the expansion plan and cost results will be the same as if no externality costs had been assumed. For purposes of this IRP, this means that both the expansion plan and certain cost results of NoReg/NoEnv, NoReg/HighEnv, and NoReg/LowEnv are identical.

EnCompass will determine an expansion plan by optimizing certain projects in the model; MP refers to these available projects or resources as "alternatives." In essence, "project" and "alternative" are simply the same as expansion units that can be added to MP's system. As detailed in Appendix K of its filing, MP first used a "busbar" analysis to narrow down the potential resource alternatives to be entered into EnCompass.[59] After this analysis, the Company made available to the model the following resources, which have been grouped by the Department according to general "type:"[60]

[58] MP provides an excellent example of the deficiencies of the model's ability to capture environmental costs in its supplemental Appendix K, filed April 2021.
[59] Typically, it is not practical for a modeler to examine every potential resource type within the CEM itself, as more alternatives slow down the model.
[60] As noted earlier in these comments, the key decisions in resource plans are the size, type, and timing of new resources. Although it is easy to assume that "type" refers to a specific type of plant (say, a reciprocating internal combustion engine, or "RICE" plant, versus a combustion turbine, or "CT" plant), for purposes of modeling, we are instead referring to the role a resource plays on the grid. For example, both a lithium ion battery and a combustion turbine unit could be considered the same "type," providing they are meeting the same peaking need on the grid. One way to define type is by whether the generation is dispatchable, intermittent, or built into load, such as energy efficiency. Another way might be to define it by what need is being served on the grid: baseload, intermediate, or peaking. For purposes of meeting Minnesota Statutes and goals, it's also important to identify resource by whether it meets renewable or energy efficiency goals.

Table 12: Available resources and projects for selection in MP's model, grouped by alternative type and size

Available Alternative Type	Specific Project or Resource	Capacity (MW)
Battery	4 hour lithium ion 8 hour lithium ion 12 hour flow	100
Contract Purchase	Five-year bilateral contract with assumptions specific to natural gas combined cycle plants	150
Demand Response Large	Product B Product D	100
Demand Response Small	Direct Load Control: Air Conditioners Direct Load Control: Water Heaters	8/4.5
Energy Efficiency	High EE Very High EE	1
Large Intermediate Plant	Natural Gas Combined Cycle	593
Large Peaking Plant	Natural Gas Combustion Turbine	282
Small Peaking Plant	Natural Gas Reciprocating Internal Combustion Engine (RICE or RECIP) Natural Gas Simple Cycle Aeroderivative	110/115
Solar	Utility Solar Utility Solar with Income Tax Credit (ITC) Utility Solar sited at Boswell (Net Zero) Utility Solar with Income Tax Credit sited at Boswell (Net Zero + ITC)	100
Transmission	Transmission: Boswell S1, Boswell S2, Boswell S3 Transmission: Solar Transmission: MN-sited Wind, MN-sited Wind with Production Tax Credit (PTC), ND-sited Wind	1
Wind	MN-sited Wind MN-sited Wind with Production Tax Credit ND-sited Wind	100

The Department analyzed various assumptions about MP's alternatives, including costs. Overall, the Department was satisfied that the assumptions used by MP were generally reasonable. The only input changes made by the Department are discussed further below.

Critically, MP forced specific alternatives to be chosen in its expansion plans, dependent upon the specific Boswell retirement scenario. These forced alternative selections are also referred to as "constraints." The purpose of the constraints is to ensure bulk electric system reliability after removal of major baseload plants such as the Boswell units, as determined by engineering requirements. The following bullet points detail the constraints in EnCompass for reliability purposes:

- StatusQuo: No CTs or CC permitted to be selected.
- Early3: After Boswell 3 is retired in 2025, the model must choose one of two options in 2026: either transmission S1 or a CT.
- PrefPlan: After Boswell 3 is retired in 2029, the model must choose one of two options in 2030: either transmission S1 or a CT.
- Early4: After Boswell 4 is retired in 2030, the model must choose one of four options in 2031: transmission S2, a CC, two CTs, or transmission S1 + one CT.
- FastExit: After Boswell 3 is retired in 2025, the model must choose one of two options in 2026: either transmission S1 or a CT. After Boswell 4 is retired in 2030, the model must choose one of three options: transmission (S2 or S3, depending on 2026 selection), one CC, or two CTs. This results in six potential options for the model to choose from.

Visual representations of these constraints can be found in Attachments 1C to 1F to these comments. The Boswell retirement alternative constraints mean that although all alternatives shown in Table 12 were made available for selection in the expansion plan runs, any selections made were *in addition* to the constrained alternative selections.

MP put some additional model constraints in place. For example, whenever a wind resource was selected, a wind transmission resource was forced to be selected as well. If a solar resource was selected that wasn't sited at Boswell, a solar transmission resource was forced to be selected as well. This is similar to how other utilities include transmission costs in expansion units, but MP specified the costs separately, making outside review easier. A table of the constraints of each resource can be found in Attachment 1G to these comments.

b. Outputs

The following table shows MP's expansion plan outputs. In this table, the Department only included resources that were selected in the expansion plans, and also identified constrained resources with asterisks. Further, since the NoReg/NoEnv, NoReg/HighEnv, and NoReg/LowEnv runs produced identical expansion plans, the Department has grouped these runs together into a category called "NoReg Group."[61]

[61] This grouping weights the averages in favor of futures with regulatory costs. However, including all six futures would weight the average in favor of futures that don't consider externality costs at all, since the costs of the NoReg/HighEnv and NoReg/LowEnv futures do not make an impact on the expansion plan. This grouping is only used for expansion plan outputs, since the NoReg group produces identical expansion plans; for the cost outputs, which are different, the Department keeps the six cost futures separate.

Table 13: MP's optimized expansion plan capacity additions (MW), grouped by Boswell retirement scenario and regulatory/externality cost future, constrained resources demarcated with asterisks and shading

Boswell Retirement Scenario	Regulatory/Environmental Cost Future	CC*	CT*	XMSN Boswell (2026)*	Wind MN PTC	Wind XMSN MN PTC*	Wind ND	Wind XMSN ND*	Solar Net Zero
StatusQuo	MidReg/MidEnv			0	300	3	0	0	300
	HighReg/HighEnv			0	300	3	100	1	300
	LowReg/LowEnv			0	200	2	0	0	0
	NoReg Group			0	0	0	0	0	0
	Rounded Average			0	200	2	0	0	200
Early3	MidReg/MidEnv		0	1	300	3	0	0	300
	HighReg/HighEnv		0	1	300	3	200	2	300
	LowReg/LowEnv		0	1	200	2	0	0	300
	NoReg Group		0	1	100	1	0	0	300
	Rounded Average		0	1	200	2	100	1	300
PrefPlan	MidReg/MidEnv		0	1	300	3	0	0	300
	HighReg/HighEnv		0	1	300	3	100	1	300
	LowReg/LowEnv		0	1	200	2	0	0	300
	NoReg Group		0	1	100	1	0	0	300
	Rounded Average		0	1	200	2	0	0	300
Early4	MidReg/MidEnv	0	282	1	300	3	0	0	300
	HighReg/HighEnv	0	282	1	300	3	100	1	300
	LowReg/LowEnv	0	282	1	200	2	0	0	200
	NoReg Group	0	282	1	100	1	0	0	200
	Rounded Average	0	282	1	200	2	0	0	300
FastExit	MidReg/MidEnv	593	0	1	300	3	0	0	300
	HighReg/HighEnv	593	0	1	300	3	100	1	300
	LowReg/LowEnv	593	0	1	300	3	0	0	200
	NoReg Group	593	0	1	200	2	0	0	100
	Rounded Average	593	0	1	300	3	0	0	200

From these results, we can see that:

- In the Boswell retirement constraints (CT/CC/XSMN Boswell columns), the model made the same decisions under each of the different regulatory/environmental futures. These decisions were:
  - In each Boswell retirement scenario where the model was forced to choose between a transmission resource and a CT in 2026 (Early3, PrefPlan, and FastExit), the model chose a transmission resource.

  - In the Early4 scenario, the model's preferred plan was to build both transmission and a CT in 2031, rather than larger transmission, a CC, or two CTs.
  - In the FastExit scenario, the model's preferred plan in 2030 was to build a CC (in addition to the 2026 CT), rather than larger transmission or two CTs.
- The model chose a variety of wind resources, depending on the Boswell retirement scenario and regulatory/environmental future chosen:
  - The model chose no wind resources in the StatusQuo scenario with the NoReg Group future.
  - The most wind resources were chosen in the Early3 scenario with HighReg/HighEnv future. In this scenario, the model chose 3 MN Wind units (and 3 MN Wind transmission units), as well as 2 ND Wind units (and 2 ND Wind transmission units).
- The model chose solar sited at Boswell ("net zero") in most scenarios and futures.
  - The model did not choose any solar in the StatusQuo scenario with LowReg/LowEnv or NoReg Group futures.
  - The model did not choose any solar *not* sited at Boswell.

The Department also notes that in MP's expansion plan modeling, no demand response, energy efficiency, contract purchases, or batteries were chosen.[62] Further, beyond the constrained plants, no additional thermal generation was selected.

As noted earlier, any plan data beyond the expansion plan selections themselves are generally best obtained through a production cost run performed after the initial expansion plan run. MP ran and obtained production cost run data from its Step 1 Expansion Plan database; however, the Company did not actually report this data in its filing, instead focusing on the data obtained from Step 2 Swim Lanes database. The Department obtained MP's Step 1 production cost data from supplemental analysis spreadsheets provided by the Company in response to Department IR No. 1.[63]

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[62] Generally, batteries, peaking plants, and even demand respond serve similar functions on the grid by serving or shaving peak load and can thus be thought of as similar resource "types" and thus interchangeable from a modeling perspective. However, in this instance, since MP's engineering staff has identified specific reliability needs with the retirement of Boswell, a CT unit chosen in the model may not be interchangeable with these other technologies.
[63] MP's supplemental analysis spreadsheets included separate cost streams for the production cost runs from Step 1: Plan Costs, Revenue Requirement, and Externality Costs. The difference between these is as follows:

- Plan Costs: These are costs reported in net present value terms (dollar is start year of plan), and they represent the costs of building the new expansion plan units, plus any variable costs of existing units. Significantly, plan costs are the objective value that the EnCompass model "solves" to.
- Revenue Requirement: These costs, like a rate case revenue requirement, comprise total operating costs, taxes, depreciation, and allowed return. The plan costs value is built into the revenue requirement. Revenue requirement costs are reported in two ways by EnCompass: once as a net present value figure for all years combined, and also as separate nominal dollar figures for each year of the plan.
- Externality Costs: These costs represent the cost of externalities associated with a given plan, but are tallied separately and as discussed above, do not affect either the expansion plan or the dispatch routine selections. Like the revenue requirement, these costs are reported once as a net present value figure for all years combined, and also as separate nominal dollar figures for each year of the plan.

A table with the results of each of these cost results can be found in Attachment 3 to these Comments. Table 14 summarizes MP's Step 1 revenue requirement + externality cost values in NPV.[64]

Table 14: MP's revenue requirement plus externalities cost results ($000, NPV in 2021 dollars) from Step 1 optimized runs, with least cost Boswell retirement scenario demarcated by shading

	StatusQuo	Early3	PrefPlan	Early4	FastExit
MidReg/MidEnv	10,796	10,763	10,760	10,826	10,761
HighReg/HighEnv	11,015	11,036	11,035	11,113	11,223
LowReg/LowEnv	10,970	10,621	10,636	10,677	10,332
NoReg/NoEnv	7,963	8,200	8,158	8,295	8,559
NoReg/HighEnv	16,613	14,724	14,876	14,753	13,130
NoReg/LowEnv	12,268	11,391	11,457	11,478	10,785

From this table, we can see that:

- The FastExit scenario was the least cost Boswell retirement scenario in three of the six optimized futures;
- In the MidReg/MidEnv future, although the PrefPlan scenario is least cost, it is very close to the cost of the FastExit scenario;
- StatusQuo is identified as the least cost scenario in both the NoReg/NoEnv and HighReg/HighEnv futures.

Aside from the revenue requirement, externalities values, and plan costs, the Company did not appear to analyze any other outputs in its Step 1 supplemental analysis from Department IR No. 1.

[64] For the Step 1 Expansion Plan cost values, MP's supplemental analysis spreadsheets actually used the net present value outputs generated by EnCompass for the revenue requirement and externality values. However, for its Step 2 Swim Lane database, MP instead calculated its own net present values from the yearly nominal dollar values for these EnCompass outputs. It's unclear to the Department why the EnCompass net present value outputs are not equal to the calculated net present value outputs, or why the Company chose to use the EnCompass direct net present value outputs in Step 1, but then calculate its own in Step 2. However, to better compare the costs from Step 1 and 2, the Department has here calculated the net present value figures from the EnCompass nominal dollar output figures.

ii. Step 2: Swim Lane Analysis

a. Outputs

In its Swim Lane analysis, MP "locked in" an expansion plan for each of the five Boswell retirement scenarios, then ran a series of production cost runs on each one, with 38 contingencies.[65] What this means is that although the Company (in Step 1) obtained thirty expansion plans for each retirement scenario and regulatory/environmental future combinations, the Company only used five expansion plans in the second step of its analysis. Table 15 shows the locked in expansion plans for each Boswell retirement scenario, compared with the average expansion plan selection result calculated in Table 13 above.

Table 15: MP's alternatives selected by model in Step 1 vs. alternatives forced into model in Step 2 for each Boswell retirement scenario

		Selected in Step 1								Not Selected in Step 1
Boswell Retirement Scenario		**CC***	**CT***	**XMSN Boswell (2026)***	**Wind MN PTC**	**Wind XMSN MN PTC***	**Wind ND**	**Wind XMSN ND***	**Solar Net Zero**	**All other resources or projects**
StatusQuo	Step 1				2	2	0	0	2	0
	Step 2	0	0	0	0	0	0	0	0	0
Early3	Step 1		0	1	2	2	1	1	3	0
	Step 2	0	0	1	2	2	0	0	2	0
PrefPlan	Step 1		0	1	2	2	0	0	3	0
	Step 2	0	0	1	2	2	0	0	2	0
Early4	Step 1	0	1	1	2	2	0	0	3	0
	Step 2	0	1	1	2	2	0	0	2	0
FastExit	Step 1	1	0	1	3	3	0	0	2	0
	Step 2	1	0	1	2	2	0	0	2	0

In Table 15, we can see that MP used similar locked in selections in Step 2 to the optimized averages from Step 1. The Department makes the following observations about deviations between Step 1 results and Step 2 assumptions:

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[65] In certain parts of its filing, MP states that the Company ran 37 contingencies. However, this appears to only be true for the NoReg/NoEnv futures, for which the "16- No Externalities" contingency was removed. In the other futures, the Company ran 38 contingencies.

- In the StatusQuo scenario, MP assumed zero locked in resources;
- In the Early 3 scenario, Step 1 results averaged one ND Wind and one ND Wind Transmission resources, whereas MP assumed zero units for each of these resources in Step 2;
- In the FastExit scenario, Step 1 results averaged three MN PTC wind and MN PTC wind transmission, whereas MP assumed two units for each for these resources in Step 2;
- In the Early3, PrefPlan, and FastExit scenarios, Step 1 results averaged three Net Zero Solar resources, whereas MP assumed two units for this resource in Step 2.

The Department notes that these are generally reasonable assumptions. However, the Department is also unclear as to why MP chose to lock in its expansion plans for Step 2. As will be discussed below, the Department instead simply optimized each contingency run, then ran an 8760 run for each optimized run. This meant that while MP only had 30 optimized runs between both Steps 1 and 2, the Department had a total of 960 optimized runs prior to its forecast/NTEC study. A visual difference between these strategies can be seen by comparing Attachments 1B and 4A to these Comments.

After locking it its five expansion plans for each Boswell retirement scenario, the Company then ran 38 contingencies for each of its six regulatory/environmental futures. The following table describes each of the contingencies examined in MP's Step 2 Swim Lane analysis.

Table 16: MP's Step 2 Swim Lane contingencies with descriptions

01_Coal+20%	Increases the price of coal by 20 percent.
02_Coal-10%	Decreases the price of coal by 20 percent.
3_Biomass+15%	Increases the price of biomass by 15 percent.
4_Biomass-15%	Decreases the price of biomass by 15 percent
05_Lower Gas-50%	Decreases the price of gas by 50 percent; appears to make changes that assumes gas to be the marginal market fuel.
06_Low Gas-25%	Decreases the price of gas by 25 percent; appears to make changes that assumes gas to be the marginal market fuel.
07_High Gas+25%	Increases the price of gas by 25 percent; appears to make changes that assumes gas to be the marginal market fuel.
08_Higher Gas+50%	Increases the price of gas by 50 percent; appears to make changes that assumes gas to be the marginal market fuel.
09_Highest Gas+100%	Increases the price of gas by 100 percent; appears to make changes that assumes gas to be the marginal market fuel.
10_WHSL Mkt-50%	Decreases prices of the wholesale electric market by 50 percent; appears to make changes that assumes gas to be the marginal market fuel.
11_WHSL Mkt-25%	Decreases prices of the wholesale electric market by 25 percent; appears to make changes that assumes gas to be the marginal market fuel.

12_WHSL Mkt+25%	Increases prices for the wholesale electric market by 25 percent; appears to make changes that assumes gas to be the marginal market fuel.
13_WHSL Mkt+50%	Increases prices for the wholesale market by 50 percent; appears to make changes that assumes gas to be the marginal market fuel.
14_CapCosts-30%	Decreases base project costs of solar, wind, and batteries by 30 percent.
15_CapCosts+30%	Increases base project costs of solar, wind, and batteries by 30 percent.
16_No Externalities Costs	Removes externality costs.
17_NoMktSales	Does not allow MP to sell economic or surplus energy into market.
18_NoSalePurchase	Removes tiered energy market, allowing only purchases of emergency energy. Also removes capability to sell economic or surplus energy into market.
19_MktAccess-50%	Reduces area interchange limits by 50 percent.
20_LoINTCONCosts	Reduces interconnection costs for wind by 30 percent and for solar by 65 percent.
21_ITC&PTC Extend	Extends 60 percent Production Tax Credit (PTC) and 26 percent Income Tax Credit (ITC) thorugh 2035.
22_WindCostLow	Uses low technology cost curve, decreases wind capital cost by 8.4 percent in 2025.
23_WindCostHi	Uses high technology cost curve, increases wind capital cost by 5.9 percent in 2025.
24_SolCostLow	Uses low technology cost curve, decreases solar capital cost by 5.6 percent in 2025.
25_SolCostHigh	Uses high technology cost curve, increases solar capital cost by 17.4 percent in 2025.
26_StorCostLow	Uses low technology cost curve, decreases lithium ion battery capital cost by 7.8 percent in 2025.
27_StorCostHigh	Uses high technology cost curve, increases lithium ion battery capital cost by 23.2 percent in 2025.
28_AFR 2020 Low	Decreases customer demand by 5 percent from the Expected Scenario from the AFR2020.
29_AFR 2020 Load w Keetac	Appears to add industrial customer to to Expected Scenario from the AFR2020.
30_AFR 2020 High Scenario	Uses High Scenario from the AFR2020.
31_ResTOU	Moves all residential customers to a hypothetical Time of Use (TOU) rate program. Modeled as reducing load during peak hours and increasing load during all other hours to keep energy sales forecast neutral.

32_High DG&EV	Increases distributed generation (DG) solar penetration rates, increases electric vehicle (EV) growth rate.
33_RenewELCC-2.5%	Decreases the ability of wind and solar to be reliable during periods of electricty shortage (ELCC) by 2.5 percent
34_RenewELCC+2.5%	Increases the ability of wind and solar to be reliable during periods of electricity shortage (ELCC) by 2.5 percent
35_PRM-2%	Decreases MISO's planning reserve margin (PRM) established in its Planning Year 2020-2021 Loss of Load Expectation Sutdy Report by 2 percent.
36_PRM+2%	Decreases MISO's planning reserve margin (PRM) established in its Planning Year 2020-2021 Loss of Load Expectation Sutdy Report by 2 percent.
37_MISO CF-2%	Decreases MISO coincidence factor by 2 percent, resulting in a MISO coincident peak demand higher than base contingency.
38_MISO CF+2%	Increases MISO coincidence factor by 2 percent, resulting in a MISO coincident peak demand lower than base contingency.

b. Outputs

MP presents its cost results in both its Main Filing, as well as in Appendix K, both the initial and supplement. The Department summarizes the Company's base case results in Table 17.

Table 17: MP's revenue requirement plus externalities cost results ($000, NPV in 2021 dollars) from Step 2, least cost Boswell scenario demarcated by shading

	StatusQuo	Early3	PrefPlan	Early4	FastExit
MidReg/MidEnv	8,010	7,903	7,891	7,918	7,944
HighReg/HighEnv	8,379	8,302	8,276	8,281	8,366
LowReg/LowEnv	7,632	7,486	7,494	7,537	7,502
NoReg/NoEnv[66]	5,841	6,044	5,965	6,028	6,198
NoReg/HighEnv	10,337	9,607	9,727	9,721	9,290
NoReg/LowEnv	8,061	7,781	7,814	7,852	7,707

[66] MP did not appear to report the NoReg/NoEnvcost results from its Swim Lane analysis in its Main Filing or any appendices or supplements. The Department obtained these figures from the Company's Swim Lane supplemental analysis spreadsheets provided in response to Department IR No. 1.

These results do not paint a consistent picture as to which is the least cost plan under each regulatory/environmental future:

- When cost futures are set at MidReg/MidEnv or HighReg/HighEnv levels, MP's locked in PrefPlan is the least cost scenario;
- When cost futures are set at LowReg/LowEnv levels, MP's locked in Early3 plan is the least cost scenario;
- When cost futures are set at NoReg/NoEnv levels, MP's locked in StatusQuo plan is the least cost scenario; and
- When cost futures are set at NoReg/LowEnv or NoReg/HighEnv levels, MP's locked in FastExit plan is the least cost scenario.

In Appendix K of its supplement, the Company discusses the NoReg/HighEnv and NoReg/LowEnv futures. Under these cost futures, MP's locked in FastExit Boswell retirement scenario was the least cost scenario in the vast majority of cases, accounting for 36 of the 39 least cost results under a NoReg/LowEnv future and 38 of the 39 least cost results under a NoReg/HighEnv future. The Company explains these results thusly:[67]

> As discussed in the Supplemental Step 1 analysis, EnCompass does not add Environmental Costs to the total power supply costs until after the unit dispatch is completed. EnCompass does include the cost of a carbon regulation tax when dispatching units, but disregards Environmental Costs when dispatching generation. When the carbon regulation tax is zero to minimal, as is the case in the "Low Carbon Regulation Cost and Low Environmental Cost" future, EnCompass does not shift dispatch towards lower carbon emitting resources. The units in the EnCompass model with the highest carbon intensity also have the highest environmental criteria pollutant intensity. Since the model does not avoid dispatching the high intensity units to avoid the environmental costs, the results are biased towards earlier and more aggressive retirement's scenarios.
> […]
> Furthermore, in the "Low Environmental Costs" and "High Environmental Costs" futures shown below, the impacts of this environmental future design shortcoming are even more pronounced. Because EnCompass does not have any price signal (i.e. Carbon Regulation Tax) to dispatch around in these futures, the model is heavily biased towards the plans that replace higher emission intense resources with lower emission intense resources. In the "Two Unit Retirement" swimlane, Minnesota Power's existing coal fleet is replaced entirely by natural gas fired resources. When dispatching these futures, EnCompass does not know that it is accruing Environmental Costs, so the total plan NPV shown in the tables will constantly be less among swimlanes which include natural gas resources.

[67] Pages 24-25, Appendix K Supplement filed April 1, 2021.

As a result of these biases in the model under the NoReg/LowEnv and NoReg/HighEnv futures, the Company effectively discounts these results. Without the NoReg/HighEnv and NoReg/LowEnv futures, the plan most frequently selected is PrefPlan, which was selected under both the MidReg/MidEnv and HighReg/HighEnv futures.

4. Department Changes to MP's Assumptions

After validating MP's datasets and reviewing the Company's assumptions and results, the Department then made a number of changes to the Company's base case.

i. Structural Changes

The first changes made by the Department were structural. As noted above, MP only permitted the EnCompass model to optimize the expansion plan, beyond the Boswell constraints, under Step 1. In Step 2, when examining the 38 contingencies, MP locked in five expansion plans, one for each Boswell retirement scenario. This means that the Company only examined the cost effects of the contingencies, not the expansion plan effects.

By contrast, the Department ran an expansion plan run and a production cost run for each contingency examined. To do this, the Department created a new database designed loosely around the Step 2 Swim Lanes database structure, with an expansion plan run added into each contingency. There were a couple of key changes made to ensure that the Department's new database operated as intended, which included:

- removing the Step 2 Swim Lane datasets that locked in the expansion plans and replacing them with the Step 1 Expansion Plan Boswell retirement constraints datasets;
- setting the expansion plan scenario settings to match MP's other expansion plan settings; and
- changing the parent run of each production cost run to be that contingency's expansion plan run.

Further, to ensure that the Department did not exceed the 10GB database cap, the Department assigned each Boswell retirement scenario its own database.[68]

Finally, the Department did not run every contingency examined by MP. The Department removed the following contingencies:

- Contingency 3: Biomass+15%;
- Contingency 4: Biomass-15%;
- Contingency 16: No Externalities Costs;
- Contingency 29: AFR2020 Load with Keetac;
- Contingency 30: AFR2020 High Scenario;
- Contingency 37: MISO CF-2%; and
- Contingency 38: MISO CT+2%.

[68] Client server version versus desktop version of EnCompass have differing abilities to save data into a single file.

The Department removed Contingencies 16, 29, and 30 because the Department examined these contingencies at broader levels within the model. The Department removed the biomass cost contigencies because MP's biomass plant (Hibberd) tends to fall more in line with a "must run" facility (like other renewables), and therefore won't respond as much to changes in fuel price. The Department considered Contingencies 37 and 38 to be more or less redudant with Contingencies 35 (PRM-%) and 36 (PRM+2%). The coincidence factor adjusts the peak demand forecast so that, for reliability purposes, MP's demand at the time of MISO's overall peak is considered in the PRM.

A visual representation of the Department's new base analysis structure can be found in Attachment 4A.

ii. Input Changes

The Department made minimal changes to the inputs and assumptions made by MP. These changes were: hydroelectric capacity changes, a heat rate assumption change, and end effects treatment.

a. Hydro Capacity

In Appendix C of its Filing, MP noted that four hydroelectric stations had FERC licenses set to expire during the planning period. Specifically, the Prairie River station is set to expire in 2023, and the Little Falls, Sylvan, and Pillager stations are set to expire in 2028. MP stated that the useful lives of those units extends beyond the planning period, and that the Company expects those units to continue to operate throughout the planning period. The Department assumes that this means the Company expects the FERC licenses to be extended or renewed. MP also states that while previous resource plans have set the retirement dates of hydro units bases on the experation of FERC licenses, the Company now sets those retirement dates based on the projected operating lives.[69]

The Department's policy has been to assume known and measurable facts when it comes to retirement dates of resources, and therefore sought to use the known retirement dates for the four hydro units in question, rather than the projected dates. However, in its EnCompass modeling, MP did not enter its hydro facilities into the model on a per-resource basis, but instead grouped its hydro resources into either "Thompson," which is a reservoir dam resource, or a collective "Run of River" resource. As a result, the Department could not simply change the retirement dates of the resources in question. The Department and MP agreed that to make the adjustment, the Department could simply back out the name plate capacity of each of the four resources at the time of their respective retirement dates from the collective Run of River capacity. It was also decided that adjusting the costs at this time would be too extensive, as it's not simply a matter of backing out costs currently attributable to each resource. Since these are generally fixed costs, they would not impact the cost difference between various potential plans.

Therefore, to account for hydro facilities whose FERC operating licenses are set to expire during the planning period, the Department incorporated a capacity adjustment but not a cost adjustment. Given the size of the adjustment, the Department does not expect this adjustment had a meaningful impact on the decisions of the model. However, given that this was known information about the size, type, and timing of a resource, the

[69] Page 7, Appendix C.

Department concludes that it was still the correct course of action to make the adjustment. The Department can provide the calculation of the adjustment to parties upon request.

b. Young 2 Heat Rate

Another minor adjustment made by the Department was to the heat rate of Square Butte's Young 2 coal plant. The Department noted that this plant had seasonal heat rate inputs for each block, but that MP's other coal resource (Boswell) did *not* use seasonal heat rates. After discussing this with MP, the Company noted that the seasonal heat rates should not have been captured in the model. The Department therefore used the higher summer heat rates for the remaining parts of the year.

The Department does not expect this to impact the model's decisions, as it is a minor change, and because MP will no longer take any of the Young 2 output for its customers by 2026.

c. End Effects

The purpose of including "end effects" in a CEM is to avoid a bias against adding energy intensive units late in the planning period. If a run was performed using only the planning period (2021 to 2035) it would be difficult for EnCompass to justify adding energy intensive units late in the planning period. Running the model past 2035 allows a better assessment of energy-related benefits.

Essentially, this routine repeats the last year of the model run several times. This ideally involves:

- Running the model as an optimization through 2045;
- Demand Side Changes:
  - Freezing the forecast of energy and capacity requirements at 2035 levels; and
  - Freezing any other load group requirements (i.e., energy efficiency, electric vehicles, etc.) at the 2035 levels;
- Supply Side Changes:
  - Extending to 2045 the lives of any generating units currently set to retire during the end effects period (2035 to 2045); and
  - Freezing the energy and capacity outputs of supply side resources at 2035 levels.

MP included some but not all of the Department's preferred end effects changes. MP ran all of its runs through 2045, a critical component of end effects treatment. MP also appeared to freeze certain load group levels at 2035 levels.

On the demand side, the Department repeated the 2035 year for the MinnPower Load Shape. Although other monthly forecasts of MP's appeared to account for end effects, the load shape did not. In EnCompass, anytime a modeler enters a new peak or energy forecast, the load shape will automatically adjust to meet the new criteria. However, simply adjusting the monthly peak forecasts to account for end effects will not fully incorporate end effects into the hourly load shape data. For end effects to be fully accounted for in the load group data, both the monthly peak and capacity time series, as well as the hourly load shape data needed to repeat the 2035 year. Since incorporating these end effects into its new base, the Department further learned of a shape factor that needs to be checked and potentially adjusted as well; if needed, the Department will incorporate this change into its modeling in the future.

On the supply side, the Department made the following additional changes to MP's model:

- Extended the life of CommGarden Solar to December 31, 2045;
- Adjusted a couple of specific MinnPower Monthly Energy figures to conform to the rest of MP's data;[70]
- Repeated the 2035 year values for the following supply-side time series:
    - Bison 1-4 Wind Firm Capacity;
    - Camp Ripley Solar Max Capacity and Firm Capacity;
    - CommGarden 1 Solar Firm Capacity;
    - Nobles 2 Wind Firm Capacity;
    - Oliver 1-2 Wind Firm Capacity;
    - Run of River Hydro Max Capacity and Firm Capacity;
    - SES Solar 20 Firm Capacity; and
    - TacRidge Wind Firm Capacity.

However, the Department was able to confirm through examining interval data for specific resources that the above supply-side changes did not fully account for end effects. Theoretically, if all components of the model are adequately frozen at 2035, for any year between 2035 and 2045, all generation in a particular hour will be the same year to year. However, the Department found that in MP's model, the model is dispatching as if there were 364 days in a year instead of 365, at least for certain units.[71] This means that the modeler can't compare the generation of a given hour, year to year, and get the same results. Despite this, for purposes of end effects, the Department decided not to pursue this any further.

The following table distinguishes the structural and input differences between MP's and the Department's base cases:

[70] The figures in question appeared to be typos.
[71] This can be seen by comparing a Bison 1 input file to Bison 1 behavior in an output file. In the input file, MP has very specific hours during which Bison 1 is producing 0. In the output file, the interval data for that unit will shift those "0" production hours one day from year to year. For example, Bison 1 is at 0 units online the first four hours of January 9, 2034. In 2035, those four 0 unit hours appear to occur on January 8th instead.

<table>
<tr><th>Type of Change</th><th>Department's New Base</th><th>MP's Base Case</th></tr>
<tr><td rowspan="3">Structural Change</td><td>Does not separate analysis into two Steps</td><td>Breaks analysis into Step 1 and Step 2</td></tr>
<tr><td>Tests 31 contingencies + base contingency for a total of 32 contingencies</td><td>Tests 38 contingencies + base contingency within Step 2 for a total of 39 contingencies
No Contingency 16 run in NoReg/NoEnv cost futures within each Boswell retirement scenario; these scenarios only have 37 contingencies + base contingency for a total of 38 contingencies</td></tr>
<tr><td>Runs both an optimized run and an 8760 run for each contingency examined</td><td>Only runs optimized runs in Step 1; only runs 8760 runs with locked in expansion plans in Step 2</td></tr>
<tr><td rowspan="4">Input change</td><td>Incorporated hydroelectric capacity adjustment to account for FERC license expirations during retirement period</td><td>Assumes all hydroelectric capacity available for duration of planning period</td></tr>
<tr><td>Changed Square Butte's Young 2 coal plant to use summer heat rates for whole year</td><td>Assumes Young 2 has different summer and winter heat rates</td></tr>
<tr><td>Applied end effects by repeating the 2035 year for the following resources:
Bison 1-4 Wind Firm Capacity
Camp Ripley Solar Max Capacity and Firm Capacity
CommGarden 1 Solar Firm Capacity
Nobles 2 Wind Firm Capacity
Oliver 1-2 Wind Firm Capacity
Run of River Hydro Max Capacity and Firm Capacity
SES Solar 20 Firm Capacity
TacRidge Wind Firm Capacity</td><td>Assumes no end effects for those resources</td></tr>
<tr><td>Extended the life of CommGarden Solar to December 31, 2045</td><td>Assumes CommGarden Solar resource retires December 31, 2043</td></tr>
</table>

	Adjusted some specific Monthly Energy values to better conform to MP's data	Includes a couple of Monthly Energy values that don't match the rest of the time series values

5. Department New Base Results

After making the above structural and input changes, the Department sought to answer the following questions:

- What were the preferred expansion plans under each of the five Boswell retirement scenarios?
- How did the five Boswell retirement scenarios rank in terms of cost?
- Are there any other issues worth discussing?
- Based on the Department's results, should the Commission approve Minnesota Power's preferred plan of retiring Boswell 3 in 2029 and taking no action on Boswell 4?

After making the above changes, the Department ran five Boswell scenarios, six cost futures, 32 contingencies, and two run types for a total of 1,920 runs. A visual representation of the Department's analysis can be seen in Attachment 4A.

i. Expansion Plan Results

As noted above, the expansion plans of the three futures with no regulatory costs[72] were identical, as EnCompass does not incorporate environmental costs into either its expansion plan or dispatch routine. Therefore, for the expansion plan results, the Department has grouped these three futures together, as it did for its review of MP's expansion plan results.[73] For the cost results, examined in the next section, the Department presents the six results separately.

One half of the Department's runs were expansion plan runs, while the other half were production cost runs. This means that the Department performed 960 expansion plan runs. However, since the no-regulatory cost futures were grouped together as a singular result, the following table shows the results of 640 runs. Each cost future shows the results of 160 runs, with each line representing 32 runs, meaning that each percentage figure is calculated from 32 total runs. For example, one could say, "When Boswell 4 is retired early under a high regulatory/high environmental cost future, at least one gas peaking unit is chosen in 75% of 32 runs."

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[72] NoReg/NoEnv, NoReg/HighEnv, and NoReg/LowEnv.

[73] As noted previously, this grouping weights results in favor of run results with regulatory costs, as the "no regulatory" cost futures comprise one quarter of the results. If the Department were to present the expansion plan of each of the six futures separately, three of those futures would contain identical results, meaning that the "no regulatory cost" futures would comprise one half of the results. The Department decided on this grouping because it appeared to more accurately represent the intentions of the Commission, which was to determine the expansion plan and cost effects of different regulatory and cost futures. Since the costs of the six futures were not identical, the Department kept these separate.

Table 19: Department's results for frequency of alternative additions within each Boswell retirement scenario and regulatory/environmental cost future

Cost Future	Boswell Retirement Scenario	Battery	Contract Purchase	DR	EE	Gas CC	Gas CT/RICE/Aero	Solar	XMSN	Wind
NoReg Group: NoReg/NoEnv NoReg/HighEnv NoReg/LowEnv	StatusQuo	0%	0%	0%	0%	0%	0%	6%	3%	3%
	PrefPlan	0%	0%	0%	0%	0%	31%	75%	78%	47%
	Early3	0%	0%	9%	0%	0%	100%	100%	100%	100%
	Early4	0%	0%	0%	0%	19%	81%	72%	81%	22%
	FastExit	0%	0%	0%	0%	100%	100%	0%	0%	0%
High Reg/High Env	StatusQuo	0%	0%	3%	0%	0%	0%	97%	97%	97%
	PrefPlan	0%	0%	3%	0%	0%	19%	100%	100%	97%
	Early3	0%	0%	0%	0%	0%	75%	100%	100%	100%
	Early4	0%	0%	0%	0%	25%	75%	94%	100%	97%
	FastExit	0%	0%	0%	0%	100%	100%	88%	94%	94%
Low Reg/Low Env	StatusQuo	0%	0%	0%	0%	0%	0%	19%	84%	84%
	PrefPlan	0%	0%	3%	0%	0%	16%	91%	94%	91%
	Early3	0%	0%	0%	0%	0%	41%	84%	88%	88%
	Early4	0%	0%	0%	0%	19%	81%	81%	91%	84%
	FastExit	0%	0%	0%	0%	97%	100%	28%	81%	81%
Mid Reg/Mid Env	StatusQuo	0%	0%	0%	0%	0%	0%	94%	97%	97%
	PrefPlan	0%	0%	3%	0%	0%	13%	97%	100%	97%
	Early3	0%	0%	0%	0%	0%	28%	97%	97%	97%
	Early4	0%	0%	0%	0%	25%	75%	88%	100%	97%
	FastExit	0%	0%	0%	0%	97%	100%	88%	94%	94%

From this table, we can see that:

- The model did not choose incremental Batteries, Energy Efficiency, or Contract Purchase under any Boswell retirement scenario or cost future examined;
- The model very minimally chose Demand Response:
    - The model chose DR in 9 percent of Early3 scenarios under the NoReg Group futures;
    - The model chose DR in 3 percent of PrefPlan scenarios under HighReg/HighEnv, MidReg/MidEnv, and LowReg/LowEnv futures;
- Intermediate gas resources (Gas CC) were highly dependent on both the Boswell retirement scenario and regulatory/environmental cost future:
    - Under every cost future, Gas CC units were selected in 0 to 100 percent of Boswell retirement scenarios;
    - While Gas CC units were chosen in close to 100 percent of FastExit scenarios, they were chosen in 0 percent of StatusQuo, PrefPlan, and Early3 scenarios;

  - Gas CC units tended to be chosen in 20 to 25 percent of Early4 scenarios;
- Gas peaking resources (CT/RICE/Aero) were highly dependent on both the Boswell retirement scenario and regulatory/environmental cost future, but were chosen more frequently across Boswell scenarios than intermediate gas resources:
  - Gas peaking resources were chosen in all scenarios but the StatusQuo;
  - Gas peaking resources were chosen at highly varied rates, from 0 percent StatusQuo to 100 percent in FastExit;
- Solar resources were highly dependent upon cost future:
  - In the MidReg/MidEnv and HighReg/HighEnv futures, solar was chosen in 88 to 100 percent of runs;
  - By contrast, in the no- and low- regulatory/environmental cost futures, solar was chosen in 0 to 100 percent of runs, again a wide spectrum of variation;
- Transmission resources matched wind additions exactly in the StatusQuo, Early3, and FastExit scenarios, indicating that these transmission resources were likely tied to new wind additions rather than new solar additions or to Boswell retirement constraints;
- While wind, like solar, varied depending on regulatory/environmental cost future, this resource was not as susceptible to changes in cost:
  - In the NoReg Group futures, wind was chosen between 0 and 100 percent of the time, but between 81 and 100 percent of the time in the other three cost futures;
  - Under the LowReg/LowEnv cost future, solar resources behaved closer to the MidReg/MidEnv cost future, while wind resources behaved closer to the NoReg Group cost future.

The following table condenses the cost future data to give a high-level summary of general trends within each Boswell retirement scenario:

Table 20: Department's results for frequency of alternative additions within each Boswell retirement scenario

Boswell Retirement Scenario	Battery	Contract Purchase	DR	EE	Gas CC	Gas CT/RICE/Aero	Solar	Transmission	Wind
StatusQuo	0%	0%	1%	0%	0%	0%	54%	70%	70%
PrefPlan	0%	0%	2%	0%	0%	20%	91%	93%	83%
Early3	0%	0%	0%	0%	0%	61%	95%	96%	96%
Early4	0%	0%	0%	0%	22%	78%	84%	93%	75%
FastExit	0%	0%	0%	0%	98%	100%	51%	67%	67%

An executive summary could therefore say that, across all futures:

- The Department's model chose combined cycle gas units primarily in the Boswell FastExit retirement scenarios;
- The Department's model chose gas peaking units primarily in the Boswell Early3, Early4, and FastExit scenarios;

- The Department's model chose wind and solar in a majority of all Boswell retirement, although wind was chosen with higher frequency;
- The Department's model never chose batteries, contract purchases, or incremental energy efficiency, and rarely chose demand response across all Boswell retirement scenarios.

After determining the most frequently resources for each Boswell retirement scenario and cost future, the Department compiled the median capacity expansion plan results. The following table shows these results:

Table 21: Department's capacity expansion plan results showing median capacity added per resource alternative, by Boswell retirement scenario and Regulatory/Environmental Cost Future

Reg/Env Cost Future	Boswell Retirement Scenario	Gas CC	Gas CT/RICE/Aero	Solar	Transmission	Wind
NoReg Group: NoReg/NoEnv NoReg/HighEnv NoReg/LowEnv	StatusQuo	0	0	0	0	0
	PrefPlan	0	0	200	1	0
	Early3	0	282	100	1	100
	Early4	0	282	200	1	0
	FastExit	1186	282	0	0	0
HighReg/HighEnv	StatusQuo	0	0	300	4	400
	PrefPlan	0	0	300	5	400
	Early3	0	282	300	4	400
	Early4	0	282	300	5	400
	FastExit	593	282	300	3	300
LowReg/LowEnv	StatusQuo	0	0	0	1	100
	PrefPlan	0	0	200	3	200
	Early3	0	0	200	3	200
	Early4	0	282	200	3	200
	FastExit	1186	282	0	1	100
MidReg/MidEnv	StatusQuo	0	0	200	3	300
	PrefPlan	0	0	300	4	300
	Early3	0	0	300	4	300
	Early4	0	282	300	4	300
	FastExit	593	282	200	3	300

From this table, we can see that:

- The Department's model only added intermediate gas capacity in the FastExit scenario, but was split as to whether to add one unit or two, depending on cost future;
- The Department's model adds no gas peaking units under StatusQuo or PrefPlan scenarios, adds two units under Early4 and FastExit scenarios, and is split as to whether to add one or two units in the Early3 scenario;

    - In the Early3 scenario, we can see that the gas peaking unit is only added in the NoReg Group and HighReg/HighEnv futures;
- The Department's model tends to add between 0 MW and 300 MW of solar, depending largely upon the regulatory/environmental cost future:
    - No solar is added in the StatusQuo and FastExit scenarios for NoReg Group and LowReg/LowEnv futures;
    - Across all futures, more solar tends to be added in the PrefPlan, Early3, and Early4 scenarios;
- The Department's model adds between 0 and 5 transmission projects, depending highly on both the regulatory/environmental cost future and the Boswell retirement scenario:
    - The most transmission tends to be added in the PrefPlan and Early4 scenarios in the HighReg/HighEnv cost future;
    - The least transmission tends to be added in the StatusQuo and FastExit scenarios in the NoReg Group cost futures;
    - Across all cost futures, more transmission tends to be added in the PrefPlan, Early3, and Eary4 scenarios;
- The Department's model tends to add between 0 MW and 400 MW of wind, depending largely upon the regulatory/environmental cost future:
    - The least wind tends to be added in the NoReg Group cost future, whereas the most wind tends to be added in the HighReg/HighEnv cost future;
    - The amount of wind added is less variable than the amount of solar added.

ii. Cost Results

Unlike its expansion plan results, which grouped the NoReg cost futures, the Department examined its six cost futures results separately. Further, while the Department examined the capacity expansion run data for its capacity expansion results, the Department examined the production cost run data for all other results, including costs. This is because, as discussed earlier, production cost runs "lock in" a given expansion plan and re-run a dispatch routine, typically at a more granular level. This means that the data outputs from production cost runs are more precise than expansion plan runs and can provide more detailed information as to the behavior of different resources.

One half of the Department's runs were expansion plan runs, while the other half were production cost runs. This means that the Department performed 960 production cost runs, the cost results of which are captured in Table 22. Each cell in the below table represents the median cost value of 32 runs.

Table 22. Department's median revenue requirement + externalities cost in 2021 Net Present Value ($000) for each Boswell retirement scenario and regulatory/environmental cost future, least cost plan demarcated with shading

	StatusQuo	PrefPlan	Early3	Early4	FastExit
NoReg/NoEnv	7,450	7,641	7,687	7,730	7,368
NoReg/HighEnv	25,158	13,349	13,292	13,340	11,727
HighReg/HighEnv	11,662	10,350	10,294	10,405	9,881
NoReg/LowEnv	16,246	10,449	10,423	10,485	9,512
LowReg/LowEnv	13,275	9,744	9,728	9,808	9,108
MidReg/MidEnv	12,043	10,037	10,047	10,081	9,430

More granular cost results of the Department's new base case can be found in Attachment 5.
From this table, we can see that:

- Across all carbon cost futures, the FastExit scenario was the least-cost plan;
- In all futures but the NoReg/NoEnv future, the StatusQuo scenario was the highest-cost plan; and
- The PrefPlan, Early3, and Early4 cost results were less clear cut; however, in all futures but NoReg/NoEnv, these three Boswell retirement scenarios tended to produce more similar cost results to each other than to the StatusQuo or FastExit scenarios.

Table 22 can be compared to Table 17 above, which shows the Company's cost results for the same Boswell retirement and carbon cost futures. Unlike the Department's results, MP did not have a consistent result of which Boswell retirement plan was least cost; it's unclear to the Department why this is the case. Notably, however, in Table 17, each cell represents the results of a singular MP production cost run under the base contingency (without any other contingencies applied). By contrast, each cell in the Department's table shows the median cost result of 32 different contingencies. However, even if the Department were only to examine the base contingency run, as MP did, the Department continued to find the FastExit plan to be least cost.

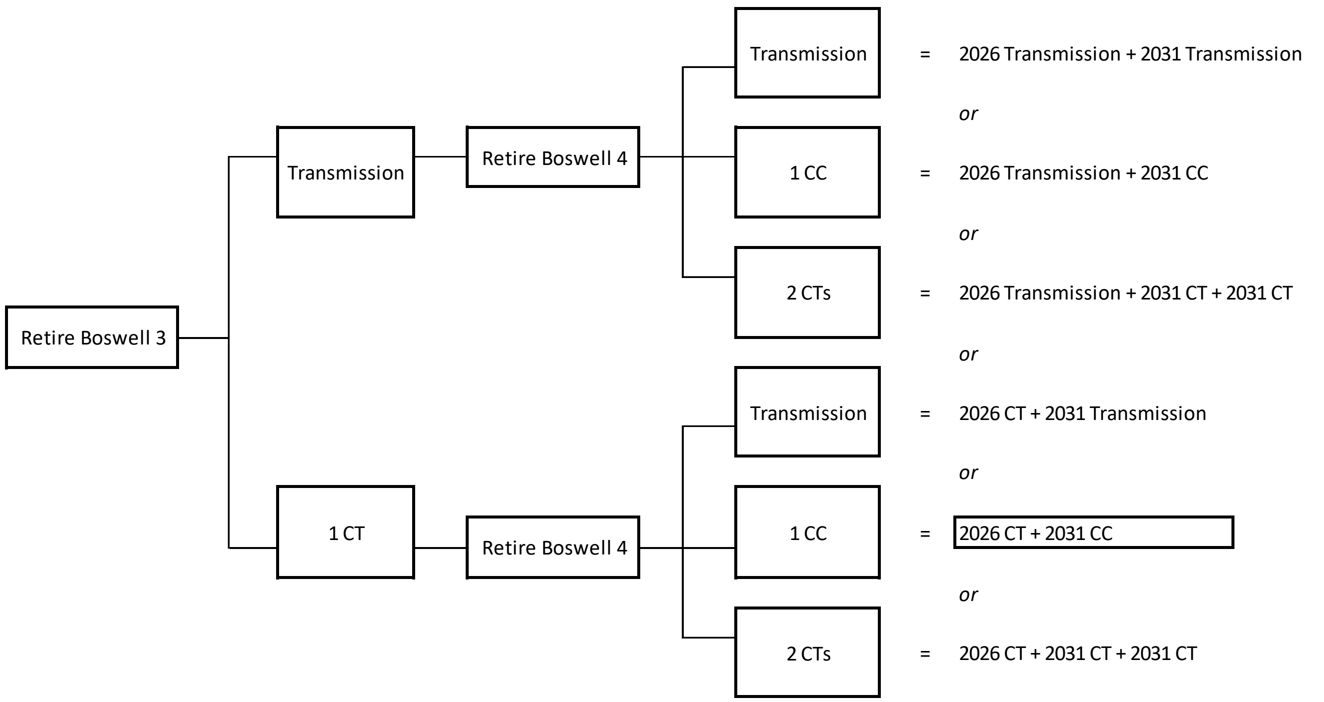
In the Department's modeling, the FastExit scenario does tend to rely heavily on the addition of carbon-intensive units in the expansion plans. The following table shows the typical expansion plan in the FastExit scenario:

Table 23. Department's typical expansion plan results for the FastExit scenario with the base contingency, by regulatory/environmental future

	NoReg Group					HighReg/HighReg					LowReg/LowEnv					MidReg/MidEnv				
	CC	CT	Sol	XMSN	Wind	CC	CT	Sol	XMSN	Wind	CC	CT	Sol	XMSN	Wind	CC	CT	Sol	XMSN	Wind
2021																				
2022																				
2023																				
2024									1	1									1	1
2025									2	2				1	1				2	2
2026		1					1					1					1			
2027																				
2028																				
2029																				
2030																				
2031	2					1		1			2					1				
2032																				
2033																				
2034																				
2035								2										2		

As described earlier, the Boswell constraints are set up so that the model must make certain choices after Boswell units are retired, in order to ensure reliability on the system. In the FastExit scenario, the model strongly preferred to add a 2026 CT and a 2031 CC, as shown in the following FastExit constraint menu.

Figure 7: Under the FastExit scenario, the Department's model chose the 2026 CT + 2031 CC as a Boswell reliability mitigation package under a large majority of runs



Of the Department's 32 contingencies, only one ever deviated from the 2026 CT + 2031 CC Boswell constraint: Contingency 9 (Highest Gas +100%), which instead chose the 2026 CT and two 2031 CTs. This was true in the NoReg Group, LowReg/LowEnv, and MidReg/MidEnv futures; in the HighReg/HighEnv future, the model chose the preferred 2026 CT + 2031 CC. Furthermore, in two cost futures (NoReg Group and LowReg/LowEnv), the model chose to build an additional CC in 2031.[74]

These outcomes indicate that under the FastExit scenario, the model strongly prefers to add multiple natural gas plants. This may contribute to the lower cost of this scenario.

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[74] The Department notes that the specific Boswell-related and natural gas projects chosen by the model were: CT 2026, Relax Constraints 2026-2030, CC 2031A, and CC 2031B. The Department is unclear as to why the model chose the 2031B project over the generic CC unit. However, the Department does not think it's a problem, given that the constraints of the generic CC dataset permit two units to be online, post 2030; the presence of both the 2031A and 2031B CCs do not seem to violate the generic CC standard.

iii. Other Results

The Department found that under all regulatory/environmental cost futures, the FastExit scenario had the lowest carbon emissions.

Table 24. Median carbon emissions (tons for Each Boswell scenario across each regulatory/environmental cost future

	StatusQuo	PrefPlan	Early3	Early4	FastExit
NoReg/NoEnv	136,819,718	95,412,386	77,558,041	56,241,561	24,167,632
NoReg/HighEnv	136,808,286	95,390,748	77,587,421	56,284,667	24,157,314
HighReg/HighEnv	72,710,470	53,454,643	35,996,639	26,250,168	16,234,603
NoReg/LowEnv	136,790,394	95,442,502	77,570,525	56,242,896	24,159,555
LowReg/LowEnv	119,295,977	81,539,086	64,651,073	46,508,749	21,589,774
MidReg/MidEnv	86,522,507	63,801,843	48,889,463	33,995,297	17,085,788

Unsurprisingly, the Department's modeling showed that under the StatusQuo scenario, carbon emissions were highest under all cost futures. The Department's model also showed that carbon emissions were lowest under the FastExit scenarios across all cost futures, even with the model's preference for selecting carbon-intensive alternatives.

6. Department Study

After seeing the results of the Department's new base case, the Department was interested in examining the effects of two things: the forecast and the ownership percentage of the Nemadji Trail Energy Center (NTEC).

Earlier in these Comments, the Department described its concerns with the forecast. If the Department were to accept MP's assumptions about the historical trends of losing large industrial customers, the model would solve based on a lower sales forecast. If those customer losses didn't transpire, this would leave the Company exposed to MISO market prices. On the other hand, if the Department were to use MP's forecast that incorporated customer agreements and service at the time of the Company's filing, the model would solve based on a higher sales forecast, thus leaving the potential for an overbuilt system. Ultimately, the Department decided that the best course of action would be to examine the expansion plan and cost effects of both the mid and high forecasts, called "MidAFR" and "HighAFR," respectively.

Secondly, the Department also learned during this proceeding that MP is considering a pursuing reduced ownership share of its yet-to-be built NTEC facility. The Commission has approved a 50 percent ownership share for NTEC, but MP stated that it is interested in a 20 percent ownership share. MP stated that none of its modeling reflects any change case regarding the NTEC ownership, either in its base case assumptions or in any of its contingencies. MP advised the Department on how to make the appropriate changes in the model to reflect the 20 percent ownership. Later, the Department also learned of a potential change in the in-service operation date for NTEC from 2025 to 2027.

The Department was concerned that both a reduced ownership percentage and a later in-service date both have the potential to affect the model's decisions. The Department therefore decided to run an NTEC change case called "NTEC20" (as opposed to the base case assumption of "NTEC50"). The NTEC20 change case reflects more conservative assumptions, as it reduces the assumed NTEC capacity currently represented in the model and also delays the availability of that capacity.

The Department looked at the forecast and NTEC changes from a top-down approach applied to all runs, rather than as singular contingencies within the model. Table 25 represents the Forecast/NTEC combinations examined by the Department:

Table 25: Department's Forecast/NTEC Study Structure

	NTEC 50% ownership with 2025 In-Service Date (MP assumption)	NTEC 20% ownership with 2027 In-Service Date
Mid Forecast (MP assumption)	MidAFR NTEC50	MidAFR NTEC20
High Forecast	HighAFR NTEC50	High AFR NTEC20

With the addition of the Department's Forecast/NTEC Study, the Department quadrupled its total runs, jumping from 1,920 to 7,680. This structure was a judgement call and may not have been necessary. An alternative approach, for example, would have been to simply add a contingency for an NTEC change case, and only use the top-down analysis for the forecast, thus doubling runs rather than quadrupling them. The determination of which inputs warrant a full study, which inputs only need a contingency, and which inputs may simply be better to change for the Department's new base case are all judgement calls that may vary based upon the modeler's expertise and experience.

In analyzing its results, the Department was interested in the following questions:

- Did either HighAFR or NTEC20 impact the five Boswell retirement expansion plans in a meaningful way?
- Did either HighAFR or NTEC20 change which Boswell retirement plan is considered least cost?

Table 26: Percentage of the time each resource type was selected in each of Department's Forecast/NTEC Study cases

	MidAFR/NTEC50	MidAFR/NTEC20	HighAFR/NTEC50	HighAFR/NTEC20
Battery	0.0%	0.2%	0.0%	0.0%
Contract Purchase	0.0%	0.5%	0.0%	0.2%
DR	1.1%	8.6%	1.1%	4.8%
EE	0.0%	0.0%	0.0%	0.0%
Gas CC	25.1%	31.7%	23.9%	35.2%
Gas CT/RICE/Aero	51.7%	63.3%	50.9%	63.9%
Solar	74.8%	77.7%	74.1%	76.1%
Transmission	83.9%	87.2%	81.9%	85.3%
Wind	78.3%	86.9%	76.3%	84.7%

From this table we can see that:

- While batteries and contract purchases continued to be very minimally chosen by the model, they were selected more frequently in NTEC20 cases:
    - Batteries were only chosen in the MidAFR/NTEC20 case, and only in less than one percent of those runs;
    - Contract purchases were only chosen in the NTEC 20 cases, and only in less than one percent of those runs at most;
- Demand response continued to be infrequently chosen across all forecast/NTEC cases, but was selected with higher frequency in NTEC20 cases;
- Energy efficiency was never chosen, regardless of forecast/NTEC study quadrant;
- Intermediate and peaking gas resources (Gas CC and Gas CT/RICE/Aero) depended more highly on NTEC variation than on forecast level:
    - Under the NTEC50 scenarios, Gas CC resources were chosen in approximately 24 to 25 percent of scenarios and gas peaking resources were chosen in 51 to 52 percent of scenarios;
    - Under the NTEC20 scenarios, gas CC resources were chosen in approximately Gas peaking resources were chosen with similar frequencies under the NTEC20 cases, at about 32 to 35 percent;
    - Under the NTEC20 scenarios, Gas peaking resources were chosen with similar frequencies under the NTEC20 cases, at about 32 to 35 percent;
- Changing the forecast and NTEC ownership appeared to have a negligible impact on the frequency with which solar resources were selected;
- Transmission resources appeared to be selected for slightly more in NTEC20 cases; and
- The model appeared to have a slight preference for wind in the NTEC20 cases.

The following table shows the median cost of each Boswell scenario and cost future, by Forecast/NTEC Study case.

Table 27. The Department's Forecast/NTEC study showed that the least cost plan continued to be the FastExit Boswell scenario in a majority of runs

		StatusQuo	PrefPlan	Early3	Early4	FastExit
MidAFR NTEC50	NoReg/NoEnv	$7,450	$7,641	$7,687	$7,730	$7,368
	NoReg/HighEnv	$25,158	$13,349	$13,292	$13,340	$11,727
	HighReg/HighEnv	$11,662	$10,350	$10,294	$10,405	$9,881
	NoReg/LowEnv	$16,246	$10,449	$10,423	$10,485	$9,512
	LowReg/LowEnv	$13,275	$9,744	$9,728	$9,808	$9,108
	MidReg/MidEnv	$12,043	$10,037	$10,047	$10,081	$9,430
MidAFR NTEC20	NoReg/NoEnv	$7,283	$7,508	$7,546	$7,493	$7,195
	NoReg/HighEnv	$14,458	$13,464	$13,273	$12,561	$11,656
	HighReg/HighEnv	$10,437	$10,387	$10,294	$10,439	$9,810
	NoReg/LowEnv	$10,827	$10,409	$10,323	$9,964	$9,382
	LowReg/LowEnv	$9,897	$9,774	$9,722	$9,771	$8,944
	MidReg/MidEnv	$10,186	$10,101	$10,011	$10,065	$9,357
HighAFR NTEC50	NoReg/NoEnv	$7,450	$7,639	$7,687	$7,730	$7,368
	NoReg/HighEnv	$14,380	$13,409	$13,291	$13,341	$11,727
	HighReg/HighEnv	$10,344	$10,350	$10,297	$10,406	$9,879
	NoReg/LowEnv	$10,887	$10,461	$10,423	$10,485	$9,512
	LowReg/LowEnv	$10,015	$9,745	$9,730	$9,808	$9,110
	MidReg/MidEnv	$10,083	$10,037	$10,045	$10,081	$9,431
HighAFR NTEC20	NoReg/NoEnv	$7,283	$7,508	$7,546	$7,640	$7,195
	NoReg/HighEnv	$14,459	$13,461	$13,272	$13,249	$11,656
	HighReg/HighEnv	$10,467	$10,386	$10,290	$10,439	$9,810
	NoReg/LowEnv	$10,827	$10,408	$10,323	$10,417	$9,382
	LowReg/LowEnv	$9,899	$9,776	$9,720	$9,769	$8,945
	MidReg/MidEnv	$10,186	$10,101	$10,012	$10,065	$9,357

More granular cost results of the Department's Forecast/NTEC Study can be found in Attachment 6.

7. Department Conclusions and Recommendations

MP ran 30 optimized plans representing five Boswell scenarios and six regulatory/environmental cost futures. The Company's preferred plan (retire Boswell 3 in 2029 and take no action on Boswell 4) was found to be the least cost plan in one of the six cost futures. The Company's FastExit scenario (retire Boswell 3 in 2025 and Boswell 4 in 2030) was found to be the least cost plan in three of the six cost futures.

The Department ran 3,840 optimized plans representing five Boswell retirement scenarios, six regulatory/environmental cost futures, 32 contingencies, and four Forecast/NTEC cases. The Company's FastExit scenario was the least cost plan in 754 of the 768 contingency/cost future combinations.

In the FastExit Scenario, the Department's model always chose a 2026 CT and at least one 2031 CC for its preferred Boswell reliability constraints; however, as stated at the beginning of this section, the Department needs to learn more from MP about how MISO's LRTP considerations may affect the model constraints.

The Department's model also chose between 0 and 300 MW new wind resources, dependent upon the regulatory/environmental cost future. Under the Department's preferred future, MidReg/MidEnv, the model chose 100 MW new wind in 2024 and 200 MW new wind in 2025.

In conclusion, the Department recommends the Commission approve the retirement dates of the FastExist scenario for the Boswell units. The Department also recommends the Commission order MP to begin a resource acquisition process for up to 300 MW new wind resources, to be on-line in the 2024 to 2025 time frame.

D. ASSESSMENT OF ENERGY EFFICIENCY RESOURCES

1. MP's Proposed Goals

In Docket No. E015/RP-15-690, the Commission established an average annual energy savings goal of 76.5 GWh for resource-planning purposes.[75] In the Petition, MP proposed an average annual energy savings goal of 65.0 GWh for 2021 to 2023 and then an average annual energy savings goal of 78.4 GWh for 2024 to 2034.[76] For the 15-year IRP the average annual energy savings goal is 72.2 GWh. MP proposed an average annual demand savings goal of 18.5 MW for 2021 to 2023 and then an average annual demand savings goal of 13.8 MW for 2024 to 2034.[77] For the 15-year IRP the average annual demand savings goal is 14.8 MW.

The Department compared MP's proposed average annual energy and demand savings goals with MP's actual 2015-2020 GWh and MW savings. MP's average annual energy savings were 72.2 GWh and the Company's average annual demand savings were 16.5 MW. Thus, MP's proposed goals for the 15-year IRP are very close the average achievements of the past 6 years and should be achievable from the conservation improvement program (CIP) process. Note that the Petition states that MP "has committed in its most recent CIP Triennial Filing to an energy savings goal of 2.5 percent [of retail sales] each year through 2023, well above the state's 1.5 percent energy savings goal."

Given the resources available and the significant delays in beginning the analysis of MP's IRP, the Department did not conduct a detailed review of the Company's proposed costs for the energy efficiency resources modeled in the 2021 IRP. Instead, the Department concluded that MP's proposed level of energy efficiency was a

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[75] See the Commission's July 18 Order.
[76] All data regarding historic achievements and proposed goals are taken from the Company's reply to Department Information Request Nos. 9 and 10 and are measured at the bus.
[77] All data regarding historic achievements and proposed goals are taken from the Company's reply to Department Information Request Nos. 9 and 10 and are measured at the bus.

reasonable proxy for the decision that would be made within the CIP process and the energy efficiency ultimately achieved by MP.

2. Competitive Bidding Process

Regarding acquiring conservation resources, the July 18 Order stated "Minnesota Power shall investigate the potential for an energy-efficiency competitive bidding process to supplement its existing conservation improvement program ("CIP"), open to both CIP-exempt and non-CIP exempt customers, and shall summarize its investigation and findings in its next resource plan."

First, MP's report reviewed four other conservation bidding programs, most of which used a reverse auction structure. [78] Second, MP's report discussed conservation and the Company's CIP-exempt large power customers. MP stated:

> Under this statute [the CIP exemption statute, 216B.241 subd. 1a(b)], customers seeking an exemption are required to file with the commissioner of the Minnesota Department of Commerce and must prove that they are implementing energy conservation and efficiency improvements. They also must show there is no need for additional incentives to manage, complete, and address EE measures.
> …
> There are approximately 14 Minnesota Power customers at the time of this filing that fall under the CIP-exempt classification, most of whom have submitted multiple reports to the Department of Commerce detailing efforts to implement EE and energy conservation strategies. These CIP-exempt customers compete in global markets and in industries that have an advantage because of other nations' favorable tax policies, trade laws, health care costs, environmental compliance or other subsidies. CIP-exempt customers are naturally incentivized to pursue all efficiency improvements to keep their product costs as low as possible, including any and all economically viable efficiency improvements related to energy.

The Department generally agrees that:

- MP already has a successful CIP;
- the legislature has exempted a significant portion of MP's load from CIP;
- and the exempt customers have an incentive to keep product costs as low as possible.

While it is possible that additional incentives, provided via a reverse auction or other process might produce additional savings from the exempt customers, the cost and potential participation levels are unknown. Overall, the Department concludes that programs to acquire conservation resources should contained within the CIP process and multiple process to achieve the same goal is not warranted.

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[78] A reverse auction is a type of auction in which the traditional roles of buyer and seller are reversed. Typically there is one buyer (here the utility) and many potential sellers (here, customers selling conservation resources to the utility).

E. ASSESSMENT OF VARIOUS POLICIES

1. 50 Percent and 75 Percent Renewables and Conservation

Minnesota Statutes §216B.2422, subd. 2 (c) requires that "As a part of its resource plan filing, a utility shall include the least cost plan for meeting 50 and 75 percent of all energy needs from both new and refurbished generating facilities through a combination of conservation and renewable energy resources."

In this docket, MP's proposed plan recommends meeting all new energy needs with 100 percent new renewable resources and maintaining existing conservation programs. Therefore, MP's proposed plan exceeds the requirements of Minnesota Statutes §216B.2422 and no further analysis of the requirement is necessary.

2. Renewable Energy Standard

a. Background

Minnesota Statutes § 216B.1691, subd. 2 (a) establishes the renewable energy standard (RES) that MP:

> shall generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota are generated by eligible energy technologies by the end of the year indicated:
>
> 1) 2012 12 percent
> 2) 2016 17 percent
> 3) 2020 20 percent
> 4) 2025 25 percent.

An eligible energy technology is defined by Minnesota Statutes § 216B.1691, subd. 1 as an energy technology that:

> generates electricity from the following renewable energy sources:
>
> 1) solar;
> 2) wind;
> 3) hydroelectric with a capacity of less than 100 megawatts;
> 4) hydrogen, provided that after January 1, 2010, the hydrogen must be generated from the resources listed in this paragraph; or
> *5)* biomass, which includes, without limitation, landfill gas; an anaerobic digester system; the predominantly organic components of wastewater effluent, sludge, or related by-products from publicly owned treatment works, but not including incineration of wastewater sludge to produce electricity; and an energy recovery facility used to capture the heat value

> of mixed municipal solid waste or refuse-derived fuel from mixed municipal solid waste as a primary fuel.

Minnesota Statutes § 216B.1691 subd. 2f requires that, in addition to the RES obligation, a publicly owned utility obtain at least 1.5 percent of its Minnesota retail sales from solar energy by the end of 2020. For MP, at least ten percent of the 1.5 percent goal must be generated by or procured from solar photovoltaic devices with a nameplate capacity of 40 kilowatts or less. The solar energy standard (SES) statute excludes certain retail sales to iron mining, paper, and wood products manufacturers from the calculation of the SES requirement.

b. Renewable Energy Standard Compliance

The Department reviews historical compliance with the RES statute in a biennial report to the legislature. The most recent report was filed January 15, 2021.[79] This report concluded that "All of the utilities subject to the Minnesota RES have demonstrated compliance with the 2019 Renewable Energy Standard requirements."

Regarding future compliance the Department notes that Table 2 of the biennial report estimates MP can comply with the RES through 2053. Therefore, no further analysis on RES compliance is necessary.

c. Solar Energy Standard Compliance

The Department reviews compliance with the SES statute in the same biennial report to the legislature. Again, the most recent report was filed January 15, 2021. This report did not make a conclusion regarding SES compliance since the first year for compliance is 2020. However, the report did state that "the three public utilities subject to the SES appear on track to comply with the first-year requirement in 2020."

Regarding future compliance MP's February 4, 2021 filing in Docket Nos. E015/M-20-828 and E,G999/CI-20-492 at Figure 2 shows that, with the projects[80] approved by the Commission's June 29, 2021 *Order Granting Petition and Requiring Compliance Filings*, the Company will be in compliance beyond 2029. Therefore, the Department concludes that MP has sufficient solar renewable energy credits to meet its SES requirement for the foreseeable future. No further analysis on SES compliance is necessary.

3. Minnesota Greenhouse Gas Emissions Reduction Goal

Minnesota Statutes § 216H.02, subd. 1 states that:

[79] The report is available at: https://www.lrl.mn.gov/docs/2021/mandated/210075.pdf
[80] The Commission's June 29, 2021 order approved three projects:
- Laskin Solar project—9.6 MW;
- Sylvan Solar project—10 MW; and
- Duluth Solar project—1.6 MW.

> It is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050. The levels shall be reviewed based on the climate change action plan study.

To calculate compliance Minnesota Statutes 216H.03, subd. 2 states:

> For the purpose of this section, "statewide power sector carbon dioxide emissions" means the total annual emissions of carbon dioxide from the generation of electricity within the state and all emissions of carbon dioxide from the generation of electricity imported from outside the state and consumed in Minnesota. Emissions of carbon dioxide associated with transmission and distribution line losses are included in this definition. Carbon dioxide that is injected into geological formations to prevent its release to the atmosphere in compliance with applicable laws, and emissions of carbon dioxide associated with the combustion of biomass, as defined in section 216B.2411, subdivision 2, paragraph (c), clauses (1) to (4), are not counted as contributing to statewide power sector carbon dioxide emissions.[81]

An overall discussion of the Department's views on calculating compliance with Minnesota Statutes § 216H.02 can be found in the Department's January 4, 2016 comments in Docket No. E015/RP-15-690 at pages 59 to 64.

The Petition's Appendix J explains how MP calculated the greenhouse gas reduction goal as follows:

> A CO_2 rate was set-up to calculate the externality cost of CO_2 and to measure the progress on meeting the state greenhouse gas goal (Minn. Stat. § 216H.02); this is referred to as "CO_2-E" in the EnCompass model. This CO_2 rate was assigned to all power supply resources, including bilateral market purchases, generation and energy sales. The accompanying CO_2 with an energy sale is removed from the power supply. The "CO_2-E" rate modeled in EnCompass was pounds per MWh and used in the swim lane analysis only. *Note that the CO_2 emissions from MISO market energy purchases and sales were calculated outside of the EnCompass model*.

[81] (c) "Biomass" includes:
(1) methane or other combustible gases derived from the processing of plant or animal material;
(2) alternative fuels derived from soybean and other agricultural plant oils or animal fats;
(3) combustion of barley hulls, corn, soy-based products, or other agricultural products;
(4) wood residue from the wood products industry in Minnesota or other wood products such as short-rotation woody or fibrous agricultural crops;

The result of MP's calculation is shown in Table 3 of the Petition. Table 3 shows that MP estimates that the proposed plan will achieve a 75 percent CO_2 reduction (from 2005 levels) in 2026 and will achieve an 80 percent CO_2 reduction (from 2005 levels) in 2031.

MP's calculation of the 2005 CO_2 level was documented in the Company's response to Department Information Request No. 9 in Docket No. E015/RP-15-690, where MP outlined its approach as follows:

a. Summed total CO_2 emissions from MP-owned generation.
b. Added known CO_2 emission from bilateral purchases that either point to a resource or based on average CO_2 emissions from the counterparty's power supply.
c. Added emissions from unidentified purchases, which includes both bilateral and the Midcontinent Independent System Operator ("MISO") spot market purchases. The CO_2 rate for unidentified purchases in 2005 is from the Emissions & Generation Resource Integrated Database ("eGRID") for the Midwest Reliability Organization ("MRO") West observed in 2005.
d. Subtract known CO_2 emissions from sales sourced from an identified generation resource.
e. Subtract CO_2 emissions from unidentified sales, which include bilateral and MISO market sales. The CO_2 emission rate is the average for MP's total power supply.

The results of the calculations were estimated CO_2 emissions of 11,542,098 tons in 2005 attributable to MP's ratepayers. For this proceeding MP calculated ratepayer CO_2 emissions assuming the Company's MISO market purchases were from coal and natural gas resources in the MISO North region. The Company's MISO market sales were assumed to be from MP's coal units. The Department does not conclude that MP's calculations are in error, but the Department did recalculate MP's emissions assuming that the Company's MISO market purchases were sourced from the entire MISO North system and that MP's market sales were sourced from MP's entire generation fleet. In addition, the Department did not add system-wide transmission losses to MP's market sales as a source of a deduction from CO_2 emissions based on the statutory language regarding line losses cited above. Finally, for determining the percent reduction only MP replace the 11.5 million ton estimate for 2005 with an 11.2 million ton estimate. For calculations here the Department used the 11.5 million ton estimate for 2005.

The results of the Department's calculations were that the CO_2 emissions reduction percentage, starting in 2025, varied between 72 and 78 percent. Thus, under the Department's calculations arrive at a result that is similar to MP's and show that MP is nearly able to meet the state's 2050 CO_2 emissions reduction goal by 2025.

IV. IMPLEMENTING THE PREFERRED PLAN

A. MP'S PROPOSED BIDDING PROCESS

1. Discussion of MP's Proposal

As indicated above, the January 24 Order required MP to "proposed bidding process for supply-side acquisitions of 100 MW or more lasting longer than five years, as set forth in Attachment A, for Commission consideration and potential approval." Attachment A to the January 24 Order stated that MP 's proposed bidding process should:

1. ensure that the RFP is consistent with the Commission's then-most-recent IRP order and direction regarding size, type, and timing;
2. provide the Department and other stakeholders with notice of RFP issuances;
3. notify the Department and other stakeholders of material deviations from those timelines;
4. update the Commission, the Department, and other stakeholders regarding changes in the timing or need that occur between IRP proceedings;
5. where MP or an affiliate proposes a project, the Company will engage an independent evaluator to oversee the bid process and provide a report for the Commission; and
6. request that the independent evaluator specifically address the impact of material delays or changes of circumstances on the bid process.

In the Petition's Appendix D the Company re-iterated the 100 MW or 5-year threshold and the six steps listed above as providing the framework for the Company's resource acquisition process going forward.

Minnesota Statutes § 216B.2422, subd. 5. states that:

> (a) A utility may select resources to meet its projected energy demand through a bidding process approved or established by the commission. A utility shall use the environmental cost estimates determined under subdivision 3 in evaluating bids submitted in a process established under this subdivision.
>
> (b) Notwithstanding any other provision of this section, if an electric power generating plant, as described in section 216B.2421, subdivision 2, clause (1), is selected in a bidding process approved or established by the commission, a certificate of need proceeding under section 216B.243 is not required.

The Commission's May 31, 2006 *Order Establishing Resource Acquisition Process, Establishing Bidding Process Under Minn. Stat. § 216B.2422, subd. 5, and Requiring Compliance Filing* in Docket No. E002/RP-04-1752 stated the overall purpose of a bidding process:

> The purpose of the competitive process—getting the best overall price for ratepayers—cannot be achieved without robust competition. And robust competition cannot be achieved without two things: (1) a fair, predictable, and transparent competitive process; and (2) widespread agreement that the process is fair, predictable, and transparent.
>
> Potential suppliers will not commit the resources necessary to compete effectively, and will not disclose the sensitive information often required to evaluate their competitive proposals, unless they have confidence in the objectivity, good faith, and predictability of the competitive process. In fact, to attract competitive proposals, it may matter less what the rules are—assuming fundamental rationality and basic fairness—than whether all potential players know the rules and know that they will be enforced evenhandedly.

To evaluate MP's proposed bidding process, the Department compared MP's proposed process to Xcel's bidding process as discussed in the Department's February 11, 2021 comments in Docket No. E002/RP-19-368. The primary differences between Xcel's bidding process and MP's proposed process are:

- MP proposes to use an "independent evaluator"[82] while Xcel uses an "independent auditor." As the Department understand the terms, under an independent evaluator approach the utility forms one group, to develop the utility's bid and the oversight of the RFP process is generally outsourced to the independent evaluator. Under the independent auditor approach the utility forms two groups, one to develop the utility's bid and one to evaluate all of the bids with the auditor monitoring the process to ensure fairness.
    - MP describes the independent evaluator's role in the past as "providing a whole series of services from commenting on the RFP, assessing separation of bidding and evaluation functions within the utility, assisting in the evaluation of bids, independently reviewing the bids, participating in the preparation of the short list and final bid selections, and monitoring the negotiation process."
    - At this time the Department concludes that MP's use of an independent evaluator with the functions described above is reasonable.
- MP proposes to have the independent evaluator specifically address the potential for the bidding process to encounter issues while in Xcel's process Xcel files a contingency plan early in the process.
    - In MP's proposal the independent evaluator has oversight of the entire RFP process—including the design, administration, and evaluation—to ensure that the RFP process is transparent and defined and that evaluation criteria are applied equally for all bidders.[83]
    - Because the independent evaluator has oversight of the entire RFP process the Department concludes that it is reasonable for the independent evaluator to address potential problems encountered during the RFP process.
- Xcel's RFP's often includes a model power purchase agreement (PPA)[84] while MP's proposal does not mention use of a model PPA.
    - The model PPA becomes part of Xcel's RFP process in that all bidder proposals are required to be complaint with the model PPA or include any desired exceptions to the model PPA.
    - Given the infrequent nature of resource acquisition proceedings filed by MP with the Commission (as compared to Xcel), the Department concludes it is reasonable for MP to determine whether the benefits of including a model PPA as part of an RFP would exceed the costs.

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[82] The February 23, 2018 *Rebuttal Testimony and Schedule of Frank L. Frederickson* in Docket No. E015/AI-17-568 explains "the Company has historically engaged an independent evaluator to oversee our larger bid processes where the Company submitted a bid."
[83] See the February 23, 2018 *Rebuttal Testimony and Schedule of Frank L. Frederickson* at page 15 (Docket No. E015/AI-17-568).
[84] For example, see Xcel's *2016 Wind Solicitation* issued September 22, 2016 (which resulted in Docket No. E002/M-16-777) and the *2019 Wind Solicitation* issued April 10, 2019 (which resulted in Docket No. E002/M-19-268). In addition, Xcel's petition in Docket No. E002/M-20-620 (a wind repowering proceeding) noted that conformance to the model PPA was a requirement in the RFP.

MP's proposal does not address the potential for changed circumstances between the time the Commission issues an IRP order and MP issues an RFP. The Commission's December 13, 2013 *Order Approving Acquisitions with Conditions* in Docket Nos. E002/M-13-603 and E002/M-13-716 addressed this potential:

> … while a resource plan is intended to plot a utility's course for the next 15 years, it is based on facts known as of a specific point in time. As more facts become known, circumstances change and utilities must adapt – even in the absence of a new resource plan order.

Therefore, the Department recommends the Commission enable MP to issue an RFP that differs from the most recent Commission IRP order if changed circumstances warrant. This means that the size, type, and timing of resources requested in an RFP may differ from the size, type, and timing in the most recent Commission IRP order.

The Department also notes that power purchase agreements can include a right of first offer (ROFO) clause. The Department does not object to the inclusion of a ROFO in PPAs. However, when negotiations occur regarding a ROFO both parties, MP and the seller, have an incentive to increase the price as much as possible. In recognition of this fact, basic accounting principles indicate that an asset was already placed in service and continues to operate under a PPA should have the purchase reflected at net book value and that acquisition adjustments should not be reflected in the purchase price. The Department's March 5, 2019 comments in Docket No. IP6949, E002/PA-18-702 clarified this by stating:

> The Department notes that traditionally, utility assets are recorded and recovered using the original cost of the asset and the related accumulated depreciation or resulting net book value of the asset. Acquisition adjustments are on top of the net book value and as a result require a significant finding of benefits to offset or justify this higher acquisition adjustment or premium before rate recovery is allowed, especially for utility assets that were already being used for public service (like MEC [Mankato Energy Center]). Use of net book value in rate base is consistent with Federal Energy Regulatory Commission requirements and Minnesota requirements under 216B.16, subd. 6…

Therefore, in order to allow a ROFO provision to be included in PPAs while simultaneously protecting ratepayers in a situation where both sides of the negotiations have an incentive to maximize costs, the Department recommends that the Commission cap any ROFO offer made by MP at net book value.

In addition to the ROFO provision, the Department notes that when issuing the RFP MP would have wide latitude regarding what to include and exclude in the RFP process. The Department notes that, when the bidding process is used, the Company should be required to seek proposals for both PPA and build–operate–transfer (BOT) projects. Thus, the Department recommends that the Commission require any RFP issued by MP to include the option for both PPA and BOT proposals unless the Company can demonstrate why either a PPA or BOT proposal is not feasible.

Finally, the Department notes that MP and the Department used a combustion turbine as a proxy for a peaking resource. The Department is neutral as to the actual technology that would be acquired to fill any future needs for peaking resources. Thus, the Department recommends that the Commission require that any RFP documents for peaking resources issued by MP be technology neutral.

2. Department Recommendation

The Department recommends the Commission approve a bidding process for MP's future resource acquisitions as follows; MP shall:

1. use a bidding process for supply-side acquisitions of 100 MW or more lasting longer than five years;
2. ensure that the RFP is consistent with the Commission's then-most-recent IRP order and direction regarding size, type, and timing unless changed circumstances dictate otherwise;
3. provide the Department and other stakeholders with notice of RFP issuances;
4. notify the Department and other stakeholders of material deviations from initial timelines;
5. update the Commission, the Department, and other stakeholders regarding changes in the timing or need that occur between IRP proceedings;
6. where MP or an affiliate proposes a project, engage an independent evaluator to oversee the bid process and provide a report for the Commission;
7. request that the independent evaluator, if engaged, specifically address the impact of material delays or changes of circumstances on the bid process; and
8. cap any ROFO offer made by MP at net book value; and
9. ensure that any RFP documents for peaking resources issued are technology neutral.

B. SECURITIZATION

In MP's 2016 Rate Case (Docket No. E015/GR-16-664), the Commission directed the Company "to develop a securitization plan for the Boswell units to address any depreciation expenses that will remain unrecovered at the end of Unit 3 and 4's expected service lives, and to file it within two years of the final order in this case."[85]

The Commission later revised and clarified its Order:

> In lieu of a securitization plan, the Company shall continue to explore securitization and, within two years of the date of this order, file a report on securitization, informed by the input of stakeholders, including the OAG and the Clean Energy Organizations.[86]

In a subsequent Order, the Commission provided the following requirements for MP's report on securitization:

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[85] In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E015/GR-16-664, Findings of Fact, Conclusions, and Order, at 14 (March 12, 2018).
[86] In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E015/GR-16-664, Findings of Fact, Conclusions, and Order, at 5 (May 29, 2018).

- a description of how securitization could be used to facilitate closure of facilities with large undepreciated balances;
- discussion on the feasibility of securitization in Minnesota and for MP;
- specific discussion of the obstacles to securitization and how they can be resolved; and
- discussion of how securitization could be used to balance the interests of ratepayers and shareholders as they apply to BEC.[87]

October 1, 2020, MP filed its Securitization Phase 1 Report (or Phase 1 Report), prepared by the Rocky Mountain Institute (RMI), addressing the above compliance requirements.

As described in the Phase 1 Report, securitization is a financing tool that allows a utility to effectively refinance a portion the assets included in its rate base, financed at a utility's weighted average cost of capital (WACC), with lower-cost securitization bonds. The savings resulting from the difference between the overall rate of return and the interest rate on the securitization bonds results in lower rate for the utility's customers.

Investors in the lower-cost securitization debt are willing to accept a lower interest rate (relative to the utility's WACC) as a result of extraordinary protections placed on the debt that make non-recovery very unlikely. As stated in the Phase 1 Report,

> [C]ustomers and regulators trade reduced flexibility in determining future rates in return for the lower financing costs charged by bondholders due to the lower risks of losses they face. The reduced flexibility will be apparent in future rate case proceedings, where rate design proposals will need to consider the surcharge amount when determining the all-in impact of a rate change on customer bills.[88]

MP, enabled by legislation that is not currently in place in Minnesota, would first create a legal property right in a designated portion of its future revenues. The Company would then sell that property right to a bankruptcy-remote special purpose vehicle (SPV) created solely for the purpose of executing the securitization transaction. The SPV would buy the property right from MP using revenues generated from the sale of securitization bonds to investors (the bond sale and property right purchase would take place simultaneously). MP would use the proceeds from the sale of the property right to cover some or all of the unrecovered costs of the assets being securitized.

According to the Phase 1 Report, new legislation will be required to enable MP to assess, on behalf of securitization bondholders, a non-bypassable, irrevocable surcharge that is subject to period adjustments (at least annually, and potentially more frequently) to ensure that cost recovery aligns closely to the scheduled payments to bondholders required by the securitization bonds.

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[87] In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E015/GR-16-664, Findings of Fact, Conclusions, and Order, at 4 (Sept. 25, 2020).
[88] Securitization Phase 1 Report at 8.

Theoretically, MP could use the proceeds from the property sale to retire debt and/or buy back equity from the market, which would then give the Company room to issue more debt and equity in the future when it needs capital to finance new investments. Practically speaking, however, there are significant frictions to reducing outstanding debt and equity balances in this manner. Instead, the securitization transaction can be timed such that MP would receive the proceeds from the property right sale at a time it needs capital for new large investments (such as new generation resources). Absent the securitization, MP would likely have to issue new debt and equity to finance the new investments. The securitization transaction allows the Company to forego those new securities issuances and use its existing debt and equity to notionally finance the new assets.

The Phase 1 Report included a general assessment of the feasibility of potential securitization for MP based on its individual characteristics. In order to be successful, the securitization bonds must be extremely safe investments, with little to no risk of default. Not only must the bondholders be paid back with interest for their investments, but they must be paid back per the repayment schedule indicated in the terms of the bonds. As a result, the securitization surcharge used to collect funds to pay the securitization bonds off must produce a very stable stream of revenue.

In assessing the potential for instability in that stream of revenue, credit ratings agencies, (Moody's, Standard & Poor's, and Fitch Ratings) review a number of characteristics of a utility, including the share of revenue generated from the utility's residential customers, overall revenue volatility, and size of securitization surcharges relative to customer bills. RMI compared MP to other utilities that have issued securitization bonds along these risk factors and determined that while the Company has the lowest percentage of total revenue from residential customers of any such utility, its overall revenue volatility appears to be comparable to the group average. Further, while MP (and ALLETE) is smaller than almost all of the other utilities that have issued securitization bonds, if it securitizes unrecovered balances for BEC3 and BEC4, the amount of its securitization, and the resulting surcharges, will also be smaller than most other prior transactions. As a result, when measured as using the ratio of securitization surcharge to total utility billings, a potential transaction from MP would likely fall well within the range considered acceptable by the credit ratings agencies.

The Phase I Report also discussed additional measures that could be implemented to mitigate potential revenue volatility, including a true-up mechanism for the securitization surcharges that would adjust the surcharge to correct for lower- or higher-than expected surcharge revenue due to lower- or higher-than expected sales. Other measures include an operating reserve account from which revenue shortfalls can temporarily be covered, and subordinated tranches within the structure of the securitization bonds that accept more risk of non-payment than other bonds within the same transaction in exchange for a higher interest rate (in other types of securitization transaction, these subordinated tranches are retained by the issuer).

The report also described potential adjustments to rate design for the securitization surcharge that could be implemented to reduce volatility, as well as other, larger changes that would require significantly more process and development, such as performance-based ratemaking. In summary, the Phase 1 Report concluded that while certain characteristics of MP may make use of securitization challenging, those issues can be overcome, and securitization would likely be a feasible option for MP were it permitted by Minnesota law.

On February 5, 2021, as part of its 2021 Integrated Resource Plan filing, MP filed its Securitization Phase 2 Report (or Phase 2 Report), with a more detailed analysis of the potential financial impacts of securitization on

MP and its ratepayers. All of the individual analyses in the report assume BEC3 and BEC4 are retired in 2030, five years prior to their current anticipated retirement year, and replaced with a combination of renewable energy assets and natural gas generation along with some market purchases. RMI examined two main "futures:" one in which a portion of the unrecovered balances of BEC3 and BEC4 are securitized in the year they retire (2030), and a second in which the securitization takes place in 2025, five years prior to retirement. For each of these two main futures, RMI analyzed a number of sensitivity cases with various bond tenors and different percentages of unrecovered costs are securitized.[89]

The results of these sensitivity cases were compared to "business as usual" (BAU) case in which BEC3 and BEC4 are retired in 2035 and replaced with the same mix of resources, as well as a case in which the units are retired in 2030 and the unrecovered balances are financed with a regulatory asset earning the Company's full weighted average cost of capital.

Generally, RMI's analysis indicates that if BEC3 and BEC4 were retired in 2030 and their unrecovered balances are simultaneously securitized, rates would increase in the near-term, but ratepayers would benefit on a net present value (NPV) basis. RMI's analysis also indicates that securitizing unrecovered balances prior to retirement creates significant risk for MP. Additionally, RMI's stress testing analysis indicates that simultaneous retirement/securitization may offer MP better protections in the event of an unexpected decrease in sales.

The Department generally concurs with these broad insights. It is the Department's understanding that given a decision to retire a unit early, a well-structured securitization of the unrecovered balance will virtually always reduce costs to ratepayers. Whether the savings from securitization allow a unit to be retired earlier that it otherwise would have been is question best answered in the resource planning process. When a unit is retired, the resulting interactions between existing units and potential new generating units are complex and modeling a unit retirement with and without savings from securitization can allow the capacity expansion model (e.g., Encompass) to determine an optimal expansion plan.

As described above, the Department's modeling indicates that the optimal plan for MP likely involves retiring BEC3 in 2025 and BEC4 in 2029. Neither MP's modeling nor the Department's modeling reflects any potential savings from securitization. Rather, both parties' modeling effectively assumes that unrecovered costs at retirement are recovered via traditional utility financing (i.e., a regulatory asset amortized over the unit's remaining depreciation life). As a result, the modeling in this case may slightly underestimate the potential benefits of early retirement for these units

In Appendix Q of MP's IRP, the Company stated that RMI's analysis includes a number of key, generic assumptions, and that a more MP-specific analysis would need to be completed before proceeding. The Department agrees that an analysis that more specifically contemplates MP's unique characteristics would be helpful in assessing the potential benefits of securitization and believes that the Phase 1 and 2 Reports demonstrate that this further evaluation would be worthwhile. In addition to a more specific analysis of the financial impact on MP, a more specific analysis of the options available for structuring securitization bonds (e.g. true-up mechanisms, operating reserve account, rate design options to minimize securitization surcharge revenue, etc.) in order for the bonds to receive the highest possible credit ratings given MP's unique

[89] Securitization Phase 2 Report at 13.

characteristics would also be worthwhile. In addition, further development of how costs and benefits should be allocated across customer classes.

There are number of other issues surrounding securitization that should be considered as well. Further clarity surrounding the types of costs that can and should be securitized is necessary. With respect to capital costs, some other states include a prudence review of any costs that are proposed for securitization.[90] Because these costs will be recovered from ratepayers, it is necessary to ensure that the costs were prudently incurred. The analysis in RMI's Phase 2 Report assumes that the securitization includes a six percent premium for community transition assistance for workers and communities negatively impacted by the retirement of Boswell. This may fall outside of the Commission's core function and duties of ensuring adequate and reliable utility service at reasonable rates. To the extent the Commission concludes that it is appropriate to include funding for transition assistance in a securitization transaction, the Department does not have the expertise necessary to determine whether proposed plans for using those funds are reasonable and cost effective. Thus, further record development of that issue is warranted.

V. DEPARTMENT RECOMMENDATIONS

A. RESPONSE TO COMMISSION'S NOTICE

1. Should the Commission approve, modify, or reject Minnesota Power's 2021 IRP?

The Department recommends the Commission modify MP's proposed resource plan to approve the retirement dates of the FastExit scenario for the Boswell units. The Department also recommends the Commission order MP to begin a resource acquisition process for up to 300 MW of new wind resources, to be on-line in the 2024 to 2025 time frame.

2. When should Minnesota Power file its next IRP? What additional information should the Commission require Minnesota Power to provide as part of its next IRP?

The Department takes no position regarding the due date for MP's next IRP. Given the potential for numerous, potentially controversial certificate of need proceedings, availability of staff cannot be estimated.[91] This is because staff assigned to resource plans also are typically the staff assigned to certificate of need filings.

The Department notes that currently IRPs are scheduled to be filed as follows:
- Great River Energy—April 1, 2023;
- Xcel—February 1, 2024; and
- Minnesota Municipal Power Agency—August 1, 2025.

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[90] See, for example, Docket No. EO-2022-0193 before the Public Service Commission of the State of Missouri.
[91] Potential time-intensive transmission CN filings in the next two years include Xcel's two generation-tie line projects (from the Sherco and King sites); three projects from MISO's Long Range Transmission Planning study; and one additional project from MISO's Joint Transmission Interconnection Queue study.

3. Are there other issues or concerns related to this matter?

The Department has no other issues or concerns regarding MP's IRP.

B. RECOMMENDATIONS FOR MP'S REPLY COMMENTS

The Department recommends that MP explain in reply comments the economic and reliability consequences of the Company's natural gas transportation contracts and explain what data and information MP has submitted and provided to MISO in its winter fuel and generator surveys.

C. RECOMMENDATIONS FOR MP'S NEXT IRP

Regarding EnCompass modeling in the next IRP, the Department recommends MP:

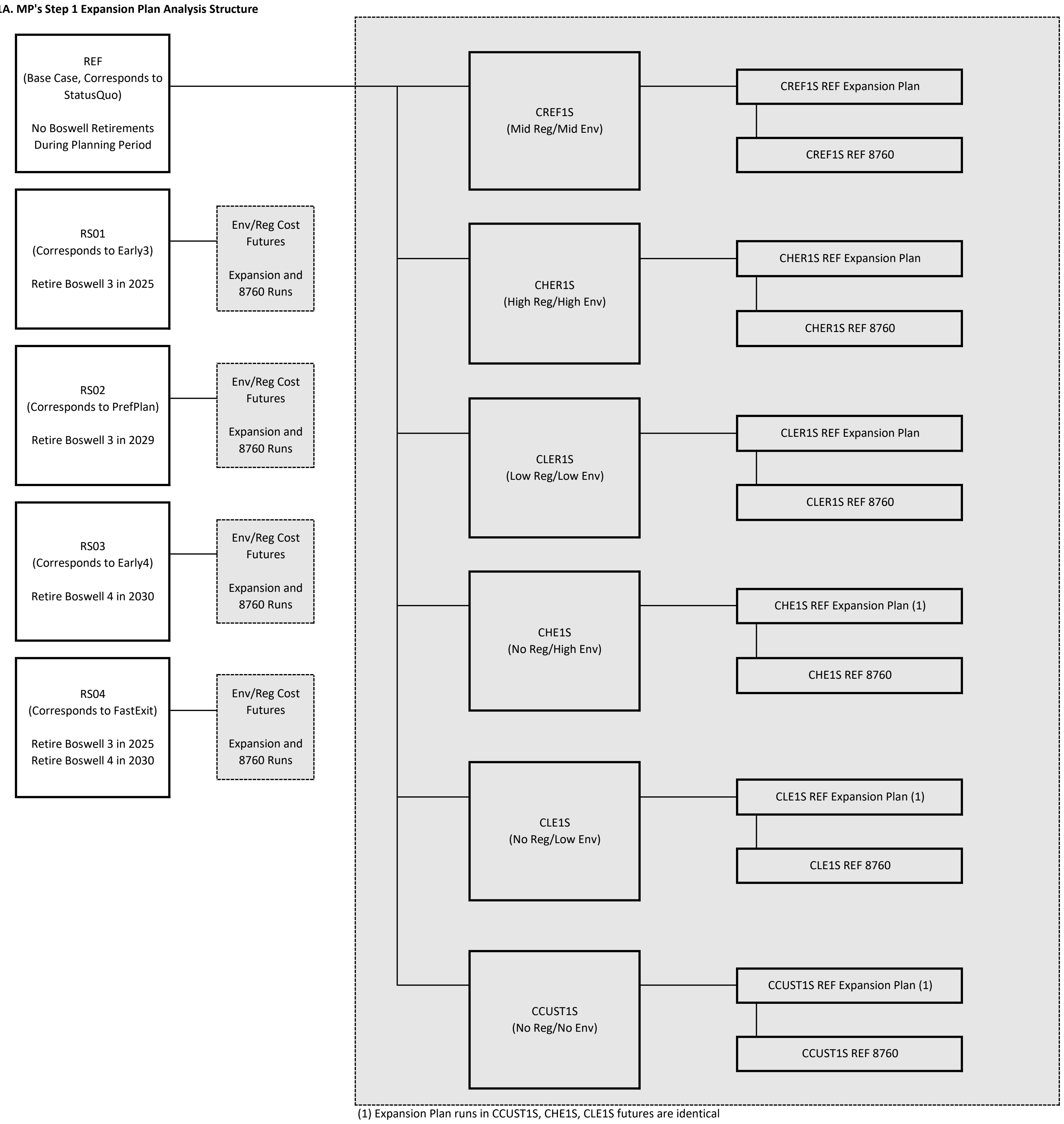
- consider MIP convergence tolerance as a factor in determining the unit sizes to use in EnCompass; and
- consider the benefits and costs of reporting fractions of units when running EnCompass for the Company's next IRP.

D. RECOMMENDATIONS FOR RESOURCE ACQUISITION

The Department recommends the Commission require MP to use a bidding process for MP's future resource acquisitions as follows; MP shall:

- use a bidding process for supply-side acquisitions of 100 MW or more lasting longer than five years;
- ensure that the RFP is consistent with the Commission's then-most-recent IRP order and direction regarding size, type, and timing unless changed circumstances dictate otherwise;
- provide the Department and other stakeholders with notice of RFP issuances;
- notify the Department and other stakeholders of material deviations from initial timelines;
- update the Commission, the Department, and other stakeholders regarding changes in the timing or need that occur between IRP proceedings;
- where MP or an affiliate proposes a project, engage an independent evaluator to oversee the bid process and provide a report for the Commission;
- request that the independent evaluator, if engaged, specifically address the impact of material delays or changes of circumstances on the bid process; and
- cap any ROFO offer made by MP at net book value; and
- ensure that any RFP documents for peaking resources issued are technology neutral.

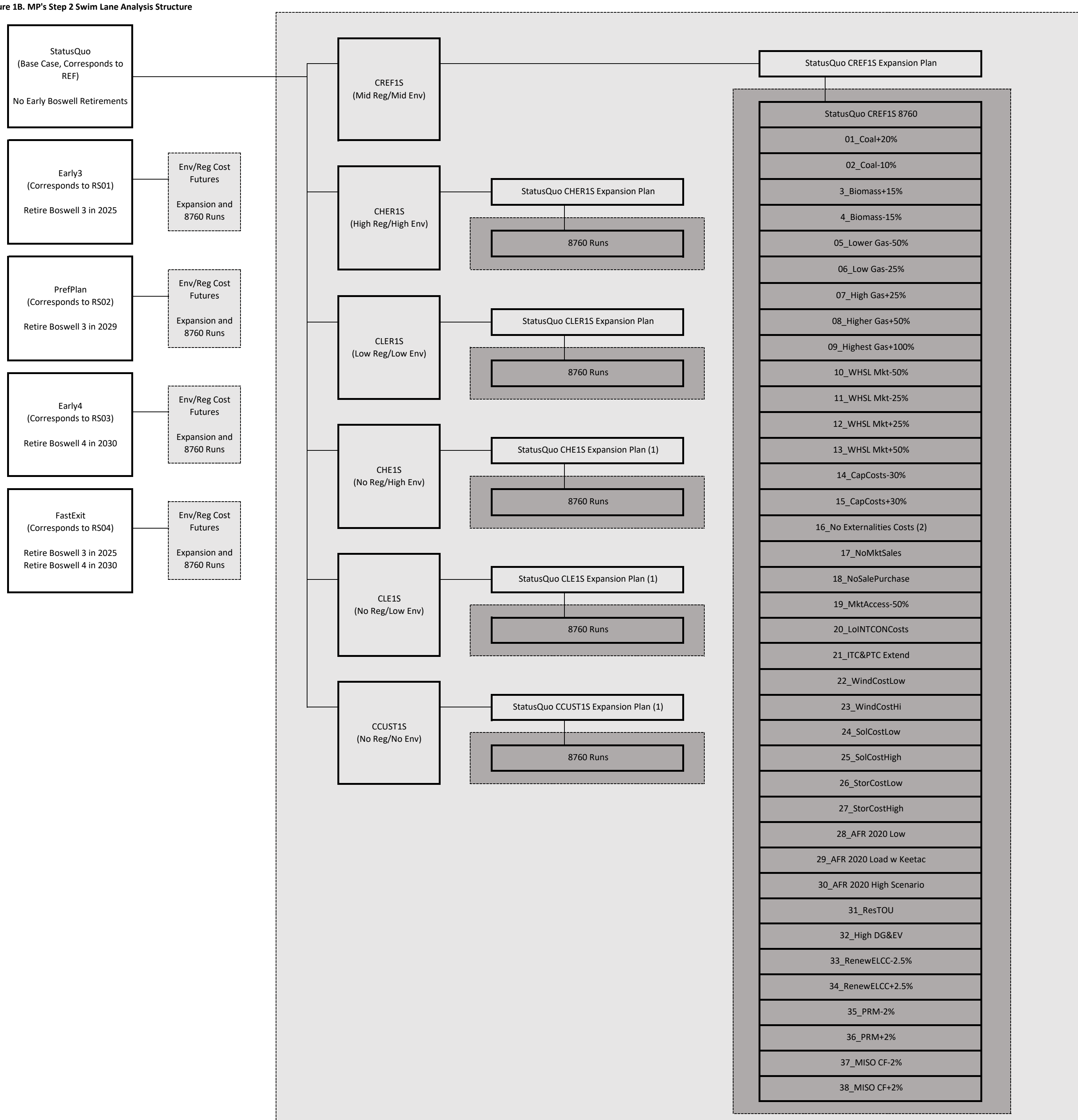
Figure 1A. MP's Step 1 Expansion Plan Analysis Structure



(1) Expansion Plan runs in CCUST1S, CHE1S, CLE1S futures are identical

5 Boswell Retirement Scenarios *x* *6 Regulatory/Environmental Futures per Retirement Scenario* *x* *2 Runs per Future* *= 60 Total Runs*

Figure 1B. MP's Step 2 Swim Lane Analysis Structure



(1) Expansion Plan runs in CCUST1S, CHE1S, CLE1S futures are identical
(2) Contingency 16, "No Externalities" was not run in the CCUST1S futures.

5 Boswell Retirement Scenarios x *6 Regulatory/Environmental Futures per Retirement Scenario* x *40 Runs per Future* = *1200 Runs (Subtotal)*

less 5 Contingency 16 Runs not in CCUST1S Future

= 1195 Total Runs

Figure 1C. In MP's Step 1 Expansion Plan Database, the Boswell RS01 Retirement Scenario (Retire Unit 3 in 2025) requires one of two reliability mitigation options

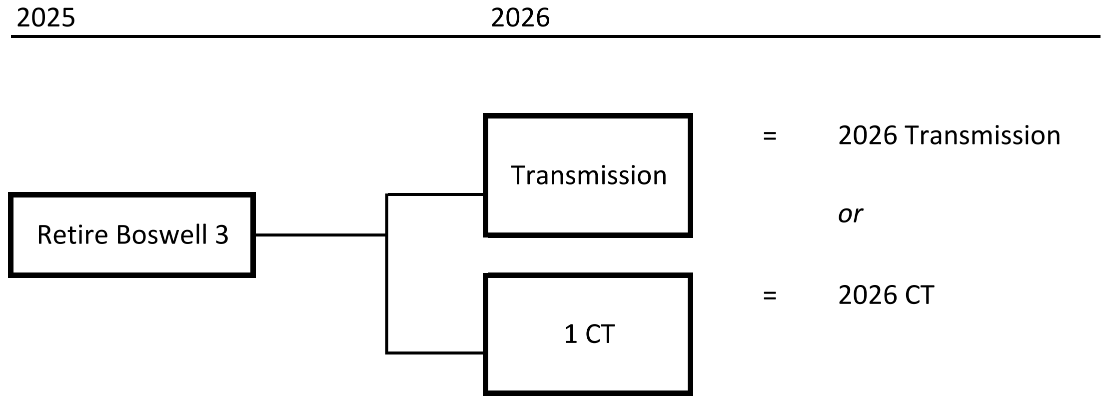


Figure 1D. In MP's Step 1 Expansion Plan Database, the Boswell RS02 Retirement Scenario (Retire Unit 3 in 2029) requires one of two reliability mitigation options

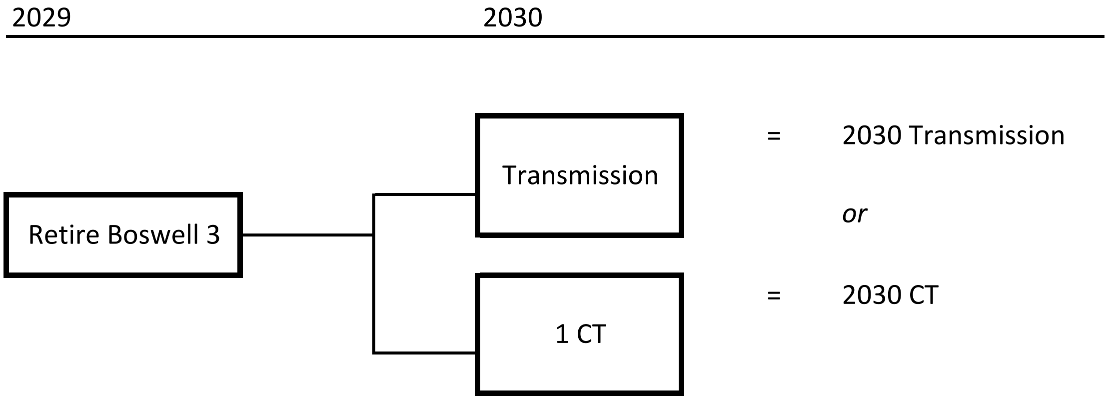


Figure 1E. In MP's Step 1 Expansion Plan Database, the Boswell RS03 Retirement Scenario (Retire Unit 4 in 2030) requires one of four reliability mitigation options

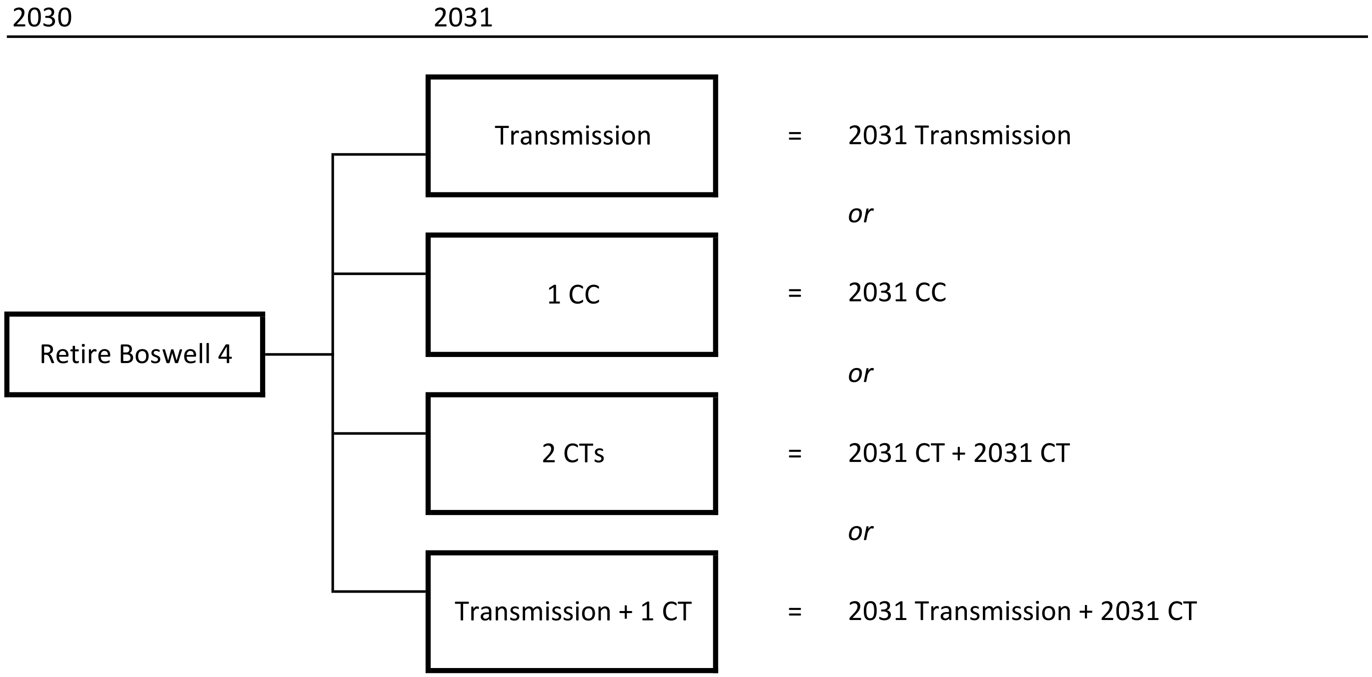


Figure 1F. In MP's Step 1 Expansion Plan Database, the Boswell RS04 Retirement Scenario (Retire Unit 3 in 2025 and Unit 4 in 2030) requires one of six reliability mitigation options

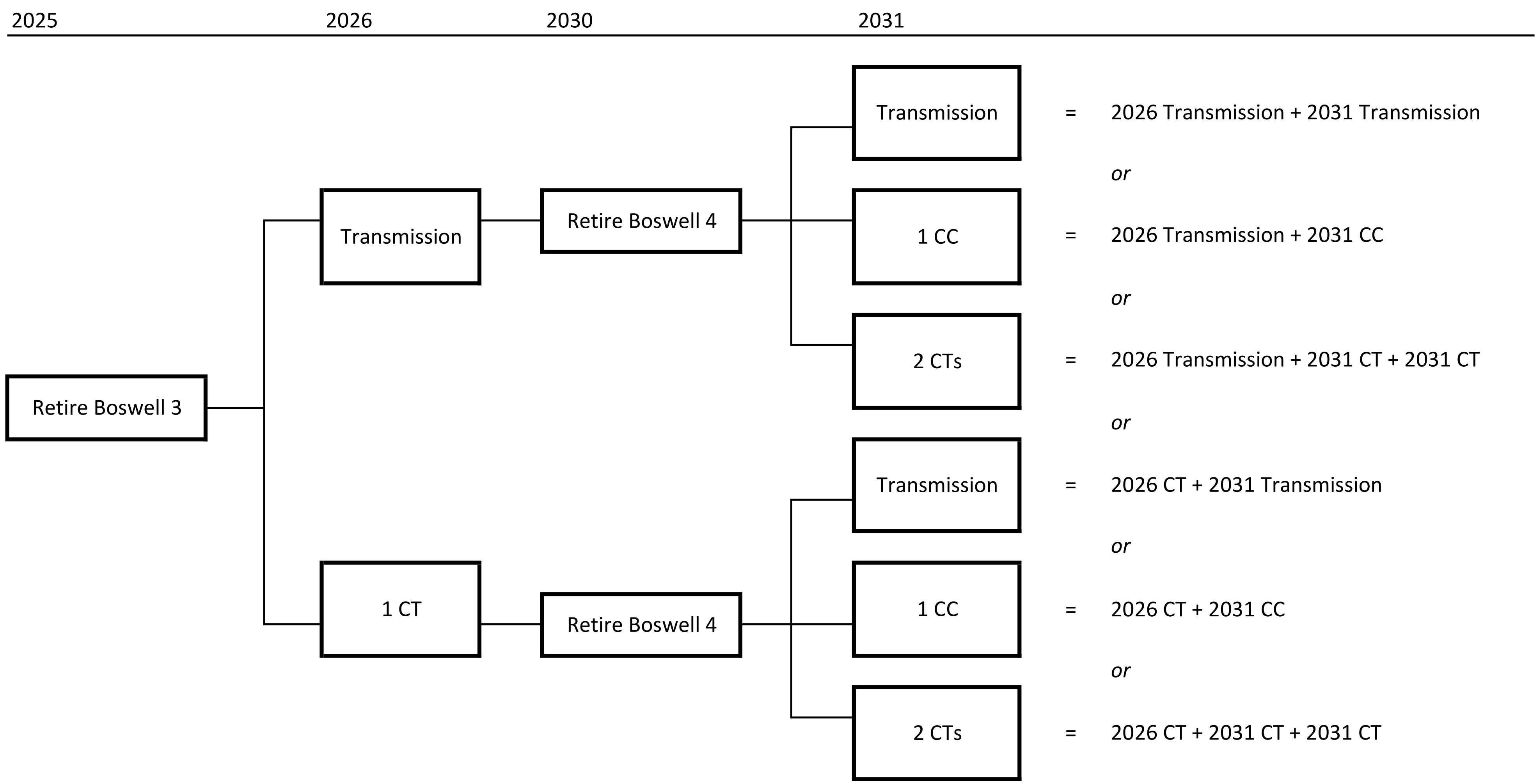


Table 1G. Available resources and projects for selection in Minnesota Power's model, with Contraints

4 hour lithium ion	2 units permitted to be added in any year from 2023-2035; no units permitted to be added before 2023 or after 2035 Total units permitted capped at 2 from 2023-2029; Total units permitted capped at 4 from 2030 onwards
8 hour lithium ion	2 units permitted to be added in any year from 2023-2035; no units permitted to be added before 2023 or after 2035 Total units permitted capped at 2 from 2023-2029; Total units permitted capped at 4 from 2030 onwards
12 hour flow	2 units permitted to be added in any year from 2023-2035; no units permitted to be added before 2023 or after 2035 Total units permitted capped at 2 from 2023-2029; Total units permitted capped at 4 from 2030 onwards
Bridge Purchase	1 unit permitted to be added in any year from 2025-2035; no units permitted to be added before 2025 or after 2035 Total units permitted capped at 1 from 2025 onwards
Demand Response Product B	1 block permitted to be added in any year from 2022-2035; no blocks permitted to be added before 2022 or after 2035 Total blocks permitted capped at 1 from 2022 onwards
Demand Response Product D	1 block permitted to be added in any year from 2022-2035; no blocks permitted to be added before 2022 or after 2035 Total blocks permitted capped at 1 from 2022 to 2027; total blocks permitted capped at 2 from 2028 onwards
Direct Load Control: Air Conditioners	1 block permitted to be added in 2026; no blocks permitted to be added before 2026 or after 2026 Total blocks permitted capped at 1 from 2026 onwards
Direct Load Control: Water Heaters	1 block permitted to be added in 2026; no blocks permitted to be added before 2026 or after 2026 Total blocks permitted capped at 1 from 2026 onwards
Energy Efficiency High	1 block permitted to be added in 2024; no blocks permitted to be added before or after 2024 Total blocks capped at 1 from 2024 onwards
Energy Efficiency Very High	1 block permitted to be added in 2024; no blocks permitted to be added before or after 2024 Total blocks capped at 1 from 2024 onwards
Natural Gas Combined Cycle	1 units permitted to be added in any year from 2025-2035; no units permitted to be added before 2025 or after 2035 Total units permitted capped at 1 from 2025-2029; Total units permitted capped at 2 from 2030 onwards.
Natural Gas Combustion Turbine	2 units permitted to be added in any year from 2025-2035; no units permitted to be added before 2025 or after 2035 Total units permitted capped at 2 from 2025-2029; Total units permitted capped at 3 from 2030 onwards
Natural Gas Reciprocating Internal Combustion Engine	1 unit permitted to be added in any year from 2025-2035; no units permitted to be added before 2025 or after 2035 Total units permitted capped at 1 from 2025-2029; Total units permitted capped at 2 from 2030 onwards
Natural Gas Simple Cycle Aeroderivative	1 unit permitted to be added in any year from 2025-2035; no units permitted to be added before 2025 or after 2035 Total units permitted capped at 1 from 2025-2029; Total units permitted capped at 2 from 2030 onwards
Utility Solar	4 units permitted to be added in any year from 2024-2035; no units permitted to be added before 2024 or after 2035 Total units permitted capped at 10 from 2024 onwards
Utility Solar with ITC	4 units permitted to be added in 2023; no units permitted to be added before or after 2023 Total units permitted capped at 10 from 2024 onwards
Utility Solar Net Zero (sited at Boswell)	Does not appear to have constraints restricting number of units added
Utlity Solar with ITC sited as Boswell	Does not appear to have constraints restricting number of units added
Wind MN-sited	4 units permitted to be added in any year from 2026-2035; no units permitted to be added before 2026 or after 2035 Total units permitted capped at 3 from 2023 to 2025; total units permitted capped at 10 from 2026 onwards
Wind MN-sited with PTC	2 units permitted to be added in any year from 2023-2025; no units permitted to be added before 2023 or after 2025 Total units permitted capped at 3 from 2023 to 2025; total units permitted capped at 10 from 2026 onwards
Wind ND-sited	2 units permitted to be added in any year from 2026-2035; no units permitted to be added before 2026 or after 2035 Total units permitted capped at 2 from 2026 onwards

Table 2A.

Party	Run Name	MIP	Objective Function (PV $000)	Percent Difference
MP	CCUST1S REF	50	1,902,744.32	
DOC	DeptMatch DB1 CCUST1S REF	50	1,902,496.26	
				0.01%
MP	CHE1S REF	50	1,902,744.32	
DOC	DeptMatch DB1 CHE1S REF	50	1,902,496.26	
				0.01%
MP	CHER1S REF	50	2,793,331.71	
DOC	DeptMatch DB1 CHER1S REF	50	2,783,424.51	
				0.36%
MP	CLE1S REF	50	1,902,744.32	
DOC	DeptMatch DB1 CLE1S REF	50	1,902,496.26	
				0.01%
MP	CLER1S REF	50	2,200,361.22	
DOC	DeptMatch DB1 CLER1S REF	50	2,203,243.78	
				-0.13%
MP	CREF1S REF	50	2,565,086.46	
DOC	DeptMatch DB1 CREF1S REF	50	2,563,026.69	
				0.08%
MP	CHER1S RS01	50	2,974,070.02	
DOC	DeptMatch DB1 CHER1S RS01	50	2,969,596.42	
				0.15%
MP	CHER1S RS02	50	2,922,225.66	
DOC	DeptMatch DB1 CHER1S RS02	50	2,912,081.92	
				0.35%
MP	CHER1S RS03	50	3,048,536.32	
DOC	DeptMatch DB1 CHER1S RS03	50	3,042,558.98	
				0.20%
MP	CHER1S RS04	50	6,661,671.17	
DOC	DeptMatch DB1 CHER1S RS04	50	6,657,025.28	
				0.07%

Table 2B.

Party	Run Name	MIP	Objective Function Stand-in (PV $000 Operating Costs + Carrying Costs)	Percent Difference
MP	PrefPlan CHER1S-1_Coal+20%	50	6,513,838.67	
DOC	DeptMatch DB2 PrefPlan CHER1S-1_Coal+20%	50	6,513,011.22	
				0.01%
MP	PrefPlan CHER1S-2_Coal-10%	50	6,369,904.16	
DOC	DeptMatch DB2 PrefPlan CHER1S-2_Coal-10%	50	6,369,615.04	
				0.00%
MP	PrefPlan CHER1S-3_Biomass+15%	50	6,425,417.28	
DOC	DeptMatch DB2 PrefPlan CHER1S-3_Biomass+15%	50	6,424,610.49	
				0.01%
MP	PrefPlan CHER1S-4_Biomass-15%	50	6,420,174.67	
DOC	DeptMatch DB2 PrefPlan CHER1S-4_Biomass-15%	50	6,419,816.43	
				0.01%
MP	PrefPlan CHER1S-5_Lower Gas-50%	50	6,284,036.14	
DOC	DeptMatch DB2 PrefPlan CHER1S-5_Lower Gas-50%	50	6,283,170.34	
				0.01%
MP	PrefPlan CHER1S-6_Low Gas-25%	50	6,390,813.68	
DOC	DeptMatch DB2 PrefPlan CHER1S-6_Low Gas-25%	50	6,389,895.48	
				0.01%
MP	PrefPlan CHER1S-7_High Gas+25%	50	6,569,579.55	
DOC	DeptMatch DB2 PrefPlan CHER1S-7_High Gas+25%	50	6,569,142.91	
				0.01%
MP	PrefPlan CHER1S-8_Higher Gas+50%	50	6,654,252.63	
DOC	DeptMatch DB2 PrefPlan CHER1S-8_Higher Gas+50%	50	6,653,578.63	
				0.01%
MP	PrefPlan CHER1S-9_Highest Gas+100%	50	6,818,692.54	
DOC	DeptMatch DB2 PrefPlan CHER1S-9_Highest Gas+100%	50	6,817,798.54	
				0.01%
MP	PrefPlan CHER1S-10_Wholesale Market-50%	50	6,014,040.37	
DOC	DeptMatDB2 PrefPlan CHER1S-10_Wholesale Market-50%	50	6,012,505.76	
				0.03%
MP	PrefPlan CHER1S-11_Wholesale Market-25%	50	6,303,606.35	
DOC	DeptMatDB2 PrefPlan CHER1S-11_Wholesale Market-25%	50	6,302,606.12	
				0.02%
MP	PrefPlan CHER1S-12_Wholesale Market+25%	50	6,584,762.76	
DOC	DeptMatDB2 PrefPlan CHER1S-12_Wholesale Market+25%	50	6,584,554.46	
				0.00%
MP	PrefPlan CHER1S-13_Wholesale Market+50%	50	6,618,700.38	
DOC	DeptMatDB2 PrefPlan CHER1S-13_Wholesale Market+50%	50	6,618,633.40	
				0.00%
MP	PrefPlan CHER1S-14_Capital Costs-30%	50	6,421,509.48	
DOC	DeptMatch DB2 PrefPlan CHER1S-14_Capital Costs-30%	50	6,420,785.20	
				0.01%

Party	Run Name	MIP	Objective Function Stand-in (PV $000 Operating Costs + Carrying Costs)	Percent Difference
MP	PrefPlan CHER1S-15_Capital Costs+30%	50	6,423,626.35	
DOC	DeptMatch DB2 PrefPlan CHER1S-15_Capital Costs+30%	50	6,422,900.17	
				0.01%
MP	PrefPlan CHER1S-16_No Externalities Costs	50	6,425,008.29	
DOC	DptMatD2 PrefPlan CHER1S-16_No Externalities Costs	50	6,424,030.94	
				0.02%
MP	PrefPlan CHER1S-17_No Market Sales	50	6,482,603.37	
DOC	DeptMatch DB2 PrefPlan CHER1S-17_No Market Sales	50	6,481,956.47	
				0.01%
MP	PrefPlan CHER1S-18_No Sales and Purchases	50	7,516,246.47	
DOC	DepMaDB2 PrefPlan CHER1S-18_No Sales and Purchases	50	0.00	
				#DIV/0!
MP	PrefPlan CHER1S-19_Market Access -50%	50	6,670,193.01	
DOC	DeptMatchDB2 PrefPlan CHER1S-19_Market Access -50%	50	6,657,986.76	
MP	PrefPlan CHER1S-20_Low Interconnect Costs	50	6,408,910.50	
DOC	DMatchDB2 PrefPlan CHER1S-20_Low Interconnect Cost	50	6,407,976.06	
				0.01%
MP	PrefPlan CHER1S-21_ITC & PTC EXTENSION	50	6,421,958.61	
DOC	DeptMatchDB2 PrefPlan CHER1S-21_ITC & PTC Extend	50	6,421,152.77	
				0.01%
MP	PrefPlan CHER1S-22_Wind Cost Curve Low	50	6,426,819.59	
DOC	DeptMatchDB2 PrefPlan CHER1S-22_Wind CostCurve Low	50	6,425,839.24	
				0.02%
MP	PrefPlan CHER1S-23_Wind Cost Curve High	50	6,422,957.99	
DOC	DeptMatDB2 PrefPlan CHER1S-23_Wind CostCurve High	50	6,422,092.53	
				0.01%
MP	PrefPlan CHER1S-24_Solar Cost Curve Low	50	6,416,546.61	
DOC	DeptMatDB2 PrefPlan CHER1S-24_Solar Cost Curve Low	50	6,416,082.56	
				0.01%
MP	PrefPlan CHER1S-25_Solar Cost Curve High	50	6,437,609.98	
DOC	DeptMatDB2 PrefPlan CHER1S-25_Solar CostCurve High	50	6,437,211.13	
				0.01%
MP	PrefPlan CHER1S-26_Storage Cost Curve Low	50	6,422,135.85	
DOC	DeptMatDB2 PrefPlan CHER1S-26_Storage CostCurve Lo	50	6,421,537.67	
				0.01%
MP	PrefPlan CHER1S-27_Storage Cost Curve High	50	6,423,435.54	
DOC	DeptMatDB2 PrefPlan CHER1S-27_Storage CostCurve Hi	50	6,423,111.87	
				0.01%
MP	PrefPlan CHER1S-28_AFR 2020 Low Scenario	50	6,217,194.29	
DOC	DeptMatchDB2 PrefPlan CHER1S-28_AFR 2020 Low Scen	50	6,216,811.57	
				0.01%

Party	Run Name	MIP	Objective Function Stand-in (PV $000 Operating Costs + Carrying Costs)	Percent Difference
MP	PrefPlan CHER1S-29_AFR 2020 Load w Keetac	50	6,745,991.22	
DOC	DeptMatDB2 PrefPlan CHER1S-29_AFR2020 Load wKeetac	50	6,744,141.02	
				0.03%
MP	PrefPlan CHER1S-30_AFR 2020 High Scenario	50	6,780,875.04	
DOC	DeptMatDB2 PrefPlan CHER1S-30_AFR2020 High Scen	50	6,778,848.22	
				0.03%
MP	PrefPlan CHER1S-31_Residential TOU	50	6,417,807.76	
DOC	DeptMatch DB2 PrefPlan CHER1S-31_Residential TOU	50	6,417,090.34	
				0.01%
MP	PrefPlan CHER1S-32_Higher DG & EV Growth	50	6,423,093.26	
DOC	DeptMatDB2 PrefPlan CHER1S-32_Higher DG&EV Growth	50	6,422,312.92	
				0.01%
MP	PrefPlan CHER1S-33_Renewable ELCC -2.5%	50	6,426,429.84	
DOC	DeptMatDB2 PrefPlan CHER1S-33_Renewable ELCC -2.5%	50	6,425,824.94	
				0.01%
MP	PrefPlan CHER1S-34_Renewable ELCC +2.5%	50	6,422,125.20	
DOC	DepMatDB2 PrefPlan CHER1S-34_Renewable ELCC +2.5%	50	6,421,652.09	
				0.01%
MP	PrefPlan CHER1S-35_PRM-2%	50	6,422,542.40	
DOC	DeptMatch DB2 PrefPlan CHER1S-35_PRM-2%	50	6,422,191.30	
				0.01%
MP	PrefPlan CHER1S-36_PRM+2%	50	6,430,484.16	
DOC	DeptMatch DB2 PrefPlan CHER1S-36_PRM+2%	50	6,429,924.96	
				0.01%
MP	PrefPlan CHER1S-37_MISO CF-2%	50	6,422,928.70	
DOC	DeptMatch DB2 PrefPlan CHER1S-37_MISO CF-2%	50	6,421,988.11	
				0.01%
MP	PrefPlan CHER1S-38_MISO CF+2%	50	6,431,719.61	
DOC	DeptMatch DB2 PrefPlan CHER1S-38_MISO CF+2%	50	6,431,427.08	
				0.00%
MP	PrefPlan CREF1S-5_Lower Gas-50%	50	6,120,689.58	
DOC	DeptMatch DB2 PrefPlan CREF1S-5_Lower Gas-50%	50	6,120,396.72	
				0.00%
MP	PrefPlan CREF1S-6_Low Gas-25%	50	6,230,280.39	
DOC	DeptMatch DB2 PrefPlan CREF1S-6_Low Gas-25%	50	6,229,764.30	
				0.01%
MP	PrefPlan CREF1S-7_High Gas+25%	50	6,409,172.06	
DOC	DeptMatch DB2 PrefPlan CREF1S-7_High Gas+25%	50	6,408,607.18	
				0.01%
MP	PrefPlan CREF1S-8_Higher Gas+50%	50	6,479,966.35	
DOC	DeptMatch DB2 PrefPlan CREF1S-8_Higher Gas+50%	50	6,479,363.19	
				0.01%

Party	Run Name	MIP	Objective Function Stand-in (PV $000 Operating Costs + Carrying Costs)	Percent Difference
MP	PrefPlan CREF1S-9_Highest Gas+100%	50	6,628,362.89	
DOC	DeptMatch DB2 PrefPlan CREF1S-9_Highest Gas+100%	50	6,627,807.94	
				0.01%
MP	PrefPlan CREF1S-10_Wholesale Market-50%	50	5,940,130.40	
DOC	DeptMatDB2 PrefPlan CREF1S-10_Wholesale Market-50%	50	5,939,158.98	
				0.02%
MP	PrefPlan CREF1S-11_Wholesale Market-25%	50	6,195,348.50	
DOC	DeptMatDB2 PrefPlan CREF1S-11_Wholesale Market-25%	50	6,194,625.86	
				0.01%
MP	PrefPlan CREF1S-12_Wholesale Market+25%	50	6,383,165.73	
DOC	DeptMatDB2 PrefPlan CREF1S-12_Wholesale Market+25%	50	6,382,782.34	
				0.01%
MP	PrefPlan CREF1S-13_Wholesale Market+50%	50	6,391,332.20	
DOC	DeptMatDB2 PrefPlan CREF1S-13_Wholesale Market+50%	50	6,391,066.14	
				0.00%
MP	PrefPlan CCUST1S-5_Lower Gas-50%	50	5,821,789.72	
DOC	DeptMatch DB2 PrefPlan CCUST1S-5_Lower Gas-50%	50	5,821,666.09	
				0.00%
MP	PrefPlan CCUST1S-6_Low Gas-25%	50	5,926,145.32	
DOC	DeptMatch DB2 PrefPlan CCUST1S-6_Low Gas-25%	50	5,925,854.06	
				0.00%
MP	PrefPlan CCUST1S-7_High Gas+25%	50	6,080,379.27	
DOC	DeptMatch DB2 PrefPlan CCUST1S-7_High Gas+25%	50	6,079,743.21	
				0.01%
MP	PrefPlan CCUST1S-8_Higher Gas+50%	50	6,115,281.63	
DOC	DeptMatch DB2 PrefPlan CCUST1S-8_Higher Gas+50%	50	6,114,928.62	
				0.01%
MP	PrefPlan CCUST1S-9_Highest Gas+100%	50	6,244,461.01	
DOC	DeptMatch DB2 PrefPlan CCUST1S-9_Highest Gas+100%	50	6,244,065.55	
				0.01%
MP	PrefPlan CCUST1S-10_Wholesale Market-50%	50	5,808,503.96	
DOC	DepMatDB2 PrefPlan CCUST1S-10_Wholesale Market-50%	50	5,808,026.86	
				0.01%
MP	PrefPlan CCUST1S-11_Wholesale Market-25%	50	5,972,479.99	
DOC	DepMatDB2 PrefPlan CCUST1S-11_Wholesale Market-25%	50	5,971,944.36	
				0.01%
MP	PrefPlan CCUST1S-12_Wholesale Market+25%	50	6,013,827.73	
DOC	DepMatDB2 PrefPlan CCUST1S-12_Wholesale Market+25%	50	6,013,446.64	
				0.01%
MP	PrefPlan CCUST1S-13_Wholesale Market+50%	50	6,005,810.04	
DOC	DepMatDB2 PrefPlan CCUST1S-13_Wholesale Market+50%	50	6,005,684.26	
				0.00%

Party	Run Name	MIP	Objective Function Stand-in (PV $000 Operating Costs + Carrying Costs)	Percent Difference
MP	PrefPlan CHE1S-5_Lower Gas-50%	50	5,823,751.45	
DOC	DeptMatch DB2 PrefPlan CHE1S-5_Lower Gas-50%	50	5,823,113.67	
				0.01%
MP	PrefPlan CHE1S-6_Low Gas-25%	50	5,926,567.87	
DOC	DeptMatch DB2 PrefPlan CHE1S-6_Low Gas-25%	50	5,926,437.11	
				0.00%
MP	PrefPlan CHE1S-7_High Gas+25%	50	6,074,342.68	
DOC	DeptMatch DB2 PrefPlan CHE1S-7_High Gas+25%	50	6,074,177.70	
				0.00%
MP	PrefPlan CHE1S-8_Higher Gas+50%	50	6,117,370.97	
DOC	DeptMatch DB2 PrefPlan CHE1S-8_Higher Gas+50%	50	6,116,890.55	
				0.01%
MP	PrefPlan CHE1S-9_Highest Gas+100%	50	6,242,762.19	
DOC	DeptMatch DB2 PrefPlan CHE1S-9_Highest Gas+100%	50	6,242,365.52	
				0.01%
MP	PrefPlan CHE1S-10_Wholesale Market-50%	50	5,806,950.61	
DOC	DepMatchDB2 PrefPlan CHE1S-10_Wholesale Market-50%	50	5,806,607.54	
				0.01%
MP	PrefPlan CHE1S-11_Wholesale Market-25%	50	5,966,192.34	
DOC	DepMatchDB2 PrefPlan CHE1S-11_Wholesale Market-25%	50	5,966,223.25	
				0.00%
MP	PrefPlan CHE1S-12_Wholesale Market+25%	50	6,011,522.98	
DOC	DepMatchDB2 PrefPlan CHE1S-12_Wholesale Market+25%	50	6,011,329.89	
				0.00%
MP	PrefPlan CHE1S-13_Wholesale Market+50%	50	6,004,800.47	
DOC	DepMatchDB2 PrefPlan CHE1S-13_Wholesale Market+50%	50	6,004,848.45	
				0.00%
MP	PrefPlan CLER1S-5_Lower Gas-50%	50	5,929,866.44	
DOC	DeptMatch DB2 PrefPlan CLER1S-5_Lower Gas-50%	50	5,929,513.11	
				0.01%
MP	PrefPlan CLER1S-6_Low Gas-25%	50	6,037,999.12	
DOC	DeptMatch DB2 PrefPlan CLER1S-6_Low Gas-25%	50	6,037,823.21	
				0.00%
MP	PrefPlan CLER1S-7_High Gas+25%	50	6,203,805.43	
DOC	DeptMatch DB2 PrefPlan CLER1S-7_High Gas+25%	50	6,203,671.89	
				0.00%
MP	PrefPlan CLER1S-8_Higher Gas+50%	50	6,254,714.11	
DOC	DeptMatch DB2 PrefPlan CLER1S-8_Higher Gas+50%	50	6,254,509.36	
				0.00%
MP	PrefPlan CLER1S-9_Highest Gas+100%	50	6,379,837.92	
DOC	DeptMatch DB2 PrefPlan CLER1S-9_Highest Gas+100%	50	6,379,538.00	
				0.00%

Party	Run Name	MIP	Objective Function Stand-in (PV $000 Operating Costs + Carrying Costs)	Percent Difference
MP	PrefPlan CLER1S-10_Wholesale Market-50%	50	5,859,965.48	
DOC	DepMat DB2 PrefPlan CLER1S-10_Wholesale Market-50%	50	5,859,483.47	
				0.01%
MP	PrefPlan CLER1S-11_Wholesale Market-25%	50	6,060,793.70	
DOC	DepMat DB2 PrefPlan CLER1S-11_Wholesale Market-25%	50	6,060,142.21	
				0.01%
MP	PrefPlan CLER1S-12_Wholesale Market+25%	50	6,142,857.13	
DOC	DepMat DB2 PrefPlan CLER1S-12_Wholesale Market+25%	50	6,142,468.97	
				0.01%
MP	PrefPlan CLER1S-13_Wholesale Market+50%	50	6,142,287.80	
DOC	DepMat DB2 PrefPlan CLER1S-13_Wholesale Market+50%	50	6,142,061.90	
				0.00%
MP	PrefPlan CLE1S-5_Lower Gas-50%	50	5,821,110.91	
DOC	DeptMatch DB2 PrefPlan CLE1S-5_Lower Gas-50%	50	5,820,754.67	
				0.01%
MP	PrefPlan CLE1S-6_Low Gas-25%	50	5,930,496.38	
DOC	DeptMatch DB2 PrefPlan CLE1S-6_Low Gas-25%	50	5,929,877.41	
				0.01%
MP	PrefPlan CLE1S-7_High Gas+25%	50	6,076,557.31	
DOC	DeptMatch DB2 PrefPlan CLE1S-7_High Gas+25%	50	6,076,170.67	
				0.01%
MP	PrefPlan CLE1S-8_Higher Gas+50%	50	6,112,228.27	
DOC	DeptMatch DB2 PrefPlan CLE1S-8_Higher Gas+50%	50	6,111,941.19	
				0.00%
MP	PrefPlan CLE1S-9_Highest Gas+100%	50	6,243,998.59	
DOC	DeptMatch DB2 PrefPlan CLE1S-9_Highest Gas+100%	50	6,243,770.27	
				0.00%
MP	PrefPlan CLE1S-10_Wholesale Market-50%	50	5,809,975.20	
DOC	DepMatch DB2PrefPlan CLE1S-10_Wholesale Market-50%	50	5,809,620.04	
				0.01%
MP	PrefPlan CLE1S-11_Wholesale Market-25%	50	5,969,092.36	
DOC	DepMatchDB2 PrefPlan CLE1S-11_Wholesale Market-25%	50	5,968,596.67	
				0.01%
MP	PrefPlan CLE1S-12_Wholesale Market+25%	50	6,010,451.30	
DOC	DepMatchDB2 PrefPlan CLE1S-12_Wholesale Market+25%	50	6,010,181.98	
				0.00%
MP	PrefPlan CLE1S-13_Wholesale Market+50%	50	6,006,961.13	
DOC	DepMatchDB2 PrefPlan CLE1S-13_Wholesale Market+50%	50	6,006,613.11	
				0.01%
MP	FastExit CHER1S-1_Coal+20%	50	6,541,231.84	
DOC	DeptMatch DB2 FastExit CHER1S-1_Coal+20%	50	6,540,846.01	
				0.01%

Party	Run Name	MIP	Objective Function Stand-in (PV $000 Operating Costs + Carrying Costs)	Percent Difference
MP	Early3 CHER1S-1_Coal+20%	50	6,551,260.07	
DOC	DeptMatch DB2 Early3 CHER1S-1_Coal+20%	50	6,550,171.40	
				0.02%
MP	Early4 CHER1S-1_Coal+20%	50	6,519,014.41	
DOC	DeptMatch DB2 Early4 CHER1S-1_Coal+20%	50	6,518,881.89	
				0.00%
MP	StatusQuo CHER1S-1_Coal+20%	50	6,554,901.41	
DOC	DeptMatch DB2 StatusQuo CHER1S-1_Coal+20%	50	6,554,724.50	
				0.00%

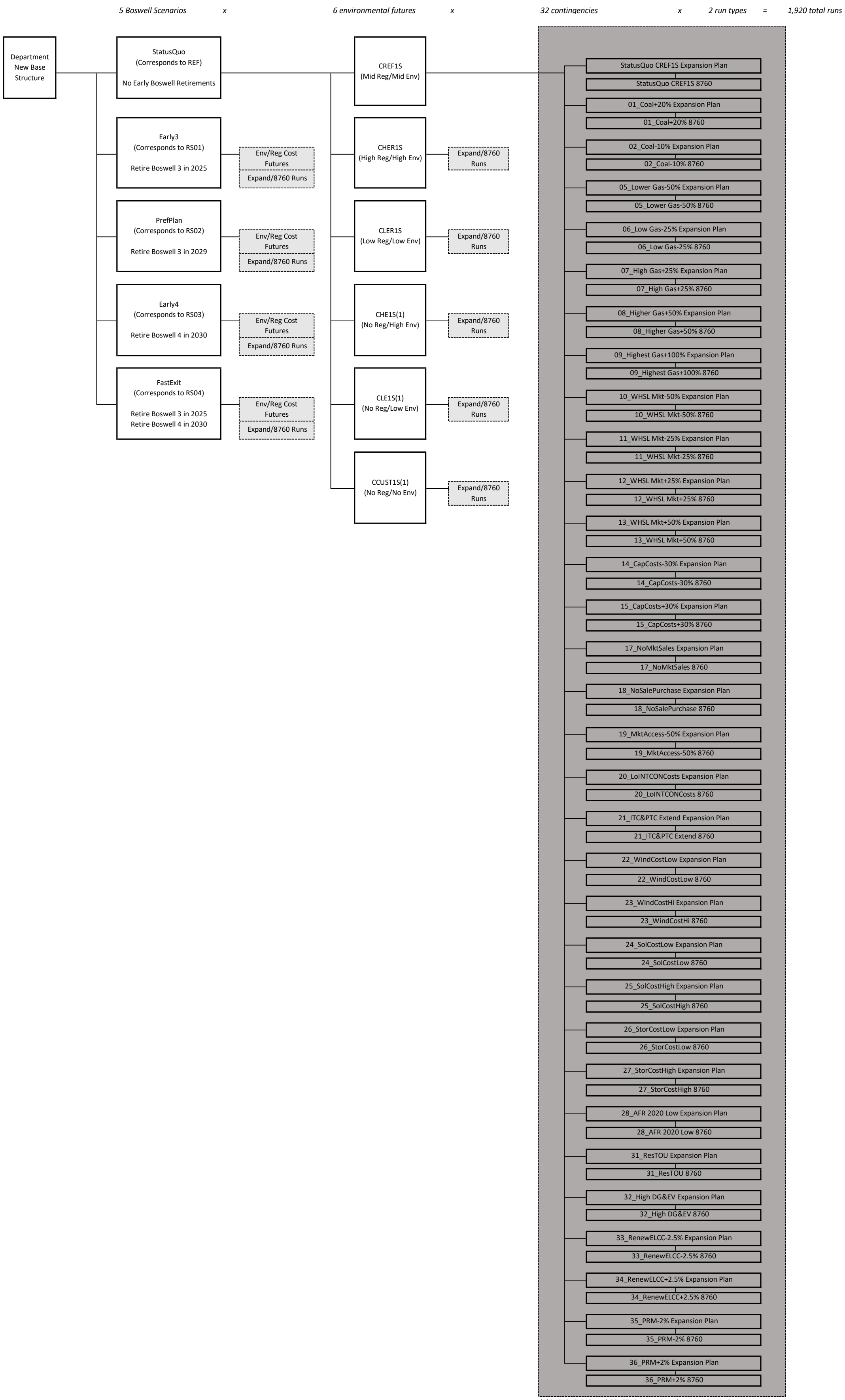
Table 2C.

Party	Run Name	MIP	Objective Function (PV $000)	Percent Difference
MP	CREF1S REF	50	5,129,215.49	
DOC	DeptMatch DB3 Minnesota Power CREF RES	50	5,126,943.23	
				0.04%
MP	PrefPlan CREF1S RES MKT	50	2,954,789.38	
DOC	DeptMatch DB4 PrefPlan CREF1S RES MKT	50	2,953,303.04	
				0.05%

Table 3A. Cost Results for Minnesota Power's Expansion Plan Database

		StatusQuo	Early3	PrefPlan	Early4	FastExit
CREF1S	**Plan Cost**	2,565,086	2,764,977	2,702,772	2,844,878	3,067,956
	Revenue Requirement	9,265,495	9,331,179	9,309,238	9,434,795	9,555,038
	Externality Cost	2,000,669	1,912,315	1,928,516	1,880,960	1,715,255
	RR + Externalities	11,266,164	11,243,494	11,237,753	11,315,755	11,270,293
CHER1S	**Plan Cost**	2,793,332	2,974,070	2,922,226	3,048,536	3,251,070
	Revenue Requirement	9,514,632	9,577,573	9,547,288	9,662,896	9,758,960
	Externality Cost	1,987,612	1,952,670	1,977,688	1,949,950	1,968,440
	RR + Externality	11,502,243	11,530,243	11,524,976	11,612,846	11,727,400
CLER1S	**Plan Cost**	2,200,361	2,464,464	2,388,608	2,554,938	2,849,372
	Revenue Requirement	8,855,984	9,010,120	8,972,178	9,116,232	9,324,737
	Externality Cost	2,520,740	2,059,763	2,107,094	2,019,463	1,515,181
	RR + Externality	11,376,723	11,069,883	11,079,272	11,135,695	10,839,917
CCUST1S	**Plan Cost**	1,902,744	2,251,024	2,168,313	2,337,848	2,710,990
	Revenue Requirement	8,525,531	8,779,045	8,734,013	8,881,420	9,163,280
	Externality Cost	-	-	-	-	-
	RR + Externality	8,525,531	8,779,045	8,734,013	8,881,420	9,163,280
CHE1S	**Plan Cost**	1,902,744	2,251,024	2,168,313	2,337,848	2,710,990
	Revenue Requirement	8,525,531	8,779,045	8,734,013	8,881,420	9,163,280
	Externality Cost	8,079,640	6,093,663	6,275,127	6,031,267	4,269,659
	RR + Externality	16,605,170	14,872,709	15,009,140	14,912,687	13,432,939
CLE1S	**Plan Cost**	1,902,744	2,251,024	2,168,313	2,337,848	2,710,990
	Revenue Requirement	8,525,531	8,779,045	8,734,013	8,881,420	9,163,280
	Externality Cost	4,021,398	2,981,076	3,081,537	2,972,242	2,079,616
	RR + Externality	12,546,929	11,760,122	11,815,549	11,853,662	11,242,896

Figure 4A. Department's New Base Analysis Structure



(1)CHE1S, CLE1S, and CCUST1S expansion plans are identical

Attachment 5. Department's new base results (revenue requirement + externalities in $000 in $2021) for each for each Boswell retirement scenario, per contingency and cost future, with least-cost results of each contingency indicated by shading

Cost Future	Contingency	Boswell Retirement Scenario				
		StatusQuo	PrefPlan	Early3	Early4	FastExit
NoReg/NoEnv Cost Future	CCUST1S 8760	7,450	7,644	7,692	7,731	7,370
	CCUST1S-01_Coal+20% 8760	7,707	7,850	7,882	7,940	7,472
	CCUST1S-02_Coal-10% 8760	7,303	7,524	7,563	7,619	7,304
	CCUST1S-05_Lower Gas-50% 8760	7,206	7,250	7,226	7,322	6,731
	CCUST1S-06_Low Gas-25% 8760	7,383	7,517	7,527	7,627	7,107
	CCUST1S-07_High Gas+25% 8760	7,601	7,818	7,884	7,945	7,728
	CCUST1S-08_Higher Gas+50% 8760	7,648	7,897	7,948	8,037	7,902
	CCUST1S-09_Highest Gas+100% 8760	7,829	8,094	8,151	8,243	8,230
	CCUST1S-10_WHSL Mkt-50% 8760	7,255	7,335	7,391	7,421	7,093
	CCUST1S-11_WHSL Mkt-25% 8760	7,475	7,591	7,649	7,690	7,361
	CCUST1S-12_WHSL Mkt+25% 8760	7,493	7,713	7,742	7,839	7,410
	CCUST1S-13_WHSL Mkt+50% 8760	7,464	7,706	7,721	7,809	7,375
	CCUST1S-14_CapCosts-30% 8760	7,448	7,590	7,603	7,677	7,367
	CCUST1S-15_CapCosts+30% 8760	7,449	7,639	7,698	7,775	7,368
	CCUST1S-17_NoMktSales 8760	7,592	7,721	7,774	7,833	7,485
	CCUST1S-18_NoSalePurchase 8760	8,291	8,455	8,520	8,546	8,113
	CCUST1S-19_MktAccess-50% 8760	7,609	7,801	7,829	7,887	7,533
	CCUST1S-20_LoINTCONCosts 8760	7,449	7,631	7,674	7,728	7,383
	CCUST1S-21_ITC&PTC Extend 8760	7,448	7,626	7,677	7,732	7,366
	CCUST1S-22_WindCostLow 8760	7,448	7,640	7,692	7,732	7,370
	CCUST1S-23_WindCostHi 8760	7,451	7,642	7,674	7,729	7,367
	CCUST1S-24_SolCostLow 8760	7,456	7,616	7,673	7,718	7,385
	CCUST1S-25_SolCostHigh 8760	7,450	7,651	7,662	7,726	7,367
	CCUST1S-26_StorCostLow 8760	7,448	7,638	7,693	7,732	7,368
	CCUST1S-27_StorCostHigh 8760	7,446	7,640	7,695	7,732	7,368
	CCUST1S-28_AFR 2020 Low 8760	7,260	7,384	7,418	7,514	7,180
	CCUST1S-31_ResTOU 8760	7,449	7,626	7,669	7,730	7,364
	CCUST1S-32_High DG&EV 8760	7,452	7,647	7,695	7,734	7,366
	CCUST1S-33_RenewELCC-2.5% 8760	7,452	7,645	7,681	7,729	7,368
	CCUST1S-34_RenewELCC+2.5% 8760	7,448	7,641	7,690	7,730	7,369
	CCUST1S-35_PRM-2% 8760	7,448	7,625	7,672	7,729	7,366
	CCUST1S-36_PRM+2% 8760	7,450	7,657	7,684	7,729	7,366
NoReg/HighEnv Cost Future	CHE1S 8760	25,174	13,242	13,294	13,334	11,724
	CHE1S-01_Coal+20% 8760	21,712	12,347	12,308	12,390	11,373
	CHE1S-02_Coal-10% 8760	26,180	13,690	13,735	13,648	11,899
	CHE1S-05_Lower Gas-50% 8760	22,683	12,740	12,497	12,222	11,182
	CHE1S-06_Low Gas-25% 8760	23,558	13,453	13,219	12,740	11,514
	CHE1S-07_High Gas+25% 8760	25,904	13,584	13,159	13,452	11,629
	CHE1S-08_Higher Gas+50% 8760	26,075	13,556	13,359	13,421	11,622
	CHE1S-09_Highest Gas+100% 8760	25,394	13,237	13,024	13,063	11,112
	CHE1S-10_WHSL Mkt-50% 8760	15,128	10,094	10,111	9,973	8,904
	CHE1S-11_WHSL Mkt-25% 8760	21,796	12,383	12,343	12,173	10,697
	CHE1S-12_WHSL Mkt+25% 8760	26,851	14,241	14,104	14,155	12,413
	CHE1S-13_WHSL Mkt+50% 8760	27,463	14,323	14,253	14,260	12,479
	CHE1S-14_CapCosts-30% 8760	25,156	13,403	13,046	13,407	11,730
	CHE1S-15_CapCosts+30% 8760	25,155	13,622	13,461	13,298	11,740
	CHE1S-17_NoMktSales 8760	22,659	12,982	12,974	12,749	11,232
	CHE1S-18_NoSalePurchase 8760	26,009	15,026	14,944	14,447	12,895
	CHE1S-19_MktAccess-50% 8760	25,216	14,031	13,854	13,676	12,004
	CHE1S-20_LoINTCONCosts 8760	25,164	12,990	13,100	12,942	11,400
	CHE1S-21_ITC&PTC Extend 8760	25,171	13,396	13,467	13,301	11,732
	CHE1S-22_WindCostLow 8760	25,152	13,228	13,274	13,175	11,728
	CHE1S-23_WindCostHi 8760	25,167	13,254	13,541	13,353	11,727
	CHE1S-24_SolCostLow 8760	24,853	13,303	13,358	13,225	11,612
	CHE1S-25_SolCostHigh 8760	25,140	13,477	13,579	13,219	11,732
	CHE1S-26_StorCostLow 8760	25,137	13,247	13,290	13,339	11,720
	CHE1S-27_StorCostHigh 8760	25,186	13,249	13,294	13,346	11,735

	CHE1S-28_AFR 2020 Low 8760	23,695	12,909	12,810	12,773	11,178
	CHE1S-31_ResTOU 8760	25,161	13,413	13,119	13,352	11,725
	CHE1S-32_High DG&EV 8760	25,158	13,188	13,295	13,352	11,728
	CHE1S-33_RenewELCC-2.5% 8760	25,154	13,655	13,357	13,349	11,728
	CHE1S-34_RenewELCC+2.5% 8760	25,140	13,177	13,063	13,342	11,726
	CHE1S-35_PRM-2% 8760	25,159	13,404	13,139	13,355	11,737
	CHE1S-36_PRM+2% 8760	25,160	13,591	13,326	13,352	11,738
HighReg/HighEnv Cost Future	CHER1S 8760	11,656	10,351	10,303	10,400	9,882
	CHER1S-01_Coal+20% 8760	11,172	10,145	10,108	10,192	9,752
	CHER1S-02_Coal-10% 8760	11,898	10,461	10,452	10,510	9,939
	CHER1S-05_Lower Gas-50% 8760	11,668	10,124	10,059	10,282	9,726
	CHER1S-06_Low Gas-25% 8760	11,665	10,329	10,272	10,472	9,871
	CHER1S-07_High Gas+25% 8760	11,873	10,584	10,577	10,659	10,122
	CHER1S-08_Higher Gas+50% 8760	12,147	10,822	10,813	10,853	10,333
	CHER1S-09_Highest Gas+100% 8760	12,413	10,709	10,687	10,695	10,158
	CHER1S-10_WHSL Mkt-50% 8760	9,182	8,650	8,700	8,746	8,359
	CHER1S-11_WHSL Mkt-25% 8760	10,441	9,692	9,718	9,766	9,374
	CHER1S-12_WHSL Mkt+25% 8760	12,843	11,029	10,983	11,054	10,446
	CHER1S-13_WHSL Mkt+50% 8760	13,281	11,076	10,980	11,056	10,414
	CHER1S-14_CapCosts-30% 8760	11,658	10,360	10,377	10,447	9,883
	CHER1S-15_CapCosts+30% 8760	11,670	10,299	10,237	10,355	9,880
	CHER1S-17_NoMktSales 8760	11,386	10,237	10,153	10,265	9,739
	CHER1S-18_NoSalePurchase 8760	14,418	12,046	11,966	11,910	11,186
	CHER1S-19_MktAccess-50% 8760	12,762	10,872	10,786	10,912	10,242
	CHER1S-20_LoINTCONCosts 8760	11,441	10,303	10,207	10,328	9,823
	CHER1S-21_ITC&PTC Extend 8760	11,647	10,320	10,280	10,371	9,865
	CHER1S-22_WindCostLow 8760	11,441	10,285	10,241	10,344	9,841
	CHER1S-23_WindCostHi 8760	11,628	10,371	10,309	10,414	9,884
	CHER1S-24_SolCostLow 8760	11,556	10,318	10,254	10,366	9,852
	CHER1S-25_SolCostHigh 8760	11,736	10,366	10,359	10,485	9,885
	CHER1S-26_StorCostLow 8760	11,655	10,350	10,292	10,405	9,875
	CHER1S-27_StorCostHigh 8760	11,673	10,362	10,300	10,412	9,884
	CHER1S-28_AFR 2020 Low 8760	10,989	9,930	9,914	9,969	9,478
	CHER1S-31_ResTOU 8760	11,652	10,346	10,291	10,398	9,862
	CHER1S-32_High DG&EV 8760	11,684	10,354	10,306	10,382	9,882
	CHER1S-33_RenewELCC-2.5% 8760	11,666	10,323	10,292	10,405	9,870
	CHER1S-34_RenewELCC+2.5% 8760	11,648	10,350	10,294	10,407	9,879
	CHER1S-35_PRM-2% 8760	11,671	10,366	10,303	10,399	9,881
	CHER1S-36_PRM+2% 8760	11,660	10,327	10,293	10,409	9,887
NoReg/LowEnv Cost Future	CLE1S 8760	16,247	10,388	10,429	10,481	9,511
	CLE1S-01_Coal+20% 8760	14,587	10,031	10,014	10,097	9,371
	CLE1S-02_Coal-10% 8760	16,673	10,557	10,576	10,586	9,568
	CLE1S-05_Lower Gas-50% 8760	14,907	9,934	9,787	9,774	8,951
	CLE1S-06_Low Gas-25% 8760	15,486	10,463	10,339	10,218	9,325
	CLE1S-07_High Gas+25% 8760	16,686	10,645	10,461	10,657	9,619
	CLE1S-08_Higher Gas+50% 8760	16,832	10,739	10,651	10,756	9,764
	CLE1S-09_Highest Gas+100% 8760	16,349	10,447	10,363	10,452	9,447
	CLE1S-10_WHSL Mkt-50% 8760	11,139	8,699	8,733	8,692	7,974
	CLE1S-11_WHSL Mkt-25% 8760	14,626	9,984	9,978	9,930	9,021
	CLE1S-12_WHSL Mkt+25% 8760	17,149	10,935	10,874	11,002	9,898
	CLE1S-13_WHSL Mkt+50% 8760	17,328	10,849	10,814	10,923	9,799
	CLE1S-14_CapCosts-30% 8760	16,246	10,460	10,309	10,542	9,512
	CLE1S-15_CapCosts+30% 8760	16,244	10,543	10,468	10,466	9,510
	CLE1S-17_NoMktSales 8760	15,082	10,299	10,313	10,251	9,320
	CLE1S-18_NoSalePurchase 8760	17,117	11,678	11,604	11,466	10,467
	CLE1S-19_MktAccess-50% 8760	16,377	10,852	10,778	10,725	9,714
	CLE1S-20_LoINTCONCosts 8760	16,264	10,254	10,329	10,288	9,331
	CLE1S-21_ITC&PTC Extend 8760	16,231	10,452	10,500	10,466	9,512
	CLE1S-22_WindCostLow 8760	16,244	10,386	10,424	10,400	9,514
	CLE1S-23_WindCostHi 8760	16,268	10,393	10,530	10,490	9,516
	CLE1S-24_SolCostLow 8760	16,108	10,404	10,444	10,424	9,436

	CLE1S-25_SolCostHigh 8760	16,256	10,500	10,544	10,419	9,517
	CLE1S-26_StorCostLow 8760	16,238	10,381	10,420	10,494	9,518
	CLE1S-27_StorCostHigh 8760	16,258	10,384	10,421	10,488	9,508
	CLE1S-28_AFR 2020 Low 8760	15,418	10,085	10,056	10,099	9,123
	CLE1S-31_ResTOU 8760	16,235	10,458	10,335	10,482	9,514
	CLE1S-32_High DG&EV 8760	16,241	10,361	10,422	10,491	9,516
	CLE1S-33_RenewELCC-2.5% 8760	16,246	10,588	10,450	10,488	9,514
	CLE1S-34_RenewELCC+2.5% 8760	16,237	10,358	10,309	10,493	9,511
	CLE1S-35_PRM-2% 8760	16,251	10,464	10,332	10,487	9,516
	CLE1S-36_PRM+2% 8760	16,264	10,558	10,436	10,491	9,513
	CLER1S 8760	13,272	9,743	9,726	9,812	9,110
	CLER1S-01_Coal+20% 8760	11,767	9,536	9,536	9,596	8,966
	CLER1S-02_Coal-10% 8760	14,003	9,806	9,790	9,858	9,155
	CLER1S-05_Lower Gas-50% 8760	12,802	9,447	9,333	9,373	8,637
	CLER1S-06_Low Gas-25% 8760	12,881	9,837	9,761	9,757	8,996
	CLER1S-07_High Gas+25% 8760	13,442	10,020	9,941	10,016	9,287
	CLER1S-08_Higher Gas+50% 8760	13,695	10,241	10,151	10,240	9,526
	CLER1S-09_Highest Gas+100% 8760	13,445	9,983	9,901	9,976	9,272
	CLER1S-10_WHSL Mkt-50% 8760	9,403	8,306	8,314	8,341	7,820
	CLER1S-11_WHSL Mkt-25% 8760	12,024	9,324	9,423	9,403	8,730
	CLER1S-12_WHSL Mkt+25% 8760	13,843	10,180	10,213	10,221	9,473
	CLER1S-13_WHSL Mkt+50% 8760	13,993	10,197	10,139	10,108	9,357
	CLER1S-14_CapCosts-30% 8760	13,272	9,745	9,718	9,851	9,109
	CLER1S-15_CapCosts+30% 8760	13,275	9,770	9,719	9,770	9,110
	CLER1S-17_NoMktSales 8760	12,787	9,656	9,694	9,714	9,014
LowReg/LowEnv Cost Futures	CLER1S-18_NoSalePurchase 8760	14,480	10,981	10,975	10,972	10,110
	CLER1S-19_MktAccess-50% 8760	13,605	10,117	10,156	10,159	9,317
	CLER1S-20_LoINTCONCosts 8760	12,673	9,639	9,623	9,702	8,961
	CLER1S-21_ITC&PTC Extend 8760	13,078	9,726	9,706	9,782	9,070
	CLER1S-22_WindCostLow 8760	12,972	9,742	9,659	9,772	9,061
	CLER1S-23_WindCostHi 8760	13,305	9,758	9,728	9,815	9,115
	CLER1S-24_SolCostLow 8760	12,891	9,710	9,691	9,761	9,048
	CLER1S-25_SolCostHigh 8760	13,284	9,721	9,795	9,823	9,104
	CLER1S-26_StorCostLow 8760	13,260	9,744	9,721	9,811	9,107
	CLER1S-27_StorCostHigh 8760	13,277	9,741	9,721	9,809	9,108
	CLER1S-28_AFR 2020 Low 8760	12,583	9,370	9,357	9,435	8,748
	CLER1S-31_ResTOU 8760	13,265	9,744	9,729	9,808	9,108
	CLER1S-32_High DG&EV 8760	13,289	9,752	9,741	9,807	9,113
	CLER1S-33_RenewELCC-2.5% 8760	13,276	9,685	9,793	9,803	9,114
	CLER1S-34_RenewELCC+2.5% 8760	13,280	9,746	9,733	9,801	9,113
	CLER1S-35_PRM-2% 8760	13,288	9,749	9,728	9,807	9,108
	CLER1S-36_PRM+2% 8760	13,278	9,741	9,781	9,811	9,112
	CREF1S 8760	12,053	10,041	10,053	10,081	9,429
	CREF1S-01_Coal+20% 8760	11,371	9,882	9,789	9,928	9,330
	CREF1S-02_Coal-10% 8760	12,402	10,124	10,123	10,166	9,494
	CREF1S-05_Lower Gas-50% 8760	11,885	9,773	9,689	9,821	9,187
	CREF1S-06_Low Gas-25% 8760	11,988	9,962	9,903	10,082	9,481
	CREF1S-07_High Gas+25% 8760	12,503	10,299	10,301	10,326	9,708
	CREF1S-08_Higher Gas+50% 8760	12,951	10,535	10,515	10,571	9,953
	CREF1S-09_Highest Gas+100% 8760	12,939	10,389	10,352	10,423	9,740
	CREF1S-10_WHSL Mkt-50% 8760	9,032	8,381	8,428	8,494	8,082
	CREF1S-11_WHSL Mkt-25% 8760	10,585	9,431	9,448	9,511	9,010
	CREF1S-12_WHSL Mkt+25% 8760	13,172	10,596	10,548	10,597	9,904
	CREF1S-13_WHSL Mkt+50% 8760	13,543	10,644	10,539	10,559	9,827
	CREF1S-14_CapCosts-30% 8760	12,038	10,042	10,047	10,131	9,436
	CREF1S-15_CapCosts+30% 8760	12,051	10,017	9,951	9,956	9,431
	CREF1S-17_NoMktSales 8760	11,719	9,878	9,901	9,931	9,340
MidReg/MidEnv Cost Future	CREF1S-18_NoSalePurchase 8760	14,628	11,499	11,466	11,294	10,663
	CREF1S-19_MktAccess-50% 8760	12,818	10,601	10,440	10,397	9,735
	CREF1S-20_LoINTCONCosts 8760	11,811	9,978	9,979	10,021	9,387
	CREF1S-21_ITC&PTC Extend 8760	11,917	10,017	10,019	10,068	9,423

	CREF1S-22_WindCostLow 8760	11,829	9,997	9,970	10,026	9,413
	CREF1S-23_WindCostHi 8760	12,056	10,040	10,053	10,097	9,440
	CREF1S-24_SolCostLow 8760	11,898	10,006	10,005	10,039	9,395
	CREF1S-25_SolCostHigh 8760	12,266	10,049	10,073	10,097	9,435
	CREF1S-26_StorCostLow 8760	12,043	10,034	10,049	10,078	9,428
	CREF1S-27_StorCostHigh 8760	12,045	10,031	10,046	10,084	9,429
	CREF1S-28_AFR 2020 Low 8760	11,354	9,637	9,638	9,682	9,069
	CREF1S-31_ResTOU 8760	11,952	10,035	10,047	10,077	9,429
	CREF1S-32_High DG&EV 8760	12,055	10,050	10,046	10,081	9,429
	CREF1S-33_RenewELCC-2.5% 8760	12,038	10,044	10,066	10,081	9,432
	CREF1S-34_RenewELCC+2.5% 8760	12,043	10,033	10,045	10,083	9,428
	CREF1S-35_PRM-2% 8760	12,049	10,042	10,043	10,080	9,432
	CREF1S-36_PRM+2% 8760	12,043	10,039	10,058	10,079	9,433

Attachment 6. Department's forecast/NTEC study results (revenue requirement + externalities in $000 in $2021) for each for each Boswell retirement scenario, per contingency and cost future, with least-cost results of each contingency within each forecast/NTEC case indicated by shading

		MidAFR/NTEC50					MidAFR/NTEC20					HighAFR/NTEC50					HighAFR/NTEC20				
Cost Future	Contigency	StatusQuo	PrefPlan	Early3	Early4	FastExit	StatusQuo	PrefPlan	Early3	Early4	FastExit	StatusQuo	PrefPlan	Early3	Early4	FastExit	StatusQuo	PrefPlan	Early3	Early4	FastExit
	CCUST1S 8760	7,450	7,644	7,692	7,731	7,370	7,280	7,507	7,541	7,514	7,195	7,450	7,634	7,692	7,731	7,370	7,280	7,508	7,541	7,621	7,195
	CCUST1S-01_Coal+20% 8760	7,707	7,850	7,882	7,940	7,472	7,587	7,728	7,760	7,692	7,317	7,707	7,850	7,882	7,940	7,471	7,587	7,728	7,759	7,846	7,317
	CCUST1S-02_Coal-10% 8760	7,303	7,524	7,563	7,619	7,304	7,125	7,377	7,433	7,403	7,122	7,303	7,528	7,563	7,619	7,304	7,125	7,377	7,433	7,526	7,122
	CCUST1S-05_Lower Gas-50% 8760	7,206	7,250	7,226	7,322	6,731	7,162	7,202	7,176	7,236	6,597	7,206	7,250	7,226	7,322	6,731	7,162	7,202	7,176	7,235	6,597
	CCUST1S-06_Low Gas-25% 8760	7,383	7,517	7,527	7,627	7,107	7,266	7,413	7,425	7,487	6,945	7,383	7,517	7,527	7,627	7,107	7,266	7,413	7,425	7,487	6,945
	CCUST1S-07_High Gas+25% 8760	7,601	7,818	7,884	7,945	7,728	7,405	7,680	7,742	7,633	7,550	7,601	7,818	7,884	7,945	7,728	7,405	7,680	7,742	7,795	7,550
	CCUST1S-08_Higher Gas+50% 8760	7,648	7,897	7,948	8,037	7,902	7,456	7,739	7,799	7,693	7,711	7,648	7,897	7,948	8,037	7,902	7,456	7,739	7,799	7,852	7,711
	CCUST1S-09_Highest Gas+100% 8760	7,829	8,094	8,151	8,243	8,230	7,618	7,934	7,990	7,860	8,031	7,829	8,094	8,151	8,243	8,230	7,618	7,934	7,990	8,039	8,031
	CCUST1S-10_WHSL Mkt-50% 8760	7,255	7,335	7,391	7,421	7,093	7,056	7,176	7,198	7,107	6,903	7,255	7,335	7,391	7,421	7,093	7,055	7,176	7,198	7,250	6,903
	CCUST1S-11_WHSL Mkt-25% 8760	7,475	7,591	7,649	7,690	7,361	7,287	7,448	7,481	7,446	7,186	7,475	7,591	7,649	7,690	7,361	7,286	7,448	7,481	7,563	7,186
	CCUST1S-12_WHSL Mkt+25% 8760	7,493	7,713	7,742	7,839	7,410	7,361	7,600	7,637	7,625	7,266	7,493	7,713	7,742	7,839	7,410	7,361	7,600	7,637	7,689	7,266
	CCUST1S-13_WHSL Mkt+50% 8760	7,464	7,706	7,721	7,809	7,375	7,359	7,602	7,652	7,671	7,231	7,463	7,706	7,721	7,809	7,375	7,359	7,602	7,652	7,672	7,231
	CCUST1S-14_CapCosts-30% 8760	7,448	7,590	7,603	7,677	7,367	7,280	7,454	7,474	7,493	7,189	7,448	7,589	7,603	7,677	7,367	7,280	7,454	7,474	7,500	7,189
	CCUST1S-15_CapCosts+30% 8760	7,449	7,639	7,698	7,775	7,368	7,282	7,557	7,612	7,493	7,187	7,449	7,638	7,697	7,775	7,368	7,282	7,557	7,612	7,673	7,187
	CCUST1S-17_NoMktSales 8760	7,592	7,721	7,774	7,833	7,485	7,409	7,584	7,621	7,613	7,323	7,592	7,721	7,774	7,833	7,485	7,409	7,584	7,621	7,752	7,323
NoReg/NoEnv Cost Future	CCUST1S-18_NoSalePurchase 8760	8,291	8,455	8,520	8,546	8,113	8,509	8,667	8,758	8,656	8,153	8,291	8,455	8,520	8,546	8,113	8,525	8,667	8,758	8,669	8,153
	CCUST1S-19_MktAccess-50% 8760	7,609	7,801	7,829	7,887	7,533	7,512	7,752	7,790	7,801	7,402	7,609	7,801	7,829	7,887	7,533	7,512	7,752	7,790	7,835	7,402
	CCUST1S-20_LoINTCONCosts 8760	7,449	7,631	7,674	7,728	7,383	7,286	7,503	7,538	7,481	7,201	7,449	7,631	7,674	7,728	7,383	7,286	7,503	7,538	7,635	7,201
	CCUST1S-21_ITC&PTC Extend 8760	7,448	7,626	7,677	7,732	7,366	7,288	7,508	7,546	7,491	7,195	7,448	7,626	7,677	7,732	7,366	7,287	7,508	7,546	7,627	7,195
	CCUST1S-22_WindCostLow 8760	7,448	7,640	7,692	7,732	7,370	7,279	7,509	7,564	7,487	7,204	7,448	7,640	7,692	7,732	7,370	7,279	7,509	7,564	7,638	7,204
	CCUST1S-23_WindCostHi 8760	7,451	7,642	7,674	7,729	7,367	7,285	7,510	7,549	7,512	7,188	7,451	7,654	7,674	7,729	7,367	7,285	7,510	7,549	7,640	7,188
	CCUST1S-24_SolCostLow 8760	7,456	7,616	7,673	7,718	7,385	7,288	7,514	7,548	7,484	7,205	7,456	7,616	7,673	7,718	7,385	7,288	7,514	7,548	7,643	7,205
	CCUST1S-25_SolCostHigh 8760	7,450	7,651	7,662	7,726	7,367	7,281	7,505	7,540	7,486	7,192	7,450	7,651	7,662	7,726	7,366	7,281	7,505	7,540	7,638	7,192
	CCUST1S-26_StorCostLow 8760	7,448	7,638	7,693	7,732	7,368	7,279	7,506	7,548	7,514	7,191	7,448	7,633	7,693	7,732	7,368	7,279	7,507	7,548	7,654	7,191
	CCUST1S-27_StorCostHigh 8760	7,446	7,640	7,695	7,732	7,368	7,284	7,507	7,543	7,514	7,194	7,446	7,634	7,695	7,732	7,368	7,284	7,508	7,543	7,651	7,194
	CCUST1S-28_AFR 2020 Low 8760	7,260	7,384	7,418	7,514	7,180	7,076	7,283	7,310	7,227	6,988	7,260	7,384	7,418	7,514	7,180	7,076	7,283	7,310	7,388	6,988
	CCUST1S-31_ResTOU 8760	7,449	7,626	7,669	7,730	7,364	7,275	7,508	7,544	7,477	7,185	7,449	7,626	7,669	7,730	7,364	7,275	7,508	7,544	7,640	7,185
	CCUST1S-32_High DG&EV 8760	7,452	7,647	7,695	7,734	7,366	7,282	7,510	7,546	7,490	7,195	7,452	7,647	7,695	7,734	7,366	7,282	7,510	7,546	7,640	7,195
	CCUST1S-33_RenewELCC-2.5% 8760	7,452	7,645	7,681	7,729	7,368	7,280	7,513	7,544	7,524	7,208	7,452	7,645	7,681	7,729	7,368	7,280	7,513	7,544	7,624	7,208
	CCUST1S-34_RenewELCC+2.5% 8760	7,448	7,641	7,690	7,730	7,369	7,280	7,513	7,546	7,481	7,194	7,448	7,641	7,690	7,730	7,369	7,280	7,513	7,546	7,638	7,194
	CCUST1S-35_PRM-2% 8760	7,448	7,625	7,672	7,729	7,366	7,281	7,504	7,546	7,482	7,188	7,448	7,625	7,672	7,729	7,366	7,281	7,504	7,546	7,637	7,188
	CCUST1S-36_PRM+2% 8760	7,450	7,657	7,684	7,729	7,366	7,285	7,507	7,557	7,518	7,234	7,450	7,657	7,684	7,729	7,366	7,285	7,507	7,556	7,658	7,234
	CHE1S 8760	25,174	13,242	13,294	13,334	11,724	14,461	13,459	13,277	12,391	11,671	14,383	13,711	13,295	13,337	11,724	14,460	13,455	13,276	13,461	11,671
	CHE1S-01_Coal+20% 8760	21,712	12,347	12,308	12,390	11,373	13,233	12,830	12,583	12,046	11,221	13,224	12,345	12,308	12,391	11,373	13,236	12,829	12,584	12,359	11,222
	CHE1S-02_Coal-10% 8760	26,180	13,690	13,735	13,648	11,899	14,682	13,823	13,424	12,733	11,777	14,775	13,926	13,735	13,648	11,899	14,682	13,824	13,425	13,692	11,776
	CHE1S-05_Lower Gas-50% 8760	22,683	12,740	12,497	12,222	11,182	14,200	13,282	12,949	11,924	11,255	13,479	12,737	12,495	12,221	11,182	14,199	13,280	12,948	12,665	11,256
	CHE1S-06_Low Gas-25% 8760	23,558	13,453	13,219	12,740	11,514	14,407	13,760	13,456	13,085	11,563	13,900	13,451	13,218	12,738	11,513	14,407	13,759	13,458	13,087	11,562
	CHE1S-07_High Gas+25% 8760	25,904	13,584	13,159	13,452	11,629	14,669	13,522	13,122	12,708	11,438	14,859	13,583	13,160	13,451	11,628	14,669	13,522	13,122	13,030	11,438
	CHE1S-08_Higher Gas+50% 8760	26,075	13,556	13,359	13,421	11,622	14,750	13,471	13,244	12,725	11,398	15,059	13,556	13,359	13,421	11,622	14,751	13,470	13,244	13,142	11,398
	CHE1S-09_Highest Gas+100% 8760	25,394	13,237	13,024	13,063	11,112	14,457	13,110	12,890	12,428	10,968	14,694	13,238	13,024	13,061	11,112	14,459	13,110	12,889	12,837	10,968
	CHE1S-10_WHSL Mkt-50% 8760	15,128	10,094	10,111	9,973	8,904	10,398	10,213	10,190	9,872	8,890	10,280	10,097	10,115	9,968	8,904	10,397	10,215	10,191	10,078	8,890
	CHE1S-11_WHSL Mkt-25% 8760	21,796	12,383	12,343	12,173	10,697	13,100	12,476	12,338	11,704	10,630	13,013	12,383	12,344	12,174	10,697	13,101	12,475	12,336	12,173	10,631
	CHE1S-12_WHSL Mkt+25% 8760	26,851	14,241	14,104	14,155	12,413	15,258	14,250	14,040	13,609	12,164	15,206	14,239	14,106	14,153	12,413	15,261	14,250	14,040	13,999	12,165
	CHE1S-13_WHSL Mkt+50% 8760	27,463	14,323	14,253	14,260	12,479	15,093	14,425	13,944	14,126	12,262	15,372	14,323	14,252	14,259	12,479	15,094	14,425	13,945	14,124	12,263
	CHE1S-14_CapCosts-30% 8760	25,156	13,403	13,046	13,407	11,730	14,458	13,520	13,353	12,586	11,670	14,379	13,402	13,045	13,406	11,731	14,457	13,520	13,353	13,161	11,670
	CHE1S-15_CapCosts+30% 8760	25,155	13,622	13,461	13,298	11,740	14,470	13,422	13,224	12,770	11,675	14,380	13,623	13,460	13,300	11,740	14,471	13,421	13,224	13,359	11,676
	CHE1S-17_NoMktSales 8760	22,659	12,982	12,974	12,749	11,232	13,627	13,144	13,001	12,219	11,210	13,487	12,983	12,972	12,748	11,232	13,627	13,146	13,000	12,820	11,209
NoReg/HighEnv Cost Future	CHE1S-18_NoSalePurchase 8760	26,009	15,026	14,944	14,447	12,895	15,822	15,141	15,077	14,786	12,833	15,468	15,025	14,943	14,446	12,895	16,063	15,141	15,076	14,870	12,832
	CHE1S-19_MktAccess-50% 8760	25,216	14,031	13,854	13,676	12,004	14,859	13,893	13,737	13,246	12,034	14,599	14,031	13,855	13,677	12,004	14,860	13,893	13,737	13,805	12,034
	CHE1S-20_LoINTCONCosts 8760	25,164	12,990	13,100	12,942	11,400	14,147	13,203	13,032	12,312	11,342	14,382	12,989	13,100	12,941	11,400	14,148	13,201	13,033	13,017	11,342
	CHE1S-21_ITC&PTC Extend 8760	25,171	13,396	13,467	13,301	11,732	14,387	13,433	13,220	12,553	11,646	14,386	13,398	13,467	13,302	11,732	14,387	13,433	13,221	13,439	11,646
	CHE1S-22_WindCostLow 8760	25,152	13,228	13,274	13,175	11,728	14,466	13,453	13,050	12,516	11,509	14,384	13,230	13,274	13,176	11,728	14,467	13,453	13,050	13,410	11,509
	CHE1S-23_WindCostHi 8760	25,167	13,254	13,541	13,353	11,727	14,458	13,461	13,297	12,568	11,671	14,388	13,175	13,544	13,353	11,728	14,457	13,461	13,299	13,405	11,670
	CHE1S-24_SolCostLow 8760	24,853	13,303	13,358	13,225	11,612	14,273	13,297	13,107	12,478	11,594	14,303	13,301	13,356	13,223	11,612	14,271	13,298	13,107	13,331	11,593
	CHE1S-25_SolCostHigh 8760	25,140	13,477	13,579	13,219	11,732	14,452	13,511	13,321	12,620	11,674	14,375	13,477	13,578	13,220	11,733	14,454	13,511	13,322	13,257	11,674
	CHE1S-26_StorCostLow 8760	25,137	13,247	13,290	13,339	11,720	14,446	13,458	13,285	12,554	11,667	14,371	13,699	13,289	13,339	11,721	14,444	13,455	13,285	13,194	11,668
	CHE1S-27_StorCostHigh 8760	25,186	13,249	13,294	13,346	11,735	14,459	13,467	13,271	12,399	11,677	14,387	13,714	13,292	13,345	11,735	14,461	13,461	13,271	13,201	11,677
	CHE1S-28_AFR 2020 Low 8760	23,695	12,909	12,810	12,773	11,178	13,776	13,099	12,910	12,188	11,152	13,666	12,909	12,810	12,773	11,178	13,776	13,099	12,910	12,570	11,152
	CHE1S-31_ResTOU 8760	25,161	13,413	13,119	13,352	11,725	14,450	13,466	13,274	12,568	11,667	14,374	13,413	13,119	13,353	11,725	14,450	13,466	13,274	13,402	11,667
	CHE1S-32_High DG&EV 8760	25,158	13,188	13,295	13,352	11,728	14,460	13,472	13,275	12,580	11,669	14,376	13,188	13,295	13,352	11,728	14,460	13,472	13,275	13,407	11,669

	CHE1S-33_RenewELCC-2.5% 8760	25,154	13,655	13,357	13,349	11,728	14,458	13,478	13,284	12,402	11,510	14,377	13,655	13,358	13,348	11,728	14,460	13,478	13,283	13,469	11,511
	CHE1S-34_RenewELCC+2.5% 8760	25,140	13,177	13,063	13,342	11,726	14,465	13,471	13,281	12,572	11,669	14,370	13,179	13,063	13,344	11,726	14,464	13,472	13,281	13,241	11,669
	CHE1S-35_PRM-2% 8760	25,159	13,404	13,139	13,355	11,737	14,460	13,461	13,282	12,607	11,670	14,383	13,405	13,139	13,355	11,737	14,461	13,461	13,284	13,416	11,670
	CHE1S-36_PRM+2% 8760	25,160	13,591	13,326	13,352	11,738	14,467	13,489	13,076	12,387	11,362	14,380	13,590	13,325	13,353	11,738	14,467	13,490	13,076	13,203	11,362
	CHER1S 8760	11,656	10,351	10,303	10,400	9,882	10,436	10,387	10,288	10,442	9,809	10,342	10,350	10,293	10,399	9,878	10,471	10,385	10,295	10,431	9,809
	CHER1S-01_Coal+20% 8760	11,172	10,145	10,108	10,192	9,752	10,220	10,151	10,062	10,300	9,667	10,126	10,144	10,098	10,192	9,740	10,225	10,150	10,071	10,294	9,666
	CHER1S-02_Coal-10% 8760	11,898	10,461	10,452	10,510	9,939	10,562	10,493	10,402	10,529	9,886	10,441	10,475	10,451	10,510	9,949	10,567	10,492	10,390	10,526	9,886
	CHER1S-05_Lower Gas-50% 8760	11,668	10,124	10,059	10,282	9,726	10,366	10,220	10,089	10,255	9,562	10,198	10,124	10,076	10,282	9,722	10,365	10,220	10,075	10,257	9,562
	CHER1S-06_Low Gas-25% 8760	11,665	10,329	10,272	10,472	9,871	10,514	10,387	10,278	10,450	9,787	10,355	10,329	10,272	10,472	9,876	10,524	10,388	10,273	10,463	9,787
	CHER1S-07_High Gas+25% 8760	11,873	10,584	10,577	10,659	10,122	10,663	10,591	10,541	10,650	10,021	10,577	10,584	10,575	10,659	10,143	10,629	10,592	10,547	10,642	10,021
	CHER1S-08_Higher Gas+50% 8760	12,147	10,822	10,813	10,853	10,333	10,786	10,740	10,754	10,788	10,227	10,779	10,823	10,825	10,852	10,334	10,788	10,740	10,753	10,790	10,227
	CHER1S-09_Highest Gas+100% 8760	12,413	10,709	10,687	10,695	10,158	10,606	10,533	10,559	10,556	9,996	10,718	10,709	10,684	10,695	10,157	10,614	10,533	10,556	10,562	9,996
	CHER1S-10_WHSL Mkt-50% 8760	9,182	8,650	8,700	8,746	8,359	8,701	8,643	8,577	8,710	8,230	8,643	8,650	8,692	8,747	8,366	8,700	8,643	8,587	8,697	8,212
	CHER1S-11_WHSL Mkt-25% 8760	10,441	9,692	9,718	9,766	9,374	9,740	9,668	9,601	9,747	9,227	9,664	9,692	9,716	9,766	9,382	9,742	9,668	9,599	9,743	9,228
	CHER1S-12_WHSL Mkt+25% 8760	12,843	11,029	10,983	11,054	10,446	11,171	11,057	10,961	11,052	10,356	11,034	11,029	10,941	11,055	10,443	11,165	11,059	10,960	11,052	10,356
	CHER1S-13_WHSL Mkt+50% 8760	13,281	11,076	10,980	11,056	10,414	11,305	11,156	11,065	11,116	10,347	11,129	11,077	10,979	11,055	10,422	11,310	11,156	11,065	11,117	10,347
	CHER1S-14_CapCosts-30% 8760	11,658	10,360	10,377	10,447	9,883	10,431	10,391	10,328	10,453	9,808	10,345	10,359	10,364	10,448	9,883	10,457	10,391	10,333	10,459	9,808
	CHER1S-15_CapCosts+30% 8760	11,670	10,299	10,237	10,355	9,880	10,438	10,343	10,228	10,338	9,812	10,346	10,298	10,232	10,354	9,882	10,469	10,342	10,227	10,337	9,813
	CHER1S-17_NoMktSales 8760	11,386	10,237	10,153	10,265	9,739	10,269	10,261	10,178	10,301	9,640	10,195	10,237	10,159	10,265	9,742	10,262	10,260	10,171	10,296	9,639
HighReg/HighEnv Cost Future	CHER1S-18_NoSalePurchase 8760	14,418	12,046	11,966	11,910	11,186	12,520	12,211	12,188	12,158	11,292	12,092	12,045	11,983	11,910	11,240	12,455	12,211	12,171	12,141	11,292
	CHER1S-19_MktAccess-50% 8760	12,762	10,872	10,786	10,912	10,242	11,220	11,119	11,024	10,977	10,308	10,956	10,872	10,783	10,911	10,238	11,215	11,120	11,020	10,966	10,308
	CHER1S-20_LoINTCONCosts 8760	11,441	10,303	10,207	10,328	9,823	10,373	10,280	10,220	10,354	9,707	10,245	10,301	10,216	10,329	9,826	10,374	10,281	10,223	10,358	9,707
	CHER1S-21_ITC&PTC Extend 8760	11,647	10,320	10,280	10,371	9,865	10,462	10,365	10,261	10,424	9,779	10,327	10,321	10,279	10,371	9,853	10,454	10,364	10,270	10,417	9,779
	CHER1S-22_WindCostLow 8760	11,441	10,285	10,241	10,344	9,841	10,382	10,315	10,228	10,416	9,786	10,268	10,286	10,246	10,344	9,845	10,372	10,314	10,236	10,429	9,786
	CHER1S-23_WindCostHi 8760	11,628	10,371	10,309	10,414	9,884	10,443	10,401	10,303	10,447	9,809	10,331	10,369	10,310	10,414	9,881	10,453	10,401	10,300	10,454	9,809
	CHER1S-24_SolCostLow 8760	11,556	10,318	10,254	10,366	9,852	10,423	10,344	10,257	10,412	9,782	10,293	10,318	10,252	10,366	9,850	10,414	10,342	10,257	10,413	9,782
	CHER1S-25_SolCostHigh 8760	11,736	10,366	10,359	10,485	9,885	10,419	10,360	10,263	10,439	9,818	10,354	10,365	10,363	10,485	9,888	10,426	10,360	10,266	10,443	9,818
	CHER1S-26_StorCostLow 8760	11,655	10,350	10,292	10,405	9,875	10,432	10,382	10,294	10,431	9,821	10,341	10,350	10,298	10,406	9,883	10,456	10,381	10,287	10,436	9,821
	CHER1S-27_StorCostHigh 8760	11,673	10,362	10,300	10,412	9,884	10,434	10,389	10,294	10,443	9,811	10,344	10,363	10,299	10,412	9,876	10,469	10,388	10,293	10,435	9,811
	CHER1S-28_AFR 2020 Low 8760	10,989	9,930	9,914	9,969	9,478	9,973	9,925	9,839	10,015	9,357	9,888	9,930	9,919	9,969	9,481	9,978	9,925	9,833	10,016	9,357
	CHER1S-31_ResTOU 8760	11,652	10,346	10,291	10,398	9,862	10,470	10,383	10,294	10,441	9,806	10,343	10,346	10,297	10,398	9,877	10,461	10,383	10,291	10,441	9,806
	CHER1S-32_High DG&EV 8760	11,684	10,354	10,306	10,382	9,882	10,468	10,396	10,295	10,450	9,818	10,355	10,354	10,297	10,383	9,878	10,468	10,396	10,302	10,443	9,818
	CHER1S-33_RenewELCC-2.5% 8760	11,666	10,323	10,292	10,405	9,870	10,430	10,391	10,301	10,427	9,813	10,349	10,325	10,311	10,405	9,889	10,473	10,391	10,298	10,442	9,812
	CHER1S-34_RenewELCC+2.5% 8760	11,648	10,350	10,294	10,407	9,879	10,443	10,389	10,285	10,434	9,815	10,344	10,351	10,297	10,407	9,892	10,473	10,391	10,289	10,438	9,814
	CHER1S-35_PRM-2% 8760	11,671	10,366	10,303	10,399	9,881	10,437	10,398	10,298	10,439	9,806	10,336	10,365	10,294	10,399	9,879	10,466	10,398	10,294	10,433	9,806
	CHER1S-36_PRM+2% 8760	11,660	10,327	10,293	10,409	9,887	10,437	10,387	10,303	10,432	9,817	10,347	10,326	10,291	10,409	9,879	10,469	10,385	10,289	10,444	9,817
	CLE1S 8760	16,247	10,388	10,429	10,481	9,511	10,827	10,415	10,326	9,896	9,385	10,889	10,611	10,429	10,481	9,511	10,826	10,413	10,326	10,516	9,385
	CLE1S-01_Coal+20% 8760	14,587	10,031	10,014	10,097	9,371	10,347	10,180	10,073	9,801	9,213	10,407	10,031	10,014	10,097	9,370	10,348	10,180	10,075	10,046	9,213
	CLE1S-02_Coal-10% 8760	16,673	10,557	10,576	10,586	9,568	10,870	10,524	10,339	10,023	9,403	11,011	10,670	10,577	10,586	9,567	10,869	10,438	10,339	10,586	9,403
	CLE1S-05_Lower Gas-50% 8760	14,907	9,934	9,787	9,774	8,951	10,666	10,170	9,985	9,582	8,913	10,333	9,935	9,788	9,773	8,951	10,667	10,171	9,985	9,941	8,913
	CLE1S-06_Low Gas-25% 8760	15,486	10,463	10,339	10,218	9,325	10,840	10,550	10,385	10,310	9,257	10,665	10,462	10,340	10,218	9,325	10,841	10,549	10,385	10,310	9,258
	CLE1S-07_High Gas+25% 8760	16,686	10,645	10,461	10,657	9,619	11,008	10,538	10,364	10,136	9,424	11,207	10,645	10,460	10,658	9,619	11,008	10,537	10,364	10,369	9,424
	CLE1S-08_Higher Gas+50% 8760	16,832	10,739	10,651	10,756	9,764	11,141	10,605	10,510	10,238	9,546	11,388	10,739	10,652	10,756	9,764	11,141	10,605	10,509	10,528	9,546
	CLE1S-09_Highest Gas+100% 8760	16,349	10,447	10,363	10,452	9,447	10,855	10,304	10,215	9,940	9,269	11,072	10,447	10,363	10,452	9,447	10,855	10,303	10,215	10,236	9,269
	CLE1S-10_WHSL Mkt-50% 8760	11,139	8,699	8,733	8,692	7,974	8,717	8,677	8,664	8,473	7,874	8,745	8,697	8,732	8,691	7,974	8,717	8,677	8,664	8,653	7,874
	CLE1S-11_WHSL Mkt-25% 8760	14,626	9,984	9,978	9,930	9,021	10,188	9,932	9,869	9,566	8,889	10,252	9,983	9,978	9,929	9,021	10,190	9,933	9,868	9,859	8,889
	CLE1S-12_WHSL Mkt+25% 8760	17,149	10,935	10,874	11,002	9,898	11,294	10,869	10,765	10,756	9,689	11,354	10,935	10,875	11,001	9,899	11,294	10,869	10,764	10,836	9,689
	CLE1S-13_WHSL Mkt+50% 8760	17,328	10,849	10,814	10,923	9,799	11,097	10,835	10,601	10,772	9,614	11,305	10,849	10,813	10,924	9,799	11,097	10,835	10,601	10,772	9,614
	CLE1S-14_CapCosts-30% 8760	16,246	10,460	10,309	10,542	9,512	10,823	10,462	10,391	10,264	9,385	10,887	10,460	10,309	10,542	9,512	10,823	10,462	10,391	10,358	9,384
	CLE1S-15_CapCosts+30% 8760	16,244	10,543	10,468	10,466	9,510	10,832	10,365	10,262	10,068	9,386	10,884	10,543	10,468	10,464	9,510	10,832	10,364	10,263	10,390	9,386
	CLE1S-17_NoMktSales 8760	15,082	10,299	10,313	10,251	9,320	10,485	10,291	10,226	9,870	9,226	10,518	10,299	10,313	10,251	9,320	10,485	10,292	10,226	10,269	9,226
NoReg/LowEnv Cost Future	CLE1S-18_NoSalePurchase 8760	17,117	11,678	11,604	11,466	10,467	12,129	11,835	11,829	11,618	10,474	11,880	11,678	11,604	11,467	10,467	12,256	11,835	11,829	11,748	10,473
	CLE1S-19_MktAccess-50% 8760	16,377	10,852	10,778	10,725	9,714	11,174	10,736	10,680	10,447	9,669	11,089	10,852	10,778	10,725	9,714	11,174	10,736	10,681	10,782	9,669
	CLE1S-20_LoINTCONCosts 8760	16,264	10,254	10,329	10,288	9,331	10,683	10,277	10,205	9,847	9,221	10,891	10,254	10,328	10,288	9,331	10,683	10,276	10,206	10,291	9,222
	CLE1S-21_ITC&PTC Extend 8760	16,231	10,452	10,500	10,466	9,512	10,794	10,391	10,292	9,890	9,376	10,882	10,452	10,499	10,467	9,511	10,793	10,392	10,292	10,501	9,376
	CLE1S-22_WindCostLow 8760	16,244	10,386	10,424	10,400	9,514	10,828	10,397	10,221	9,951	9,314	10,887	10,386	10,424	10,400	9,515	10,828	10,396	10,222	10,492	9,314
	CLE1S-23_WindCostHi 8760	16,268	10,393	10,530	10,490	9,516	10,837	10,406	10,325	9,993	9,386	10,896	10,359	10,530	10,490	9,516	10,836	10,407	10,325	10,492	9,385
	CLE1S-24_SolCostLow 8760	16,108	10,404	10,444	10,424	9,436	10,749	10,325	10,242	9,929	9,352	10,854	10,404	10,444	10,424	9,436	10,751	10,400	10,242	10,452	9,353
	CLE1S-25_SolCostHigh 8760	16,256	10,500	10,544	10,419	9,517	10,828	10,432	10,337	10,050	9,389	10,891	10,500	10,543	10,417	9,516	10,828	10,432	10,337	10,417	9,389
	CLE1S-26_StorCostLow 8760	16,238	10,381	10,420	10,494	9,518	10,826	10,413	10,322	9,912	9,382	10,882	10,615	10,420	10,495	9,517	10,827	10,411	10,322	10,408	9,382
	CLE1S-27_StorCostHigh 8760	16,258	10,384	10,421	10,488	9,508	10,825	10,409	10,322	9,902	9,387	10,889	10,605	10,421	10,488	9,508	10,826	10,406	10,322	10,404	9,387
	CLE1S-28_AFR 2020 Low 8760	15,418	10,085	10,056	10,099	9,123	10,384	10,114	10,027	9,645	9,023	10,436	10,085	10,056	10,100	9,123	10,384	10,007	10,027	9,921	9,023

	CLE1S-31_ResTOU 8760	16,235	10,458	10,335	10,482	9,514	10,821	10,404	10,320	9,976	9,377	10,882	10,458	10,335	10,482	9,514	10,821	10,404	10,320	10,491	9,377
	CLE1S-32_High DG&EV 8760	16,241	10,361	10,422	10,491	9,516	10,826	10,409	10,323	9,991	9,386	10,887	10,361	10,422	10,491	9,516	10,826	10,409	10,323	10,495	9,386
	CLE1S-33_RenewELCC-2.5% 8760	16,246	10,588	10,450	10,488	9,514	10,834	10,417	10,328	9,912	9,314	10,883	10,588	10,450	10,488	9,514	10,834	10,414	10,328	10,509	9,314
	CLE1S-34_RenewELCC+2.5% 8760	16,237	10,358	10,309	10,493	9,511	10,825	10,410	10,328	9,984	9,382	10,884	10,358	10,310	10,493	9,511	10,825	10,410	10,328	10,417	9,382
	CLE1S-35_PRM-2% 8760	16,251	10,464	10,332	10,487	9,516	10,825	10,407	10,324	9,985	9,384	10,892	10,464	10,332	10,488	9,516	10,825	10,408	10,323	10,491	9,384
	CLE1S-36_PRM+2% 8760	16,264	10,558	10,436	10,491	9,513	10,828	10,415	10,229	9,911	9,247	10,893	10,558	10,437	10,490	9,513	10,827	10,416	10,230	10,405	9,246
LowReg/LowEnv Cost Futures	CLER1S 8760	13,272	9,743	9,726	9,812	9,110	9,902	9,778	9,727	9,764	8,945	10,012	9,743	9,730	9,812	9,114	9,900	9,783	9,726	9,760	8,945
	CLER1S-01_Coal+20% 8760	11,767	9,536	9,536	9,596	8,966	9,700	9,593	9,503	9,605	8,855	9,611	9,536	9,538	9,595	8,962	9,699	9,592	9,505	9,605	8,855
	CLER1S-02_Coal-10% 8760	14,003	9,806	9,790	9,858	9,155	10,033	9,804	9,754	9,917	9,022	10,211	9,803	9,794	9,858	9,160	10,034	9,805	9,756	9,913	9,022
	CLER1S-05_Lower Gas-50% 8760	12,802	9,447	9,333	9,373	8,637	9,884	9,523	9,364	9,486	8,570	9,729	9,446	9,332	9,373	8,633	9,881	9,523	9,362	9,483	8,570
	CLER1S-06_Low Gas-25% 8760	12,881	9,837	9,761	9,757	8,996	9,931	9,746	9,691	9,798	8,909	9,910	9,837	9,744	9,756	9,000	9,928	9,746	9,686	9,799	8,909
	CLER1S-07_High Gas+25% 8760	13,442	10,020	9,941	10,016	9,287	10,104	9,956	9,920	9,869	9,130	10,236	10,020	9,936	10,016	9,282	10,106	9,957	9,913	9,869	9,129
	CLER1S-08_Higher Gas+50% 8760	13,695	10,241	10,151	10,240	9,526	10,269	10,058	10,018	10,031	9,317	10,464	10,242	10,149	10,240	9,524	10,270	10,058	10,020	10,030	9,317
	CLER1S-09_Highest Gas+100% 8760	13,445	9,983	9,901	9,976	9,272	9,990	9,799	9,758	9,760	9,092	10,210	9,983	9,901	9,975	9,276	9,991	9,798	9,756	9,763	9,092
	CLER1S-10_WHSL Mkt-50% 8760	9,403	8,306	8,314	8,341	7,820	8,233	8,289	8,273	8,289	7,706	8,252	8,306	8,314	8,340	7,818	8,231	8,288	8,272	8,293	7,706
	CLER1S-11_WHSL Mkt-25% 8760	12,024	9,324	9,423	9,403	8,730	9,483	9,327	9,278	9,304	8,562	9,489	9,324	9,415	9,403	8,729	9,484	9,327	9,281	9,304	8,562
	CLER1S-12_WHSL Mkt+25% 8760	13,843	10,180	10,213	10,221	9,473	10,366	10,229	10,155	10,190	9,312	10,369	10,180	10,218	10,222	9,475	10,370	10,229	10,151	10,194	9,312
	CLER1S-13_WHSL Mkt+50% 8760	13,993	10,197	10,139	10,108	9,357	10,321	10,184	10,097	10,103	9,192	10,300	10,197	10,138	10,107	9,358	10,324	10,184	10,097	10,096	9,192
	CLER1S-14_CapCosts-30% 8760	13,272	9,745	9,718	9,851	9,109	9,894	9,678	9,787	9,792	8,945	10,014	9,745	9,715	9,851	9,105	9,901	9,687	9,783	9,791	8,946
	CLER1S-15_CapCosts+30% 8760	13,275	9,770	9,719	9,770	9,110	9,894	9,731	9,658	9,652	8,947	10,017	9,770	9,714	9,771	9,116	9,896	9,731	9,658	9,647	8,947
	CLER1S-17_NoMktSales 8760	12,787	9,656	9,694	9,714	9,014	9,781	9,706	9,653	9,611	8,892	9,862	9,656	9,698	9,714	9,010	9,785	9,706	9,658	9,613	8,891
	CLER1S-18_NoSalePurchase 8760	14,480	10,981	10,975	10,972	10,110	11,387	11,367	11,133	11,068	10,160	11,052	10,981	10,977	10,971	10,076	11,365	11,368	11,202	11,091	10,160
	CLER1S-19_MktAccess-50% 8760	13,605	10,117	10,156	10,159	9,317	10,383	10,134	10,102	10,148	9,292	10,264	10,117	10,178	10,159	9,331	10,376	10,134	10,095	10,136	9,292
	CLER1S-20_LoINTCONCosts 8760	12,673	9,639	9,623	9,702	8,961	9,763	9,677	9,615	9,645	8,852	9,793	9,638	9,625	9,704	8,960	9,765	9,676	9,615	9,647	8,852
	CLER1S-21_ITC&PTC Extend 8760	13,078	9,726	9,706	9,782	9,070	9,861	9,752	9,694	9,673	8,941	9,970	9,726	9,706	9,782	9,069	9,857	9,752	9,689	9,668	8,941
	CLER1S-22_WindCostLow 8760	12,972	9,742	9,659	9,772	9,061	9,889	9,767	9,650	9,659	8,942	9,921	9,742	9,662	9,772	9,064	9,891	9,769	9,650	9,656	8,942
	CLER1S-23_WindCostHi 8760	13,305	9,758	9,728	9,815	9,115	9,894	9,784	9,730	9,828	8,997	10,019	9,757	9,732	9,815	9,110	9,897	9,784	9,723	9,829	8,997
	CLER1S-24_SolCostLow 8760	12,891	9,710	9,691	9,761	9,048	9,894	9,735	9,668	9,654	8,922	9,920	9,710	9,691	9,761	9,054	9,898	9,735	9,669	9,651	8,922
	CLER1S-25_SolCostHigh 8760	13,284	9,721	9,795	9,823	9,104	9,913	9,798	9,734	9,772	8,943	10,014	9,722	9,797	9,823	9,111	9,913	9,797	9,746	9,772	8,944
	CLER1S-26_StorCostLow 8760	13,260	9,744	9,721	9,811	9,107	9,897	9,772	9,720	9,759	8,947	10,021	9,742	9,721	9,804	9,107	9,898	9,778	9,723	9,763	8,947
	CLER1S-27_StorCostHigh 8760	13,277	9,741	9,721	9,809	9,108	9,889	9,773	9,721	9,756	8,947	10,016	9,741	9,732	9,802	9,114	9,898	9,778	9,719	9,759	8,946
	CLER1S-28_AFR 2020 Low 8760	12,583	9,370	9,357	9,435	8,748	9,583	9,398	9,357	9,389	8,650	9,605	9,370	9,363	9,435	8,746	9,581	9,398	9,355	9,392	8,650
	CLER1S-31_ResTOU 8760	13,265	9,744	9,729	9,808	9,108	9,897	9,775	9,720	9,774	8,943	10,017	9,744	9,728	9,808	9,112	9,897	9,775	9,717	9,768	8,943
	CLER1S-32_High DG&EV 8760	13,289	9,752	9,741	9,807	9,113	9,906	9,776	9,724	9,781	8,943	10,016	9,752	9,741	9,812	9,109	9,902	9,776	9,715	9,775	8,943
	CLER1S-33_RenewELCC-2.5% 8760	13,276	9,685	9,793	9,803	9,114	9,901	9,772	9,724	9,771	8,944	10,024	9,747	9,793	9,811	9,107	9,903	9,771	9,722	9,771	8,944
	CLER1S-34_RenewELCC+2.5% 8760	13,280	9,746	9,733	9,801	9,113	9,897	9,781	9,723	9,774	8,946	10,015	9,745	9,730	9,801	9,112	9,894	9,781	9,715	9,772	8,946
	CLER1S-35_PRM-2% 8760	13,288	9,749	9,728	9,807	9,108	9,900	9,777	9,723	9,777	8,944	10,021	9,749	9,730	9,808	9,110	9,902	9,778	9,720	9,773	8,944
	CLER1S-36_PRM+2% 8760	13,278	9,741	9,781	9,811	9,112	9,898	9,782	9,713	9,777	8,948	10,012	9,740	9,774	9,810	9,110	9,902	9,781	9,731	9,776	8,948
MidReg/MidEnv Cost Future	CREF1S 8760	12,053	10,041	10,053	10,081	9,429	10,191	10,100	10,007	10,066	9,353	10,081	10,040	10,044	10,082	9,431	10,189	10,100	10,003	10,066	9,353
	CREF1S-01_Coal+20% 8760	11,371	9,882	9,789	9,928	9,330	9,969	9,882	9,790	9,915	9,255	9,860	9,883	9,801	9,928	9,327	9,970	9,883	9,791	9,913	9,255
	CREF1S-02_Coal-10% 8760	12,402	10,124	10,123	10,166	9,494	10,286	10,184	10,113	10,145	9,414	10,202	10,122	10,128	10,166	9,499	10,288	10,184	10,119	10,135	9,414
	CREF1S-05_Lower Gas-50% 8760	11,885	9,773	9,689	9,821	9,187	10,104	9,847	9,775	9,876	9,143	9,873	9,773	9,684	9,821	9,196	10,106	9,847	9,777	9,873	9,143
	CREF1S-06_Low Gas-25% 8760	11,988	9,962	9,903	10,082	9,481	10,262	10,051	9,944	10,039	9,359	10,075	9,963	9,910	10,083	9,481	10,261	10,051	9,942	10,044	9,359
	CREF1S-07_High Gas+25% 8760	12,503	10,299	10,301	10,326	9,708	10,383	10,304	10,280	10,285	9,589	10,364	10,298	10,302	10,326	9,719	10,386	10,304	10,285	10,284	9,589
	CREF1S-08_Higher Gas+50% 8760	12,951	10,535	10,515	10,571	9,953	10,579	10,483	10,449	10,470	9,787	10,644	10,535	10,509	10,570	9,945	10,577	10,484	10,452	10,475	9,786
	CREF1S-09_Highest Gas+100% 8760	12,939	10,389	10,352	10,423	9,740	10,329	10,255	10,226	10,227	9,575	10,517	10,389	10,356	10,423	9,740	10,323	10,255	10,229	10,223	9,574
	CREF1S-10_WHSL Mkt-50% 8760	9,032	8,381	8,428	8,494	8,082	8,452	8,435	8,387	8,486	7,938	8,383	8,381	8,425	8,494	8,079	8,446	8,435	8,378	8,489	7,938
	CREF1S-11_WHSL Mkt-25% 8760	10,585	9,431	9,448	9,511	9,010	9,464	9,446	9,393	9,470	8,872	9,429	9,430	9,447	9,512	9,009	9,476	9,441	9,387	9,473	8,872
	CREF1S-12_WHSL Mkt+25% 8760	13,172	10,596	10,548	10,597	9,904	10,830	10,700	10,584	10,622	9,822	10,701	10,596	10,552	10,597	9,901	10,829	10,700	10,576	10,622	9,822
	CREF1S-13_WHSL Mkt+50% 8760	13,543	10,644	10,539	10,559	9,827	10,842	10,730	10,622	10,618	9,759	10,745	10,643	10,540	10,559	9,819	10,839	10,730	10,617	10,620	9,759
	CREF1S-14_CapCosts-30% 8760	12,038	10,042	10,047	10,131	9,436	10,191	10,093	10,078	10,133	9,358	10,083	10,041	10,039	10,131	9,435	10,180	10,092	10,082	10,151	9,357
	CREF1S-15_CapCosts+30% 8760	12,051	10,017	9,951	9,956	9,431	10,184	10,049	9,947	9,945	9,355	10,082	10,017	9,951	9,956	9,423	10,178	10,048	9,951	9,952	9,355
	CREF1S-17_NoMktSales 8760	11,719	9,878	9,901	9,931	9,340	10,072	9,943	9,869	9,896	9,254	9,945	9,877	9,908	9,930	9,339	10,074	9,935	9,866	9,899	9,254
	CREF1S-18_NoSalePurchase 8760	14,628	11,499	11,466	11,294	10,663	11,982	11,773	11,585	11,592	10,770	11,654	11,498	11,478	11,293	10,629	11,997	11,773	11,697	11,597	10,770
	CREF1S-19_MktAccess-50% 8760	12,818	10,601	10,440	10,397	9,735	10,745	10,712	10,627	10,487	9,742	10,543	10,601	10,447	10,398	9,730	10,748	10,711	10,613	10,471	9,742
	CREF1S-20_LoINTCONCosts 8760	11,811	9,978	9,979	10,021	9,387	10,081	10,033	9,932	10,014	9,307	9,992	9,978	9,978	10,022	9,383	10,082	10,033	9,936	10,018	9,307
	CREF1S-21_ITC&PTC Extend 8760	11,917	10,017	10,019	10,068	9,423	10,171	10,079	9,993	10,050	9,355	10,051	10,017	10,023	10,068	9,419	10,167	10,078	9,997	10,052	9,354
	CREF1S-22_WindCostLow 8760	11,829	9,997	9,970	10,026	9,413	10,125	10,056	9,968	10,052	9,334	10,024	9,998	9,973	10,026	9,412	10,124	10,056	9,966	10,047	9,334
	CREF1S-23_WindCostHi 8760	12,056	10,040	10,053	10,097	9,440	10,186	10,111	10,015	10,079	9,361	10,088	10,039	10,052	10,096	9,434	10,193	10,112	10,017	10,081	9,361
	CREF1S-24_SolCostLow 8760	11,898	10,006	10,005	10,039	9,395	10,148	10,079	9,982	10,027	9,331	10,028	10,006	10,007	10,038	9,395	10,148	10,080	9,985	10,022	9,331
	CREF1S-25_SolCostHigh 8760	12,266	10,049	10,073	10,097	9,435	10,213	10,114	10,040	10,086	9,358	10,125	10,049	10,070	10,094	9,432	10,202	10,115	10,033	10,083	9,358
	CREF1S-26_StorCostLow 8760	12,043	10,034	10,049	10,078	9,428	10,181	10,102	10,008	10,068	9,361	10,083	10,033	10,041	10,078	9,437	10,188	10,102	10,012	10,064	9,361

	CREF1S-27_StorCostHigh 8760	12,045	10,031	10,046	10,084	9,429	10,182	10,109	10,009	10,074	9,357	10,084	10,031	10,053	10,084	9,432	10,184	10,110	10,017	10,063	9,357
	CREF1S-28_AFR 2020 Low 8760	11,354	9,637	9,638	9,682	9,069	9,750	9,685	9,603	9,670	8,983	9,643	9,637	9,636	9,682	9,070	9,748	9,685	9,601	9,673	8,983
	CREF1S-31_ResTOU 8760	11,952	10,035	10,047	10,077	9,429	10,178	10,105	10,008	10,065	9,349	10,067	10,035	10,040	10,077	9,430	10,179	10,105	10,009	10,059	9,349
	CREF1S-32_High DG&EV 8760	12,055	10,050	10,046	10,081	9,429	10,198	10,101	10,022	10,070	9,358	10,091	10,050	10,053	10,081	9,424	10,203	10,101	10,021	10,062	9,358
	CREF1S-33_RenewELCC-2.5% 8760	12,038	10,044	10,066	10,081	9,432	10,183	10,102	10,019	10,066	9,353	10,089	10,044	10,064	10,081	9,437	10,189	10,103	10,011	10,066	9,353
	CREF1S-34_RenewELCC+2.5% 8760	12,043	10,033	10,045	10,083	9,428	10,189	10,101	10,015	10,062	9,345	10,086	10,033	10,049	10,083	9,431	10,185	10,100	10,012	10,070	9,345
	CREF1S-35_PRM-2% 8760	12,049	10,042	10,043	10,080	9,432	10,186	10,105	10,013	10,062	9,357	10,080	10,042	10,046	10,080	9,423	10,189	10,104	10,012	10,067	9,357
	CREF1S-36_PRM+2% 8760	12,043	10,039	10,058	10,079	9,433	10,190	10,102	10,022	10,061	9,358	10,078	10,038	10,056	10,079	9,428	10,181	10,102	10,014	10,068	9,358

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
Comments

Docket No. E015/RP-21-33

Dated this **29th** day of **April 2022**

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Jessica L	Bayles	Jessica.Bayles@stoel.com	Stoel Rives LLP	1150 18th St NW Ste 325 Washington, DC 20036	Electronic Service	No	OFF_SL_21-33_Official CC Service List
Laura	Bishop	Laura.Bishop@state.mn.us	MN Pollution Control Agency	520 Lafayette Rd Saint Paul, MN 55155	Electronic Service	No	OFF_SL_21-33_Official CC Service List
Jon	Brekke	jbrekke@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_21-33_Official CC Service List
Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron	200 S 6th St Ste 4000 Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_21-33_Official CC Service List
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_21-33_Official CC Service List
Riley	Conlin	riley.conlin@stoel.com	Stoel Rives LLP	33 S. 6th Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-33_Official CC Service List
Hillary	Creurer	hcreurer@allete.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_21-33_Official CC Service List
Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota St Ste W1360 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_21-33_Official CC Service List
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_21-33_Official CC Service List
Stephanie L	Fitzgerald	sfitzgerald@mncenter.org	Minnesota Center for Environmental Advocacy	1919 University Ave W Ste 515 Saint Paul, MN 55104-3435	Electronic Service	No	OFF_SL_21-33_Official CC Service List

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Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_21-33_Official CC Service List
Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_21-33_Official CC Service List
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-33_Official CC Service List
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Becky	Lammi	cityclerk@ci.aurora.mn.us	City of Aurora	16 W 2nd Ave N PO Box 160 Aurura, MN 55705	Electronic Service	No	OFF_SL_21-33_Official CC Service List
Emily	Larson	eLarson@duluthmn.gov	City of Duluth	411 W 1st St Rm 403 Duluth, MN 55802	Electronic Service	No	OFF_SL_21-33_Official CC Service List
James D.	Larson	james.larson@avantenergy.com	Avant Energy Services	220 S 6th St Ste 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-33_Official CC Service List
Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota Street, Suite W1360 St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-33_Official CC Service List
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	Yes	OFF_SL_21-33_Official CC Service List
Susan	Ludwig	sludwig@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_21-33_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_21-33_Official CC Service List
Daryl	Maxwell	dmaxwell@hydro.mb.ca	Manitoba Hydro	360 Portage Ave FL 16 PO Box 815, Station Main Winnipeg, Manitoba R3C 2P4 Canada	Electronic Service	No	OFF_SL_21-33_Official CC Service List
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Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-33_Official CC Service List
Evan	Mulholland	emulholland@mncenter.org	Minnesota Center for Environmental Advocacy	1919 University Ave W Ste 515 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_21-33_Official CC Service List
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_21-33_Official CC Service List
Jennifer	Peterson	jjpeterson@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_21-33_Official CC Service List
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_21-33_Official CC Service List
Susan	Romans	sromans@allete.com	Minnesota Power	30 West Superior Street Legal Dept Duulth, MN 55802	Electronic Service	No	OFF_SL_21-33_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	Yes	OFF_SL_21-33_Official CC Service List
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Greg	Wannier	greg.wannier@sierraclub.org	Sierra Club	2101 Webster St Ste 1300 Oakland, CA 94612	Electronic Service	No	OFF_SL_21-33_Official CC Service List
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