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June 25, 2021

—Via Electronic Filing—

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

RE: REPLY COMMENTS
2020-2034 UPPER MIDWEST INTEGRATED RESOURCE PLAN
DOCKET NO. E002/RP-19-368

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Reply Comments regarding its 2020-2034 Upper Midwest Integrated Resource Plan to the Minnesota Public Utilities Commission in response to comments received by parties.

In these Reply Comments we respond to comments regarding the Preferred Plan we proposed in our June 2020 Supplement (the Supplement Plan) and discuss an Alternate Plan that we developed in response to the significant feedback we heard from stakeholders over the course of this proceeding. Specifically, we analyzed the impact of removing the Sherco Combined Cycle (CC) from our system and developed an alternative system resource mix, reflected in the Alternate Plan, that does not include the Sherco CC.

In addition to not including the Sherco CC, our Alternate Plan proposes the following key actions:

- Retiring all of our coal generation by 2030, and reducing operations at some units prior to retirement;
- Extending the life of our Monticello plant to 2040;
- Adding nearly 6,000 MW of renewables and 250 MW of storage to our system;

- Adding substantial demand-side management, including average annual energy efficiency savings of over 780 gigawatt hours;
- Adding firm dispatchable resources as needed in the near-term, while maintaining flexibility in the latter years to incorporate new technologies that help meet grid needs.

While we continue to believe the Sherco CC would be a valuable system resource and a reasonable and appropriate solution to retiring more than 2,400 MW of coal generation on our system while maintaining system stability and providing dispatchable energy to complement the increasing amount of renewables on our system, we also believe the Alternate Plan presented in these Reply Comments represents the best path forward for our customers, stakeholders, and the states we serve. Our Alternate Plan achieves greater emissions reductions, decreases customer costs, maintains reliability, adds more renewables in a faster timeframe, reduces our reliance on natural gas, and supports a new and more resilient approach to system restoration.

However, there are consequences presented by the Alternate Plan that are not necessarily captured by our economic model. For example, if the retirement of Sherco Unit 3 is accelerated to 2030 but the Sherco CC is not built, the Company will – for the first time since the 1970s – be operating a system without central station power in Becker, which represents a fundamental shift in the way we plan and operate our system. Additionally, any decision to not build the Sherco CC will result in both the loss of property tax base for the City of Becker and Sherburne County as well as future jobs related to constructing and operating the plant and associated pipeline. Thus, the Alternate Plan carries significant operational and economic consequences that all parties and the Commission should be mindful of as we move through this Resource Plan.

We acknowledge that this is a substantial update and appreciate that parties may wish to review and comment on our Alternate Plan, which we support. We look forward to discussing both our Supplement Plan and Alternate Plan with the Commission and bringing this Resource Plan proceeding to a close so that we can continue our transition to a cleaner energy future for Minnesota.

Request for Protection of Trade Secret Information

The Company recognizes and supports the need for transparency in review of our Resource Plan. We also take seriously our responsibility to maintain the security of the information and systems involved in the delivery of safe, reliable energy to our customers.

Not Public data is included in the following sections of this filing: Executive Summary, Reliability, System Restoration and Blackstart, Modeling and Rebuttal, and Forecasting and Renewable Energy Siting. These Sections contain data regarding customer information and forecast investments and information that could be used to identify the resources we currently and plan to rely on to restore the grid from widespread blackout conditions. This information is trade secret information as defined by Minn. Stat. § 13.37(1)(b). This information derives independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from its use. This information also is security information as defined by Minn. Stat. § 13.37(1)(a) because it could be improperly used by someone to harm the electric grid.

These Reply Comments can be accessed on and downloaded from our website at: xcelenergy.com/UpperMidwestEnergyPlan

Please contact Bria Shea at (612) 330-6064 or bria.e.shea@xcelenergy.com if you have any questions regarding this filing.

/s/

GREG P. CHAMBERLAIN
REGIONAL VICE PRESIDENT
REGULATORY & GOVERNMENT AFFAIRS

Enclosures
c: Service List

Xcel Energy®

UPPER MIDWEST INTEGRATED RESOURCE PLAN

2020-2034

Reply Comments

Northern States Power Company
Docket No. E002/RP-19-368

TABLE OF CONTENTS

2020-2034 Upper Midwest Resource Plan Reply Comments

APPENDICES

THE 2020-2034 UPPER MIDWEST RESOURCE PLAN REPLY COMMENTS
LIST OF TABLES AND FIGURES

APPENDICES
LIST OF TABLES AND FIGURES

Appendix A: Encompass Inputs and Assumptions

Appendix B: L&R Tables

Appendix C: Sensitivities

Appendix D: Clean Energy Tax Reform

2020-2034 UPPER MIDWEST INTEGRATED RESOURCE PLAN
REPLY COMMENTS

SECTION 1: REPLY COMMENT EXECUTIVE SUMMARY

We are excited to bring this proceeding to a close so that we can take the next step toward our carbon-free vision, while ensuring we continue to provide reliable and affordable power to our customers.

As the Commission understands, building a resource plan is akin to assembling a puzzle – all of the pieces must fit together to ensure our customers receive safe, affordable and reliable power that is also consistent with the Company's and our states' carbon reduction goals. Our plans must consider the existing system and potential futures that will impact not only our system, but the larger region. The more we, and others, transition away from the traditional bulk power system construct, the more we rely on the collective to deliver reliable, affordable and carbon-free power. We believe the plan we presented in our June 30, 2020 Supplement (the Supplement Plan) achieved this balance and remains a reasonable and appropriate plan that is consistent with the public interest.

We understand, however, that many stakeholders had concerns with the Supplement Plan's inclusion of a combined cycle plant at Sherco (the Sherco CC). Indeed, while many stakeholders were supportive of the main elements of our Supplement Plan—including our proposed shutdown of our coal fleet by 2030, the extension of operations at our Monticello Nuclear Plant, significant additions of renewable resources, and the Company's carbon reduction goals—many parties opposed our proposal to construct the Sherco CC and the pipeline infrastructure investment needed for the gas supply.

We take this kind of stakeholder feedback seriously. In fact, we have spent the past several months conducting extensive analyses to determine whether there were viable alternatives to our Supplement Plan that would advance our carbon-free vision—while maintaining reliability, affordability, and safety—without building the Sherco CC. We analyzed the impact of removing the Sherco CC from our plans on the reliability of our system, on our emergency system restoration, or "blackstart" plan, and on the costs and expansion plans included in our Supplement Plan. Through this work, we have developed an alternative system resource mix that does not include the Sherco CC, and this "Alternate Plan" is the principal focus of these Reply Comments.

To be clear, we continue to believe the Sherco CC would be a valuable system resource. Our 2015 proposal to build the Sherco CC was informed by our decades of experience operating the electric grid using large-scale economic and dispatchable power sources with inherent attributes that support stability, voltage, and overall reliability. This operational experience—and our track record of providing reliable, safe, and affordable energy—has been anchored by the core features of this "central station power" paradigm. We further believe the Sherco CC represents a reasonable and appropriate solution to retiring more than 2,400 MW of coal generation on our system while maintaining stability on the 345 kV transmission loop surrounding the Twin Cities and providing dispatchable energy to complement an ever-increasing amount of renewables on our system.

However, after a great deal of analyses by our Energy Supply, Transmission, System Restoration, and Resource Planning teams, we have arrived at an Alternate Plan. This plan does not include the Sherco CC, but will—according to the extensive analysis discussed in these Reply Comments—preserve the fundamental principles of reliability and safety. At the same time, the Alternate Plan is expected to achieve significant, incremental benefits, including:

- **Increased Economic Benefits:** The economic modeling for our Alternate Plan shows $606 million in Present Value of Societal Cost (PVSC) savings and $46 million in Present Value of Revenue Requirements (PVRR) savings. This represents an improvement over our Supplement Plan of approximately $372 million in incremental PVSC and $142 million in incremental PVRR benefits.
- **Increase Renewables & Carbon Free Energy:** Our modeling also shows that the Alternate Plan is expected to achieve a generation portfolio that is approximately 54% renewable and 81% carbon-free by 2030, which represents a significant increase for both metrics relative to our Supplement Plan.
- **Increased Carbon Reduction:** While Xcel Energy has stated a carbon reduction goal of 80% by 2030, and our Supplement Plan was projected to achieve that goal, our Alternate Plan is expected to achieve an 86% reduction in carbon emission by 2030, compared to 2005 levels.
- **Improved Blackstart Capability:** Lastly, our Alternate Plan contemplates a shift in blackstart planning from a "central station" approach to a "zonal" approach, which, when fully implemented in 2030, is expected to improve our blackstart capability, so that we could achieve a broader and faster restoration of service following a widescale outage.

It is important to note, however, that our Alternate Plan does present certain consequences that are not necessarily reflected in the economic modeling or carbon reduction numbers. For example, if the retirement of Sherco Unit 3 is accelerated to 2030 but the Sherco CC is not built, the Company will – for the first time since the 1970s – be operating a system without central station power in Becker. That will involve a fundamental shift in the way we plan and operate our system. Similarly, deciding to not build the Sherco CC will result in both the loss of property tax base for the City of Becker and Sherburne County, as well as the loss of future jobs in constructing and operating the plant and associated pipeline, which are significant consequences that all parties and the Commission should be mindful of as we move through this resource plan.

On balance, however, we believe the Alternate Plan presented in these Reply Comments represents the best path forward for our customers, stakeholders, and the states we serve. It is projected to reduce customer costs over the planning period, achieve substantially greater carbon reduction, and allow us to move faster in pursuing a more renewable and carbon-free generation system, all while preserving reliability and improving our blackstart restoration capabilities. And regardless of what plan the Commission ultimately approves, Xcel Energy remains steadfast in its commitment to our employees, and our partnership with the City of Becker and local stakeholders. We have been deeply engaged in this work since our 2015 Resource Plan (and before), and we have been able to bring a number of proposals forward that have significant potential to benefit the Becker community. Should the Commission approve our Alternate Plan, we are committed to ensuring that all of our current employees continue to have jobs and committed to continued investment in the Sherco area, which includes our recent proposal to add 460 MWs of solar adjacent to the Sherco site. We also are committed to continuing our work with stakeholders in and around Becker to attract additional economic development to the area.

In this Executive Summary, we summarize our Alternate Plan, the updates we made to our modeling assumptions, and our plans to maintain reliability and ensure we can restore the system in blackstart conditions. The remainder of the Replies are organized as follows:

Section 2: Reliability

Section 3: System Restoration and Blackstart

Section 4: Encompass Modeling and Rebuttal

Section 5: Customer Rate and Bill Impacts

Section 6: Forecasting and Renewable Siting

I. ALTERNATE PLAN

Our Alternate Plan builds upon the Company's vision for the future of our system that was included in our Supplement Plan. The Alternate Plan continues to include the following core components:

- Elimination of coal-fired generation from our system by 2030;
- Seasonal dispatch of Sherco Unit 2 and King, until their respective retirements;
- Acquisition of significant utility-scale wind and solar by 2030;
- A substantial increase in Energy Efficiency (EE) savings and Demand Response (DR) resources; and
- Extending operation of the Monticello nuclear plant to 2040 and continuing operation of Prairie Island at least until the end of its operating license in 2033/2034.

The main changes to highlight in the Alternate Plan as compared to our Supplement Plan are as follows:

- Elimination of the Sherco CC;
- Reutilization of interconnections at retired Sherco and King coal sites which enables significant solar and wind additions as well as some hydrogen-capable combustion turbine (CT) resources; and
- Beginning a process to shift our current emergency system restoration (blackstart) plans from our current centralized restoration approach to a zonal restoration approach.

Figure 1-1 below demonstrates that the fleet transformation reflected in the Alternate Plan exceeds the reduction in CO_2 emissions proposed in our Supplement Plan. This increased carbon reduction is due, in part, to the very low capacity factors of the natural gas resources being proposed as compared to the Sherco CC. The Sherco CC had an approximately 80 percent capacity factor in our modeling results, but the combustion turbine (CT) resources modeled in the Alternate Plan average 5 percent or lower. CT resources can provide significant value to the system for reliability, firm capacity and energy during occasional extended periods of low renewable output – but operating at low annual capacity factors means they will emit much less carbon than a combined cycle plant. Operating in synchronous condenser mode or – looking forward – operating on hydrogen, means they can provide valuable services for the grid while emitting even less (or no) carbon.

Figure 1-1: Alternate Plan Carbon Reductions

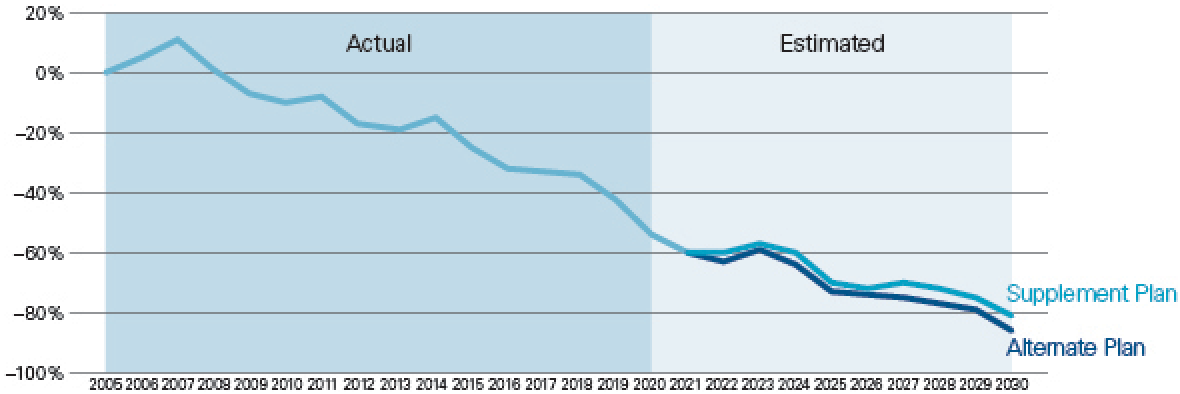
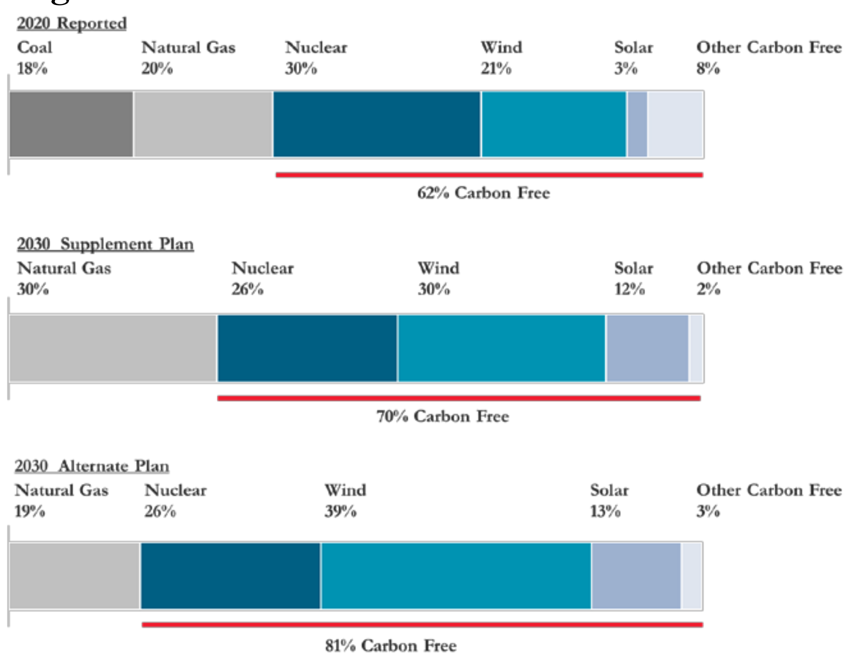


Figure 1-2 below compares the Company's current generation mix to the Supplement Plan's projected generation mix, and Alternate Plan by 2030 and 2034 and their respective percentages of carbon-free generation.[1]

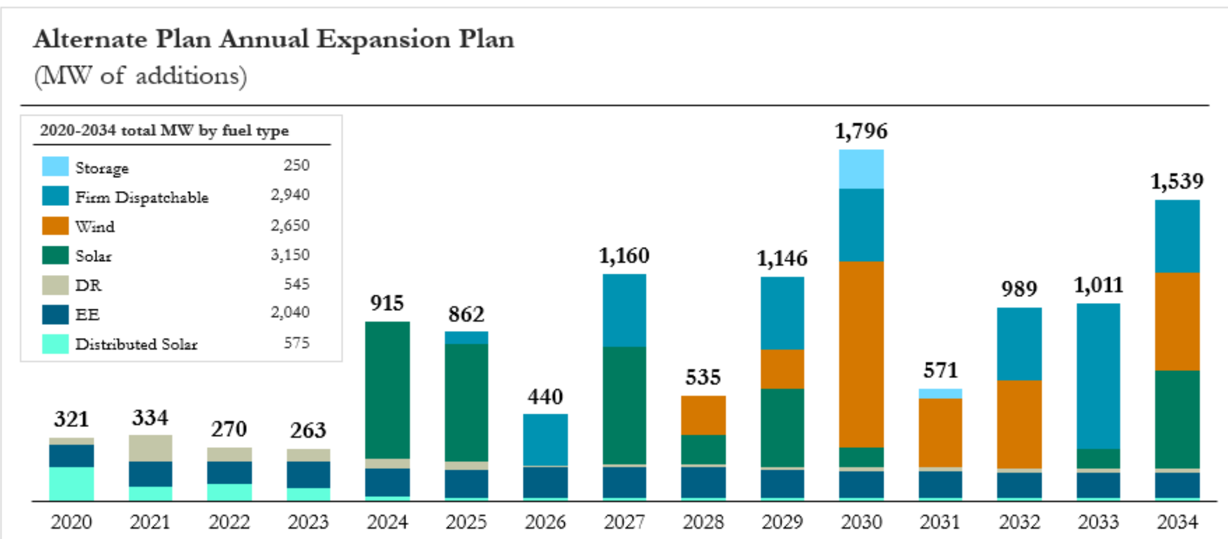
Figure 1-2: Alternate Plan Generation Mix 2020-2034



[1] As discussed further in the Modeling Section 4, in order to provide an "apples to apples" comparison of the Supplement Plan to the Alternate Plan, we created an updated Supplement Plan that reflects changes that have occurred since our 2020 filing. The key updates include: a newer version of our EnCompass (our modeling software), smaller generic renewable units for the model to select, and Commission approval of the addition or extension of about 1,200 MW of renewables to the system. The impact of this update, generally, is a lessened need for future expansion and thus less renewables in the updated Supplement Plan. Accordingly, unless otherwise indicated, when we discuss comparisons of the Alternate Plan to the Supplement Plan in these Reply Comments, we are assuming the inclusion of these modeling updates.

As shown above, compared to the Supplement Plan, our Alternate Plan results in reduced gas generation on our system and increased renewable generation. To facilitate the transition away from coal and toward a low-carbon system, the Alternate Plan includes significant renewable resource additions, continuing operation of our nuclear fleet and extending our Monticello operating license, substantial EE and DR additions, and a sufficient amount of firm dispatchable resources to maintain reliability. Figure 1-3 below presents the amount and timing of the resource additions that comprise our Alternate Plan.

Figure 1-3: Alternate Plan Resource Additions



A. Alternate Plan Resource Changes

Below we lay out the specific resource changes we are planning from 2020-2034 in the Alternate Plan.

1. *Renewable and Infrastructure Resources*

As with the Supplement Plan, renewable additions continue to be the cornerstone of the Alternate Plan, which results in increased additions of renewables relative to our Supplement Plan. The Alternate Plan proposes to add approximately 3,150 MW of utility scale solar by 2034 (starting in 2024) and approximately 2,650 MW of wind by 2034. This represents an approximately 27 percent increase over the total renewable capacity indicated in updated modeling for the Supplement Plan. Given existing transmission constraints, thoughtful and timely reuse of the Company's interconnection rights delivers significant value in the Alternate Plan.

Without the planned addition of the Sherco CC, a significant amount of interconnection rights will become available for reuse when the existing coal units retire. In order to enable reuse of these interconnection rights for renewable resources, the Company proposes to build transmission tie-lines (gen-tie lines) from the Sherco and King sites that can interconnect substantial amounts of incremental wind and solar resources. Specifically, we propose constructing a double circuit 345 kV gen-tie line to connect solar, wind, and firm dispatchable resources to the Sherco interconnection and one single-circuit 345 kV gen-tie line to connect solar to the interconnection at King. FERC has granted the current generation owners the right to utilize the associated transmission for new generation at those sites as the old generation retires as part of the energy transition. This is an important attribute for us to utilize to ensure our customers retain the maximum value from our prior investment in the bulk power system, a right only the owners of the sites can utilize. Therefore, we have reflected the cost of Company ownership for a portion of the resources that utilize the interconnection at Sherco and King.

2. *Coal Resources*

The Alternate Plan maintains our plan to retire our entire fleet of coal-based generating units by 2030. As with the Supplement Plan, not only are we maintaining our Commission-approved plan to retire Sherco Units 1 and 2 in 2026 and 2023, respectively, we also are maintaining our proposal to retire the Allen S. King plant at the end of 2028, and we are proposing to retire Sherco Unit 3 in 2030, both several years ahead of their originally planned retirement dates. The Alternate Plan also continues to reflect our commitment to offer the King plant—in addition to Sherco Unit 2—into MISO on a seasonal and/or fully economic basis until its retirement.

3. *Nuclear Resources*

Like our Supplement Plan, the Alternate Plan proposes to operate the Monticello generating plant through 2040 (10 years longer than its current license), and to continue operation of both Prairie Island (PI) Units at least through the end of their current licenses (PI Unit 1 to 2033 and PI Unit 2 to 2034).

In addition to being a significant source of carbon free power, our nuclear units contribute to the important balance and diversity of resources that is critical to an affordable and reliable clean energy transition. Specifically, our nuclear units provide stability, voltage, and overall reliability -- some of the positive grid-supporting attributes of central station power that we will lose when the coal units retire.

Many participants in the docket expressed their support for our plan to pursue an extension of the Monticello license, including Deputy Commissioner Aditya Ranade,[2] who based his support, in part, on a report commissioned by the Department of Commerce conducted by Global Energy & Water, LLC. The report concluded that, while aggressive, the Company's forecasts for Capital and O&M spending – including for Monticello – are attainable.[3] [4] Deputy Commissioner Ranade's comments also highlight the significant uncertainties associated with potential replacements for the nuclear units, lifecycle greenhouse gas emissions for natural gas, and the feasibility of significant transmission construction required to connect utility-scale renewable energy to the grid.

We also acknowledge our current modeling—for both the Supplement Plan and Alternate Plan—shows incremental benefits by also extending the licenses for the Prairie Island Units, but there is some time to make a decision regarding potential extension for Prairie Island in the future. By allowing additional time for a decision on whether to extend the Prairie Island license, we can ensure that it will be made with more robust information, including outreach and discussions with the Prairie Island Indian Community, the City of Red Wing, and other interested community members, experience with the initial phases of planning for the Monticello re-licensing, and continuing efforts to identify a long-term used fuel storage solution. This path also allows us to dedicate our resources toward the necessary near-term actions, including the extensive work required to prepare for and pursue a Monticello license extension.

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[2] *Letter from Aditya Ranade, Deputy Commissioner to Mr. Will Seuffert, RE: Comments of the Deputy Commissioner, Minnesota Department of Commerce, Division of Energy Resources, February 11, 2021*

[3] The Monticello forecast budget for O&M spending through 2040 is aggressive but attainable with Xcel's attention to cost controls. (Ref: Page 3)

[4] The Monticello forecast budget for capital spending is well within reason considering the age and the need to prepare the unit for relicensing (See Chart 2, Page 12 of this report). The forecast capital spending for the next 20 years is well below capital spending during the last 10+ years. The outlier that is still not very well documented is the capital necessary to accomplish the Subsequent License Application/Review (SLA/SLR) and it will not be until Xcel completes is license review and application to the NRC. (Ref: Page 3) It should also be noted that the report's conclusions are based on an estimated cost of $50 million to extend the NRC license for 20 years, which is significantly higher than the Company's estimates. Based on SLRs recently granted by the NRC to other nuclear units, the Company estimates the cost of relicensing is approximately $25 million.

4. Combined Cycle Resources

Our Alternate Plan removes the combined-cycle unit at the Sherco Plant and does not include any new combined-cycle resource additions. As discussed further below, we conducted extensive supplemental analysis to validate that there were viable alternatives to building the Sherco CC. We analyzed the impact of removing the Sherco CC from our plans on the reliability of our system, on our blackstart plan, and on the costs and expansion plans included in our Supplement Plan. Based on this analysis, we concluded that we could remove the Sherco CC from our plan, develop an alternative blackstart plan, achieve deeper emissions reductions and maintain reliability, and keep the major elements of our Supplement Plan, all while decreasing costs for our customers.

5. Firm Dispatchable and Blackstart Resources

Our Alternate Plan proposes to add approximately 2,900 MW of cumulative firm dispatchable resources by the end of the planning period, which is generally consistent with additions under the Supplement Plan. As we considered the prospect of operating without a Sherco CC, we identified the need for other dispatchable resources that could support grid reliability and resiliency in light of the increased renewables being added to the system and the baseload units being retired. What emerged from that study was a plan that would rely on strategically placed peaking units that would operate on natural gas in the near-term and could be converted to operate on 100 percent hydrogen in the future.

These resources would be located at four sites, two of which are existing gas-powered sites (or, brownfield sites) and would essentially be repowering efforts. While the other two would be built at new sites (or, greenfield sites), they will be built close to existing pipelines so would not require significant new infrastructure. In addition to their eventual ability to operate on hydrogen, the new site CTs will have a clutch mechanism that will allow them to operate in synchronous condenser mode providing support to the grid when needed without using natural gas, and therefore without carbon or other emissions when operating in this mode. Also, it should be noted that CTs require significantly lower capital investments than CCs.

Beyond these near-term additions (which are approximately 1,100 MW), we are not committing to a specific resource type to meet the remaining need (approximately 1,800 MW). While these resources need to be longer-duration, firm dispatchable resources than the use-limited resources we have available today, we will evaluate the technologies available in a future resource plan.

And while the Alternate Plan includes some specific near-term investments in our blackstart units, there are also some longer-term investments we believe are essential for reliability purposes as we begin to move from a centralized blackstart plan to a zonal blackstart plan. Our blackstart plans are discussed in more depth in Section 3 of these Reply Comments.

6. *Energy Efficiency and Demand Response*

Our Alternate Plan continues to propose the EE and DR investments included in our Supplement Plan. We propose to achieve energy savings ranging from 2 to 2.5 percent annually, which consistently and greatly exceeds the 1.75 percent electric savings goal included in Minnesota's recently passed Energy Conservation and Optimization (ECO) Act. By targeting these savings levels, we plan to achieve more than 780 GWh in average energy savings in each of 2020-2034, and more than 800 MW of additional demand savings by 2034 when compared to the 1.5 percent level approved in our last Resource Plan. Furthermore, we are also working toward an incremental 400 MW of DR by 2023, as required by the Commission's Order in our last Resource Plan, which grows our DR resources to approximately 1,500 MW total by the end of the planning period. [5]

B. The Alternate Plan Accelerates Carbon Reduction

Our Alternate Plan enables and accelerates deeper levels of carbon reduction than contemplated in our Supplement Plan. At the time we filed our Supplement, our Plan achieved an 81 percent carbon reduction from 2005 levels by 2030.

Our Alternate Plan achieves over 85 percent carbon reduction by 2030, and even deeper carbon reduction in the years immediately after 2030, largely by eliminating the Sherco CC and replacing it with renewables and firm dispatchable resources. As shown in Figure 1-1 on page 5, there is an uptick in emissions across 2033 and 2034, which results primarily from the Prairie Island retirement dates included in the Alternate Plan. If we were to extend the Prairie Island units further into the future – consistent with baseload plans in our Initial and Supplement filings' Scenario 12 – our system could approach 90 percent carbon reduction by the end of the planning period. As we have noted previously, however, we are not proposing an extension to

[5] As discussed in our February 1, 2021 filing in Docket No. E002/M-21-101 (Load Flexibility Programs), we have experienced a change in load availability as a result of the COVID-19 pandemic. Nevertheless, we are forecasting continued growth of DR despite these challenges and are committed to meeting the 400 MW requirement set by the Commission in our last IRP (Docket E002/RP-21, January 11, 2017 Order). If it is determined that a modification to the 2023 timeline is warranted due to these challenges, we will make a request at a later time.

Prairie Island at this time. Rather, we plan to address the potential future of that plant in a future filing.

We anticipate that some parties may advocate that we could achieve even further carbon reductions by eliminating some of the firm dispatchable generation additions included in the Alternate Plan. We do not think this is prudent. As the bulk power system operator and infrastructure provider charged with providing critical power to over one million customers throughout the Upper Midwest, we need sufficient firm dispatchable resources to maximize renewable capability and production and to ensure a reliable and affordable clean energy transition. The replacement firm dispatchable generation included in the Alternate Plan serves an important role for system stability and blackstart needs, and can support capacity and energy needs when variable renewables are not available (such as the polar vortex of 2019 or the cold weather event our region experienced earlier this year). Yet on average, these resources have relatively low capacity factors – meaning their contribution to carbon is also is relatively low. Whereas modeling results for Scenario 9 show the Sherco CC running at an 80 percent capacity factor, the CT resources modeled in the Alternate Plan average 5 percent or lower – sometimes substantially lower – throughout the planning period. In this way, the CT resources in the Alternative Plan fulfill a fundamentally different purpose than the Sherco CC. They are, in essence, a necessary insurance policy that enables us to pursue deep carbon reduction and higher and higher levels of renewable penetration while ensuring that our customers will receive reliable and affordable service during the hottest and coldest days of the year, even when renewable generation is limited or non-existent. Right now, CTs are the most efficient and economical resource to support the energy transition, and we will ensure the assets are hydrogen-ready so we can leverage technology within the lifetime of these assets as we transition to future carbon-free fuels and advanced storage mechanisms.

Further, we note that these carbon-reduction results may be conservative, given our commitment to consider carbon-free approaches to providing for firm dispatchable needs beyond those specific blackstart and system stability resources described above. We believe that technological advancement may enable even greater carbon reduction as we move through the next decade, which is why we maintain our position of technology neutrality when it comes to firm dispatchable resources beyond the approximately 1,100 MW of incremental gas resources that are needed for blackstart and system stability and also plan to design each such resource to be hydrogen-capable.

C. The Alternate Plan Increases Customer Savings

Section 4 provides the detailed Encompass analysis we performed in order to examine the relative benefits and costs of the Alternate Plan, which we compared to both the updated Reference Case (i.e. "business as usual") and our Supplement Plan. This analysis shows that the Company's Alternate Plan increases customer savings on both a PVSC and PVRR basis relative to both of these cases.

Table 1-1: Alternate Plan Cost/Savings, Relative to the Reference and Supplement Plan

Scenario	PVSC ($ millions)	PVSC Delta to Reference Case ($ millions)	PVRR ($ millions)	PVRR Delta to Reference Case ($ millions)
Reference Case (Scenario 1)	41,067	--	37,165	--
Supplement Plan (Scenario 9)	40,833	(234)	37,261	96
Alternate Plan – Current Policy	40,461	(606)	37,120	(46)

The Company's proposal to reutilize its interconnection rights at Sherco and King—which allows for substantial incremental renewable additions relative to both our Reference and Scenario 9 cases—drives savings on a PVSC basis relative to the Supplement Plan. While the proposed transmission gen-tie lines require significant investment, the total cost is lower, on a per kW basis, than our estimate of the average observed cost to interconnect new renewables through the interconnection queue. In total, the average cost per kW for resources on the Sherco gen-tie line is under $140/kW and on the King line it is approximately $55/kW, as compared to the estimated average MISO queue costs, based on observed queue results, of $500/kW for wind and $200/kW for solar.

While there are significant savings associated with the Alternate Plan, pending tax-reform proposals have the potential to significantly reduce the costs of the Company-owned resources and significantly improve the customer savings associated with our Alternate Plan. Given the current Administration's ambitious clean energy goals, the U.S. Congress is currently considering several tax reform proposals that would affect our realized cost of renewables.

One example of such legislation is the Clean Energy for America Act, sponsored by Senator Wyden, and co-sponsored by, among others, Senators Klobuchar and Smith.[6] Among other things, this bill essentially proposes to replace existing wind and solar energy credits with a technology neutral credit, which would allow utilities to take either a production tax credit (PTC) or an investment tax credit (ITC) for solar projects, and consequently pass the benefits of tax credits on to customers earlier in a project's life than under the current ITC construct.

While it is too early to tell which of these policies, if any, will ultimately be signed into law,[7] any policy change that enhances the value of the tax credits will benefit our customers under the Alternate Plan. This is not only because it will reduce the cost of utility ownership of the first 2,000 MW on the Sherco gen-tie and 600 MW on the King gen-tie, but also because, if tax credits are extended in the future, these benefits will flow back to our customers. One benefit for customers of Company ownership of resources is our ability to opportunistically take advantage of changes in tax policy. For example, with the extension of the wind PTC last year, we were able to take actions that allowed the Dakota Range project to qualify for the 100 percent PTC level rather than the 80 percent PTC, and flow the benefits of these tax credits back to customers.[8]

D. The Alternate Plan Maintains Affordable Customer Bills

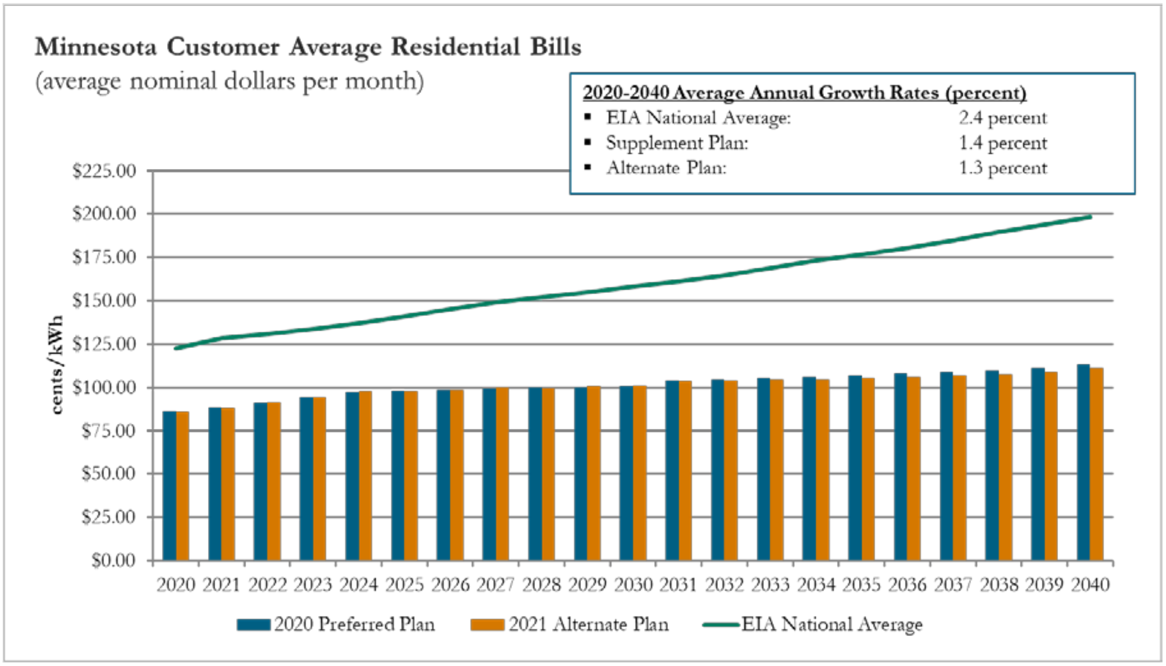
In addition to the PVSC and PVRR analysis, we also looked at the impact of the Alternate Plan on customer bills. Our June 2020 filing included a customer cost analysis that showed our Supplement Plan achieved our carbon goals and reliability objectives while maintaining affordability. Our updated customer bill impact analysis found that our Alternate Plan continues to keep average residential customer bills well below the national average. Additionally, our projected average bill and rate growth remains below inflation and is over a full percentage point below national averages for bill and rate growth. And, we believe technological improvements will continue to drive the costs of renewables and storage down.

As shown in Figure 1-4, below, NSP System residential customers – on average – pay substantially less per month than the national average in both Plans. We also continue to expect our average bill levels will grow more slowly than the national average, by approximately a full percentage point per year. The Alternate plan results

[6] S. 1298 – 117th Congress (2021-2022): Clean Energy for America Act.
[7] We provide, as Appendix D, a slide from a recent Morgan Stanley presentation that rates the probability of success of various clean energy tax reform proposals currently under consideration in Congress.
[8] *See* Updates to Wind Portfolio, Oct. 9, 2020, Dockets Nos. E002/M-16-777, E002/M-17-694.

in a slightly lower total bill than the Supplement Plan over the term of the analysis, but both plans are largely comparable, especially through the planning period.

Figure 1-4: Minnesota Average Residential Bills



Further discussion and analysis surrounding our customer rate and bill impacts can be found in Section 5 of these Reply Comments.

II. UPDATES TO ASSUMPTIONS IN THE ALTERNATE PLAN

Developing the Alternate Plan without the Sherco CC has been a significant modeling undertaking, with more specialized inputs and assumptions than we have previously used. In particular, we spent significant time developing an approach to ensure that we make efficient re-use of the interconnection capacity that would be available as we cease operating existing generation, enabling us to bring on more renewable capacity.

Based on our review of parties' comments, the Company has recognized that there is widespread concern among stakeholders – primarily based on environmental and cost considerations – regarding the addition of the Sherco CC, which would have made use of approximately 40 percent of the interconnection rights that will become available as the existing Sherco coal units retire. An important part of evaluating a potential shift away from the Sherco CC, therefore, was to develop an opportunity for reuse of the interconnection rights for a different mix of resources.

Thus, with the retirement of Sherco and King coal resources by 2030, the Company is seeking to introduce options for fully reutilizing the interconnection rights and existing infrastructure at both plant locations. With approximately 2,000 MW of interconnection rights owned by the Company at the Sherco site and 600 MW at King, there is a significant opportunity for the Company to add large quantities of incremental renewables, avoid MISO queue risk and accelerate our carbon reduction trajectory. We discuss our approach to modeling these resources below.

Relatedly, as we have discussed in prior filings in this docket, as we retire our baseload generation and transition to higher levels of renewable generation, we need to ensure we are planning to add sufficient resources to maintain reliability through a variety of system conditions. These reliability considerations are amplified in the Alternate Plan, which does not include a combined cycle at Sherco, and we discuss them below in Section C.

Finally, in addition to these new specific considerations for our Alternate Plan, we made several other modeling adjustments compared to our Supplement Plan. The Section 4 Modeling discussion outlines the process by which the Company arrived at its new Alternate Plan, and the benefits of that Plan relative to both the Reference Case and Scenario 9 (our Supplement Plan). For the purpose of these Reply Comments, and to isolate the impact of the changes, the Company determined it was appropriate to make only limited updates to our input assumptions. As discussed further in Section 4, our changes primarily reflect 1) those required by the Commission to provide an up-to-date view of our baseline resources; 2) modeling methodology updates that improve upon how we simulate the operation of our system and potential future additions; and 3) changes necessary to reflect current policy regarding federal renewable tax credits.

A. Gen-ties for Sherco and King POI re-use

As discussed, earlier, without the planned addition of the Sherco CC, a significant amount of interconnection rights will become available for reuse when the existing coal units retire. In order to enable reuse of these interconnection rights for renewable resources, the Company proposes to build transmission tie-lines from the Sherco and King sites that can interconnect substantial amounts of incremental wind and solar resources and circumvent congestion in the broader MISO queue. The Company conducted significant reliability and economic modeling to assess the viability and cost-effectiveness of the Sherco and King gen-tie concepts, with different configurations and amounts of generation they can reliably deliver. Due to the distances and large quantity of new capacity we are considering at the Sherco site, the

Company has completed significant exploratory study work to identify any major technical issues with the gen-tie.

Initial reliability screens showed the lines could be added while maintaining system stability, assuming the requisite equipment is added and identified MW limits are followed. We subsequently developed EnCompass economic modeling to confirm whether the Sherco and King gen-tie concepts could yield customer savings and accelerate carbon reduction on our system, while also meeting customer energy and capacity needs. As discussed below, we believe reusing the interconnections in this way will result in customer savings, and we expect nameplate renewable additions can exceed the approximately 2,000 MW of the Company's interconnection rights at Sherco and approximately 600 MW of interconnection rights at King. This will both maximize our opportunities for accredited generation replacement – per the MISO tariff rules – and fully optimize energy flows on the transmission lines given the complementary nature of wind and solar production.

1. *Pursuing generator interconnection reuse enables benefits for customers and the Company*

The Company has discussed MISO queue congestion issues at length in other recent filings. As noted in those filings, existing transmission capacity continues to be constrained in our region and beyond, requiring high estimated upgrade costs in order to bring new projects online. While these costs vary widely between project locations, rounds of MISO study, and technology, we try to capture $/kW upgrade costs we can incorporate into our modeling that best represent what a project may – on average – face to interconnect to the broader grid as a Network Resource (i.e. to ensure capacity accreditation across the life of the installation). For wind, we assume that interconnection costs will be $500/kW and for solar, we assume $200/kW. These assumptions are consistent with those we used for greenfield CC and CT resources, respectively. The assumed interconnection costs for greenfield renewables reflect our understanding of the current MISO queue constraints and review of the latest Definitive Planning Phase (DPP) process, where interconnection costs are assigned. These values are consistent with those assumed in our June 2020 Supplement filing and modeling.

The limitations on renewable additions caused by this congestion is recognized by the Department. In this docket, the Department's comments discuss these constraints, analyzing results from recent DPP study cycles and concluding that "either substantial new transmission needs to be built or Xcel will be limited to pursuing projects that avoid the MISO [generator interconnection queue]."[9] We largely agree with the Department's analysis. While in some cases, we observe a few projects navigating the MISO queue process to interconnect with lower costs than we assume here, other projects are assigned substantially higher costs and eventually drop out of the queue entirely. As discussed further in the Modeling Section 4, in recent studies, this is particularly true for projects requesting Network Resource Interconnection Service (NRIS) interconnections, in DPP phase 2 or 3 when Southwest Power Pool affected system study costs are incorporated. In future DPPs, large costs could be triggered in either RTO system as the remaining transmission capacity is used.

Given the relatively high costs to interconnect greenfield renewables, and the fact that we expect constraints to continue for some time, the re-use of interconnection rights the Company currently holds at Sherco and King is a hedge against the interconnection queue in MISO. If the proposed gen-tie lines can be constructed for reasonable costs – and we believe they can – and enable substantial renewable additions, we can reduce the average cost per MW relative to the queue and make use of these valuable interconnection rights to the benefit of customers.

Achieving the significant carbon reduction needed to meet the state's goals across all sectors of the economy will require using all available tools. Indeed, even if significant transmission lines are built over the next decade, the gen-tie lines will still be a critical tool to add thousands of MW of renewables to our system that we would lose forever if not timely used. Because we currently hold these rights, we want to ensure we make the best use of this opportunity to reutilize them to the benefit of our customers and the state's carbon reduction goals, bringing significant new renewables online at an equal or lower average cost per MW than the broader MISO queue can offer for the next decade. Based on our modeling, options to build gen-ties at Sherco and King to connect resources with those existing interconnections offer us those opportunities.

2. *Assumed configuration and costs for Sherco and King gen-ties*

Sherco Gen-Tie: For the Sherco gen-tie line, the Company has assumed the construction of a double circuit line terminating at a location in Lyon County, MN. Further details about our model assumptions are included in Section 4 and Attachment A. For the purposes of modeling, we assumed the construction of a 345 kV transmission line approximately 140 miles in length (for a total of 280 circuit miles).[10] This double-circuit line enables us to interconnect approximately 3,600 MW

[9] DOC Comments at 41.

of renewable resources, as they would be routed to resource rich areas. If the Alternate Plan is approved, the final lengths and routes for this line would be developed in additional regulatory processes.

King Gen-Tie: For the King gen-tie line, the Company has assumed the construction of one, single circuit 345 kV line to utilize the approximately 600 MW of interconnection rights that will become available when King ceases operations in 2028. Line costs are modeled on the assumption that it would be approximately 15 miles long. As with the Sherco line, if the Alternate Plan is approved, final length and route would be further developed in future regulatory processes.

3. Gen-tie resource MW limits, timing and costs

Appropriately representing specific tranches of resources that can be selected for generator interconnection reuse required implementation of some new and creative modeling approaches. Overall, we believe our approach makes the most efficient use of the interconnection rights that will become available when our coal units retire, maximize the total accreditation potential of hybrid resources behind these points of interconnection, and reflect MISO and FERC requirements regarding ownership of a portion of these resources. We describe this approach further below.

a. MISO rules regarding ownership of generator replacement resources

As a threshold matter, there are specific requirements governing generator replacement and the ownership of resources that reutilize these interconnection rights. MISO's generator replacement rules are set out in Attachment X of the MISO Tariff, which contains MISO's Generator Interconnection Procedures or "GIPs." The general timing rules of generator interconnection replacement under the MISO Tariff require (1) that a request for generator interconnection replacement be submitted *at least one year prior* to the date that an existing generation facility will cease operation, Attach. X § 3.7.1(ii), and (2) the expected commercial operation date for a replacement facility must be *within three years* of the date that the existing facility ceases operation, Attach. X § 3.3.1.[11] These generator interconnection rules allow for the owner of an existing facility to request to itself replace the facility with another facility. The rules do not allow the owner of an existing facility to submit a request for a third party to build a replacement facility that will use the owner's existing interconnection

[11] Additionally, § 3.3.1 states that "For Existing Generating Facility that is in suspension pursuant to Section 38.2.7 of the Tariff or in Forced Outage, the start date of suspension or outage shall be considered the date of cessation of operation of the Existing Generating Facility for purposes of calculating the three (3) year limit."

rights. This reflects FERC's policy of prohibiting the buying and selling of interconnection rights

These rules, therefore, have the effect of prohibiting approximately the first 2,000 MW of Sherco interconnection reuse and the first 600 MW of King interconnection reuse from being fulfilled by PPA resources. These totals are approximately equivalent to the Company's interconnection rights at each respective site, per the existing unit sizes and – in the case of Sherco Unit 3 – our ownership share.

Although these rules limit the interconnection of non-Company-owned projects as generation replacement resources, PPA projects would be allowed as surplus resources for NSP-owned replacement resources. Our understanding is that the total existing interconnection rights creates a floor of owned installed capacity, but not a ceiling. Said another way, we can exceed 2,000 MW of installed capacity on the Sherco gen-tie, and any surplus capacity above that level does not necessarily need to be owned by the Company. The 2,000 MW interconnection rights do set a ceiling on the amount of instantaneous energy injection; meaning that if the model chose 2,000 MW of wind and 1,500 MW of solar for the Sherco gen-tie tranche, those resources combined could only inject 2,000 MW of energy into the grid at any given time and any excess production would need to be curtailed. Finally, these gen-ties can support only about half of the total resource additions that are needed under the Alternate Plan, and there is no restriction on ownership of resources that do not take advantage of the reuse of interconnection rights.

b. Tranches of capacity of interconnection re-use

In order to develop a proxy for generator replacement timing and total MW thresholds through modeling, the Company incorporated two new elements into our EnCompass set up. First, we included the estimated annual revenue requirements of the proposed gen-tie lines (as outlined above) into our Alternate Plan model as a fixed cost. Then, we set up tranches of renewables that the model could select to interconnect via these gen-ties and would fulfill the interconnection capacity left open when each coal unit ceases operations. The size threshold and timing of the tranches reflect a three-year replacement window; and as described above, we offer the model solar, wind and firm dispatchable capacity options in accordance with the timing of these windows and expected completion and in-servicing of the gen-tie lines.

Table 1-2: Retiring Coal Units and Selection Windows for Modeling Gen-tie Resources

Retiring Unit	Open Interconnection	Replacement Resource Window	Replacement Resources Allowed
Sherco 2	720 MW	2024-2026	Solar only
Sherco 1	710 MW	2027-2029	Solar, and Wind + ~400 MW of CT (2028-2029)
Sherco 3	566 MW	2030-2032	Solar + Wind
AS King	591 MW	2028-2030	Solar only

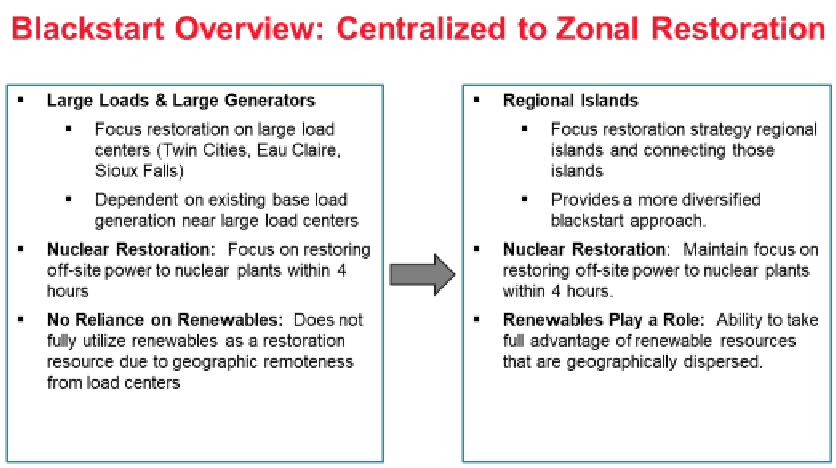
While generator interconnection reuse requires some Company ownership, there are still substantial opportunities for PPA resources on the gen-tie lines. We have reflected the cost of Company owned projects utilizing the existing interconnection by adjusting the cost of the first 2,000 MW interconnecting at the Sherco site and 600 MW at the King site to reflect our owned revenue requirements. The remainder of the capacity at each site is reflected at generic pricing, because, per the requirements described above, these additions could be PPA resources incorporated onto the gen-tie lines after the interconnection threshold is achieved. Costs assumed for gen-tie wind and solar resources are further detailed in Section 4 and Appendix A. As described further in the Modeling discussion in Section 4, we have also conducted sensitivities that examine the costs and benefits of our Alternate Plan under different federal tax credit reform futures; however, as these potential changes have not yet been put into law, our primary analysis represents our estimated revenue requirements as they exist under current policy.

B. Blackstart and Stability Resources

While we have developed an alternative system resource mix in this Alternate Plan that does not include the Sherco CC, we still need the important bulk power system supporting capabilities that would be provided by the Sherco CC. Regardless of the resource mix, our plan must also be operationally sound and meet the challenge of delivering power during times of high variability or the complete absence of renewable resource production such that those resources cannot provide sufficient stable energy. Operational reality calls for sufficient firm dispatchable capability to cover the inherent intermittence of renewable energy.

As discussed below and in Section 3, the Company has also worked to further develop a blackstart plan to support a future with increasing amounts of renewable resources. We discussed in both our initial July 2019 and our June 2020 Supplement that, as our Sherco units retire and our existing Initial Units reach the end of their useful lives, we will have to adjust our blackstart plan to incorporate different units and restoration paths. If the Alternate Plan is approved, we will need to transition from our current centralized restoration approach to a zonal restoration approach. While a different approach, the concepts remain the same – alignment of the zones is intended to match customer loads with the new types and locations of generation resulting from this Resource Plan to repower and stabilize the grid. Figure 1-5 below provides an overview of this shift in system restoration approach.

Figure 1-5: Summary of Change in System Restoration Plan Approach



Today, we rely on a single Blackstart Unit in Minnesota and Wisconsin to set the plan in motion. With the zonal approach, there would be Blackstart capabilities in each of the new zones. Thus, the zonal approach is more diversified, in that it will not rely on one or two large generators to repower a large portion of the system. Rather, small generators will be geographically distributed around our service area that will create a series of smaller islands that we will eventually join together, which will allow for the incorporation of renewables as part of the start-up process. And while this plan will ensure at least the same restoration pace, it also has the potential to restore greater numbers of customers across our entire footprint (not just our load centers) faster than the current plan.

Given that such resources will primarily serve the purpose of system restoration, we believe a separate proceeding to more broadly discuss restoration of the Minnesota system from a catastrophic event would be appropriate, particularly in light of the increase of renewable resources throughout the state and decrease of thermal baseload units that traditionally have been relied on for such purposes. In that proceeding, we would intend to discuss the specific resources we would intend to add to meet our system restoration needs under a zonal approach in future years. In the modeling used to develop the Alternate Plan, however, **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS].

1. Initial Blackstart Units

In our June 2020 Supplement we noted that our Initial Unit in Minnesota and our Target Unit in Wisconsin are reaching the end of their useful lives in the mid-2020s. While we included cost placeholders for the blackstart investments in our 2020 filing, we continued to work internally to develop plans to replace the unique and important grid attributes these units provide while also minimizing the amount of new gas-fired capacity on our system.

As noted in the blackstart discussion in Section 3, our new proposed Minnesota Initial Unit– **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]. In Wisconsin, **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

The units mentioned above have been included in our Alternate Plan in the years they will need to be placed into service to be able to replace the existing units at their current retirement dates. These near term blackstart investments will enable the feasibility of our restoration plans with limited near term re-routing, as we work to further develop the transition from a centralized blackstart plan to a more zonal approach that can incorporate more variable and use-limited resources.

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[12] **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS].

Table 1-3: Blackstart Units Modeled in Alternate Plan in 2025-2026

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

2. *Additional Greenfield CTs for System Support*

Aside from the two near-term blackstart needs highlighted above, there are two additional key CT units we believe are essential for reliability purposes. The first is a CT planned to be located in Fargo, and the other is a CT on the proposed Sherco gen-tie, in Lyon County, which will serve to support solar and wind additions on the proposed line and general energy needs.[13] Both of these locations are nearby existing gas infrastructure and avoid lengthy pipeline extensions to interconnect to the gas transmission system. **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS].

III. ACTION PLANS

A. Five-Year Plan (2020-2025)

Below, we discuss near-term actions by resource type and note that the resource additions are shown as selected by the modeling tool and may need to be smoothed during the implementation process to create a portfolio of projects that can be constructed effectively within the constraints of the market for equipment and labor.

[13] We also have a regulatory commitment to build a CT in Fargo that this would fulfill. We anticipate initiating a regulatory proceeding in North Dakota to procure this resource.

Solar. Our Alternate Plan continues to include significant amounts of large-scale solar resources, in addition to forecasted growth of distributed solar. Most notably, we have proposed significant amounts of solar additions through a gen-tie line reutilizing the interconnection at the retired Sherco and King coal sites (1,450 MW at Sherco and 650 MW at King). These additions start in 2024 with the retirement of Sherco Unit 2 and thus our development activities and associated regulatory proceedings will proceed in the near-term as we replace that capacity. We have already proposed the addition of a 460 MW Sherco Solar Project that is currently pending before the Commission.[14] The plan also indicates the addition of generic solar within the timeframe, which could be located elsewhere on the system.

Wind. We are continuing progress on the approximately 770 MW of wind generation from our recent repowering efforts.[15] Our Alternate Plan also proposes 2,150 MW of wind additions through a gen-tie line reutilizing the interconnection at the retired Sherco site. While these wind additions do not begin until 2028, procurement activities and potentially the regulatory proceedings for some additions could fall within the five-year plan. Additionally, to the extent we encounter opportunities to economically repower existing resources, or if specific customer programs (e.g. Renewable*Connect) require specific procurements, we expect to pursue them and submit the plans for approval in separate proceedings.

In total, there are nearly 6,000 MW of renewable additions over the course of this 15-year plan. Our proposal to reutilize interconnection opportunities with wind and solar additions fulfills just over 4,000 MW, with a requirement to own the first 2,600 MW of these additions, between the King and Sherco gen-ties. Accordingly, we expect to issue RFPs, that would allow PPAs to bid, to procure some of these resources as well.

Coal. Consistent with our last Resource Plan, we are continuing to work to retire Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026. The Alternate Plan also continues to propose retiring King at the end of 2028 and Sherco 3 in 2030.

Nuclear. Our Alternate Plan continues to include a request to operate our Monticello nuclear unit for an additional 10 years beyond its current license. We plan to initiate a Certificate of Need proceeding in Minnesota in the next several months, as well as a Subsequent License Renewal process with the Nuclear Regulatory Commission, within the next several years. Within the next five years, we will also continue our evaluation of, and make a decision on, the extension of the Prairie Island license in

[14] Docket No. E,G999/M-20-891
[15] Docket No. E002/M-20-620

the five-year plan. This work will include outreach and discussions with the Prairie Island Indian Community, the City of Red Wing, and other community interests, and continuing efforts to identify a long-term used fuel storage solution. If a decision is made to extend the Prairie Island license, we would file a petition seeking a Certificate of Need in Minnesota within the Five-Year Action Plan window as well as commence a Subsequent License Renewal process with the Nuclear Regulatory Commission thereafter.

Firm Dispatchable and Blackstart Resources. Unlike our previous proposed plans, the Alternate Plan does not include the Sherco CC, notwithstanding our statutory authorization to construct, own, and operate the unit in our sole discretion. However, in order to reliably operate our system and support our transition to a new blackstart restoration approach without the Sherco CC, we need to invest in hydrogen-capable CT units in the near-term. This includes 400 MW of CTs in Lyon County, Minnesota, 400 MW CTs in Fargo, North Dakota and two specific brownfield repowered resources in Wisconsin and Minnesota by 2026. We would expect to initiate regulatory proceedings in other states for the resources in Fargo, North Dakota and Wisconsin in the five-year action plan. We would also initiate a proceeding in Minnesota for the Lyon County CT. The repowered facility in Minnesota, however, does not require a separate regulatory proceeding for a certificate of need as it falls under an exemption. Specifically, it qualifies under Minn. Stat. § 216B.243, Subd. 8(a)(6), which applies to "the modification of an existing electric generating plant to increase efficiency, as long as the capacity of the plant is not increased more than ten percent or more than 100 megawatts, whichever is greater." In addition, we also propose initiating a new regulatory docket in the near-term to discuss broader blackstart issues that would include the consideration of other blackstart additions (beyond those mentioned in this paragraph) in the later years of the plan to consider optimal technologies.

Demand Response. The Alternate Plan continues to include the acquisition of 400 MW of incremental DR resources by 2023.

Energy Efficiency. The Alternate Plan continues to include significantly increased levels of EE with average annual energy savings of over 780 GWh.

Additional infrastructure. Our Alternate Plan includes two company-owned gen-tie lines connecting to our soon-to-be-retired coal plants at King and Sherco. The Sherco gen-tie line will be a double circuited 140-mile 345kV line terminating at a single location going south from Sherco to Lyon County in southern Minnesota. This gen-tie will enable the interconnection of over 2,100 MW of wind, nearly 1,500 MW of solar, and approximately 400 MW stability-providing and reliability-enhancing CT at the end of the line. The King gen-tie line will be one approximately 15-mile 345kV line going east from King into Wisconsin where we will reutilize the King interconnection to build 650 MW of solar. In order to ensure the preservation of both valuable interconnections and allow the appropriate regulatory processes to ensue, we are including these investments in our five-year action plan. We anticipate both gen-tie lines to take approximately five years to permit and build, and therefore we would start these efforts, including the associated regulatory proceedings, within the five-year plan window. Similarly, we would also initiate regulatory proceedings for many of the wind, solar, and CT resources within that same time frame.

B. Long-Term Plan (2026-2034)

The proposed actions we would take during the 2026-2034 period, under the Alternate Plan, include:

- Adding 3,150 MW of utility-scale solar over the course of the plan, with 1,850 MW of the total being added during 2026-2034.
- Adding 2,650 MW of wind over the course of the plan, with additions beginning in 2028.
- Continuing plans to retire Sherco Unit 1 in 2026, and the proposed retirement of King in 2028 and Sherco Unit 3 in 2030.
- Adding 250 MW of storage.
- Accommodating 575 MW of distributed solar over the course of the plan.
- Continuing to pursue a Certificate of Need, and a license extension with the NRC, for the Monticello plant and continuing next steps for Prairie Island, once determined.
- Adding approximately 1,900 MW of firm dispatchable resources in the long-term; these additions could be DR, storage, hydrogen, CTs, or other new technologies depending on cost, reliability, and state policy goals
- Developing additional regional transmission infrastructure.
- Continuing plans to grow our DR portfolio by approximately 550 MW, to a total portfolio size of approximately 1,500 MW by 2034.
- Continuing plans to achieve average annual energy savings of over 780 GWh, through our EE programs.

In addition to these specific plans, we continue to anticipate that, over the next fifteen years, we will consider ways to increase electricity storage on our system, explore technologies and resources that can help us achieve 100 percent carbon-free electricity by 2050, and find ways we can leverage carbon-free electricity to reach statewide environmental goals—including by electrifying other sectors of the economy, like transportation.

IV. CONCLUSION

The Alternate Plan achieves increased renewables, a greater reduction in carbon emissions, and adds less gas capacity than our Supplement Plan while improving reliability and affordability.

We recognize that any plan will have impacts both on the communities we serve and our employees. We appreciate not only the challenge but the stakes for those impacted, and we plan to build on our successful track record of working with our communities, policymakers, stakeholders and employees to successfully manage this clean energy transition.

In order to ensure we have the all the necessary resources and supporting infrastructure to continue to operate our system in a safe, reliable, and affordable way, Xcel Energy needs to plan for the future. Accordingly, we respectfully request approval of our Alternate Plan as detailed in this filing and highlighted below:

- Approval of Company ownership of Sherco and King gen-tie lines plus renewable resources added on the lines;
- Approval of 400 MW of CTs in Lyon County, Minnesota and 400 MW CTs in Fargo, North Dakota;
- Approval to continue pursuing a 10-year extension for our Monticello Nuclear plant; and
- Approval for blackstart shift to zonal approach and need for blackstart resources in each zone which includes:
  - Two specific blackstart additions in Minnesota and Wisconsin by 2026; and
  - New regulatory docket to discuss broader blackstart issues that would include the consideration of other blackstart additions in other zones in the out years of our plan to consider optimal technologies.

We recognize there will be additional regulatory proceedings to ensure resource acquisitions are in the public interest and siting and routing requirements are met. In our last resource plan, the Commission approved the use of the Modified Track 2 process for the acquisition of wind and solar resources through 2021.[16] We believe the Modified Track 2 process has proven to be successful since our last IRP. The process ensures competitive resource procurements when the Company submits a bid to build a resource, while maintaining the efficiencies of the Commission's Track 1 process. We also note that the Department has supported our use of the Modified Track 2 process to acquire wind and solar resources since our last IRP but has raised concerns when we have acquired resources outside of the Commission's approved processes. Therefore, we request that the Commission allow for the use of the Modified Track 2 process to acquire resources approved in this IRP. Specifically, we request that the Commission approved the use of the Modified Track 2 process for the following acquisition proceedings:

- Solar and wind resources that utilize the transmission interconnection at Sherco
- Solar resource that utilize the transmission interconnection at King
- Approximately 400 MWs of CTs in Lyon County to connect to the transmission interconnection at Sherco
- Any wind or solar additions needed before the next resource plan.

As discussed above, we note that the ownership and geographical scope of the resources acquired to utilize the interconnection rights at King or Sherco will necessarily be limited. However, a competitive bidding process, such as the Modified Track 2 process, continues to provide a valuable framework to evaluate competing proposals and advance the public interest.

In addition, we anticipate the following regulatory filings:

- A Certificate of Need (CN) and Route Permit for a transmission line to the interconnection at Sherco
- A CN and Route Permit for a transmission line to the interconnection at King
- Site permits needed for any acquisitions of generation, including generation to utilize the Sherco and King interconnections.

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[16] *See* Docket No. E002/RP-15-21. ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS (January 11, 2017) at Order Point 5.

- New regulatory docket to discuss broader blackstart issues that would include the consideration of other blackstart additions in other zones in the out years of our plan to consider optimal technologies.

SECTION 2: RELIABILITY

A. Reliability Has Always Been, and Continues to Be, a Central Part of our Planning

We are excited about our active role in leading the clean energy transition, and our plan to increase the amount of renewable generation and achieve significant emission reductions, while at the same time maintaining a reliable system. We believe that both our Supplement Plan and Alternate Plan achieve this balance. But, doing so required a careful examination of reliability considerations as we move from a system built on baseload and load-following resources to one that relies more on variable, weather-dependent resources. The variable and intermittent nature of renewable resources creates a certain amount of unpredictability in our system which must be managed through careful planning.

The North American Electric Reliability Corporation (NERC) defines a reliable electrical system as one that is able to meet the electricity needs of end-use customers even when unexpected equipment failures or other factors reduce the amount of available electricity, and divides reliability into two categories:[1]

- *Adequacy*. Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time. Maintaining adequacy requires system operators and planners to take into account scheduled and reasonably expected unscheduled outages of equipment, while maintaining a constant balance between supply and demand.
- *Security*. For decades, NERC and the bulk power industry defined system security as the ability of the bulk-power system to withstand sudden, unexpected disturbances, such as short circuits or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by manmade physical or cyber-attacks. The electrical system must be planned, designed, built, and operated in a manner that considers these modern threats, as well as more traditional risks to security.

The ability to provide reliable electric service depends on a complex and interconnected network of generating resources and transmission infrastructure that provides capacity and delivers energy to customers. Historically, the grid consisted

[1] North American Electric Reliability Corporation, http://www.nerc.com/AboutNERC/Documents/NERC%20FAQs%20AUG13.pdf (last accessed on June 22, 2021).

primarily of traditional thermal and hydropower sources which can and have been essential to serving our reliability function. The grid has continued to transition away from many of these traditional resources. Thermal plants are retiring and variable and use-limited resources such as wind, solar and battery energy storage are increasing. This means that the quantity of resources that have traditionally provided grid resilience attributes are decreasing, and the quantity of resources that require the grid to operate more flexibly are increasing. Overall, grid operators must ensure that, as the mix of resources on the grid continues to evolve, all the necessary resource attributes that ensure the reliable supply and delivery of electricity to customers remain present.

In its 2020 Long-Term Reliability Assessment Report, NERC recognized that the increase in renewable generation creates new planning considerations and a growing need to factor in the uncertainty associated with the inherently variable nature of these resources:[2]

> The addition of variable energy resources, primarily wind and solar, and the retirement of conventional generation is fundamentally changing how the [bulk power system] BPS is planned and operated. Resource planners must consider greater uncertainty across the resource fleet as well as uncertainty in electricity demand that is increasingly being affected by demand-side resources. As a result, reserve margins and capacity-based estimates can give a false sense of comfort and need to be supplemented with energy adequacy assessments. Energy assessments are key to understanding the reliability needs of a future BPS.

These heightened planning considerations are becoming necessary year-round and not just in the summer months. As MISO stated in its recent report on Winter Storm Uri in February 2021:

> Resource adequacy planning needs to be refined. Historically, tight supply and demand conditions typically only occurred on a few peak days in the summer, but today MISO experiences such conditions with increasing frequency across all seasons. Changing from an annual to a seasonal resource adequacy construct will help address this new reality.[3]

[2] See North American Electric Reliability Corporation, 2020 Long-Term Reliability Assessment, available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf (last accessed on June 22, 2021).
[3] *See* MISO, "The February Arctic Event, Event Details, Lessons Learned and Implications for MISO's Reliability Imperative" available at: https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf (last accessed on June 22, 2021).

Indeed, MISO's CEO, John Bear, recently explained that "five of the six events that have stressed our system . . . have been non-summer cold weather events."[4] Winter storms and polar vortex conditions have affected the region multiple times including in 2011, 2014, 2019 – and most recently, in early 2021. In light of these winter weather emergencies that are occurring with greater frequency, we must ensure resource adequacy across the entire year.

In addition to these extreme weather events, variations in weather impact fuel for generation. For example, extended periods where there is no wind or sun, extreme heat conditions which may decrease water levels for hydro generation, significant snowfalls that cover solar panels are just a few of the considerations that negatively impact reliability and resource adequacy and which we must factor in. The changing nature of our resource mix and increasing dependence on variations in fuel supply changes the roster of risks that negatively impact reliability and adequacy of energy supply to our customers. While renewable generation is an excellent energy resource, it is not by itself an excellent capacity or demand resource. To be an excellent capacity or demand resource, we must be able to have control over the resource, that is, ensure that it is firm and dispatchable. As our system planners understand, resource adequacy is the foundation of a reliable Bulk Power System, and we must take steps to reduce the reliability risks.

As discussed in more detail below, the recent electricity blackout events in Texas underscore the need to carefully plan the system to be resilient to extreme weather events. We and other utilities are significantly increasing the amount of renewable generation on our systems, and as a result, increasing the risks associated with lack of continuity of energy supply. To mitigate those risks, our renewable additions must be measured and supported by sufficient firm, dispatchable resources. In addition, all resource types must be reasonably prepared for extreme weather conditions. Weather-related threats to the electricity system are increasing in frequency and intensity and are projected to worsen in the future. As a result, it is prudent to take steps to ensure that we have sufficient production capacity to handle unexpected demand spikes or supply shortfalls.

Our Alternate Plan represents yet another step in the ongoing evolution of the regional electric grid. While the electric utility industry has evolved significantly over the past several decades, that evolution has accelerated in recent years.

Our new plan marks the end of an era. We no longer plan to rely on large central station power (discussed below) for resource additions and will continue our move

[4] *See* S&P Market Intelligence, "Grid Officials Mull Lessons Learned from February Freeze," June 11, 2021.

toward a diverse resource mix that is distributed across the region. This move requires thoughtful planning to ensure reliability and maximize efficiencies while increasing the amount of variable generation on the grid.

In the next section, we set forth the history of the grid over the past century and the advancement of utility systems to reliably meet customer needs. This historical context provides useful background for the development of our Alternate Plan and for our vision for the future. Over the past century, we have continually adapted to changes in technology and the needs of our customers. Throughout our history, we have always prioritized reliability. The move away from central station power marks an inflection point in the ongoing evolution of the grid. We are confident that we can meet the challenges before us as we continue this evolution.

B. History of the Grid

1. 1911-1960: Generation Near Load, A History Rooted in Coal

Most of the Company's first generators were coal-powered and constructed close to the Twin Cities, our main load center. Built in 1911, the Riverside Plant in Minneapolis was the first coal-powered station on the Xcel Energy system and was expanded numerous times in the following years. The coal-powered High Bridge Plant in St. Paul was built in 1923.

For over 50 years, the Riverside and High Bridge units formed the hub of Northern States Power Company, a predecessor to Xcel Energy.

These early plants were located in the center of our largest loads. By the late 1950s, however, the existing system and local generation plants could no longer produce and deliver enough electricity to meet the needs of the growing population and economy encompassing the NSP System. At the time, load was growing by 7 percent annually – doubling every 10 years. The then-existing transmission system was strained and it became evident that significant high-voltage upgrades to the transmission system and new generation sources had to be added to continue to provide adequate service to customers.

2. 1960-1990: Transmission and Economies of Scale

In the 1960s and in response to the need for larger electric generators to support the rapid load growth, the Company built the 345 kV transmission loop around the Twin Cities that follows the Highway 494/694 ring. The expanded transmission system allowed interconnected generators to efficiently supply a larger geography of load. Whereas in the past, the system could withstand an outage of a smaller power plant and local generation support was available, once the larger plants came on-line, power could be imported from other states if one of the generators went off-line.

In addition, to provide greater reliability, the Company embarked on a series of investments that benefited the area and supported the overall goals of maximizing economies of scale and enhancing fuel diversity. NSP and six other regional utilities constructed a new 345 kV transmission line from the Twin Cities to St. Louis. Two other 345 kV lines, connecting the Twin Cities to Chicago and Omaha, were also built. NSP was also instrumental in developing and building a 500 kV transmission line from Winnipeg to the Twin Cities. This line facilitated the import of significant amounts of hydro-electric generation from Manitoba to Minnesota and the rest of the NSP System.

This transmission system development facilitated the Company's ability to support highly efficient large central station generators in the 1970s. In that timeframe, NSP's new plant investments included the following:

- 1968: Allen S. King Plant
- 1971: Monticello Nuclear Plant
- 1973-74: Prairie Island Nuclear Plant
- 1973-74: Sherco Plant
- 1980s: Sherco Unit 3

These large generators were made possible because of the development of the regional transmission system. Together, these generators allowed NSP to provide adequate and low-cost service to all of its customers served by the integrated system.

These larger central station power generators were much more efficient and cost-effective than the smaller generators built in previous decades and allowed the system to be expanded in a way that served all customer needs throughout the five-state region. The addition of the 500 kV transmission line from Manitoba to Minnesota facilitated the import of a significant amount of hydroelectric generation.

In the 1980s and 1990s, the Company added a significant amount of natural gas generation to the system, including peaking units and combined-cycle intermediate units spread throughout the system to provide system support as well as energy and capacity to the system.

The development of these larger power plants supported customer needs by efficiently maximizing the economies of having a robust transmission system and several large central-station generation sources. Because the Company now had coal, nuclear, hydro, and natural gas generation, we reduced our overreliance on any particular fuel source, allowing us to hedge our fuel cost risk.

3. 1990-2010: Further Transmission Expansion, Renewables and RTOs

Although stand-alone resources and intra-system integration were historic cornerstones of utility systems, significant regulatory changes in the past several decades have moderated the importance of utilities having significant stand-alone resources in the same manner as in the past. This change allowed utilities to move away from planning and operating on a stand-alone basis toward a competitive market-based structure that expanded the benefits of the larger system and allowed for increased participation by more market participants.

In the 1990s, the Company began to add wind resources to our system and we have continued to add increasing amounts of renewable resources since that time. The Riverside and Highbridge plants, once the cornerstones of the Xcel system, were replaced with natural gas generation in the late 2000s as part of the Metropolitan Emissions Reductions Program (MERP).

One of the most significant developments in this phase was the creation of regional transmission operators (RTOs). FERC Order Nos. 888 and 889 required all public utilities to provide open access to their transmission facilities. These landmark orders further required utilities to separate their marketing and generation functions from their transmission functions and set the stage for the formation of RTOs.

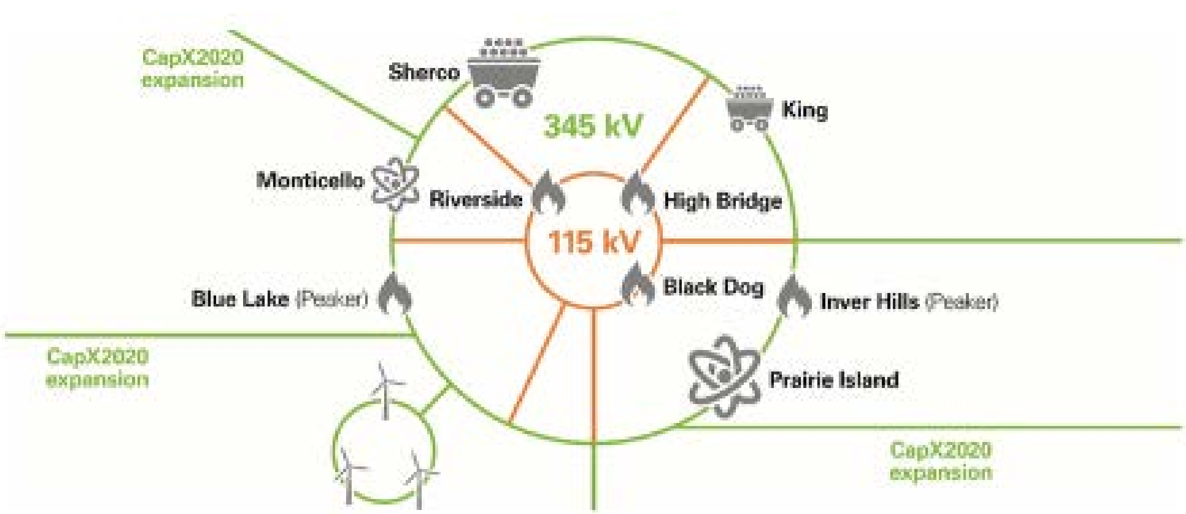
This led to the development of the Midcontinent Independent System Operator (MISO) as an independent system operator in the early 2000s, further opening the regional system to competitive forces.

Beginning in 2005, MISO implemented its energy market function and began centralized dispatch of all generation across its upper-Midwest footprint. The centrally-operated market was expanded in 2009 to include ancillary services and in 2013 to include a voluntary capacity auction. This overall competitive market structure allows energy, capacity, and ancillary services to be transacted through a centralized market based on bids and offers that are cleared and administered by MISO.

As the system has evolved, coordinated transmission planning across a broader region has continued to take on increased importance. The CAPX transmission expansion projects, which were planned and built in 2004-2017, were the first major expansion of the regional transmission system in 30 years. The CAPX effort included 10 utilities that partnered to develop the project and meet a broad set of needs across the region. Transmission planning through the MISO Transmission Expansion Process (MTEP) has played an important role in developing transmission that serves broad regional needs. The CAPX lines and Multi-Value Project (MVP) lines developed across the MISO footprint were critical investments necessary to take the next step in enabling renewable resources to interconnect to the grid across a broad geography while maintaining reliability in the region.

The below figure is a simplified illustration of the major components of our current system. The Riverside, Highbridge, and Black Dog plants are located on the 115 kV system in the core of our Twin Cities load. Our nuclear, coal, and additional dispatchable resources are located on the 345 kV system surrounding the Twin Cities. The 345 kV ring is connected to surrounding load centers by 345 kV lines, including three lines completed as the CAPX 2020 expansion.

Figure 2-1: Major Components of Our Current System



4. *2010 – Present: Higher Levels of Renewables and Coal Retirement*

This balanced system relying on a mix of central station power with expanded transmission ties to the wider system has produced a highly reliable system and one that enabled a significant integration of variable renewable resources. This balanced system also allowed for the creation of a Blackstart plan where small plants would be started and through utilization of the transmission system would provide power to the central station power units in order to bring them online. The Sherco CC was proposed as a continuation of this highly reliable system, restoration plan, and its reliance on central station power.

Over the past decade, we have added over 3,000 MWs of wind resources and over 500 MWs of solar resources. In 2020, approximately 30 percent of our generation was from renewable sources and we plan to continue to add large additions of renewable resources in the next decade. In addition, we have proposed to retire our coal fleet by 2030 and achieve our goal of reducing carbon emissions by 80 percent from 2005 levels. Our 2020 Supplement Plan proposed a resource mix that achieved some of the most ambitious carbon reduction goals of any utility in the United States through retirement of our coal fleet, extension of nuclear, significant renewable additions, demand-side management, including both energy efficiency (EE) and demand response (DR), and a mix of load-supporting, firm peaking resources. The Supplement Plan also continued to include the addition of a combined cycle unit at the Sherco site to be placed into service prior to the retirement of Sherco Unit 1 in 2026.

5. *The Future: Our Alternate Plan*

In response to the concerns raised by stakeholders regarding the Sherco CC, we conducted extensive supplemental analysis. We analyzed the impact of removing the Sherco CC on the reliability of our system, on our blackstart plan, and on the costs and expansion units included in our preferred plan. We created three teams to evaluate these impacts: (1) a transmission and system stability team; (2) a blackstart team; and (3) a renewable integration and replacement resources team. The teams had the following objectives:

- <u>Transmission and System Stability</u>*:* Conduct analysis to determine whether system stability can be maintained without the construction of the Sherco combined cycle and the replacement of the retiring Sherco capacity largely with renewable generation and any necessary supporting CT capacity. Ensure that voltage is maintained within Nuclear Regulatory Commission requirements at our Monticello Nuclear Plant and develop a plan to address any thermal or voltage violations.
- <u>Blackstart</u>: Conduct analysis to determine alternative target units and blackstart paths assuming no combined cycle at Sherco and retirement of the coal units according to current planning timelines.

- Renewable Integration and Replacement Resources: Conduct analysis to determine (1) whether dispatchability needs can be economically met without construction of the Sherco combined cycle, (2) combinations of replacement generation and other investments that could be viable economic alternatives to the Sherco combined cycle, and (3) a recommended replacement strategy based on economic modeling and system considerations.

As discussed in more detail below, based on the analysis conducted by each team, we concluded that we could remove the Sherco CC from our plan, develop an alternative blackstart plan, achieve greater emissions reductions and improved reliability, and maintain the major elements of our Supplement Plan without increasing costs to our customers.

Our Alternate Plan achieves increased renewables and adds less gas capacity than our Supplement Plan. In addition, we plan to continue our partnership with the City of Becker and local stakeholders and to make investments in the Sherco area, including our recent proposal to add 460 MWs of solar adjacent to the Sherco site. We are excited to bring this Alternate Plan to the Commission and our stakeholders for consideration.

Throughout this resource plan proceeding, we have analyzed our potential plans to ensure that we maintain reliability. In our initial 2019 Resource Plan filing, we developed a Reliability Requirement to ensure we would have sufficient capacity on our system to meet our customers' needs every minute of every day as the grid evolves to include significant amounts of variable resources. Our Alternate Plan also meets the Reliability Requirement we developed to ensure reliability as part of our initial 2019 Resource Plan filing.

C. Background on Development of the Reliability Requirement

Given the amount of dispatchable capacity that is scheduled to retire from our system in the next 15 years, in connection with our original filing in this proceeding, we developed a Reliability Requirement as a starting point to ensure that our system would continue to be resilient and that our customers continue to experience the high levels of reliability they expect. The Reliability Requirement concept grew out of the evolution of the grid including the volume of new variable, renewable resources we propose to add, and the fact that MISO planning constructs will need to evolve to incorporate the potential effects of large variable resource additions. In establishing the Reliability Requirement, we took the following steps:

1. Approximating the customer peak demand to serve as a proxy for the most likely conditions where we could expect to have a gap between renewables performance and customer load.
2. Assessing the contribution we could reasonably expect from duration-limited resources like demand response or energy storage to fill the gap.
3. Estimating the extent to which it is financially and operationally reasonable to rely on the MISO market to contribute a portion to filling the gap.

Using these inputs, we derived a level of firm dispatchable resources needed to support the significant renewable additions we are planning to reasonably assure reliability. It is this level of firm dispatchable resources that ultimately formed the Reliability Requirement that we incorporated into our modeling for our initial 2019 Resource Plan filing. In short, we developed and designed a Reliability Requirement to ensure that we would have the proper mix of resources on our system to meet our customers' needs every minute of every day.

D. Application of the Reliability Requirement in 2019 Preferred Plan

In our initial 2019 Resource Plan filing, we included the Reliability Requirement in our Strategist modeling because Strategist was incapable of modeling reliability needs every hour of the year; rather, Strategist could only provide a view of needed capacity to meet *annual* requirements according to load duration curve assessments. Specifically, Strategist took 2,014 hours of load for each year – one week from each month – and arranged the load from highest to lowest, creating a load duration curve. It then simulated a resource portfolio dispatch that ensured that energy was procured to serve the annual load, which was later adjusted to account for market purchase and sales opportunities.

We used the Strategist modeling to analyze our proposal to retire our coal generation and a new resource plan that achieved ambitious carbon reduction goals and dramatically shifted our generation mix in our initial plan. In furtherance of our goals, we developed a level of firm, dispatchable resources that we ultimately incorporated into our modeling known as the Reliability Requirement. Using the Reliability Requirement and other inputs to the Strategist modeling including the addition of the Sherco CC, we determined a minimum level of firm dispatchable, load supporting resources necessary to maintain a reliable supply of power during high-impact low-frequency events such as the 2019 polar vortex as well as other "typical" summer or winter days that have low renewable performance due to low wind speeds and/or the lack of sunshine. What we found is that firm dispatchable resources are needed to fill extended periods of time when output from renewable resources are low and load is high. Therefore, to ensure reliability during *all conditions*, the Company proposed the addition of 1,700 MW of firm peaking resources in the out years of the Initial Preferred Plan.[5]

E. Application of the Reliability Requirement in 2020 Supplement

In preparing our 2020 Supplement Plan, we conducted modeling using our legacy Strategist tool and also used a new, more robust modeling tool – Encompass. The Encompass modeling better reflects actual market conditions and hourly production cost models. While EnCompass uses representative days to evaluate capacity expansion, we use the model's full 8,760-hour chronological modeling capabilities to run dispatch and costing analyses for the years 2020 to 2045. The EnCompass modeling provides more granular forecasting capabilities and thus a more accurate view of our future energy and capacity needs. As a result, the Encompass modeling serves as a better proxy for our reliability needs. Encompass validated our use of a Reliability Requirement in our Initial Preferred Plan and confirmed our assessment that there is a need for firm dispatchable resources to support the variable renewable generation additions we are proposing.

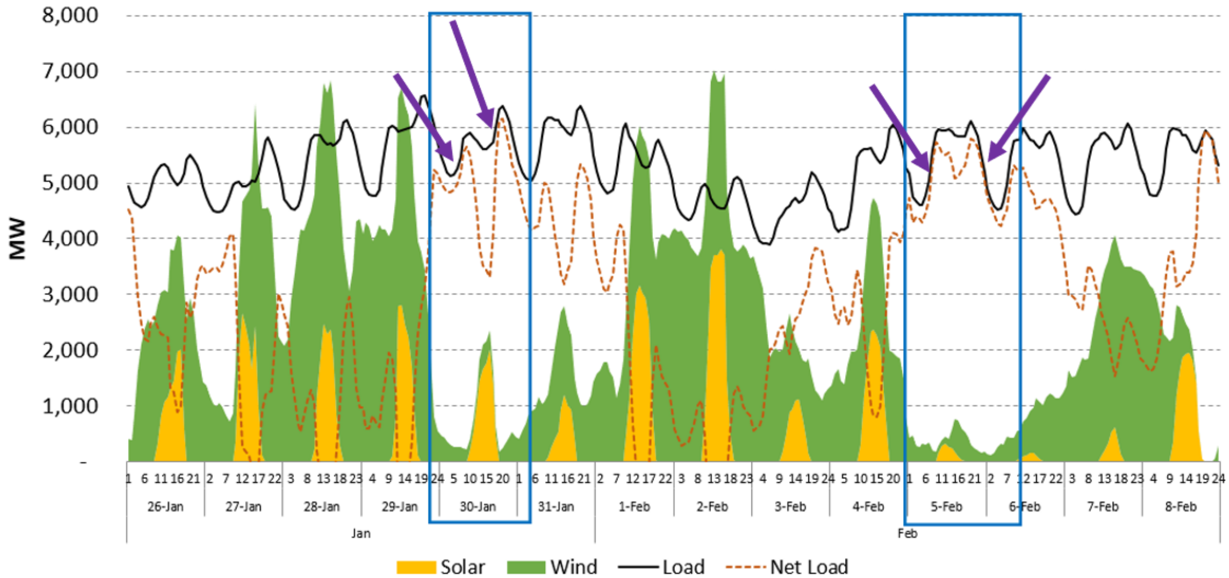
In the Supplement, EnCompass selected approximately 2,600 MW of firm, peaking resources in the 2030 to 2034 timeframe through its optimization; this means that we did not force the model to include these resources – it selected them as part of a least-cost and reliable portfolio. Using Encompass, we learned that a more diverse range of resources provides operational value for system stress-related events. We ultimately selected a portfolio that included a greater balance between solar, wind, and firm dispatchable additions as compared to the Strategist modeling, which selected large quantities of solar additions with much smaller quantities of wind and firm peaking resources. The Supplement Plan continued to include the Sherco CC.

Conducting an analysis based on data from the 2019 polar vortex, we saw that firm dispatchable resources were critical to meeting demand during severe and prolonged cold temperatures. During the January 29-31, 2019 three-day time period, despite relatively high wind speeds, the output from wind resources was significantly lower than expected due to the ambient temperature dropping below the minimum operating temperature of the wind turbine equipment. At multiple time periods during these three days, output from renewable resources would not have met actual consumer demand without a contribution from dispatchable resources. Figure 2-2 below depicts the approximated output for the NSP System during the 2019 polar

[5] Had we not included the inputs from the Sherco CC, we likely would have seen a higher need for firm dispatchable resources.

vortex, assuming that we had *twice as much wind* on our system with the same average level of output.

Figure 2-2: Approximated NSP System Output – 2019 Polar Vortex



This data shows that adding more renewables to the NSP System alone is not sufficient to mitigate all gaps in output caused by low temperatures or low wind speeds. As this Figure shows, even when we hypothetically doubled the amount of wind output (shown in green), there were at least two periods – during the January 30 to February 5 period – where wind generation was likely to have minimal impact on net load.

We experience these types of events – long durations where renewable output is low – periodically, and we need to ensure we have resources available to support our customers' load throughout them. As discussed in more detail below, Winter Storm Uri was another example of this type of event that affected our system and the nationwide electrical system.

F. Winter Storm Uri Demonstrates the Need for Firm Dispatchable Resources

In mid-February 2021, a powerful winter storm brought snow, ice and below-freezing temperatures across much of the United States and the Upper Midwest. Weather conditions prompted emergency declarations in several states and the extreme weather brought widespread power outages to millions of Americans.

Texas saw the most extreme impacts, where the cold weather caused problems with all of the state's power sources and, at the same time, demand for electricity soared. Faced with a massive discrepancy between supply and demand, grid operators initiated rolling blackouts to provide relief to the grid and with the hope of averting a catastrophic system failure. Recent reports have indicated that the ERCOT portion of the Texas power grid came within five minutes of a catastrophic and complete failure.[6] Had the system collapsed, a statewide blackout would have occurred, taking weeks or even months to correct.[7] In an attempt to avoid this situation, the state initiated rolling blackouts, which lasted for days, and caused suffering, destruction, and even death. An extended blackout would no doubt have made a difficult situation much worse. Amidst the freezing temperatures, thousands of Texans did not have heat or running water for days. Pipes in many homes and buildings froze, then thawed – spewing water and causing untold amounts of damage. Businesses were unable to function, leading to lost production and ripple effects on suppliers and the entire U.S. economy.

The cold weather in Texas broke record lows over the past 100 years and devastated Texas' grid infrastructure within ERCOT, as major generation units failed for some period of the storm. All modes of energy supply were affected and demonstrated they were ill-prepared to handle extreme weather. The learnings from Texas reinforce the importance of ensuring a diverse resource portfolio – and that resources are reasonably equipped to handle extreme weather circumstances.

The cost to Texans from this single event is estimated to be more than $200 billion, which will likely lead to large rate increases in the future. Many energy experts believe the damage and loss that occurred in Texas could have been prevented had the state required the necessary investments to improve the weather-resistance measures of the system.

G. Impacts of Winter Strom Uri in Minnesota

While also impacted by winter storm Uri, Minnesota's electric system was spared the disastrous situation that unfolded in Texas. As compared to the 2019 polar vortex that only lasted a few days, winter storm Uri brought extreme cold temperatures to Minnesota that was longer in duration, but less acute overall. Renewable performance during Uri was predictably low throughout the entire cold spell. Figure 2-3 below

[6] Wall Street Journal, "The Texas Grid Came Close to an Even Bigger Disaster During February Freeze" available at: https://www.wsj.com/articles/texas-electrical-grid-bigger-disaster-february-freeze-black-starts-11622124896, May 27, 2021.
[7] *Id.*

shows the average temperatures throughout the entire Midwest between February 12-18, 2021 was 20 to 25 degrees below normal. Since resources in this area were weatherized to a greater degree than in Texas, they were better able to withstand these temperatures. Nevertheless, the temperatures reached such low levels that they created operational difficulties for some wind turbines at different time periods throughout this event.

Figure 2-3: Average Temperature (F): Departure from 1981-2010 Norms February 12, 2021 to February 18, 2021

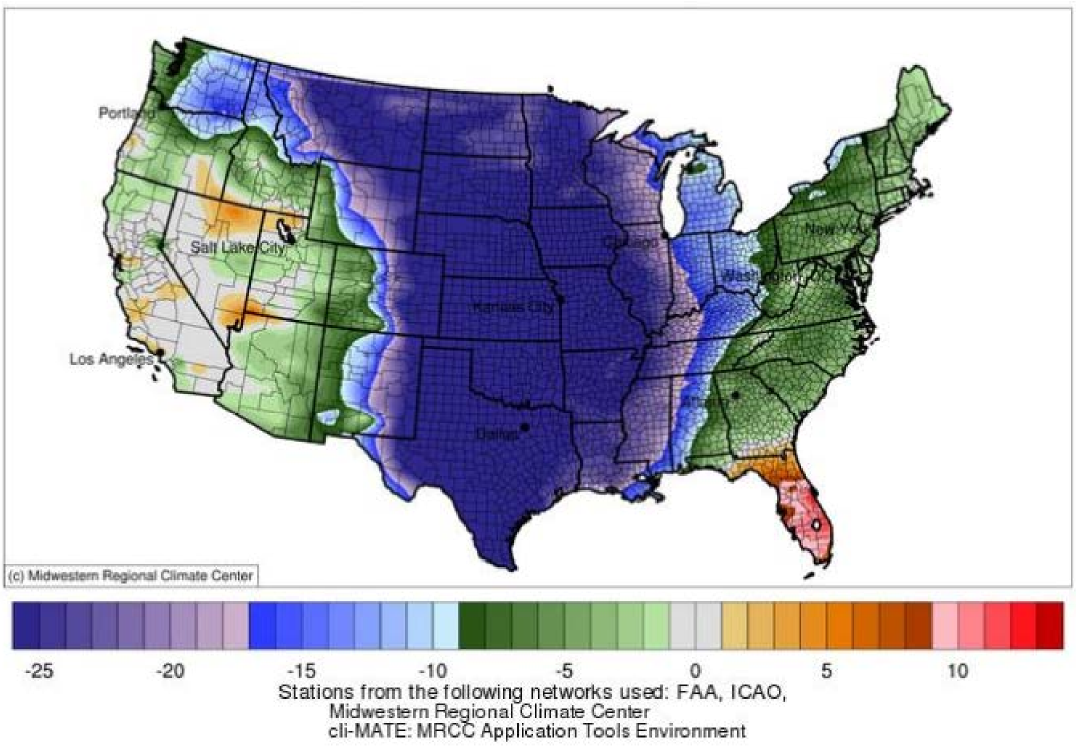
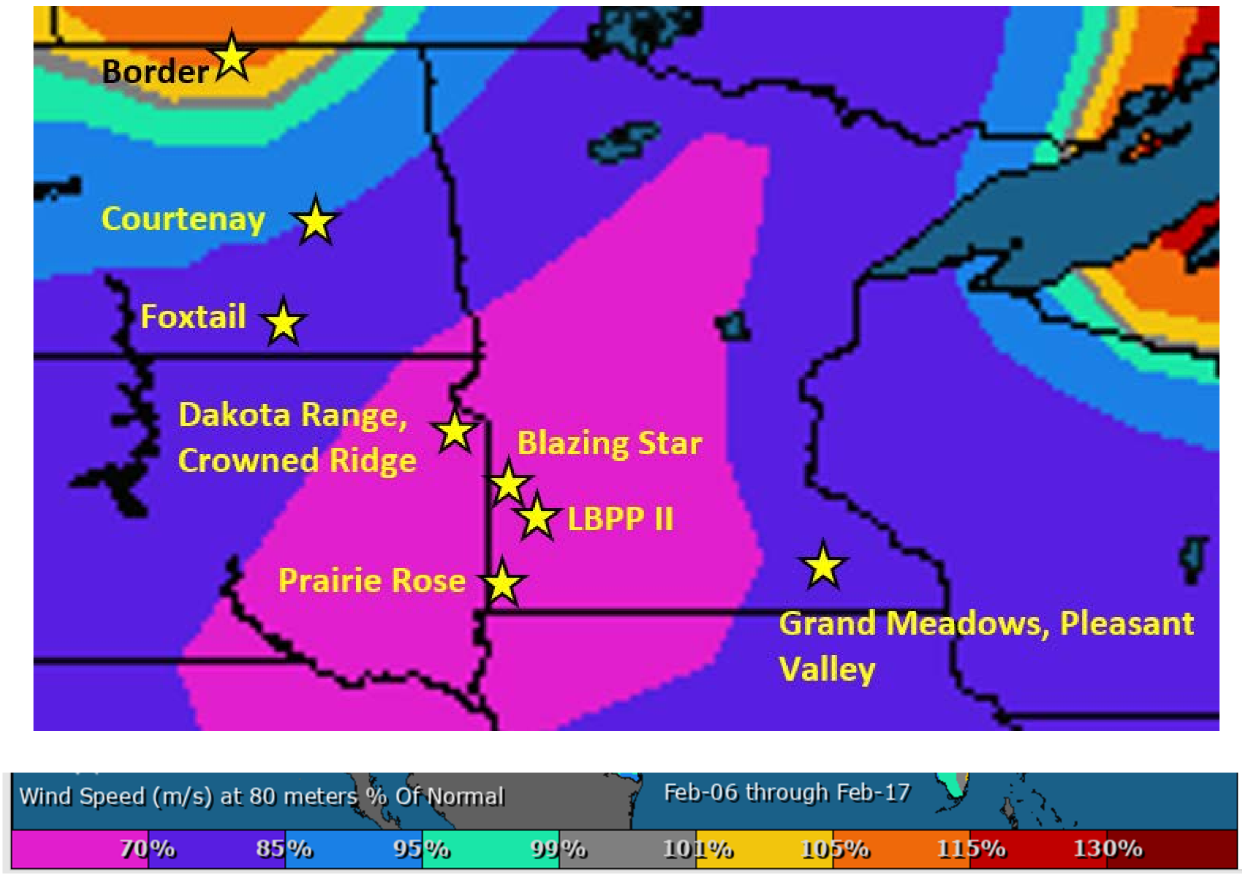


Figure 2-4 below shows that the average wind speeds during this timeframe were about 70 to 85 percent below normal levels.

Figure 2-4: Average Wind Speed Departure from Normal at Turbine Height – February 6-17, 2021



Figures 2-3 and 2-4 demonstrate that multiple weather risks can impact the *entire* NSP System footprint at once – including a wind fleet spanning a distance of approximately 500 miles. Similarly, extreme events can span all or nearly all of MISO's footprint, limiting the ability to rely on the broader MISO system in times of need. To meet the shortfall in the output of variable resources, we relied on our resource diversity and our dispatchable generation, including units fueled by natural gas and fuel oil.

Our three nuclear units performed extremely well throughout the February cold spell. At any given time, nuclear plants have 18 to 24 months of fuel supply and can run when other energy resources are interrupted by extreme weather or other circumstances. Nuclear plants are built to withstand extreme weather, as proven during hurricanes and freezing temperatures driven by severe weather and temperatures not uncommon during Minnesota winters. Indeed, our nuclear fleet operated at 100 percent capacity factor during recent polar vortex events. Thus, as we make future resource planning decisions, it is important to consider overall system diversity and the important benefits offered by nuclear power. Nuclear power is the source of most of the country's emissions-free energy. In addition to its carbon reduction benefits, nuclear power has long been a reliable, efficient, and job-creating energy source. Because of their comprehensive safety procedures and stringent federal regulations, nuclear plants are among the most robust elements of critical energy infrastructures. Indeed, nuclear power plants represent approximately 20 percent of the electricity generated in the United States and approximately 30 percent of the Company's generation in the Upper Midwest. As a result, our nuclear units continue to be a major source of reliable, carbon-free generation for the NSP System.

These events and circumstances illustrate the real value of firm, dispatchable resources and fuel diversity, in particular during periods of extreme weather. The presence of a breadth of firm dispatchable resource types – nuclear, CCs, fuel flexible CTs and other dispatchable resources that may become commercially viable in the future ensure that we can reliably meet our responsibility to provide reliable electric service in all conditions, including extended durations of extreme weather.

Although extreme, severe weather events are on the rise and can reasonably be expected to occur again. The 2019 polar vortex and the 2021 Winter Storm Uri in Minnesota underscore the need to manage the transformation of our generation portfolio, while at the same time preserving the reliability and stability of our system. A disruption in electric service during a similar weather event in the future would have detrimental and potentially very serious impacts on our customers and public safety in general.

H. Our Current Plan Meets the Challenges of the Changing Future

As we continue to retire coal and add renewables, our modeling continues to show the need for some firm, dispatchable resources. To date, the Sherco CC has been a central component of our plan to help mitigate reliability concerns and support the transition away from coal and toward a zero-carbon future.

What we need to support the system are resources that have high capacity values (i.e. grid scale), long duration, and are affordable. Our Alternate Plan proposes to add hydrogen-ready CTs (and/or other dispatchable peaking technologies, such as large-scale batteries, as they become commercially viable) in the future which provide the same reliability and resilience benefits as the Sherco CC, but does not require the same significant natural gas infrastructure investment, reduces the dispatch of natural gas resources on our system, and results in lower overall emissions. Additionally, firm dispatchable resources provide numerous benefits needed to stabilize the system during peak demand periods. These include near-instant availability, making them the ideal suppliers of peak power and the best backups for intermittent wind and solar generation. They can also be turned on and used for short periods of time to meet temporary increases in demand. They are also capable of operating for extended periods if necessary. These capabilities provide the Company with a measure of insurance to address peak load and operate reliably in rapidly-fluctuating power market conditions. If a spike in prices suddenly occurs, we can quickly ramp-up the firm dispatchable resources to minimize costs for our customers. Finally, new CTs, are critical to the transition as we do not currently have other options that meet our high capacity, long duration, affordability needs. Additionally, CTs, which can be hydrogen-ready, can be converted to carbon free fuels or used for storage and, therefore, may also play a significant role in our efforts to reduce carbon emissions and transition to clean energy. Given these attributes, CTs and other technologies with similar attributes are the ideal complement to high penetrations of intermittent renewable resources.

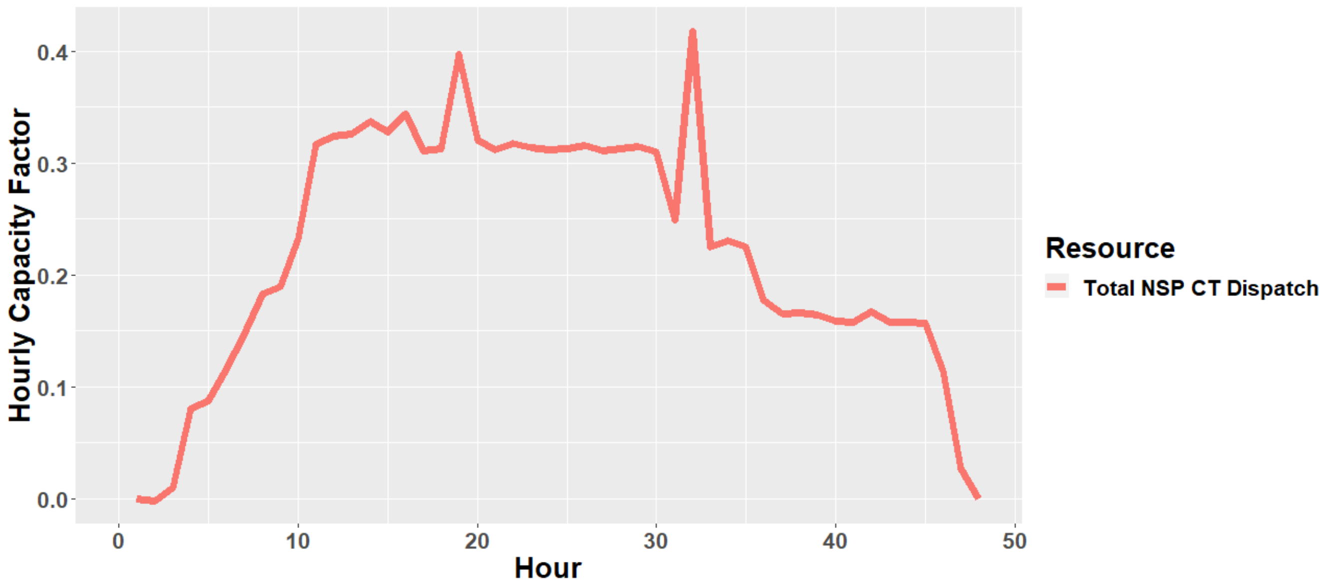
In this Resource Plan, the emergence of new technologies, such as storage, has been an ongoing consideration. We are in favor of utilizing storage for certain circumstances such as peak shaving or extending solar generation's capabilities. However, the ability of storage to provide the same attributes as CTs is not yet economically feasible or fully understood in this climate zone. For example, the capabilities of the storage resource predominantly modeled by parties in Comments – conventional lithium-ion batteries – are currently limited to four hours. Four-hour batteries are simply not sufficient to meet our reliability needs in all cases, particularly when needed in substantial amounts for multi-day contiguous periods.[8] For example, on January 30 and 31, 2019 our CT fleet dispatched for a period of 45 contiguous hours – a critical time period during the 2019 polar vortex.

The pattern of our full NSP system CT dispatch activity is shown for the entire 45-hour period in Figure 2-5 below. Even assuming very optimistic operating conditions, a larger amount of four-hour lithium ion battery system capacity would be required to provide the same level of power for this 45-hour period as compared to the amount of CT capacity in operation during the multi-day event.[9] Not only is installing a larger amount of storage capacity less economical at this time, but the Company's additional

[8] The challenge of short-duration storage providing adequate coverage on multi-day events was also noted during a recent CAISO presentation: CPUC Advanced DER & Demand Flexibility Management Workshop, May 25, 2021.
[9] Such optimistic operating condition assumptions include temperature, economic conditions, and any other grid constraints. This also assumes 100% depth of discharge with no penalties and no parameters on average daily state of charge. Since MISO had initiated grid emergency procedures during this time frame it is assumed the batteries were not allowed to charge during the hours of the CT dispatch shown in Figure 2-5, as that would have increased the stress on the greater system.

reliability concerns, including those raised by extreme weather and restoration capabilities, would remain unaddressed.

Figure 2-5: NSP System CT Dispatch Profile During Multi-Day Polar Vortex Event – January February 7-8, 2021



In addition, batteries provide limited value in system restoration, which we discuss in more detail in Section 3 System Restoration and Blackstart. While some batteries can provide blackstart or system restoration services in certain limited circumstances, the portion of the battery reserved for this purpose would provide very little, if any other grid value because it must maintain its charge at all times to be prepared for a restoration event.[10] In addition, if the system becomes unstable and goes back down after the initial start, the battery must be prepared to again blackstart and support other generating units repeatedly until the system stabilizes. For extreme weather conditions in which the grid is still stable, moreover, such as the February 2021 cold spell, batteries providing restoration services would likely be unavailable for providing much-needed energy to the bulk power grid.

[10] The battery referenced by the Sierra Club in its comments from the Imperial Irrigation District (IID) is not reserved specifically for blackstart. Rather, it blackstarted a gas unit on one occasion. Attempts to reach IID directly were unsuccessful; however additional information is presented by IID staff in a 2021 Utility Dive webinar: Don't Be Left in the Dark – Embrace BESS for Black Start Recovery | Utility Dive (last accessed April 2021). A similar example from another utility can be found here: Hybrid solutions: GE Completes First Battery Assisted Black Start of a GE Heavy Duty Gas Turbine | GE News.

Finally, regarding the ability of standalone, four-hour, lithium ion batteries to operate during cold weather – very little literature and existing operational data from climates similar to the NSP System is domestically available on this topic. For example, neither NREL ATB 2019 or 2020 make explicit assumptions about cold weather parameters or thermal management systems for standalone storage, nor are battery-specific topics yet found in the MISO Winterization Guidelines.[11] Although many utility-scale storage assets would have HVAC or thermal management systems to help maintain temperatures within safe operational limits, no common-denominator, publicly-available protocols or best practices are fully defined for operation in our region. Additionally, once defined, costs would need to be inclusive of these assumptions, including any costs and operational impacts from required auxiliary HVAC systems.

Based on our analysis, battery energy storage systems (BESS) without dedicated thermal management or HVAC systems, such as some distributed storage systems, may not be able to operate at all when temperatures drop below minus 22 degrees Fahrenheit, much less operate efficiently or anywhere near their installed capacity levels. While we expect that more operational data will become available, and likely changes in operational limits or winterization guidelines will occur as the technology continues to mature, currently, BESS is simply a less predictable alternative to CTs and other firm dispatchable generation.

I. Risks of Relying on MISO to Fulfill Gaps in Our Customer's Energy Needs

As mentioned in the modeling section, the Company's load comprises approximately 50 percent of MISO's Local Resource Zone 1 and 7 percent of MISO's overall load. Given our size proportional to the MISO system, and that we are responsible for mitigating both economic and reliability risks, it is likely not possible to rely exclusively on MISO to fulfill gaps in our electric service needs.

As a member of MISO, we should and do rely on market energy purchases when other MISO resources can provide energy cheaper than our own resources and we do in fact rely on the MISO market to fill some of these needs. In this way, relying on MISO helps reduce economic risk to our customers. However, purchases from the MISO market are considered non-firm; in other words, they do not provide capacity that we can use towards meeting a key reliability planning requirement; our annual fixed resource adequacy planning (FRAP) obligations as a market participant within

[11] Midcontinent Independent System Operator (MISO), 2018 MISO Winterization Guidelines287888.pdf (misoenergy.org) (last accessed on June 22, 2021).

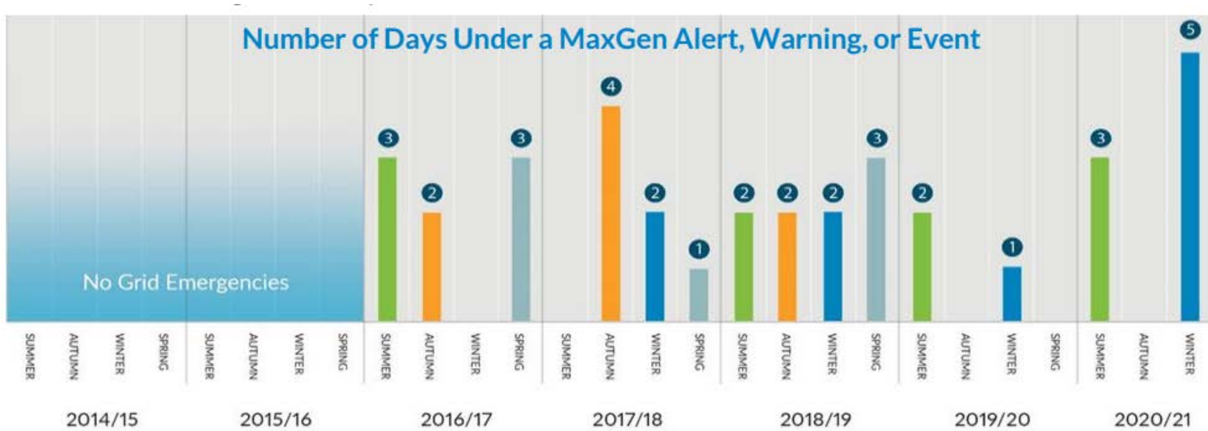
MISO. Since compliance with FRAP obligations is only for single year periods at a time, and because the acquisition of new generation capacity often takes multiple years, our least cost and most responsible course of action is to plan several years in advance for the acquisition of generation capacity. Simply using the MISO Planning Reserve Auction as a means of securing capacity for single year-periods is also insufficient as a resource planning option. Pursuant to Minn. Stat. § 216B.2422, we have to demonstrate that we have enough capacity to serve our obligations for a five-year period. In addition, in a catastrophic scenario where we were unable to secure sufficient capacity in the Planning Reserve Auction for a given year, our customers, and potentially other MISO regions, could face reliability and price spikes similar to what Texas experienced this past year – as it would be unlikely we could build new generation within a single-year period.

In fact, in the recent past, such as during Winter Strom Uri in Minnesota, there have been time periods when customers did not experience a system-wide disruption to their service in part because we have sufficient responsive capacity and duel fuel capabilities (i.e. onsite diesel as an alternate fuel) on the system to accommodate net demand over sustained periods, as well as provide power to our neighbors as we are able. Indeed, during Winter Storm Uri, all of our units that had dual fuel capability utilized diesel fuel during the storm.

We believe there is substantial risk to planning for a static MISO reliability construct. It is imperative that we continue to plan for a system that has sufficient capacity to meet our customer's needs. There is a technical import limit of approximately 2,300 MW into our system from the broader MISO area, although the available import/export capacity can vary significantly by the hour. To the extent we are forced to rely on MISO resources because we do not have adequate capacity to serve our load on an hourly basis, we are exposed to uncapped market risk because we do not have a resource hedge to mitigate our exposure. Our ability to purchase our theoretical import limit at any given moment depends on timely available excess generation from our neighboring utilities or merchant generators in MISO. However, excess generation may not be available in the market to meet an internal shortfall on our system. This is especially true if the energy shortfall results from weather events which would impact the same regional area that we serve. As such, it is incumbent upon us to analyze the likelihood of shortfalls for each capacity expansion plan we consider and be prepared for situations where excess generation is not available. The Reliability subsection in the Modeling section of these Reply Comments provides additional details about this analysis.

In addition to the potential lack of availability, relying solely on MISO to meet internal shortfalls may expose customers to drastic price spikes or load shedding events because there is an increasing likelihood that other load-serving entities in the NSP geographic system would have internal shortfalls during the same time periods. Figure 2-6 below shows a recent increase in the number of MISO-declared grid emergency events; these are the very times when drastic price spikes and load shedding events are the most likely to occur.

Figure 2-6: Number of Days with a MaxGen Alert, Warning, or Event



Over reliance on the MISO market is an unacceptable financial and reliability risk to our customers. Given that the 2021 NERC Summer Reliability Assessment indicates a chance of capacity shortfalls for MISO in scenarios with above-normal load levels this very summer, this is not an imagined or future concern, but one that impacts us now.[12] As a result, our goal is to maintain enough responsive capacity to hedge risk to our customers and minimize the number of hours in which we are unable to serve our customers due to insufficient native capacity.

J. Maintaining Stability Along the Sherco Gen-Tie Line in the Alternate Plan

In addition to ensuring both the Supplement Plan and Alternate Plan include sufficient firm dispatchable capacity to reliably provide power in all hours of the year, in developing the Alternate Plan, we needed to ensure we considered investments along the planned gen-tie lines to maintain stable interconnections. Given the

[12] *See* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20SRA%202021.pdf (last accessed on June 22, 2021). Given the amount of load projected with a hotter than expected summer (1-in-10 weather) forecast, or with high resource outages, MISO "may require use of load modifying resources (LMRs) and/or non-firm imports during peak periods."

assumed length of the gen-tie line at King (approximately 16 miles), we determined that additional reactive support likely would not be necessary. For the Sherco gen-tie line, however, which is assumed to be a 140-mile double-circuit line, we believe investments will be needed to ensure adequate inertial support and voltage performance.

Our study specifically considered system stability using series compensation along the longest sections of line and synchronous condensers at the end of the gen-tie lines, but we are not proposing any specific reactive support technology at this time. Series Compensation is used to reduce the impedance of the line to help with power delivery and improve voltage performance of the line. Synchronous condensers, STATCOMs, and switched capacitor banks could all potentially be used as reactive support resources for the radial generation options we evaluated. Synchronous condensers are proven technology that provides reactive support and are a source of short circuit current/system inertia for grid strength. STATCOMS also provide reactive support but do not provide short circuit current/system inertia to the system.

Grid strength refers to the "stiffness" of a transmission system, higher grid stiffness is desirable since it results in better system stability performance. Grid stiffness is higher closer to generating stations, since traditional thermal and hydro generators produce significant amounts of short circuit current/inertial support. Grid strength at any location is directly proportional to the magnitude of available short circuit current, and the metric used for system strength is called Short Circuit Ratio ("SCR"). SCR decreases as distance from generating stations increases.

Historically, large synchronous generation (primarily fossil-fuel) has provided our transmission system its strength, and additional investments for reactive support have not been necessary. As we increase renewable generation on our system, specific investments to provide grid strength and reactive support may be needed for several reasons. First, renewable resources are typically located and connected to remote locations of the transmission system. Second, renewable resources (which interface with the grid through inverters) do not necessarily provide system strength themselves unless they have grid-forming inverters and are programmed for system support.

There are several approaches to mitigating these issues. Typically, the initial mitigation involves fine-tuning the generating plant's controller settings (which does not involve additional capital investments by the transmission or generation owner). However, this mitigation approach becomes ineffective below a threshold SCR—that is, at an unacceptably weak bus. In such cases, the only viable solution may be to increase the bus strength above the threshold. This requires increasing the available short-circuit current, which can only be accomplished with a synchronous machine, which will provide inertia under a system fault. Installing a synchronous condenser is the typical solution for reinforcement of grid strength at unacceptably weak transmission buses. Synchronous condensers enable any inverter-based resource interconnected to that bus to achieve acceptable stability performance and thus enhances transmission system reliability.

Given the length of the proposed Sherco gen-tie line and our goal of maximizing renewable integration along the line, we studied a variety of renewable and reactive-support additions to identify the conditions under which the line maintained stability. Based on this study, we first concluded that resources to provide inertial and voltage support were needed at the Sherco-end of the line. Specifically, we studied the inclusion of two synchronous condensers at Sherco. Second, to achieve maximum renewable integration along the line, resources to support stability also are needed at the Lyon County end. Specifically, we studied the inclusion of 400 MW of CTs operating as synchronous condensers at the end of the line.[13] With these resources in place, we determined the gen-tie lines could support up to 2,600 MW of transfer capacity at any given time, which closely aligns with the 2,400 MW of interconnection capacity that will be available at Sherco when the coal units retire.[14]

As we have noted elsewhere in these comments, this proposed line is still in preliminary stages, and these stability investments are intended to be indicative of cost only. Should the Commission approve the Alternate Plan, we would commence further regulatory proceedings related to the line, including specific proposed stability investments.

K. Our Supplement Plan and Alternate Plan Provide Appropriate Reliability

To deliver the reliable power our customers and Americans in general have come to expect, preparation and planning is key. Now, more than in previous years, the consequences of a prolonged crisis are clear. One of the most important and responsible things we do as a Company is plan for how we can provide electricity to our customers under all conditions, even the most severe. Recent real-life events have provided conclusive evidence that renewable, variable, non-dispatchable resources are

[13] In addition to providing voltage support, these CTs generally align with the firm dispatchable needs we see in our Encompass modeling, and therefore, operating them as synchronous condensers for the majority of the year when they are not dispatching real power is an efficient use of resources. **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS].

[14] We note that our capacity expansion modeling assumed 2,000 MW of open interconnection at Sherco rather than 2,400 MW to reflect Southern Minnesota Municipal Power Agency's partial ownership stake of Sherco Unit 3 and related interconnection rights.

unable to provide sufficient energy at certain times throughout the year and that we need firm dispatchable resources as part of our resource mix to support the significant renewable generation additions we are planning over the next fifteen years.

Our switch to a chronological hourly dispatch model was a critical improvement to our resource planning analysis. To develop our Alternate Plan, we ran an hourly dispatch for all 8760 hours of the years through the modeling period. The Encompass model is able to analyze the available resource mix, including market purchases, to ensure load serving need are met reliably and cost-effectively. Our Alternate Plan adds approximately 3,000 MW of cumulative firm peaking, load-supporting resources to ensures a stable system under all conditions. We have actual data showing that natural gas and fuel oil units can do what weather-based variable generating systems cannot do – be turned-on/dispatched. Conversely, while new technologies, such as storage, certainly offer additional opportunities to integrate high levels of renewables, they also have constraints that were are not able to include in our capacity expansion plan optimization process; these include constraints such as forced outage rates and some additional dispatch parameters. Before we can fully incorporate emerging technologies as a cornerstone resource for maintaining grid reliability, additional information still must be taken into consideration. We need that flexibility to ensure that we can provide our customers with reliable electricity service every minute of every day.

SECTION 3: SYSTEM RESTORATION AND BLACKSTART

As we have discussed previously in this Resource Plan, we must reexamine our blackstart and system restoration plans due to planned generating unit retirements and our related goals to achieve significant carbon reductions on our Upper Midwest system. While we periodically reevaluate our system restoration plan, our current reexamination necessarily goes deeper in light of aging generating units, the general industry shift away from large centralized generating units, the impending retirement of our coal fleet, and our consideration of an Alternate Plan that would not replace our coal units with other central-station power resources. These changes affect all aspects of our operations, including the way that we plan for the restart of our Upper Midwest system from a catastrophic event to ensure that electric service can be quickly and safely restored to customers as soon as practicable.

While we have always known the importance of a dependable blackstart plan, the recent event in Texas has brought awareness to this issue on a national level. During Winter Storm Uri, the Texas electric grid came within five minutes of a complete collapse in mid-February 2021, according to a Wall Street Journal article.[1] The article explains that problems experienced in Texas when power was disrupted for extended periods in the extreme cold could have been much worse. The blackstart resources, or as explained in the article, the "little-known network designed to jolt the grid back to life" were not working properly. When the storm hit, nine of the thirteen primary generators designed to get a downed system going again were, at times, out of commission, according to grid operators. And six of fifteen secondary generators – what the article describes as "the fail-safe for the fail-safe" – had periodic trouble as well, including freeze damage and problems getting fuel. The article continues, if grid operators had completely lost control of the situation, the spotty performance of the blackstart units could have left Texans without power for much longer than a few days. How long is impossible to say, though by the grid operators' own estimate, a total collapse could have caused weeks or even months of outages.

As it was, over 150 people died,[2] 4.5 million homes and businesses lost power at its peak and it produced an estimated $295 billion in damage, nearly 70 percent of Texans lost electricity at some point during the storm for an average of 42 hours,

[1] See *The Texas Grid Came Close to an Even Bigger Disaster During February Freeze*, Rebecca Smith, May 27, 2021 10:25 am ET at: https://www.wsj.com/articles/texas-electrical-grid-bigger-disaster-february-freeze-black-starts-11622124896?st=5iephyk8icuvb1n&reflink=article_copyURL_share Last Accessed June 17, 2021.
[2] *See* Texas Department of State Health Services at https://www.dshs.state.tx.us/news/updates.shtm#wn Last Accessed June 17, 2021.

almost half of Texans (49 percent) lost access to running water for an average of more than two days, and nearly one-third of people reported water damage in their homes.[3]

As we transition away from the thermal baseload units our system was built around, careful planning on system restoration is increasingly important. Historically, the baseload, intermediate, and peaking units we used to run our system were well designed to serve not only our normal operating needs but also system restoration. The retirement of these units and replacement with variable renewable resources requires rethinking our overall approach. As discussed below, we are in the process of developing a plan to reliably restart the system without baseload coal units that will allow us to tap into the potential of renewable resources for system restoration and restore generation and load in more areas of our system simultaneously. We refer to this as our new "zonal" blackstart plan because it includes blackstart resources in several zones in each of Minnesota, Wisconsin, and the Dakotas, rather than single initial and target units in Minnesota and Wisconsin.

This plan and the increase in diversity of blackstart resource locations will be resilient and built for a high renewable penetration future, but we believe it is worth considering in more detail with regulators and other stakeholders to ensure we are planning appropriately for the future. In the meantime, we intend to make several investments in blackstart resources that will meet both our short-term needs and support the zonal plan in the future.

While blackstart capabilities are not often needed, when they are, the need is urgent, and it is essential that the specialized resources be able to deliver. In this section, we will discuss:

- Background on system restoration planning, including a brief summary of our current System Restoration Plan and why it needs to be redesigned for the future,
- Our new zonal approach, and how it is reflected in the Alternate Plan,
- The potential that our new approach may necessitate additional proceedings and potentially a broader System Restoration proceeding that involves all Minnesota utilities, and
- A discussion of near-term investments we make to support our blackstart plan both now and in the future.

[3] See, University of Houston, Chris Stipes, March 29, 2021 available at: https://uh.edu/news-events/stories/2021/march-2021/03292021-hobby-winter-storm.php Last Accessed: June 17, 2021.

A. Overview of System Restoration Planning and Current Upper Midwest Plan

At a high level, a System Restoration Plan specifies the process we use to restore our system to full operation following a full- or partial-black out across not only our system, but the broader transmission network. When the grid is operating normally, the electric power used within a generating plant (i.e. "station power") is provided from the plant's own generators. If all of the plant's main generators are shut down, station power is provided by drawing power from the transmission grid, which can be used to start the plant. However, during a wide-area outage, power from the grid will not be available. In the absence of grid power, a so-called "blackstart" needs to be performed to "bootstrap," or self-start the power grid into operation.

System Restoration Plans are required by the North American Electric Reliability Corporation (NERC), developed in concert with neighboring utilities, and are subject to review and approval by MISO.[4] Developing such a plan involves developing models, strategies and procedures to configure the system such that one or more generators can be brought online while also picking-up sufficient customer load to balance the generators' and transmission network's minimum requirements for stability. The process begins by starting the "Initial Unit(s)" (sometimes also referred to as a "Blackstart Unit"). These are generating units that have an on-site, independent power source that can provide the Initial Unit the capability to start its primary generators without reliance on the external transmission network. Energy from the Initial Unit is utilized to provide start-up energy to the "Target Unit(s)," which are typically larger units with output that can be controlled and adjust to fluctuations on the grid as customer load is added. Energy from the Initial and Target Unit(s) is used to support bringing subsequent units and load back online until our system is fully restored and reconnected to the Eastern Interconnection.

As each unit starts, its generation is balanced with customer load along the connected transmission and distribution lines to maintain stability on the system. This process sets up "islands," where part of the transmission and distribution systems in a

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[4] NERC EOP-005-3 – System Restoration from Blackstart Resources, requires transmission operators to submit their plans for review. NERC EOP-006-3 gives MISO the authority to review and approve the plans. EOP-006-3 R5. Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]. EOP-006-3 R5.1. The Reliability Coordinator shall determine whether the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its Reliability Coordinator Area. The Reliability Coordinator shall approve or disapprove, with stated reasons, the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator. *See* NERC Reliability Standards at: https://www.nerc.com/pa/Stand/Pages/AllReliabilityStandards.aspx?jurisdiction=United%20States

geographic area begin serving at least part of the customer load in that area. Once we determine an island is stable, we can synchronize and reconnect/restore more generators and load, essentially expanding the island and restoring our interconnections with other utilities until the system is fully restored. The longer the system is down, the harder it is to restore, so we work to determine the most efficient paths possible.[5]

The restoration is initiated under the instruction of the Transmission Operator and proceeds under the general guidance of a site-specific restoration plan. Not all power generation units have, or are required to have, this blackstart capability. Blackstart-capable units have specific configurations, additional on-site emergency generators and must be held to the highest reliability standards to ensure responsiveness in the face of an emergency. NERC defines a Blackstart Resource in the following way:

> [a] generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for Real and Reactive Power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.[6]

Ensuring a unit has the appropriate configuration and controls for blackstart is typically a consideration when the generator is being built; however, generating units can be retrofit to make them capable of providing blackstart service, and it may be appropriate to do so if it is economically practical and does not compromise the reliability of the unit.

At a high level, our existing System Restoration Plan currently uses a state-by-state approach, with our restoration focused primarily on restoring load in the large population/load centers in Minnesota, Wisconsin, and the Dakotas.[7] Although our plan primarily relies on our own thermal resources, in some cases we rely on other utilities to help get portions of our system started and in other cases, other utilities rely on the NSP System to get their systems started. The outcome of this process is

[5] The longer the system is down, equipment and facilities cool and may require special cold-start protocols, which take longer to get the unit running. Additional impacts include effects such as the fact that substation batteries will only keep the substations operational for a limited time. If the substation batteries deplete, we cannot easily isolate or energize the substation.
[6] *See* NERC Glossary of Terms, https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf
[7] We note that the Xcel Energy Minnesota and Wisconsin systems each have separate System Restoration Plans because they are separate operating companies. In practice however, the two plans comprise an overall plan to restore the NSP System in whole.

the creation of one to three Northern States Power "islands" that we then reconnect to our neighbors and ultimately to the Eastern Interconnection.

1. *Planning Considerations*

When designing a System Restoration Plan, a key step is to identify the generating units in a system that can be used as Initial Unit(s) and Target Unit(s). This section discusses plant configuration and location considerations.

a. Initial Units.

Only certain unit types and sizes are appropriate for consideration as Initial Units or Target Units. As noted previously, the Initial Unit is the first generating unit (or group of units at a common site) that sets restoration in motion and needs to be started without the support of the grid in the event of a widespread outage. The Initial Unit should be maintained to as high of a degree of start reliability as possible, because the rest of the system depends on the unit working, including under adverse conditions. Further, the Unit must be dispatchable (i.e. controllable and not dependent on intermittent fuel sources) and capable of running without any balancing load for several hours (and potentially days) if needed. It must also have special controls that allow the plant to run at a stable frequency without an established and energized electrical grid, while beginning to restore subsequent parts of the system. Finally, it must have sufficient capability to stabilize voltage and frequency as the transmission system is energized and load is added. These are typically specifications that are determined when building a new plant, and an existing unit is not easily (or inexpensively) retrofitted to serve this purpose.

In the NSP System specifically, the Initial Unit must be large enough to stabilize transmission to a Target Unit and provide power to start that Target Unit. The ideal design includes several small units rather than fewer large units. This is because the plant as a whole needs to be big enough to energize the high voltage transmission system and restore a larger Target Unit (explained further below), but each individual unit must be small enough to operate at very low loads for an extended period of time; the individual Units must also be able to start with an independent fuel source (such as emergency diesel generators or auxiliary batteries). Since most mid-size or large generators have minimum load environmental permit restrictions, multiple small Units will reduce emissions or permit restriction limitations during restoration. Further, having multiple smaller units helps ensure that if one Unit fails to start, the remaining units can still provide sufficient energy to start the Target Units.

b. Target Units.

Target Units are the subsequent generating units on the restoration path and are started by the Initial Unit(s). In a System Restoration Plan, there is typically a specific designated Target Unit that provides the most efficient restoration path, but several units could be used if needed. There are several essential considerations when evaluating a generator for use as a Target Unit, and not all fuel and generator types are well-suited to this function. A generator's fuel type, dispatchability, and its ability to provide and absorb reactive power are a few of the most important considerations for suitability as a Target Unit.

Today, eligible Target Units include coal, natural gas, hydro, and fuel oil. Renewable generation, such as solar and wind are not currently considered eligible Initial or Target Units due to their inherent intermittent nature, and their general inability to provide or absorb reactive power. Nuclear Units are also not eligible as they can only come online after the balance of the system is fully stable. One new option being explored for blackstart technical and economic feasibility is longer-duration battery energy storage systems (BESS). While it is not yet proven, we intend to continue to monitor studies and advances for potential use on our system in the future.

After fuel source and reactive power response considerations, we consider several other items when choosing Target Units:

- Availability of multiple generating Units at the site,
- Minimum operating limits for the site,
- Ramp rate of the Units,
- How fast a Unit can come online once it receives station power,
- Unit's ability to act as a stabilizing Unit in the Island,
- Amount of stabilizing load in close proximity to the Target Unit(s), and
- Amount of switching required in order to energize the Unit.

[PROTECTED DATA BEGINS

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c. Current Generator Type Suitability.

We discuss the suitability of the various eligible generator types that can be used in the System Restoration Plan below.

- *Hydroelectric units.* These units can be designed for blackstart capability and have fast primary frequency response characteristics and a steep ramping rate capability. Hydro units can serve as either Initial or Target Units.
- *Diesel generator sets.* Diesel sets usually require only battery power to start and can be started very quickly. They are small in size and useful only for supplying the power needed to start larger units, therefore are only suitable to be located at Initial Units or Target Units in conjunction with other types of generators and are typically not suitable or permitted for supplying power to the transmission system.
- *Reciprocating Internal Combustion Engine (RICE) generators.* These are typically 5-20 MW natural gas and/or diesel-fired generators, suitable for fast starts, variable loads, and standalone operation or dispatch as part of normal grid operation. They are typically installed in groups for flexible operation and to capture economies of scale.
- *Aero-derivative gas turbine generator sets.* This type of gas turbine typically requires only a small backup generator support to start. These units can usually be started using remote commands and can pick up load quickly. They require a minimum load before energizing any significant transmission system elements. Aero-derivative turbines can serve as either Initial or Target Units.
- *Larger gas turbines operating in a simple cycle mode, and steam turbine units.* These units can serve as Target Units or be coupled with reciprocating engine generator sets to make the plant an Initial Unit. The reciprocating units can be started and used to energize plant auxiliary buses, to start either the gas turbine or steam turbine. A gas turbine is generally quicker to bring online than a steam generator. The time to restart and available ramping capability is generally a function of how long the unit was offline. Both gas and steam units require a stabilizing (i.e., minimum) load before energizing any significant transmission system elements.
- *Battery energy storage systems.* As noted above, smaller batteries currently can be used to start Initial Units. Larger BESS also can be configured to be *technically* capable of providing blackstart service, likely as part of a relatively small Initial Unit. However, studies suggest that they may not yet be economically viable

for this purpose.[8] This is because the upfront capital expense of building a battery with sufficient duration to provide this capability is high. Further, because a blackstart unit has to maintain access to sufficient fuel on-site, the battery would likely not be able to be used for any purpose other than blackstart, resulting in low overall utilization. There are also technical concerns with regard to how batteries can absorb reactive power (discussed more below), which would be needed if the battery was not paired with another type of generation asset. We discuss use of BESS from a reliability perspective in Section 2. Reliability and in Appendix A: EnCompass Modeling Assumptions.

We note additionally that the Sierra Club cited to a BESS in relation to a blackstart plan for the Imperial Irrigation District (IID), a publicly owned water and energy utility that serves 150,000 electric customers in southern California. Actually, IID's BESS is not a designated Blackstart Unit; IID only used their small battery system as a kickstarter or Initial Unit in a blackstart *pilot test*. Their BESS was not installed as part of an integrated resource planning or blackstart plan process, but rather as part of a settlement in which IID was required to install a storage system and had a minimum spending threshold.[9] In a related webinar, IID staff commented that the primary benefits of the BESS to date have been for *voltage support*, <u>not</u> blackstart services.[10] Further, IID was clear that, if a BESS is used for multiple purposes (as would be the case with IID if they were to also plan to use the BESS for blackstart services) and it is included in the System Restoration Plan, each time the BESS is taken out of Blackstart mode, the RTO/ISO Reliability Coordinator must be notified and/or an alternative Blackstart resource must be made available.[11] In practice, therefore, blackstart BESS would need to be dedicated to blackstart and cannot be easily used for multiple functions, such as power generation or voltage support like other blackstart resources can be today. This decreases operational flexibility and also increases costs, due to the need for redundancy that would otherwise not be necessary. For these reasons, BESS is not practicable today, but we intend to

[8] For example, a Burns & McDonnell study performed in 2017 for ISO-NE, assuming it refers to this https://www.iso-ne.com/static-assets/documents/2018/08/a4.0_rc_tc_2018_08_07_08_2017_black_start_study.pdf
[9] As part of the settlement, IID agreed to pay a $3 million fine and improve the reliability of its power grid by spending at least $9 million on battery storage and other infrastructure upgrades. The 30 MW BESS IID procured cost $35 million. See *For $35M battery, public agency turned to former official – after rejecting 3 cheaper offers*, Sammy Roth, Palm Springs Desert Sun, August 9, 2017 (updated 4:45 p.m. PT August 18, 2017), at: A public utility gave a former board member's company a $35M contract (desertsun.com) Last Accessed: June 22, 2021.
[10] *See* "Don't Be Left in the Dark – Embrace BESS for Black Start Recovery," Utility Dive, at: https://resources.industrydive.com/bess-for-black-start-services?utm_source=UD&utm_medium=Event&utm_campaign=PowerEngineers. Last Accessed June 22, 2021.
[11] This requirement is unique to resources that have a finite energy source. Batteries and other resource types that have a finite energy source (water and fuel oil are one of those as well unless a reserve is kept available specifically for blackstart) cannot be used for blackstart if they are used for other purposes unless there is a commitment for additional fuel availability.

continue to monitor studies and advances for potential use on our system in the future.

Ultimately, after evaluating these parameters, system planners conduct technical studies on a short list of sites to determine which Initial and Target Unit(s) and their associated paths are most suitable and expeditious to restore the system.

2. Reactive Power and the Link Between Initial Units, Target Units, and the Transmission System

The transmission system is another critical piece of the System Restoration Plan and has bearing on which Initial Units and Target Units are the most suitable. System operators must take special care when energizing transmission lines during a system restoration, due to the especially light loads present on the system. When lines are energized with little or no real power load, the charging current produces reactive power (MVAR). Therefore, before a line or transformer is energized, there must be sufficient generation MVAR capacity online to absorb the capacitive reactance produced by that line/transformer. If not balanced properly, it is easy to overwhelm the generator by collapsing its magnetic field, causing the generator to trip off-line, and potentially re-collapse the system.

When we begin to start up motors and pumps at the next generating plant, the Initial Unit(s) must be capable of providing that reactive component back to the system in order to start the motors. During this time, we must also be energizing transmission lines and transformers to bring customer load onto the system. We must balance the load and generation carefully because, without sufficient load, damage to our or customer equipment can occur from an overload of reactive power; if we energize lines and restore load too quickly, we can trip relays and will have to begin the process again.

All substations on the current restoration path must have emergency generators for maintaining full operating capability of switches, breakers, and relays at those substations. The emergency generators provide the AC power required to operate transformer pumps and fans as well as the transformer Load Tap Changers (LTCs), which are needed to help regulate output voltage on the transformers. The emergency generators also maintain the battery chargers and ensure we maintain full battery capabilities to provide the DC power necessary for protective relaying, the motor operated disconnects, breaker trip coils, and communication equipment within the substation.

Generating units that interconnect with other utilities must also have a "sync scope," which is a device that measures frequency, voltage, and phase angle (Volts/VARs) to ensure the two "islands" (one on each side of the point of interconnection) are perfectly in sync before interconnecting. If they are not perfectly in sync, both islands could go back down, and equipment could sustain damage. This becomes important when we start to reconnect our system with our neighboring systems, or when we bring the various parts of our service area back together between Minnesota and Wisconsin, for example.

Finally, we generally plan system restoration assuming that the event that caused the outage caused no damage to the system. However, because this is a possibility, we must plan alternate restoration paths that we can use in case the catastrophic event damaged a portion of the system. We also must incorporate differing procedures based on the weather extremes in our geographic footprint and operating procedures that vary depending on unit type and operation. For example, any large generating unit that uses steam will take approximately one hour to wind down and fully stop operating. If ambient temperatures are cold, the water that remains in the Unit's pipes and boiler can freeze. Therefore, if we expect restoration of that Unit to take three or more hours, we may need to begin draining the pipes and boilers. Also, Units may require specific site emergency power arrangements to ensure they can be effectively utilized as part of a restoration plan. If a unit is drained, frozen, or does not have adequate emergency or transmission supplied power, our restoration of those generating Units will likely be delayed by several days, until after the Unit(s) goes through operational procedures that prepare it for a cold restart.

B. Xcel Energy's Current Blackstart Plans in the Minnesota and Wisconsin Systems

Each of our current dispatchable generating units plays a role in the System Restoration Plan, but a few are particularly essential.

1. Minnesota

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2. *North Dakota and South Dakota*

[12] In this case, the spinning reserves are the amount of additional generation that is on stand-by in the event that another generator within the island fails. To help ensure consistent availability and reliability of electricity during the restoration process, utilities keep generation capacity on reserve that can be accessed quickly if there is a disruption to the power supply. For example, if another generator or a major transmission line within the NSP/GRE/MP Island goes down, then NSP will access its reserve capacity at Sherco Unit 3 to compensate for that loss.

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3. Wisconsin and Michigan

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C. Changes to the System Restoration Plan are Necessary as We Retire our Coal Units

In this Resource Plan, we are proposing to retire all of our coal units and, at the same time, bring on significant additions of renewable resources. A similar trend of fewer baseload and more renewable resources is also expected in the overall MISO footprint. In addition, other resources that are part of our current System Restoration Plan are either scheduled to retire or we anticipate will retire before 2030. We outline the planned generation retirements on the NSP System and additions that are part of our Alternate Plan in Table 3-1 below.

Table 3-1: Planned Generation Retirements Through 2030

Year	Total MW Retired	Alternate Plan Resource Additions
2023	874 MW	
2024	358 MW	700 MW Solar
2025	695 MW	600 MW Solar 60 MW Firm Dispatchable
2026	1,311 MW	260 MW Firm Dispatchable
2027	210 MW	600 MW Solar 374 MW Firm Peak
2028	511 MW	200 MW Wind 150 MW Solar
2029	876 MW	400 MW Wind 400 MW Solar 374 MW Firm Dispatchable
2030	173 MW	200 MW Storage 950 MW Wind 100 MW Solar 374 MW Firm Dispatchable
2031	322 MW	50 MW Storage 350 MW Wind
2032		450 MW Wind 374 MW Firm Dispatchable
2033		100 MW Solar 748 MW Firm Dispatchable
2034	765 MW	500 MW Solar 500 MW Wind 374 MW Firm Dispatchable
2035	31 MW	600 MW Wind

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To comply with our requirements for a System Restoration Plan, we must identify, plan for, and ensure new or refurbished Initial and/or Target Units that can be brought online before existing units retire, or identify alternative restoration paths. For both operational and customer cost reasons, it is important to plan for these changes well in advance of any given Unit's retirement date. Initial and Target Units are the starting point to restoring grid service and, as such, there are substantially higher plant-specific reliability standards and additional unit controls than is required for a Unit not providing these functions. Therefore, it is important, and most cost-effective, for customers that we identify new restoration plans for both Minnesota and Wisconsin now, and re-focus appropriate levels of capital investment into the new restoration path. Further, we must allow time for any required permitting and regulatory approvals associated with replacement Units, so that they can be brought online in a timely manner to maintain the integrity of our System Restoration Plan and ensure that we secure continued interconnection rights at existing Unit sites.

In addition to Unit retirement timing, key considerations as we reexamine our System Restoration plan include:

- Can we refurbish or repower existing Units to provide the essential capabilities or are new Units designed for their specific role in system restoration more beneficial,
- What are the impacts if we change the location of the Initial Units and Target Units from their current general locations in terms of transmission paths, interconnection rights, etc.,
- What are the potential "extra" benefits associated with use of specific generating assets as Initial and Target Units in terms of satisfying needs beyond blackstart (i.e., renewables following, peaking, etc.),
- What does the Company's and MISO's changing resource mix mean to how we restore the system (i.e., significant increased levels of renewables and fewer large thermal resources), and
- Can we practicably anticipate commercial viability of new technologies, such as BESS.

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PROTECTED DATA ENDS] Also, as we otherwise note, there is likely need for additional work, analyses and regulatory proceedings including potentially a broader

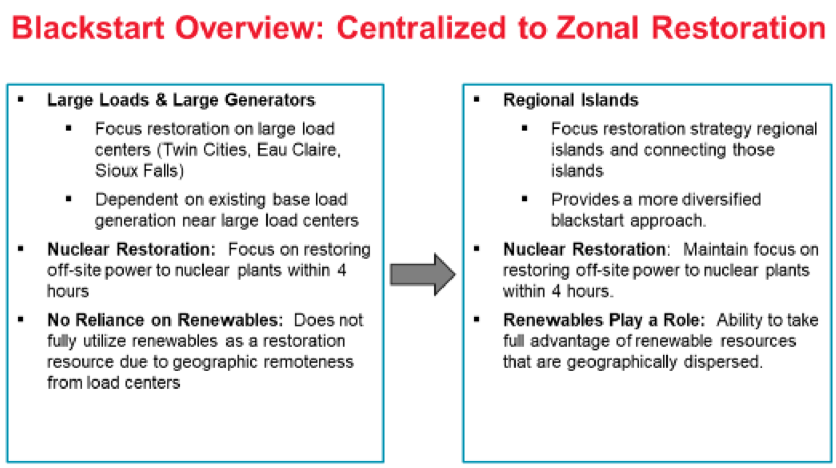
Blackstart proceeding that looks more broadly at blackstart needs for Minnesota and the Upper Midwest area.

We discuss our new zonal approach in more detail below.

D. Change to a Zonal Approach with this Alternate Plan

The System Restoration Plan underlying the Alternate Plan presented in this Reply will take a zonal approach, and will have a greater number of regional islands, or zones than we have today. Figure 3-1 below summarizes the change from our current approach.

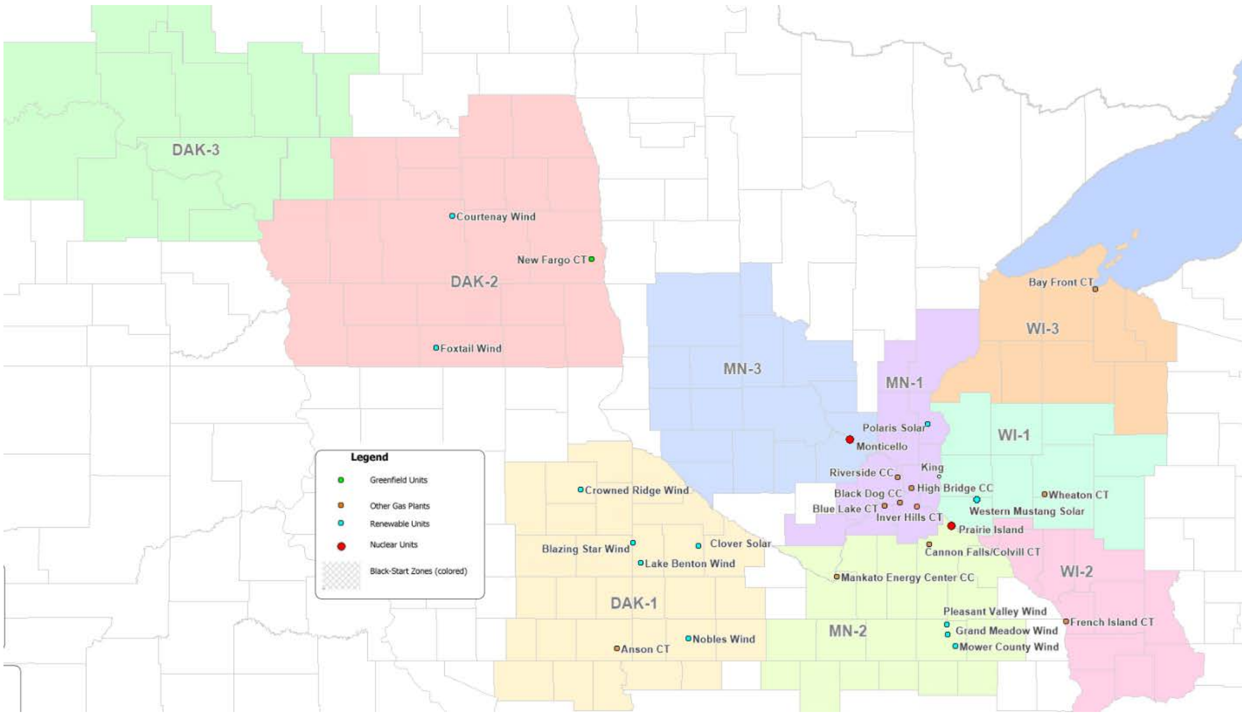
Figure 3-1: Summary of Change in System Restoration Plan Approach



While a different approach, the concepts remain the same – alignment of the zones is intended to match customer loads with the new types and locations of generation resulting from this Resource Plan to repower and stabilize the grid.

As shown Figure 3-2 below, we expect to have nine zones throughout our NSP System footprint. If the Alternate Plan is approved, we will transition to the zonal approach over time, likely over the next ten years.

Figure 3-2: Anticipated System Restoration Plan Zones



Blackstart capabilities continue to be a fundamental element of the System Restoration Plan. Today, we rely on a single Blackstart Unit in Minnesota and Wisconsin to set the plan in motion.[13] With the zonal approach, we will need Blackstart capabilities in each of the new zones. However, as outlined in Table 3-2 below, while the Alternate Plan includes more firm dispatchable Units, the overall level of thermal resources – and carbon emissions – on the NSP System will be substantially lower than it would be with the current System Restoration Plan reflected in our 2020 Supplement. Another exciting change with the zonal approach is that it is more diversified, in that it will not rely on one or two large generators to repower a large portion of the system. Rather, small generators will be geographically distributed around our service area that will create a series of smaller islands that we will eventually join together, which will allow for the incorporation of renewables as part of the start-up process. And while this plan will ensure at least the same restoration pace, it also has the potential to restore greater numbers of customers across our entire footprint (not just our load centers) *faster* than the current plan.

[13] In some parts of our service area where we are not the largest generator, we rely on other utilities to start the restoration.

When assessing our restoration plans, we begin with our forecasts for peak load, since it is a good representation of cold-load "pick-up." When loads have been offline for long periods of time, we expect a large spike in load from household motors (e.g., air conditioners, refrigerators, freezers, etc.) that start-up once an area is re-energized. This cold-load pick-up mimics a system peak and eventually settles out as homes adjust temperatures – but we have to plan to the peak. We show the peak load projections that we used for our restoration estimates below

Table 3-2: Forecasted 2030 Loading for Summer and Winter

Region	2030 Summer	2030 Winter
NSP Overall	9,042 MW	6,881 MW
MN	6,465 MW	4,920 MW
WI	1,899 MW	1,455 MW
SD	362 MW	275 MW
ND	319 MW	240 MW

The anticipated 2030 summer peak load of approximately 9,050 MW breaks down to roughly 3,450 MW residential and 5,600 MW non-residential load. Looking ahead to 2030, it appears that there will be sufficient firm dispatchable generation to restore all residential load, from a complete regional perspective. The next block of load, namely commercial and industrial loads will be dependent on any remaining firm, available renewables and available resources from outside the NSP System. We note that we use residential load as a benchmark in system restoration planning due to the implications on human life from an extended outage – particularly in weather extremes, as was illustrated in Texas with Winter Storm Uri. However, we develop our plan cognizant of the need to restore critical loads such as hospitals and water services as quickly as possible.

Table 3-3 below illustrates the difference between the resources involved with our current centralized plan and the new zonal plan. Specifically, we show the resources included in the modeling for our Alternate Plan and in relation to the resources associated with our current centralized restoration plan.

This table helps to illustrate the increased resilience of our new zonal approach. For example, by 2030 we will significantly increase our ability to incorporate renewable resources – going from utilization of approximately 50 MW of solar resources located near the Twin Cities today to nearly 6,000 MW of renewables located across our footprint in the Alternate Plan. We note that, in this table, the 2021 Centralized EP

Plan column includes all resources (including PPAs) that we currently have as part of our restoration plan, and the 2030 Modified Zonal Plan column includes all resources we expect to be in-service as of 2030 and available for system restoration based on our proposed zonal approach.

When we look at what renewable generation is available for restoration purposes, we take into consideration the generators' proximity to the islands and whether or not it is interconnected on the NSP System transmission or another entity's transmission. With the focus on load centers in our current centralized approach, there are very few renewable resources in proximity to the island that we are building out from the Twin Cities metro area – minimizing the role of renewables, which are generally in rural areas distant from the load centers. Because the zonal approach will build small, geographically-dispersed islands, we are in a better position to incorporate our renewable resources to restore customers – and it increases our potential to restore greater numbers of customers across our entire footprint *faster* than our current restoration because of the smaller, geographically-dispersed islands approach. We will also improve our ability to restore all or nearly all of our system from our own resources, rather than relying neighboring utilities.

Table 3-3: Comparison of Centralized Plan and Modified Zonal Restoration Plan

	NSP 2021 Centralized EP Plan	2030 Modified Zonal Plan with Alternate Plan
Firm Dispatchable (FD) Generation Available	6,595 MW	5,175 MW
Restoration % by XE only FD generation (Summer)	45-70%	55%
Restoration % by XE only FD generation (Winter)	80-90%	75%
XE-owned Renewables Available for Utilization	1,691 MW	5,930 MW
XE-owned Renewables Utilization Rate	50 MW	2,025 MW
Total XE owned Resources for restoration	6,645 MW	7,200 MW
Total % Restored (Summer)	45-70%	80%
Total % Restored (Winter)	80-90%	105%
Resource Gap without Renewables	2,445 MW	3,865 MW
Resource Gap after using Renewables	2,395 MW	1,840 MW

**Includes additional blackstart resources beyond those included in economic modeling.*
#This value takes into consideration location of the renewables within the zonal plan and utilizes the anticipate availability multiplier used by MISO for accreditation, which is 18% for wind and 50% for solar and storage. This reduces the amount of renewables that we have available for restoration purposes as shown in the table (XE-owned Renewables Utilization Rate.

Table 3-4 below shows our restoration estimates under the Alternate Plan with limited additional resources needed for restoration in addition to what is selected in our economic modeling. From a very high level, it appears that these levels of system resources are adequate to restore most residential loads and a substantial amount of commercial and industrial loads during both Summer and Winter load conditions.

Table 3-4: Generation MW Gap Analysis per Zone (MW) – Alternate Plan with Additional Restoration Resources Included

				Renewables		Gap Considering Renewables		Residential Load Restored with renewables
Zone	Summer Load	Summer Residential Load	Firm Generation	Total	Usable	With	Without	
MN-1	5,305	2,015	2,030	1,810 Solar	905	-2,370	-3,275	100%
MN-2*	815	310	787	295 Wind	54	+26	-28	100%
MN-3*+	585	220	400	680 Solar	340	+155	-185	100%
DAK-1*	600	225	787	696 Wind 110 Solar	175	+362	+187	100%
DAK-2*	360	135	436	190 Wind	0	+76	+76	100%
DAK-3	78	30	0	150 Wind	0	-78	-78	0%
WI-1	785	300	300	100 Wind 75 Solar	55	-430	-485	100%
WI-2*	450	170	277			-173	-173	100%
WI-3*	280	105	40			-240	-240	37%
Unspecified location resources				115 Solar 200 Storage 1500 Wind	430			

*Additional blackstart resources will be required to complete the transition to the zonal plan from the centralized restoration plan currently in use in order to restore residential load.
+Assumes no Sherco CC was constructed and Sherco 3 has retired. No firm dispatchable generation within this Zone in 2030. Additional firm dispatchable resources will be identified in the future.

Although the zonal restoration plan will largely be adequate to restore most residential and commercial and industrial loads during both Summer and Winter load conditions, there remains a gap between available planned resources and projected loads. With renewables, the gap during summertime conditions appears to be approximately 1,840 MW if renewables can be used at the accredited levels we have projected for this purpose. However, as discussed in the Reliability section, the variable nature of renewables introduces a higher level of uncertainty as to whether they will be available when needed. Without the renewables, the gap could extend as high as 3,865 MW (as illustrated in Table 3-3 above).[14]

As we have noted, additional blackstart resources and investments will be needed to fully transition to the zonal approach, and the tables we present above that reflect the

[14] Using MISO accreditation values of renewables is reasonable for planning purposes but does not guarantee availability. Continued investigation is needed to incorporate the range of available levels of renewable generation and how to reliably operate them in parallel with firm dispatchable generation to accelerate the restoration process.

restoration capabilities under a full zonal approach include assumptions about resources that are not specifically reflected in our economic modeling. Given that such resources will primarily serve the purpose of system restoration, we believe a separate proceeding to more broadly discuss restoration of the Minnesota system from a catastrophic event would be appropriate, particularly in light of the increase of renewable resources throughout the state and decrease of thermal baseload units that traditionally have been relied on for such purposes. In that proceeding, we would intend to discuss the specific resources we would add to meet our system restoration needs under a zonal approach.[15] As noted in our action plan, we intend to commence this proceeding in the coming years.

In the meantime, and as we discuss in more detail below, we need to make changes to some of our current blackstart units regardless of the path we take in the future.
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Beyond these Units and these Zones, we expect we will have additional needs for firm

[15] We are committed to being technology-neutral as we examine these opportunities in the future.
[16] The placeholder continues to be reflected in the Supplement Plan discussed in this Reply.

dispatchable generation to support the zonal restoration approach. As we have otherwise noted, we will address any further need for blackstart resources and related incremental investments in these and other Zones in a future proceeding dedicated to system restoration.

E. Selection of the Current Minnesota Blackstart Unit Replacement

In our June 2020 Supplement, we noted that blackstart critical units in Minnesota and Wisconsin **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** While we included cost placeholders for needed blackstart investments in our 2020 Supplement, we continued to work internally to develop plans to replace the unique and important grid attributes these units provide, while also minimizing the amount of new gas-fired capacity on our system and financial impacts to our customers. We have since finalized our plans.

As we have noted, our current Minnesota Initial Units are retiring. Our assessment is that refurbishment would only be a short-term solution due to their age, and therefore is not cost-effective. The balance of this section discusses our plans for Minnesota's Initial Units, including a general discussion of the alternatives we considered.

1. *The Plan for Minnesota's Initial Units*

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[17] **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**

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2. *Factors Considered*

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[18] **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**

[19] **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**

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4. *Alternatives Considered*

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a. Current Initial Unit Site.

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b. Other Sites Considered.

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c. Selected Site.

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F. Specific Plan to Implement the new Blackstart Initial Units

1. *Specific Plans for the* **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**

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21 **[PROTECTED DATA BEGINS**

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2. *A Certificate of Need is not Required*

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Therefore, these improvements are exempt from the certificate of need requirements (CN) of Minn. Stat. § 216B.243 under Minn. Stat. § 216B.243, subp. 8(a)(5) and (6), which states that the CN requirements do not apply to "conversion of the fuel source of an existing electric generating plant to using natural gas" and "the modification of an existing electric generating plant to increase efficiency, as long as the capacity of the plant is not increased more than ten percent or more than 100 megawatts, whichever is greater." Notwithstanding these exemptions, we will, of course prove the prudence of our investments at the appropriate time in a future rate case or other applicable proceeding.

G. Conclusion

Given the importance of maintaining a reliable, efficient System Restoration Plan – not only for our customers, but also in support of other regional entities as well – it is necessary to construct new Blackstart capable units at **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** sites. The work we will perform to ready **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** to be the new Initial Site is exempt from certificate of need requirements. Further, we would like to commence a blackstart specific proceeding to address our transition to a zonal plan, including additional resources needed for that plan.

SECTION 4: MODELING AND REBUTTAL

A. Introduction

Examining our Alternate Plan without the Sherco CC has been a significant modeling undertaking, with more specialized inputs and assumptions than we have previously used. Resource Planning has historically focused primarily on size, type, and timing, without regard to units' locations. Given the Company's significant quantities of retiring resources in the next ten years, however – not least 2,000 MW at the Sherco site and 600 MW at King – we have an important opportunity for interconnection re-use at a time when the queue is significantly constrained. Our Alternate Plan proposes an approach to reusing these interconnection rights that results in customer benefits. This section outlines the process by which the Company updated selected modeling inputs, re-evaluated its Reference Case and Supplement Plan (baseload Scenario 9), and developed the Alternate Plan that we think is the best path forward for our customers, stakeholders, and the states we serve.. It also addresses the relative benefits of these plans and responds to preferred plans put forward by other modeling parties. Finally, we discuss lessons learned and proposed process improvements for the future resource plans, based on our experience and the comments and alternative modeling provided by other parties in the docket.

The Company attempted to take a balanced approach in its updates to baseline assumptions, ensuring we were responsive to the direction of the Commission and making updates that would both improve the precision of the model and conform with current policy; however, as this docket has stretched on for over two years and now a third round of modeling from the Company, we attempted to keep as many of the baseline inputs consistent with our June 2020 Supplement as possible. While this means that some inputs are not up to date with the latest vintages available, we believe this choice was appropriate to provide a more direct comparison with our previously filed plan, and also to bring this docket to a timely resolution. That said, in lieu of updating all inputs we conducted a number of sensitivity tests – as we always do – to ensure we have considered the benefits and costs of our updated plans under a range of potential futures.

After updating our baseline modeling, we developed specialized model inputs to examine the potential for full interconnection re-use at the Sherco and King sites as our existing coal units retire from now until 2030. Our Alternate Plan was developed with these special inputs and adjustments to Scenario 9. First, we removed the Sherco CC, which opened up the full approximately 2,000 MW of interconnection rights the Company will have available when the Sherco coal units fully retire. Likewise, when King retires, the Company will have 600 MW of open interconnection to reuse with other resources. After these units retire, we have three years to add new resources, or else we lose the rights and the corresponding value of the interconnection. Thus, we established tranches of resources – mostly renewable, along with some supporting CT capacity on the Sherco line – according to the resources available in the areas where we intend to build transmission lines. These gen-tie lines will be designed to facilitate the addition of those additional renewable resources through the existing interconnection points at Sherco and King (gen-tie lines). The types and limits of the resources we optimized on the gen-tie lines were informed by a cross-cutting team of Company experts examining resource availability, transmission planning and stability, blackstart needs, regulatory implications of interconnection re-use, and more. The result was a plan that is able to add substantial amounts of clean, renewable generation – along with some supporting firm dispatchable generation; in total, over 4,000 MW of renewables and approximately 400 MW of supportive CT capacity. We note that the CT capacity proposed will be capable of hydrogen fuel blending from day one and it can also operate in "synchronous condenser mode," with a clutch between the turbine and generator, which enables it to support system stability needs without burning fuel or releasing any associated emissions.

Reutilizing the interconnection rights we currently hold at these sites provides essential value to customers. It is a well-known issue in the industry broadly, as well as here in Minnesota, that generator interconnection queues (GIQs) are becoming more and more backlogged as the proposed additions of renewable energy are outpacing available transmission to carry those clean electrons from the source to load centers. MISO is no exception and we have been observing queue delays and challenges for the past few years. The Department perhaps stated the challenge best in its initial comments on our June 2020 Preferred Plan, saying:

> "Since Xcel's preferred plan involves obtaining interconnection for substantial amounts of new capacity, it is not clear that the plan is achievable within the MISO GIQ construct. 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. Therefore, it would appear that either substantial new transmission needs to be built or Xcel will be limited to pursuing projects that avoid the MISO GIQ."[1]

We agree that the queue is a significant challenge to the Company to achieving its near-term carbon reduction goals. We are working to achieve 80 percent carbon reduction by 2030 and we will need to bring on significant amounts of zero-carbon generation to achieve this goal. 2030 is only nine years away, so reutilizing our existing interconnection rights to the extent possible is an essential piece of our approach.

[1] DOC Comments at 41.

That said, when we conduct resource planning, we are attempting to balance many objectives, not only carbon reduction. In addition to our environmental goals, we examine our plans on affordability, risk management and reliability metrics as well. We discuss each of these at a high level here, and in further detail in subsequent sections.

Table 4-1: Company Plan Performance Across Selected Key Planning Metrics

	Plan	Updated Scenario 9	Alternate Plan
Cost	PVSC delta ($ million, cost/(savings) relative to Reference Case)	($234)	($606)
	PVRR delta ($ million, cost/(savings) relative to Reference Case)	$96	($46)
Environment	Carbon reduction by 2030 (percent, from 2005 levels)	80%	86%
	Total carbon-free generation, 2034 (percent of total generation)	73%	82%
Risk and Reliability	Firm capacity-to-peak demand ratio	0.63	0.58
	Sensitivities - range of cost deltas relative to Reference Case	(1,090) – 124 *Median: (202)*	(2,163)-16 *Median: (544)*
	2034 Native capacity shortfall events	0	0
	2034 expected unserved energy (EUE)	0	0
	Loss of Load Hours (LOLH)	0	0
	2034 maximum 3-hour net load ramp under base assumptions (MW)	4,081	4,484

Overall, both the Company's Supplement Plan as updated here (Updated Scenario 9) and the Alternate Plan meet the goals of our core planning objectives, to reduce carbon at a reasonable cost, while also maintaining reliability and mitigating risk. The Supplement Plan achieves 80 percent carbon reduction and PVSC savings of $234 million relative to the Reference Case. It does this while also maintaining reliability and mitigating customer risk, by including sufficient firm dispatchable generation to cover a substantial portion of customer load. Particularly in the winter where – as we have seen again in recent years – significant customer needs may occur when variable renewables are not available. In the absence of a seasonal resource adequacy construct, being able to meet the majority of the Company's winter load with dispatchable resources on our system is a critically important risk and reliability consideration.

The Company's Alternate Plan achieves even more savings on a PVSC basis ($606 million relative to the Reference Case) with significant additional potential upside if federal tax credit reform is passed. Further, the Alternate Plan reduces our carbon emissions by a greater amount than the Supplement Plan, achieving more than an 85 percent reduction from 2005 levels by 2030. This is, in large part, because we have unlocked the ability of the Sherco and King interconnection rights to be reutilized, in light of MISO interconnection queue constraints. With these dedicated gen-tie transmission lines that enable us to incorporate more renewable generation from resource rich areas and deliver that energy to the existing interconnection, we believe the Alternate Plan provides an opportunity to add more renewable generation, faster, while reducing overall system costs relative to the "business as usual" Reference Case. Due to the magnitude of renewables we are able to add on the gen-tie lines, and the relative cost of those lines as compared to observed GIQ results for projects receiving similar levels of accredited capacity, we are seeing gen-tie additions come in at an average of under $140/kW for the Sherco interconnection and $55/kW at King. We note that, although some parties disagreed with our assumed generic interconnection costs, the average costs outlined for resources on the gen-ties is on par with or lower than the alternate costs those parties proposed we use. In that way, if the Commission does determine that our Alternate Plan merits approval, reutilizing our interconnection to bring on additional renewables is a low-regrets approach at worst, and at best, will provide customers significant savings.

We have also conducted sensitivity testing to address modeling party concerns around our load assumptions, technology, fuel or carbon cost assumptions, as well as some additional testing the Company undertook to address other risks associated with foregoing a third full refresh of our input assumptions. On a cost basis, the results of these sensitivity analyses confirm that both the Supplement Plan and the Alternate Plan are robust to a broad range of future cost and load futures, showing cost savings across nearly all sensitivities. In fact, the only sensitivities where these plans do not result in savings are ones where carbon costs are not incorporated into the modeling, and the median results for each plan show hundreds of millions of savings expected, relative to a "business as usual" Reference Case.

We also examine the Company's plans with regard to mitigating capacity and energy risk and/or potential reliability concerns. Here again, we believe our plans protect customers while still enabling a large amount of clean energy expansion on the system. The plans maintain a sufficient ratio of firm and dispatchable capacity-to-peak demand ratios, exhibiting that our plans do not leave customers unhedged on this measure of market risk. Further, the Company's plans exhibit no expected reliability concerns across several metrics that are broadly accepted throughout the industry, as well as additional metrics we examine to assess relative risk of plans.

This is in large part because the acceleration and expansion of so many renewable resources, while also maintaining our plan to extend the life of our zero-carbon Monticello nuclear plant an additional 10 years and a number of, largely technology neutral, dispatchable generation resources means that the Alternate Plan is also able to achieve higher levels of carbon reduction – on par or approaching the levels in other modeling parties' proposed plans – while, importantly, mitigating risk and reliability concerns. The Supplement Plan also achieves our carbon reduction goals, as previously mentioned. The fact that both the plans meet this objective while maintaining an appropriate level of firm dispatchable capacity, helps ensure we can meet customer needs across all hours of the year and appropriately hedge risk while also meeting our environmental goals.

Unfortunately, the same cannot be said of some other modeling parties' preferred plans. We have conducted supplemental risk and reliability analyses on these plans, in addition to examining our own plans; these assessments show that the Sierra Club and CEOs' proposed plans lack sufficient firm dispatchable capacity to adequately mitigate customer risk and reliability concerns. On the other end of the spectrum, we strongly disagree with CAE's approach of assuming each MW of renewables in our plan requires incurring the cost of equivalent gas capacity to "back up" the resources. We do recognize that a reasonable amount of hedging customer load against volatility in market prices and renewable variability important. We believe our proposed plans provide a reasonable middle ground between these extreme approaches.

Furthermore, we were unable to evaluate CUB's proposed alternative plan, in large part because it did not attempt to fully model our five-state integrated system's full load, nor all the resources with which we serve that load, nor did it provide an evaluation of its plan's PVSC (the former of which is out of compliance with Fixed Resource Adequacy Planning principles and the latter of which is a requirement for Commission consideration of a plan). These deficiencies cannot be overlooked. And despite the Company's Resource Plan docket being a public proceeding, CUB was also unable to produce all the datasets we would have needed to attempt to analyze the plan as proposed in response to discovery requests. We have several additional concerns regarding the validity of CUB's modeling, but suffice to say that if a plan cannot be evaluated because it does not meet such basic requirements, it should not be adopted as an alternative to the Company's plans.

Finally, we appreciate the level of thoughtful engagement we have received to date in this docket, and the extent to which parties have raised valid input for consideration and, in some cases, incorporation into our revised plans. We believe the process could be even more robust with some additional structure around what constitutes a complete alternative plan. Further, we recognize that several parties have a desire to see us optimize distributed solar, alongside the bundles of energy efficiency and demand response resources we already include in our modeling. We appreciate this, although we believe additional work is necessary in order to determine an appropriate methodology. As such we propose to continue working with parties to be able to include more distributed energy resources in our modeling optimization in our next resource plan.

Below we discuss in greater detail the approach and modeling outcomes conducted in support of these Replies.

B. Updates to Inputs and Assumptions

In order to model our Alternate Plan and limit the number of input updates the Commission and stakeholders would need to consider, the Company determined it was appropriate to make only limited updates to the majority of its standard input assumptions for the purposes of these Replies. Our changes primarily reflect 1) those required by the Commission to provide an up to date view of our baseline resources; 2) modeling methodology updates that improve upon how we simulate the operation of our system and potential future additions, 3) changes necessary to reflect current policy regarding federal renewable tax credits., and 4) an updated approach to calculating PVSC, per discussion with the Department. These changes are described further below.

There are, of course, a substantial number of modeling inputs the Company could have chosen to update, and we recognize that many of the modeling parties did update other inputs in their comments and modeling. However, many of these updates deal with uncertain future prices and loads, with continually changing inputs. Rather than updating each input for a third time in this docket, we have chosen to examine a range of potential future outcomes through extensive sensitivity testing. Below we describe the selected input updates we did make and how we use sensitivity testing to further examine important assumptions.

1. Additions Since June 2020 Modeling

As we noted in our June 2020 Supplement, the Company determined we would utilize a January 2020 “lock-in date” for inputs and assumptions to our Supplement Plan. However, in response to acquisition needs for certain customer programs and the acceleration of future investments in response to the Commission’s request for COVID-19 relief and recovery opportunities, several projects have been added or uprated and extended on our system since that date. During the hearing in which the

Commission considered our first tranche of wind repowering proposals,[2] Commissioners expressed a desire for us to update our resource baseline to reflect these approvals and re-evaluate the optimal future resource portfolios.

We have added the following projects – detailed in Table 4-2 below, to our baseline of existing resources.

Table 4-2: Resources Approved Since January 2020 and Reflected in Modeling

Resource	Addition or Extension	Fuel Type	MW (installed capacity)	Achieved/Expected Online Date
Mower County	Extension (repower)	Wind	99	January 2021
Elk Creek	Addition	Solar	80	December 2021[3]
Deuel Harvest	Addition	Wind	100	December 2021
Heartland Divide II	Addition	Wind	200	December 2021
St. Cloud Hydro	Extension	Hydro	8.5	November 2021
Nobles	Extension (repower)	Wind	201	December 2022
Grand Meadow	Extension (repower)	Wind	101	December 2023
Border Winds	Extension (repower)	Wind	150	December 2024
Pleasant Valley	Extension (repower)	Wind	200	December 2024
Ewington	Extension (repower)	Wind	20	December 2021[4]

[2] Per discussion during the December 23, 2020 hearing in Docket No. E002/M-20-620.
[3] Note that the Commission recently approved an Amended and Re-Stated Purchase Power Agreement between the Company and National Grid Renewables for this project, as it is now expected to be delayed until May 2023; however, under this agreement the Seller will provide capacity, energy, and renewable energy credits (RECs) to the Company to cover this delay, and thus the Company has included the Project at its originally agreed upon commercial online date for purposes of modeling.
[4] The Company has a pending contract amendment in Docket No. E002/M-20-620 that would push this in-service date back to September 2022. This is not reflected in modeling, but as this project only represents an estimated <6 MW of accredited capacity and is delayed less than 1 year, the impact to our overall planning will be minimal.

While we did our best to incorporate all projects that were approved up to the date of filing, in order to finalize modeling and develop these Replies, we did need to impose a cutoff date for changes to our baseline portfolio inputs. Thus, the Company has only included projects in our baseline that were approved as of June 1, 2021. As of that date, the Company had two other acquisitions pending before the Minnesota Commission; one for the 120 MW wind repower/expansion with ALLETE Clean Energy (Docket No. E002/M-20-620) and the Company's self-built proposal for a 460 MW solar project near the Sherco site (Docket No. E002/M-20-891). Further, our Wisconsin operating company affiliate, NSP-W, had a proposed project outstanding before the Wisconsin Public Service Commission for a 74 MW solar project slated to be placed into service in or around October 2022. Since June 1, 2021 both the ALLETE project and the Wisconsin solar project have been approved by the respective Commissions. While we have not incorporated these into our baseline, we note that the accredited MW associated with these projects is relatively small – under 60 MW in total – and thus we would not expect them to have a significant impact on our expansion plan modeling. Further, as we noted in the Sherco Solar petition, we envision that project to be a partial fulfillment of the MW our Preferred Plan indicates, and thus the updated expansion presented in these Replies are effectively inclusive of that project.

2. *System Resources and Needs Prior to Expansion Plan Modeling*

Based on the updates discussed above, we have re-examined our load and resources balance, *prior* to the additions contemplated in updated expansion planning. As can be seen in the below table, even with the additions highlighted above, the Company would still expect to have experience a deficit by 2026 and our capacity position becomes relatively tight by 2025.

Table 4-3: 2020-2034 Reference Case System Net Accredited Capacity Surplus/Deficit Prior to Expansion Planning (MW, Unforced Capacity[5])

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,295	2,295	2,295	2,295	1,647	1,647	1,647	994	994	994	994	994	994	994	994
Nuclear	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,019	1,019	1,019	498	0
Combined Cycle	2,078	2,078	2,078	2,078	2,078	2,078	1,787	1,551	1,551	1,551	1,551	1,551	1,275	1,275	1,275
Combustion Turbine	1,781	1,781	1,781	1,781	1,635	1,325	1,325	1,280	1,280	1,280	1,280	737	737	737	737
Hydro, Large - Diversity Summer	342	342	342	342	342	0	0	0	0	0	0	0	0	0	0
Hydro	539	659	657	657	657	168	168	168	168	168	168	168	162	158	158
Renewable, Biomass	110	110	110	86	86	61	61	61	29	29	29	19	19	19	19
Renewable, Wind	500	624	733	680	755	681	676	675	672	650	649	633	630	565	561
Renewable, Solar	495	531	614	647	632	612	591	570	548	526	503	480	456	431	435
Demand Response	1,045	1,192	1,273	1,349	1,407	1,454	1,470	1,485	1,499	1,511	1,518	1,526	1,536	1,547	1,560
Total existing and approved resources	**10,826**	**11,253**	**11,524**	**11,556**	**10,881**	**9,668**	**9,368**	**8,426**	**8,383**	**8,350**	**7,711**	**7,128**	**6,828**	**6,225**	**5,740**
NSP total obligation	**9,430**	**9,380**	**9,416**	**9,426**	**9,406**	**9,381**	**9,370**	**9,385**	**9,393**	**9,341**	**9,354**	**9,362**	**9,404**	**9,459**	**9,523**
Net Position	**1,396**	**1,873**	**2,108**	**2,131**	**1,475**	**287**	(1)	(959)	(1,011)	(991)	(1,643)	(2,234)	(2,576)	(3,234)	(3,783)

As a threshold matter, it is important to note that the Company's planning process is intended to ensure we procure resources to cover the full resource gap indicated in the table above. In other words, our capacity expansion modeling is solving to add resources that provide enough accredited capacity to meet our full Planning Reserve Margin Requirement (PRMR) obligations at MISO, informed by our load for our entire upper Midwest service area (including NSP-W), our effective planning reserve margin, and the existing and approved resources we have on the system. In reference to the Company's Fixed Resource Adequacy Plan (FRAP) to MISO, which fulfils our PRMR obligation, the Department aptly describes that our resource planning "mimics the FRAP process (capacity hedging) and serves to limit the Company's exposure to reliability risks…"[6] Not every modeling party put forward a proposed alternative plan that can meet these requirements. We discuss this further in Section D below.

Further, the Company's load makes up over fifty percent of MISO's Local Resource Zone 1 load and approximately seven percent of MISO overall. As a result, we believe it is important both to system reliability and our own customers' economic risk to plan a system that can meet all our expected customer load with resources we own or contract directly (rather than relying on the MISO planning reserve auction). As a large market player in Zone 1, the planning and resource choices we make inherently

[5] "UCAP."
[6] DOC Comments at 34.

have an impact on the reliability and risk our customers and other Zone 1 entities face, especially when considering any transmission constraints.

We therefore would neither propose, nor accept, any plan that was not able to meet our basic fixed resource adequacy needs, given the planning reserve and resource adequacy values we are provided by MISO and which evolve over time. For example, MISO releases new planning reserve margin, coincident factor, and RA values each year. And over the past few years, both the Company's effective reserve margin (based on the planning reserve margin requirement and our coincident factor) has been increasing. While we do not directly update our reserve margin inputs to reflect the latest values here - again for ease of comparison with the June 2020 Plan – we have conducted sensitivity testing that evaluates how we would expect future capacity plans to respond to this higher reserve value. This is also discussed in Section D below.

3. Model Vintage and Smaller Generics

Since our June 2020 Supplement was filed, we have upgraded EnCompass software from Version 4.2 to Version 5.0. One of the changes between these versions has a relatively significant effect on our modeling outcomes, namely, how the model selects representative days for its hourly generation shaping. In Version 4.2, a straight average approach is used to convert an 8670-hour renewable generation profile to representative days for each calendar month of the year. Version 5.0, on the other hand, uses a ranked peak algorithm for the typical day conversion, which preserves the maximum and minimum value and avoids flattening renewable shapes. This especially affects wind shapes, although solar shapes also change somewhat. Figures 4-1 and 4-2 illustrate how the Versions 4.2 and 5.0 conversion algorithms shape our generic wind and solar profiles differently. This representative data depicts on-peak and off-peak days for the month of July.

Figure 4-1: Typical Day Conversions for Wind Shapes, EnCompass Versions 4.2 versus 5.0

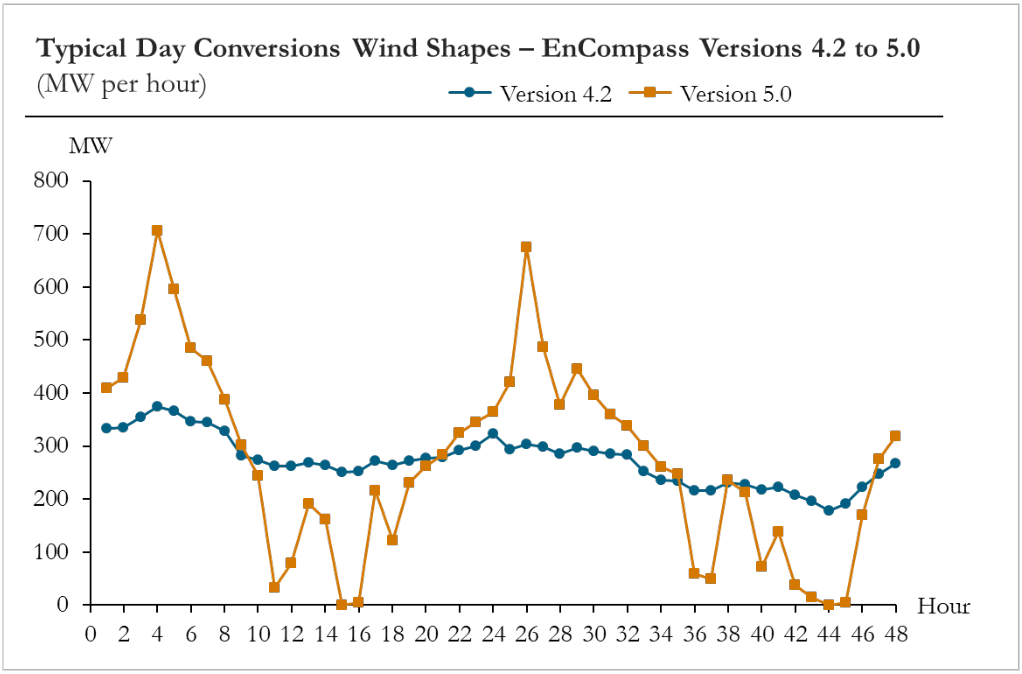
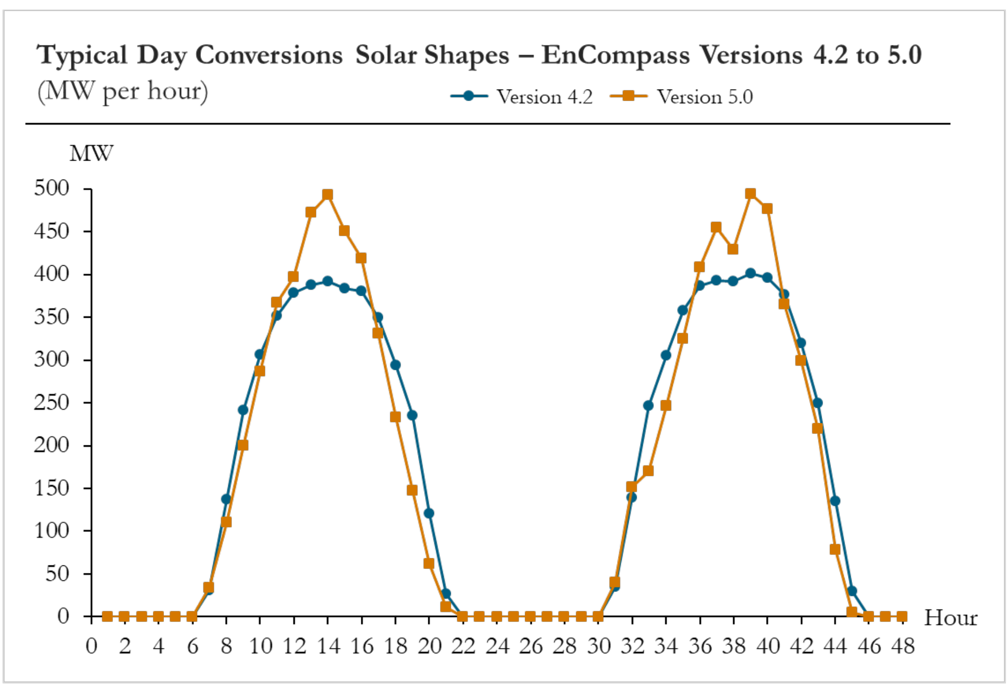


Figure 4-2: Typical Day Conversions for Solar Shapes, EnCompass Versions 4.2 versus 5.0



This change in typical day conversion algorithm impacts our capacity expansion runs, which use a representative on-peak and a representative off-peak day for each month of the year to select resources. Considering the variability of renewable generation profiles is better preserved using Version 5.0, we believe this change better represents real system conditions. It is our understanding that that the Clean Energy Organizations and Sierra Club have used Version 5.0 in the instant docket, as does another IRP recently filed in the state. Therefore, we determined it was appropriate and acceptable to change to this updated version for modeling in these Reply Comments.

We also made a change to the size of some of our generic resources at the same time as updating EnCompass versions. Various parties noted in their comments that the large size of wind, solar and battery generic resources in our June 2020 filing may not appropriately account for the modularity of these resources, as they are often installed in smaller increments than we had modeled previously. We appreciate those comments. The large generics sizes we used in our June 2020 filing was largely a vestige of Strategist modeling and we used them in EnCompass at that time to maintain consistency between the models. As we are moving forward with EnCompass as our long-range planning model now and have not continued to maintain Strategist since the June 2020 filing, we believe it is appropriate to reduce generic sizes for these Reply Comments as well.[7] The modeling included here uses 50 MW generic sizes for all wind, solar and battery resources, reduced from 750 MW, 500 MW, and 321 MW respectively.

4. *Other Input Assumptions*

The Company has made limited additional updates to base inputs and assumptions beyond those discussed above. Given the Alternate Plan proposed in these Reply Comments is notably different than the one presented in our June 2020 Supplement, we determined it would be preferable to keep as many of our inputs constant as possible, in order to provide a clear comparison of the Supplement Plan and simplify consideration of the Alternate Plan for the Commission and parties. Aside from the updates described above, the only additional major updates the Company made to input assumptions was to incorporate recent federal extensions to the Production and Investment Tax Credits into our wind and solar technology cost assumptions,[8] how

[7] We learned, in the course of updating our modeling, that EnCompass is able to complete optimizations substantially faster with smaller generics, whereas we expect that Strategist would have run much slower and encountered more truncation challenges.
[8] Consolidated Appropriations Act of 2021. Section 132.

costs related to curtailment of renewable resources are captured,[9] and some ongoing capital and maintenance costs related to existing facilities.[10]

That said, we realize that parties identified both minor and substantive suggested changes to our input assumptions, including to technology cost trajectories, and interconnection costs. For example, several parties noted in their initial comments that the source we use for our renewable price inputs – the National Renewable Energy Laboratory's *Annual Technology Baseline* report – has been updated since the vintage had used in our June 2020 Supplement filing. We also note that other external and internal inputs that parties did not specifically raise – such as the Company's planning reserve obligation within MISO – have also been updated since that time.

While forecasts created at a specific point in time will become outdated, the industry is currently in the midst of particularly accelerated change and to say the landscape is evolving quickly would be an understatement. The Resource Plan incorporates so many input assumptions – both external and internal, and updated on a range of timeframes – that it would neither practical nor useful to attempt to continually maintain the latest version of every input used. Further, to continue litigating input assumptions nearly two years into this Resource Plan process risks further delaying Commission direction on resources that we will need to begin planning for and adding to our system within five year action plan window.

Rather, to the extent that updates to these other inputs would significantly affect our Alternate Plan or costs associated with this future plan, we have examined the impact of these changes through sensitivity testing that reflects a broad range of future outcomes. We have designed sensitivities that test an appropriate range around these key inputs to capture many of the issues parties have raised in their comments. For example, we include sensitivity testing that examines substantially lower wind, solar, and standalone battery technology prices than our base assumptions – even lower

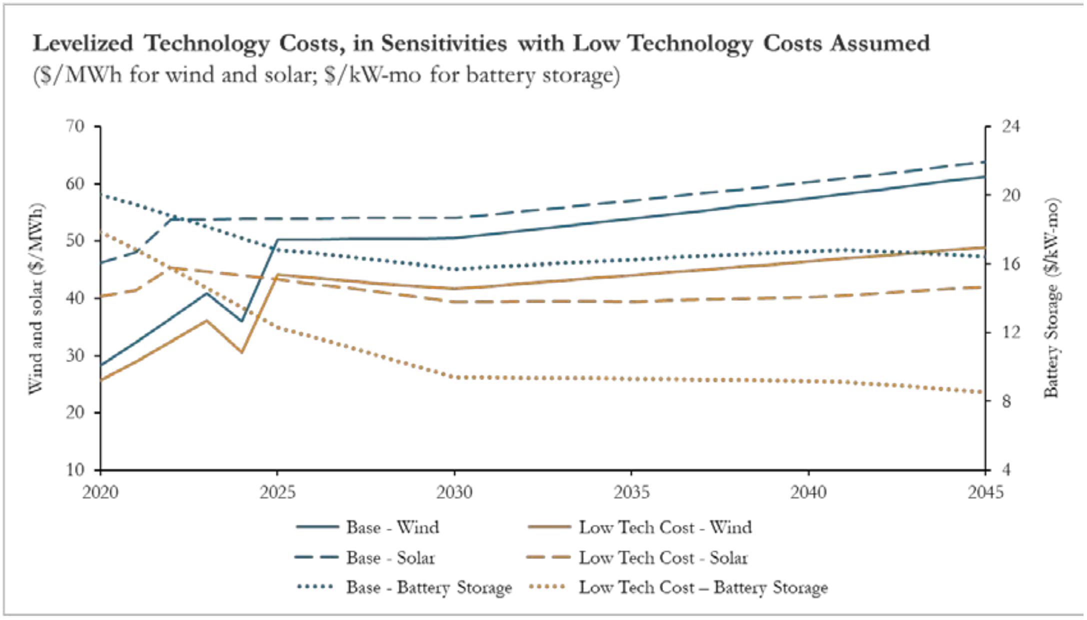
[9] Previously the Company did not assign any costs to curtailed generation. In the modeling presented here, the Company is including costs for curtailed generation of renewable resources at the same cost as the utilized generation. This better reflects the cost of curtailment, as many renewable resources as the "take or pay."
[10]. With regard to the other cost adjustments, the Company discovered it had previously overestimated some costs – primarily our fixed operations and maintenance budgets – for the King coal unit. This most significantly impacts Scenario 1 and other cases where it is operated to the end of its existing financial life. Adjusting these inputs to their more appropriate values actually reduces the cost of the Reference Case by a larger amount than Scenario 9 or the Alternate Plan, given the plant remains in operation for 10 additional years.

than those included in the 2020 NREL ATB [11] and generally on par with the proposed cost of standalone battery energy storage indicated by some modeling parties, especially in later years.[12] We also examine high and low load sensitivities, high and low fuel price sensitivities, a range of future potential carbon costs, and selected combinations of these sensitivities consistent with the futures analyses presented in our June 2020 Supplement. Therefore, we believe this adequately addresses stakeholder concerns that we have not sufficiently considered the potential for future low technology costs for the purposes of this IRP.

[11] Several parties also noted corrections to our method of applying tax credits and calculating estimated levelized renewable energy costs. As these parties noted, however, the changes were minor and would result in higher assumed prices. We did not believe it was necessary to adjust our pricing in a manner that would increase generic renewable prices, in particular because we know cost trajectories are generally expected to decline over time – current inflationary trends notwithstanding – and, importantly, resource planning modeling is a high level and directional process and such minor adjustments will not substantially affect the outcomes of a given plan. That said, we plan to reexamine our method of utilizing ATB outputs in our modeling in the future to ensure that we appropriately reflect the application of those inputs to our region and existing policy.

[12] Some parties indicated concerns regarding our assumed standalone battery energy storage costs, in particular that battery lifetimes should be extended to 15 years, from 10, which substantially reduces the levelized cost. We did not make adjustments to our base assumptions at this time, but rather we test cost differences in sensitivities and will reexamine this assumption in future planning processes. Our lifetime assumption was based on the Company's current understanding of the technology performance under expected operating conditions. There are many factors relating to dispatch that affect the lifetime of storage assets, including average daily state-of-charge, depth of discharge, and charging and use at extreme warm and cold temperatures. While round-trip efficiency and depth of discharge have explicitly stated assumptions in NREL ATB 2019, many of the other variables listed do not. If batteries are dispatched in ways such that variables above substantially differ from their warranty specifications, their lifetimes, capacity and/or performance can decrease. Additionally, aside from the pricing, we make relatively optimistic operational and planning assumptions for batteries in our modeling. Batteries are the only resource we modeled with a 0 percent Forced Outage Rate and 100 percent capacity accreditation (UCAP) in EnCompass. Furthermore, unlike solar resources, no declining ELCC has been applied to firm capacity ratings, which would be appropriate for the scale of battery resources adopted in some modeling party plans. For all these reasons, we chose to examine potential lower battery costs in the context of a sensitivity, rather than adopting other modeling parties' assumptions. Sensitivity results are discussed in Section IV.

Figure 4-3: Comparison of Low Technology and Base Cost Sensitivities



Additionally, for the purposes of these Replies, we have developed two new sensitivities. One tests a broader range of outcomes related to resource adequacy and the other examines potential upside of our proposal under certain renewable tax reform outcomes. The results of these sensitivity tests are detailed further in Section D below; but importantly, they show that both the Supplement Plan and the Company's Alternate Plan are robust and prudent across a range of potential futures.

Finally, several parties discussed and modeled the extension of existing contracted hydroelectric capacity and the potential impact of increased levels of distributed solar adoption at certain assumed incremental costs. Regarding the hydro contracts, we do not, as a matter of general practice, model any contract extensions (thermal or renewable) in the Resource Plan, because it would require too much speculation regarding future terms and pricing.[13] That said, we think it is appropriate to continue evaluating the opportunity for existing contracts to be extended to meet our future system needs, especially to the extent those proposals enable benefits relative to the resource plan that is ultimately approved.

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[13] That said we acknowledge the CEOs' modeling provided a helpful representative datapoint for consideration in its initial comments.

Regarding distributed solar, we were not able to incorporate distributed solar into our modeling, for reasons we discuss further below in Section E. However, as we discuss below, we are open to working with parties on future modeling efforts to examine appropriate methods and costs to use to model distributed solar as a selectable resource, rather than incorporating an assumed adoption level. At this stage we still expect that, to the extent distributed solar of any kind is added to our system, it would contribute to the overall amount of solar capacity indicated in the Plans.

5. *Updated Approach to Calculating PVSC*

The last update we made regarded how carbon costs related to market sales are captured in the PVSC calculation. Previously, costs in scenarios (and/or years) where there is a regulatory cost of carbon in effect were removed for the volume of carbon emissions attributable to economy market sales. Since the MISO market price forecast is already adjusted upwards to account for carbon regulatory costs in these scenarios and years, the Department proposed that this increased revenue from sales fully accounts for the cost impact and that further adjustment in unwarranted. We agreed with this proposal and have adjusted our methodology accordingly. Costs related to carbon externalities, in the scenarios (and/or years) where externality costs are in effect instead of regulatory costs, continue to be reduced for market sales.

6. *Updated Reference Case and Scenario 9*

Based on the updates noted above, the Company has re-evaluated both of the primary baseload scenarios relevant to our plans; the Reference Case and baseload Scenario 9. The Reference Case maintains coal and nuclear retirement dates at the units currently approved financial end of life. Scenario 9 – which has formed the basis of our preferred plans throughout this resource plan process, including the Supplement Plan – retires our King and Sherco 3 coal units early, in 2028 and by 2030 respectively, and extends operation of our Monticello nuclear unit until 2040.

Table 4-4: Summary of Baseload Unit Retirement Dates in the Updated Reference and Scenario 9 Cases

		Retirement Date Modeled	
Unit	**Type**	**Updated Reference Case**	**Updated Scenario 9**
Sherco 1	Coal	2026	2026
Sherco 2	Coal	2023	2023
Sherco 3	Coal	2034	2030
King	Coal	2038	2028
Monticello	Nuclear	2030	2040
Prairie Island 1	Nuclear	2033	2033
Prairie Island 2	Nuclear	2034	2034

Starting from our baseline of existing and approved resources, assumed unit retirement dates, and assumed load and reserve requirements, our capacity expansion models use economic optimization to select least-cost combinations of resources that can meet our customer needs over the fifteen year planning period.

Our Reference Case – reflecting a "business as usual" approach, where no currently approved baseload unit retirement dates are changed – shows that approximately 1,000 MW of solar additions constitute the most optimal resources to meet our capacity needs in the near term, and that our plan indicates a combination of the Sherco CC, wind, solar, and firm peaking resources will meet customer needs throughout the remainder of the planning period. The Company's modeled Reference Case expansion plan is detailed below. A full load and resources table for this Scenario is included in Appendix B.

Table 4-5: Updated Reference Case Annual Capacity Additions Through 2034, (MW, installed capacity)

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**0**
Wind	-	-	-	-	-	-	-	-	-	-	-	250	450	800	800	**2,300**
Solar	-	-	-	-	-	1,000	-	-	-	-	1,150	450	-	-	250	**2,850**
Firm Dispatch-able	-	-	-	-	-	-	-	-	-	374	-	374	374	748	374	**2,244**
Sherco CC	-	-	-	-	-	-	-	835	-	-	-	-	-	-	-	**835**
Demand Response	33	132	67	62	47	41	12	14	15	17	19	20	21	22	24	**545**
Energy Efficiency	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126	**2,041**
Distributed Solar	173	72	87	68	25	16	15	15	15	15	15	15	15	15	15	**575**

Our updated Scenario 9 (the Supplement Plan) – reflecting early retirement of the King and Sherco 3 units in 2028 and 2030 respectively, and the extension of the Monticello nuclear unit through 2040 – reflects a similar expansion plan, although with some incremental solar and firm dispatchable capacity pulled forward to fulfill capacity needs as the remaining coal units retire early. By 2034, this plan adds nearly 4,500 MW of renewable capacity, 2,600 MW of firm dispatchable generation, and the 835 MW Sherco CC, in addition to the incremental demand-side management resources included in all our cases. The Scenario 9 re-optimization also now selects battery energy storage within the planning period, with 150 MW added by 2034.

We recognize these total additions are somewhat less than the June 2020 Supplement indicated. Some of these changes are related to the move to smaller generics and the differences between model vintages; however, the recent addition of a substantial quantity of repowered wind resources, as well as some new PPAs, also defers resource needs further into the future. A full load and resources table for this updated Supplement Plan (or Updated Scenario 9) is also included in Appendix B.

Table 4-6: Updated Supplement Plan Annual Capacity Additions Through 2034 (MW, installed capacity)

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Storage	-	-	-	-	-	-	-	-	-	-	-	-	100	-	50	150
Wind	-	-	-	-	-	-	-	-	-	-	-	-	50	950	850	1,850
Solar	-	-	-	-	-	1,000	-	-	-	600	450	100	-	50	500	2,700
Firm Dispatch-able	-	-	-	-	-	-	-	-	-	374	374	748	374	748	-	2,618
Sherco CC	-	-	-	-	-	-	-	835	-	-	-	-	-	-	-	835
Demand Response	33	132	67	62	47	41	12	14	15	17	19	20	21	22	24	545
Energy Efficiency	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126	2,041
Distributed Solar	173	72	87	68	25	16	15	15	15	15	15	15	15	15	15	575

These results show that the incremental renewable resources added since our June 2020 Supplement – alongside the additional few updates to our modeling inputs and assumptions – serve to modify our incremental expansion plan needs. Whereas Scenario 9 from our June 2020 Supplement added capacity throughout the 2025-2030 timeframe, our updated plan adds a substantial amount of solar in the last year of enhanced ITC eligibility and then little additional capacity until 2030 (aside from the Sherco CC). We also note that this updated Scenario 9 is the first time our baseload scenario modeling has included standalone storage resource capacity. Whereas previously certain sensitivities selected energy storage, we believe that the new EnCompass vintage's ability to better capture wind and solar variability – as well as reduced generic sizes – lead the model to more appropriately value modular energy storage attributes.

As we noted in our June 2020 Supplement, we believe baseload Scenario 9, reflected in the Supplement Plan, is the baseload scenario that best balances our four core planning objectives at this time: cost, environment, reliability, and risk. This plan results in customers savings on a Present Value of Societal Cost (PVSC) basis relative to the Reference Case; in our updated modeling, the Supplement Plan yields $234 million of savings across the full 2020-2045 modeling period, and $96 of PVRR costs. It achieves these savings while continuing to meet our goal to reduce carbon emissions by 80 percent from 2005 levels by 2030 (the "80x30" goal). And it balances our need to maintain and add substantial carbon-free capacity to our system – largely from variable renewables – while also ensuring we have an adequate level of firm dispatchable capacity on our system to appropriately hedge customer market risk and maintain reliability.

Table 4-7: Updated Reference Case and Scenario 9 Net Present Value of Revenue Requirement Results, 2020-2045

Scenario	PVSC ($ millions)	PVSC Delta to Reference Case ($ millions)	PVRR ($ millions)	PVRR Delta to Reference Case ($ millions)
Reference Case (Scenario 1)	**$41,067**	--	**$37,165**	--
Supplement Plan (Scenario 9)	**$40,833**	(234)	**$37,261**	96

We further demonstrated in our June 2020 Supplement that this balance between new variable renewables, firm flexible and baseload generation, and the substantial targeted load reduction through demand-size management best manages customer risks – as evidenced by its robust results across the various sensitivities tested and our reliability examination – and maintains fuel and attribute diversity on our system. While we did not re-create all the baseload scenarios presented in our Supplement for the purposes of these Reply Comments, we believe our updated modeling continues to show that the Supplement Plan is a prudent baseload scenario to compare to the Alternate Plan presented here.

C. New Modeling Inputs and Assumptions Introduced in this Reply

Throughout this Resource Plan process, the Company has recognized that there is widespread concern among stakeholders – primarily based on environmental and cost considerations – regarding the addition of a gas-fired CC at the Sherco site, which would have made use of approximately 40 percent of the Company's interconnection rights that will be available as the existing Sherco coal units retire. As discussed elsewhere in these Reply Comments, however, the Sherco CC would have been an important resource for system stability and restoration purposes. As such, the critical elements of evaluating a potential shift away from the Sherco CC included developing an opportunity for reuse of the interconnection rights made available at the Sherco and King sites while also ensuring sufficient firm dispatchable resources are added to support customer needs.

While land on the Sherco site itself provides limited opportunity for redevelopment of non-thermal resources, the transmission grid in the Twin Cities area was largely built around major thermal generation sites like Sherco and – to a lesser degree, King – which provides an opportunity to reutilize the existing generation delivery transmission infrastructure to interconnect new resources. Thus, with the retirement of Sherco and King coal resources by 2030, the Company is seeking to introduce new options for fully reutilizing the approximately 2,000 MW of interconnection rights belonging to the Company at the Sherco site and 600 MW at King. With these rights comes a significant opportunity for the company to add large quantities of incremental renewables, avoid MISO queue risk and accelerate our carbon reduction trajectory.

Below we discuss our approach to modeling additions that reuse these interconnection rights. We also discuss the firm dispatchable resources added in the modeling for our Alternate Plan and how these resources support system stability and our blackstart restoration plan.

1. *Gen-Ties for Sherco and King POI Re-Use*

In order to enable reuse of these interconnection rights for renewable resources, the Company proposes to build transmission tie-lines out of both the Sherco and King sites that can interconnect substantial amounts of incremental wind and solar resources and circumvent congestion in the broader MISO queue. The Company has conducted multiple rounds of reliability and economic modeling to assess the viability of the Sherco and King gen-tie concepts, with different configurations and amounts of generation they can reliably deliver. Due to the distances and large quantity of new capacity we are considering at the Sherco site, the Company has completed significant exploratory study work to identify any major technical issues with the gen-tie concept.

These initial transmission stability screens have identified stable operation of the system under multiple fault conditions, given the assumed equipment and MW limits for the gen-tie. This is further discussed in Section 2 Reliability. We subsequently developed EnCompass economic modeling to confirm whether the Sherco and King gen-tie concepts could yield customer savings and accelerate carbon reduction on our system, while also meeting customer energy and capacity needs. We expect nameplate renewable additions can exceed the approximately 2,000 MW of the Company's interconnection rights at Sherco and approximately 600 MW of interconnection rights at King, in order to maximize our opportunities for accredited generation replacement – per the MISO tariff rules – and fully optimize energy flows on and maximize utilization of the transmission lines given the complementary nature of wind and solar production.

a. Pursuing generator interconnection reuse enables benefits for customers and the Company.

The Company has discussed MISO queue congestion issues at length in other recent filings. As we have previously noted, existing transmission capacity continues to be constrained in our region and beyond, requiring high estimated upgrade costs in order to bring new projects online. While these costs vary widely between project locations, rounds of MISO study, and technology, we try to capture $/kW upgrade costs we can incorporate into our modeling that best represent what a project may – on average – face to interconnect to the broader grid as a Network Resource (i.e. to ensure capacity accreditation across the life of the installation). For wind, we assume that interconnection costs will be $500/kW and for solar, we assume $200/kW. These assumptions are consistent with those used for greenfield CC and CT resources, respectively.

We believe these assumptions are justified, based on our current understanding of the MISO queue, recent observed interconnection study costs, and the length of time it will likely take MISO to pursue large-scale new transmission buildout to alleviate the queue congestion for fully deliverable resources. Interconnection constraints are a well-documented and recognized issue in the industry, in MISO and other regional markets. In this docket, the Department has discussed these constraints in some detail in its comments, analyzing results from recent DPP study cycles and concluding that "either substantial new transmission needs to be built or Xcel will be limited to pursuing projects that avoid the MISO [generator interconnection queue]."[14]We agree with the Department's analysis, and accordingly, have not adjusted our transmission interconnection costs for the purposes of our updated modeling. We discuss queue issues – in particular an assessment around recent queue results and the importance of fully considering queue costs in our modeling – further in Section D below.

b. Assumed configuration and costs for Sherco and King gen-ties.

The Company created primary transmission configurations and associated MW limits for modeling to evaluate for the Sherco gen-tie. After evaluating these options, we are proposing – and modeling here – a double circuit line that terminates in in Lyon County, MN. Details about our model assumptions are included below, and are also included in Appendix A. Given the general scope of resource plan proceedings, the project parameters and costs described below are indicative only and will be subject to change, if the plan is approved and we further develop more precise transmission and generation project siting details.

As noted above, the Sherco gen-tie modeling includes costs assumed for the construction of two individual 345 kV circuits on a common double circuit tower that will terminate in Lyon County, MN. For the purposes of modeling, we assumed costs based on a gen-tie approximately 140 miles in length (for a total of 280)circuit miles.[15] These lines enable us to interconnect a substantial quantity of renewable resources, as southwest Minnesota is a resource rich area for both wind and solar. **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS][16]

The amount and mix of resources the model actually selects are limited primarily by the instantaneous output limit for the point of interconnection (POI) at Sherco. Per the existing generator interconnection allowances for the portion of the Sherco plant that we own, we assume that no more than approximately 2,000 MW can be delivered through the POI at any given time. The precise amount of each technology our economic optimization selects ultimately depends on the mix of resources available, the amount of energy that can flow through the point of interconnection at a given time, and the resource adequacy value of each generation type. But as noted previously, the amount of installed capacity can and does exceed the POI limit.

[14] DOC Comments at 41.
[15] As noted, final route miles and locations will depend on future regulatory processes.
[16] Discussed further, in Part III.C below.

Total costs estimated for this route option are $528 million[17] in capital expenditures. This estimate assumes capital costs of approximately $3.5 million per mile for both circuits, plus VAR support (e.g. synchronous condensers and series compensation of the lines). While these are general cost estimates and subject to change as we would undertake detailed project design, they are in line with the Company's experience on other projects. Synchronous condensers are located on the ends of the line and provide voltage, inertia and short circuit response to the system. Series compensation is located on the longest individual section of the transmission line and reduces the impedance (electrical length) of the line to reduce VAR losses. Other options for VAR support may exist but have not yet been evaluated.

For the King gen-tie, the Company has assumed the construction of one, single circuit 345 kV line to utilize the approximately 600 MW of interconnection rights that will become available when King ceases operations (as proposed in 2028). Line costs are modeled on the assumption that it would be approximately 15 miles long. We estimate the costs of the King line would be approximately $36 million – which equates to just under $2.5 million per mile – due to the smaller amount of MW flowing along the gen-tie. Further, VAR support is not included in the King line's estimate because of the shorter line mileage, the strength of the existing system in the area and smaller amount of MW flowing along the gen-tie. As with the Sherco line, final lengths and routes will be further developed and subsequently modified and/or approved in future regulatory processes.

While we believe these cost estimates are appropriately conservative, they are indicative only and will be subject to future refinement. As such, and as with any project, there are potential future cost pressures or alternate routing configurations that could affect the total cost to build the lines and the total MW they can carry. For example, as discussed further below, the MW limits modeled for wind and solar on the Sherco gen-tie are partially dependent on the support of approximately 400 MW of CT capacity that can also operate in synchronous condenser mode,[18] to be built at

[17] In 2021 dollars.

[18] Synchronous Condensers (SCs) are one of many VAR support technologies that can be used on the transmission system to provide voltage and other ancillary support services. The SC is a generator that is started up, usually by a smaller generator, and acts as a motor load on the system. However, rather than burning fuel, electricity from the system is used to maintain the spinning speed of the generator/motor while the voltage controls (excitation system) are then used to supply or consume VARs on the system. This is how SC's provide voltage control. Further, the SC, through the rotating mass of the generator, provides inertial and short circuit response to the system, which not all VAR support technologies are able to provide. There are several ways to design a SC system, both through retrofitting or standalone options. For the CT capacity contemplated at Lyon Co, we would utilize a design that places a clutch between the turbine shaft and generator, which allows the unit to be used either as a generation facility or a SC with minimal time needed for switching.

the end of the proposed gen-tie **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]. Without that reactive power support, the total limits on the line for incremental wind and solar build would be lower. The Company has represented this resource with inclusion of a generic greenfield CT, as discussed further below.

As we developed this proposed path, we preliminarily evaluated a limited number of other routing options and transmission configurations that would have different costs/benefits associated with construction. For example, we have examined an option that routes the Sherco gen-tie as two single circuits, still terminating at Lyon County, but on separate towers for most of their length. This option does reduce some operational risk associated with the double circuit approach, like re-setting MISO's Most Severe Single Contingency (MSSC - the single largest contingency in MISO) and loss of the capacity on the line due to an event that causes a tower failure. Ultimately, however, separating the routes for their full length increases estimated costs relatively significantly. Therefore, we are not proposing that configuration at this time; however, this or other options could be further explored in future project planning and proceedings.

As with any proposal of this type and scale, there are several key factors could affect the final cost and capacity totals, including but not limited to:

- Route path and length finalization, including any accommodations to meet regulatory requirements or landowner preferences in the certificate of need process (which is common in routing and siting proceedings)
- An identified need for additional VAR support, as technical design for the both the line and renewable projects develops[19]
- Commodity costs and inflationary changes
- Developments on renewable technology costs and future procurement process outcomes

However, we believe ability to interconnect more renewables faster – thereby accelerating and achieving deeper carbon reduction, on par with other modeling

[19] Our cost estimates were developed with generic models for VAR support, line design, wind turbines, solar inverters, transformers and collector networks with the best available data. As the project is further developed, we will continue evaluating these details.

parties' alternative proposed plans – for a lower cost than our Supplement Plan indicates this is a concept that is worth pursuing on behalf of our customers.

2. *Gen-Tie Resource MW Limits, Timing and Costs*

Appropriately representing specific tranches of resources that can be selected for generator interconnection reuse required implementation of some new and creative modeling approaches. Overall we believe our approach makes the most efficient use of the interconnection that will be left available when our coal units retire, maximize the total accreditation potential of hybrid resources behind these points of interconnection, and reflect MISO and FERC requirements regarding ownership of a portion of these resources. We describe this approach further below.

a. MISO rules regarding ownership of generator replacement resources.

As a threshold matter, there are specific requirements governing generator replacement and the ownership of resources that reutilize these interconnection rights. MISO's generator replacement rules are set out in Attachment X of the MISO Tariff, which contains MISO's Generator Interconnection Procedures or "GIPs." The general timing rules of generator interconnection replacement under the MISO Tariff require (1) that a request for generator interconnection replacement be submitted *at least one year prior* to the date that an existing generation facility will cease operation, Attach. X § 3.7.1(ii), and (2) the expected commercial operation date for a replacement facility must be *within three years* of the date that the existing facility ceases operation, Attach. X § 3.3.1.[20] These generator interconnection rules allow for the owner of an existing facility to request to itself replace the facility with another facility. The rules do not allow the owner of an existing facility to submit a request for a third party to build a replacement facility that will use the owner's existing interconnection rights. This reflects FERC's policy of prohibiting the buying and selling of interconnection rights as a stand-alone asset. These rules, therefore, have the effect of prohibiting approximately the first 2,000 MW of Sherco interconnection reuse and the first 600 MW of King interconnection reuse from being fulfilled by PPA resources. These totals are approximately equivalent to the Company's interconnection rights at each respective site, per the existing unit sizes and – in the case of Sherco Unit 3 – our ownership share.

[20] Additionally, § 3.3.1 states that "For Existing Generating Facility that is in suspension pursuant to Section 38.2.7 of the Tariff or in Forced Outage, the start date of suspension or outage shall be considered the date of cessation of operation of the Existing Generating Facility for purposes of calculating the three (3) year limit."

Although these rules limit the interconnection of non-Company-owned projects as generation replacement resources, PPA projects would be allowed as surplus resources for NSP-owned replacement resources. Thus, our understanding is that the total existing interconnection rights creates a floor of installed capacity, but not a ceiling. Said another way, we can exceed 2,000 MW of installed capacity on the Sherco gen-tie, and any surplus capacity above that level does not necessarily need to be owned by the Company.

The 2,000 MW interconnection rights do, however, set a ceiling on the amount of instantaneous energy injection; meaning that if the model chose 2,000 MW of wind and 1,500 MW of solar for the Sherco gen-tie, those resources combined could only inject 2,000 MW of energy into the grid at any given time and any excess production would need to be curtailed. The model makes economic optimization decisions – incorporating hourly production profiles for these resources – that incorporate these tradeoffs, sometimes adding incremental accredited capacity even though energy from those resources may be curtailed at times.

b. Tranches of capacity of interconnection re-use

In order to develop a proxy for generator replacement timing and total MW thresholds through modeling, the Company incorporated two new elements into our EnCompass set up. First, we included the estimated annual revenue requirements of the proposed gen-tie lines – outlined above – into our Alternate Plan model as a fixed cost. Then, we set up tranches of renewables that the model could select to interconnect via these gen-ties and would fulfill the interconnection capacity left open when each coal unit ceases operations. The size threshold and timing of the tranches reflect the three-year replacement window; and, as described above we offer the model solar, wind and firm dispatchable capacity options in accordance with the timing of these windows and expected completion and in-servicing of the gen-tie lines.

Table 4-8: Retiring Coal Units and Selection Windows for Gen-tie Resources

Retiring Unit	Open Interconnection	Replacement Resource Window	Replacement Resources Allowed
Sherco 2	720 MW	2024-2026	Solar only
Sherco 1	710 MW	2027-2029	Solar, and Wind + ~400 MW of CTs (2028-2029)
Sherco 3	566 MW	2030-2032	Solar + Wind
AS King	591 MW	2028-2030	Solar only

c. Generator interconnection re-use requires some Company ownership, but there are still substantial opportunities for PPA resources.

Given the requirements described above – in particular with respect to minimum ownership requirements for generator replacement resources – we also believed it was appropriate to make modifications to assumed renewable resource costs that will reutilize open interconnection and be connected to the gen-ties. While these costs start from the same underlying assumptions as generic resources, we subsequently adjust the cost of the first 2,000 MW interconnecting at the Sherco site and 600 MW at the King site to reflect our owned revenue requirements under current tax law.[21] We also remove incremental transmission interconnection costs (as the gen-tie costs are already accounted for elsewhere in the model). The remainder of the capacity at each site is reflected at generic pricing, without incremental transmission costs, because – per the requirements described above – these additions could be PPA resources incorporated onto the gen-tie lines after the interconnection threshold is achieved.[22]

[21] We already use the Company's general financing assumptions in our evaluation of generic resource costs, thus differences between generic and owned revenue requirements primarily reflect differences in how the Company recovers its revenue requirements and how we are able to utilize the federal tax credits. Firm dispatchable units included in these tranches of resource additions reflect generic pricing, as there is no inherent difference between our assumed revenue requirements for owned dispatchable units vs contracted units.

[22] There are myriad flaws in the Center for the American Experiment's (CAE) analysis, but one specific error in its cost modeling is that it assumes the Company will own every MW of new generation in our expansion plan and that it will add significant cost to the Preferred Plan as presented in the June 2020 Supplement. As noted here, however, the Company does not assume we will own every MW of additions in its plans, although we do believe there are often customer benefits associated with utility ownership. Further, our generic resource cost assumptions – taken from the NREL ATB model – already assume a rate of return on equity, so adding a full utility revenue requirement on top of the assumed prices – even if it were the correct amount – would be double counting. CAE puts forward no evidence to back up their conclusory assessments with regard to the level or economics of Company ownership.

Costs assumed for gen-tie wind and solar resources are further detailed in Appendix A. As described further below, we have also conducted sensitivities that examine the costs and benefits of our Alternate Plan under different federal tax credit reform futures; however, as these potential changes have not yet been put into law, our primary analysis represents our estimated revenue requirements as they exist under current policy.

3. Blackstart and Stability Resources Included in the Alternate Plan

As discussed in Section 3 of this Reply, the Company has also worked to further define its System Restoration Plan for blackstarting the system in the case of a catastrophic event. We discussed in both our initial July 2019 and our June 2020 Supplement that, as our coal units and other resources that are part of our system restoration plan retire, we will have to adjust our system restoration plan to incorporate different units and restoration paths. While we propose to initiate a new proceeding to develop and refine a new approach to system restoration, there are several specific units that we have included in our Alternate Plan that serve both system restoration and system stability needs in the relative near term.

In our June 2020 Supplement we noted that blackstart critical units in Minnesota and Wisconsin **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. While we included cost placeholders for needed blackstart investments in our 2020 filing, we continued to work internally to develop plans to replace the unique and important grid attributes these units provide at a reasonable cost and with limited impact on system emissions.

As noted in Section 3 of these Reply Comments, in Minnesota **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]. In Wisconsin, **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

[23] **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

The plans mentioned above have been included in our Alternate Plan in the years they will need to be placed into service to be able to replace the existing facilities at their current retirement dates. These near term blackstart investments will enable our existing system restoration plans with limited near term reconfiguration, as we work to further develop the transition from a centralized system restoration plan to a zonal approach that can incorporate more variable renewable and resources. General cost and operational assumptions used in our modeling are included in the updated assumptions documentation attached to this Reply as Appendix A.

[PROTECTED DATA BEGINS

[24] Note **[PROTECTED DATA BEGINS**

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D. Xcel Energy Alternate Plan Results and Analysis of Modeling Party Plans

1. *Expansion Plan and Resources Selected on Dedicated Gen-ties*

a. Alternate Plan capacity expansion results.

Considering all the parameters discussed above, the Company reoptimized a Plan – still based on baseload Scenario 9 – that removes the Sherco CC and enables the full interconnection capacity at Sherco and King to be reused for other resources. This Plan also includes key blackstart and Sherco gen-tie stability needs. The Alternate Plan results in substantial renewable generation being added across the full planning period, including both generic and company-owned solar resources (reusing Sherco interconnection rights) as early as 2024. We note that this plan is inclusive of the capacity we have proposed for the Sherco Solar project; in effect, that project remains the first step in fulfilling some of the substantial renewable capacity reflected in our plans, through the reuse of our interconnection rights at the Sherco site.[25]

[25] As the Commission voted in the June 3, 2021 hearing for Docket No. E002/M-20-891, the Company will submit capacity expansion modeling that examines the impact of the Sherco Solar project on our plans, and further analysis that addresses our proposed cost allocation methods, on July 9, 2021.

Figure 4-4: Alternate Plan Annual Expansion Plan, by Fuel Type

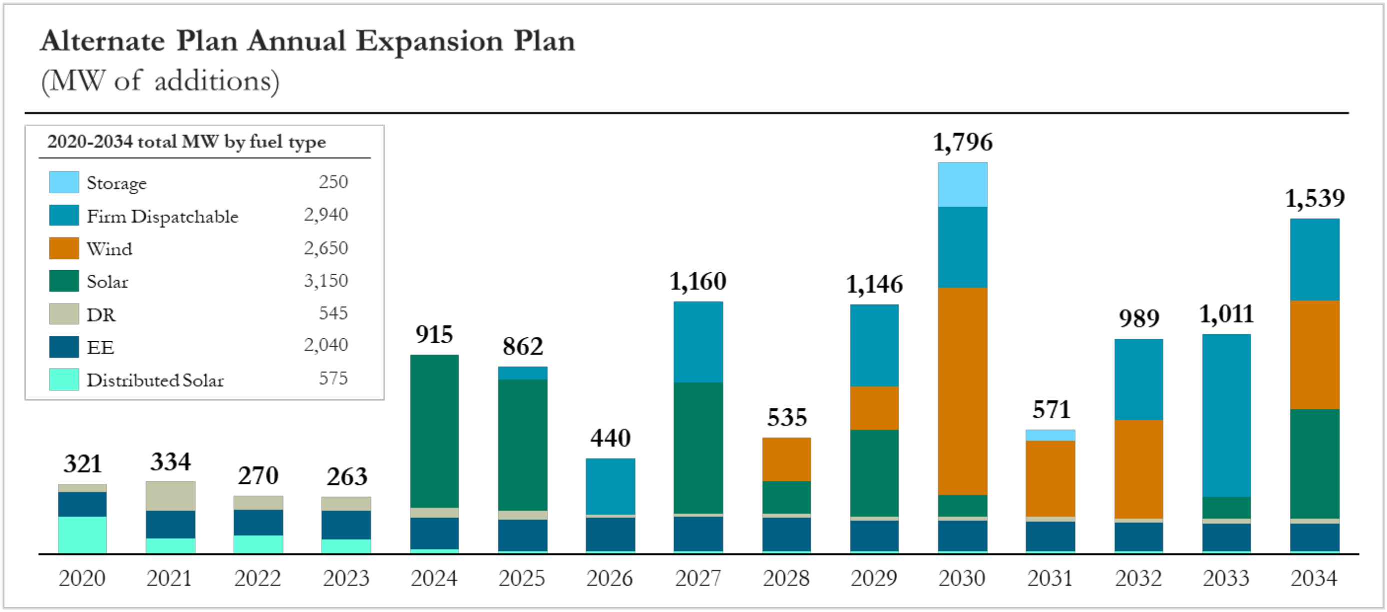


Table 4-10: Alternate Plan Annual Expansion Plan, by Fuel Type (MW, installed capacity)

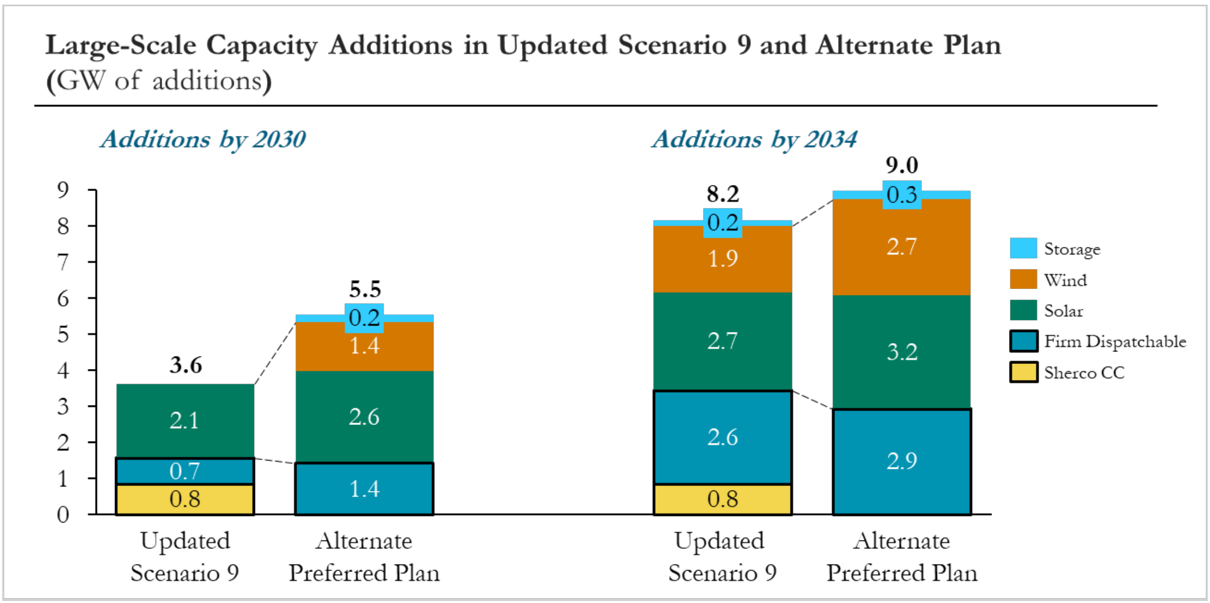
Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Storage	-	-	-	-	-	-	-	-	-	-	200	50	-	-	-	250
Wind	-	-	-	-	-	-	-	-	200	200	950	350	450	-	500	2,650
Solar	-	-	-	-	700	600	-	600	150	400	100	-	-	100	500	3,150
Firm Dispatch-able	-	-	-	-	-	60	259	374	-	374	374	-	374	748	374	2,937
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0
Demand Response	33	132	67	62	47	41	12	14	15	17	19	20	21	22	24	545
Energy Efficiency	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126	2,041
Distributed Solar	173	72	87	68	25	16	15	15	15	15	15	15	15	15	15	575

As can be seen from the figure below, the Alternate Plan installs more renewables and less "modeled-as-gas" firm dispatchable generation than the Supplement Plan. Enabling reutilization of the interconnections at Sherco and King allow us to access accredited renewables that do not have to go through the MISO queue, enabling the economic addition of renewables in the 2024-2030 timeframe, as well as throughout the remainder of the planning period.[26] Removal of the Sherco CC from the plan

[26] We assume resources on each gen-tie can receive full capacity accreditation, in line with MISO's preliminarily proposed approach for hybrid resource accreditation. This is further discussed in Section IV below.

results in a need for incremental firm dispatchable generation starting in the 2027 timeframe; however, the majority of the capacity selected as firm peaking in the model will be considered technology neutral for the purposes of the current resource plan. The near-term blackstart and other resources discussed above total just under 1,100 MW. For the remaining approximately 1,900 MW selected as firm peaking in 2030 and beyond, we will continue to monitor technology development and evaluate other options that could meet this need.

Figure 4-5: Updated Baseload Scenario 9 Expansion Plan as compared to the Alternate Plan, 2030 and 2034[27]

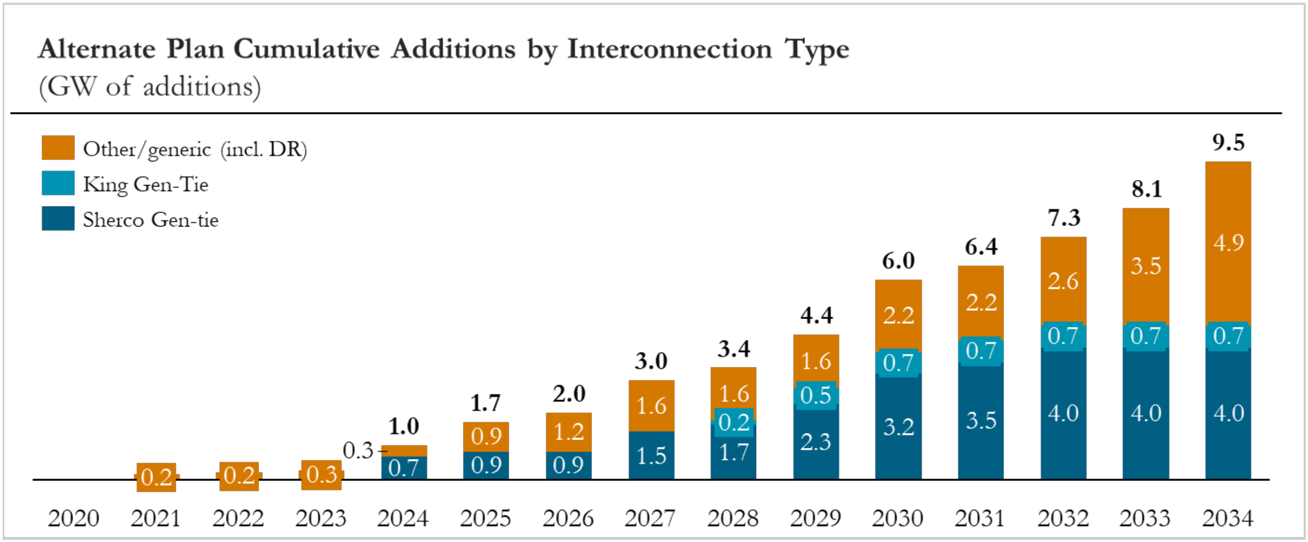


b. Alternative Plan gen-tie resources and ownership requirements.

The Alternate Plan adds over 9,000 MW of new resources by 2034, incremental to our existing baseline. Just over half of these are slated to be interconnected via the Sherco or King interconnection re-use approach, whereas the remaining generation is not modeled with any specific locational aspects considered. In this way, we are enabling a path to bring more renewables on our system – relative to the updated Reference and Supplement Plans – while making efficient use of our interconnection capabilities, avoiding current MISO queue congestion and, on average, reducing the expected costs of interconnection relative to the expected costs of going through the GIQ as an accredited resource.

[27] Demand-side resources are excluded from this chart, as they are assumed to be consistent across cases.

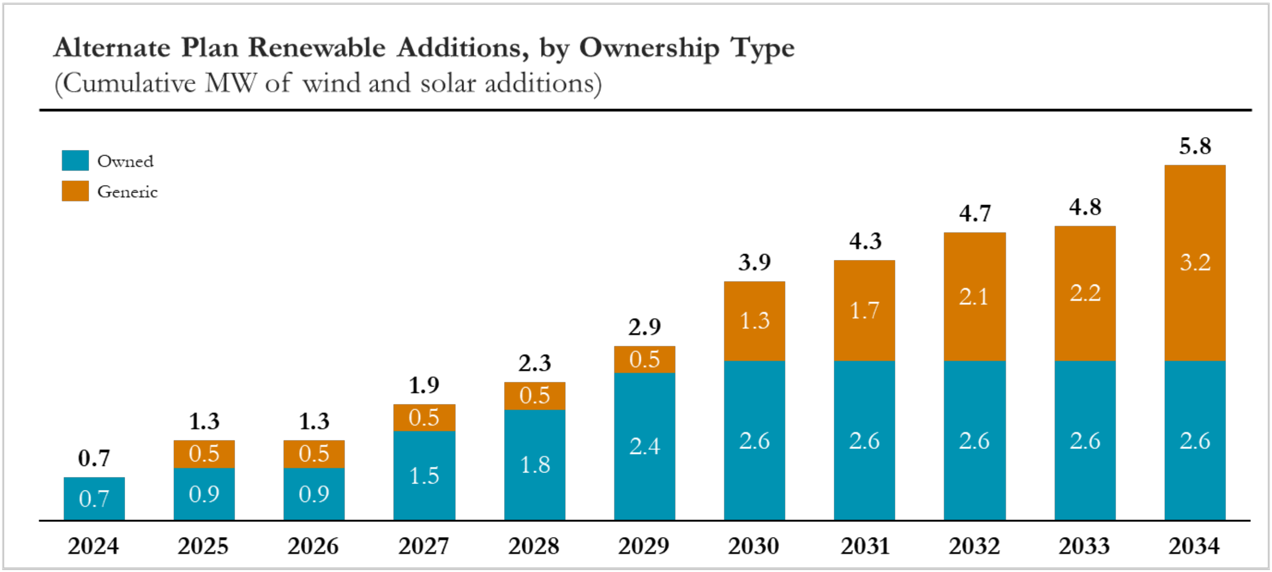
Figure 4-6: Alternate Plan Cumulative Capacity Additions, by Interconnection Type



Given the rules described previously around interconnection re-use,[28] we are also introducing an additional new element to our plan, which is a differentiation between owned and generic resources. Historically, we largely have limited our resource plans to considering size, type and timing considerations; however, we reiterate here – as we also discussed in our 2016-2030 IRP – that generator interconnection reuse requires us to consider location and, now, ownership to an extent. For the purposes of total MW that have to be owned rather than generic, and the costs associated with those differences, we have assumed ownership only for the minimum MW required by MISO rules. To the extent incremental resources can be added to the interconnection over and above that level, they could be either owned or PPA resources, and thus we have modeled them as generic resources. Figure 4-7 below illustrates proposed wind and solar capacity in our plan by ownership type.

[28] In summary, per FERC rules, the owner of the existing generator interconnection agreement cannot transfer the interconnection rights to any other entity, and as such, the current owner must also own the replacement generation. That said, our understanding of these requirements limits the ownership need to only the MW required to fill the interconnection agreement on an installed basis. That means that, for the Sherco interconnection, the Company must own the first approximately 2000 MW and for King the first 600 MW, on an installed capacity basis.

Figure 4-7: Modeled Wind and Solar Additions in Alternate Plan, by Required Ownership Type



2. *Benefit and cost results of modeled scenarios*

a. Primary net present value cost/(savings) results.

In order to examine the relative benefits and costs of the Alternate Plan, we compare it both to the updated Reference Case (i.e. "business as usual") as well as Updated Scenario 9 (representing a refresh of the Supplement Plan). This analysis shows us that the Company's Alternate Plan substantially increases customer savings on a PVSC basis relative to both of these cases.

Table 4-11: Alternate Plan Cost/Savings, Relative to the Reference and Supplement Plan

Scenario	PVSC[29] ($ millions)	PVSC Delta to Reference Case ($ millions)	PVRR ($ millions)	PVRR Delta to Reference Case ($ millions)
Reference Case (Updated Scenario 1)	41,067	--	37,165	--
Supplement Plan (Updated Scenario 9)	40,833	(234)	37,261	96
Alternate Plan	40,461	(606)	37,120	(46)

The Company's interconnection reutilization proposal enables achievement of this savings. It allows us to bring on substantial incremental renewable capacity by reutilizing our interconnection rights. While the proposed transmission gen-ties do require some significant investment – especially for the Sherco gen-tie – we are able to utilize these lines to access and bring online significant renewable capacity, sooner, than is indicated in the Reference Case or Updated Scenario 9. Overall, the gen-tie costs are lower, on a per kW basis, than our estimate of observed costs to interconnect new renewables through the queue. We estimate the average cost per kW for resources that could interconnect to the Sherco gen-tie line is under $140/kW. The King line it is even less expensive, at approximately $55/kW.

Our modeling also shows that the Alternate Plan achieves PVSC savings, relative to the Reference Case, through several other factors, such as: reducing costs associated with our existing coal units (both on a fixed and variable operating and maintenance cost basis), removing the costs associated with the Sherco CC, benefits associated with market interactions, and reduced carbon emissions. On a PVRR basis, we note that the Alternate Plan shows slight savings relative to the Reference Case, whereas our Updated Scenario 9 shows some incremental costs.

[29] The methodological adjustment in calculating PVSC described earlier in this section contributes to differential savings relative to the Supplement Plan. When calculating PVSC under the previous method, however, the plan results in savings of approximately $429 million, whereas the updated modeling for the Supplement Plan shows PSVSC savings of approximately $205 million calculated using the same method.

b. Incremental benefits associated with tax reform.

We believe the above indicates that the savings potential of the Alternate Plan for customers is significant, even when considering existing policy around tax credits. Given the current Administration's ambitious clean energy goals, however, the U.S. Congress is currently considering several tax reform proposals that would affect our realized cost of renewables. Significantly, some of these proposals would have the effect of increasing customer savings by eliminating solar ITC normalization requirements.[30] Other proposals include allowing renewable energy owners to take tax credits as a "direct pay" option, extending the ITC and PTC further into the future, and allowing solar owners to opt for PTCs rather than ITCs.

One example of such legislation is the Clean Energy for America Act, sponsored by Senator Wyden, and co-sponsored by, among others, Senators Klobuchar and Smith.[31] Among other things, this bill essentially proposes to replace existing wind and solar energy credits with a technology neutral credit, which would allow utilities to take either a PTC or an ITC for solar projects, and consequently pass the benefits of tax credits on to customers earlier in a project's life than under the current ITC construct.

While it is too early to tell which of these policies, if any, will ultimately be signed into law,[32] any policy change that improves our ability to pass on the benefits of tax credits earlier will benefit our customers under the Alternate Plan. This is not only because it will reduce the cost of utility ownership of the first 2,000 MW on the Sherco gen-tie and 600 MW on the King gen-tie, but also because if tax credits are extended in the future, these benefits will flow back to our customers. One benefit to customers of Company ownership of resources is our ability to opportunistically take advantage of changes in tax policy. For example, with the extension of the wind PTC last year, we were able to take actions that allowed the Dakota Range project to qualify for the 100 percent PTC level rather than the 80 percent PTC, and flow the benefits of these tax credits back to customers.[33]

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[30] Federal tax law currently does not allow investor owned utilities to pass through the benefits of solar investment tax credits any faster than over the expected life of the project. This has the impact of reducing the overall benefit of these tax credits that accrue to customers on a net present value basis. This difference is not relevant for PTC projects, such as wind projects, because wind PTCs are earned and flowed through to customers on a production basis rather than over the life of the asset.
[31] S. 1298 – 117th Congress (2021-2022): Clean Energy for America Act.
[32] We provide, as Appendix D, a slide from a recent Morgan Stanley presentation that rates the probability of success of various clean energy tax reform proposals currently under consideration in Congress.
[33] *See* Updates to Wind Portfolio, Oct. 9, 2020, Dockets Nos. E002/M-16-777, E002/M-17-694.

The Company will continue to evaluate the effect of tax policy proposals under consideration; for the purposes of evaluating potential impacts our Alternate Plan, we have examined potential plan benefits under a hypothetical scenario in which the Company could take the full value of future renewable tax credits up front as a "direct pay" option, and also that we would be allowed to opt-out of normalizing any solar ITCs earned. This has the effect of significantly increasing the benefits to customers of our proposed plan; $990 PVSC savings and $429 million of PVRR savings, relative to the Reference Case.

3. Carbon Reduction Goals and Plan Performance

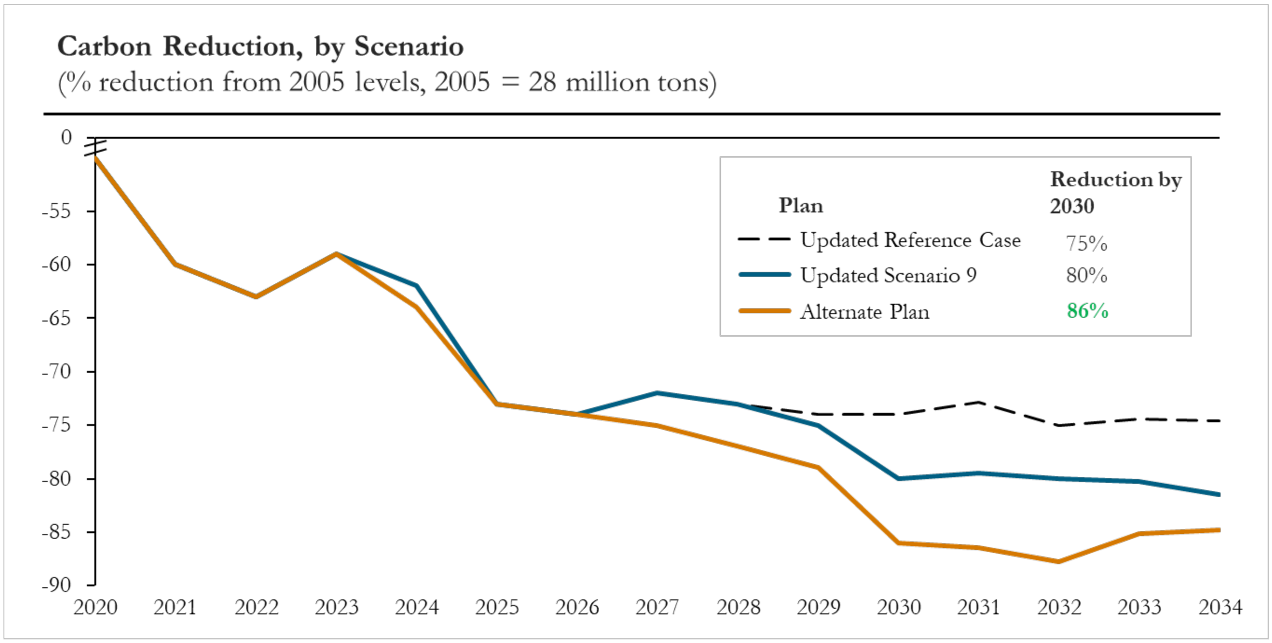
A core element of our plans is to enable the Company's carbon reduction goals – to achieve 80 percent reduction from 2005 levels by 2030 and set us on a path to achieving 100 percent carbon free generation by 2050. As such, both measures that examine the carbon associated with the electricity we serve customers, and the total amount of carbon-free generation from our system resources, are important metrics to examine to ensure our plans are charting a course to achieving both our 2030 and 2050 goals.

a. Carbon reduction goals.

Relative to our interim goals to reduce the carbon emissions associated with serving our customers,[34] we showed in our June 2020 Supplement that our Preferred Plan (Scenario 9) achieved "80 by 30," and – importantly – no case that retired both nuclear units at their currently contemplated dates achieved this goal. The Supplement Plan presented here continues to achieve the 2030 goal in our modeling, as shown below. The Alternate Plan is able to achieve an even higher reduction in carbon emissions, exceeding 85 percent carbon reduction by 2030. Therefore, both of these plans are consistent with our near-term carbon reduction goals and set us on a path toward achieving our ultimate goal of 100 percent carbon-free generation by 2050.

[34] This metric makes adjustments for market purchases and sales, which ensures that we do not underrepresent the emissions associated with serving our customers every hour of every day.

Figure 4-8: Carbon Reduction by Scenario



Although, as shown above, the Alternate Plan achieves significant incremental reductions in emissions compared to the Supplement Plan, it contains a relatively noticeable uptick in emissions levels around 2033, associated with the currently anticipated Prairie Island unit retirements. If we were to extend these units further into the future as well – consistent with baseload plans in our Initial and Supplement filings' Scenario 12 – our system would achieve sustained carbon reduction at these levels – approaching 90 percent – through the end of the planning period. As we have noted previously, we are not proposing an extension to Prairie Island at this time, rather, we plan to address the potential future of that plant in a future filing. However, the Supplement Plan (Updated Scenario 9) is, generally, "on the path" to achieving the savings associated with Scenario 12, because this scenario relies on Monticello extension as well. Overall, as evidenced by these carbon trajectories, our nuclear resources are a critical component to meeting our carbon reduction goals.

Toward that end, we want to address the Department's analyst comments that ultimately recommended to not extend the Monticello license and suggested perhaps we should even retire it early.[35] There were four factors that contributed to this recommendation from the these comments, each of which are easily refuted or contrary to state policy.

[35] The Deputy Commissioner of the Division of Energy Resources at the Minnesota Department of Commerce, Aditya Ranade, filed comments supporting the extension of our Monticello nuclear unit on a policy basis.

First, the Department conducted a high-level assessment of the Company's demand and energy forecast and concluded it has a systematic bias and lowered our forecast by 10 percent, which clearly impacts our system needs and disadvantages nuclear. We discuss our disagreement with this action in Section 6 of this Reply, but in summary the Department's assessment was a limited review of historical forecasts that did not review the technical details of our forecast nor test the Company's previous or current statistical models. The Department's analysis also did not account for assumptions that were made and determined to be reasonable at the time that the forecasts were developed.

Second, the Department increased our Monticello operations and maintenance costs by 1 percent annually which is contrary to the report filed in this docket on December 23, 2020 by the Department's consultant, Global Energy & Water Consulting, LLC (Global).[36] Global's report concluded at page 3, that "The Monticello forecast budget for O&M spending through 2040 is aggressive but attainable with Xcel's attention to cost controls." Thus, by the Department's own consultant's report, there was no need to escalate the Monticello O&M costs.

Third, the Department increased our Monticello capital costs by 10 percent which is again contrary to the conclusions in the Global report. The report concluded, at page 3:

> The Monticello forecast budget for capital spending is well within reason considering the age and the need to prepare the unit for relicensing. The forecast capital spending for the next 20 years is well below capital spending during the last 10+ years. The outlier that is still not very well documented is the capital necessary to accomplish the Subsequent License Application/Review (SLA/SLR) and it will not be until Xcel completes is license review and application to the NRC.

Again, the Department's consultant's report confirmed the capital costs are within reason and thus there was no need to escalate them.

Fourth, the Department used the mid-point externality costs, whereas the Company uses high externality and high regulatory cost of carbon values in its base PVSC modeling. While the mid-point externality costs are within the range approved by the Commission, we use the high end of the range in our base PVSC analyses and the mid-point scenario certainly disadvantages nuclear (and any other clean energy) on a

[36] See the December 23, 2020 filing in this docket, *Independent Investigation of Cost Overruns and Cost Estimates for Xcel Energy's Monticello and Prairie Island Nuclear Power Plants* prepared by Global Energy & Water Consulting, LLC (Global).

relative basis. The Sierra Club takes a similar approach to their analysis. We believe the high values are most appropriate to use in our modeling, given it provides a reasonable bookend to PVRR values, although as discussed further below, we also test our Plans against the mid-point and find that they result in savings relative to the Reference Case, where Monticello is not extended.

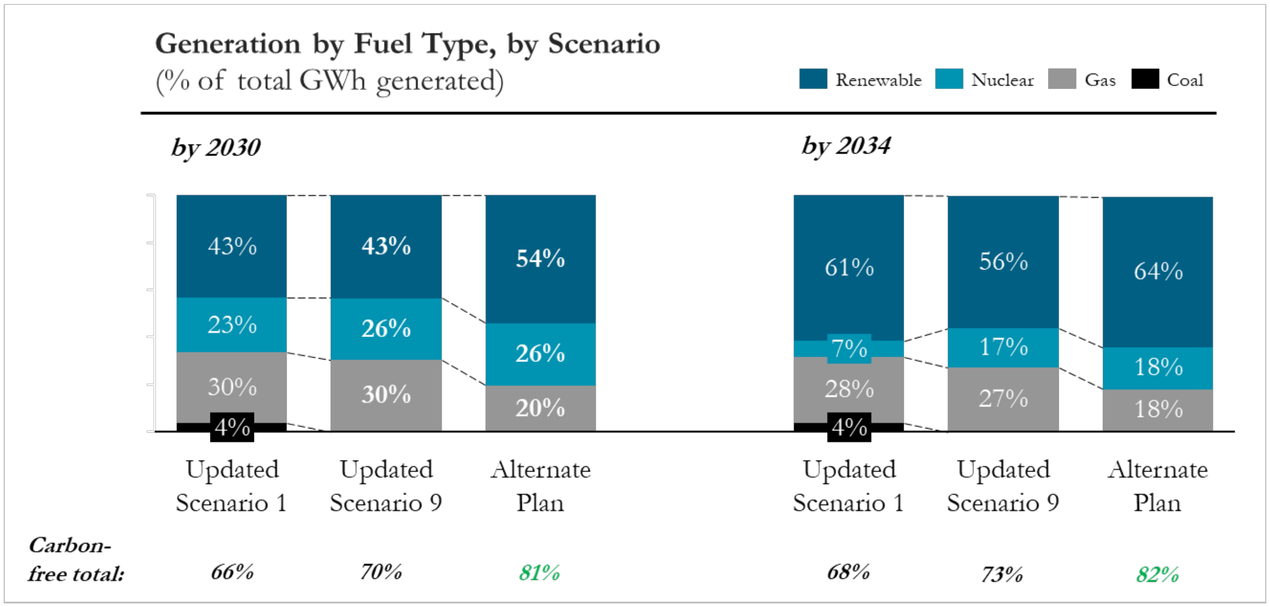
Finally, in order to address the Department's proposal, the Company also updated its baseload Scenario that includes early coal retirement but retires Monticello in 2030 (Scenario 4). We see from that analysis that, when the nuclear units are removed from our model, the model does not achieve the same PVSC savings and it chooses additional CT resources (this capacity expansion plan is discussed further in Section D below). Thus, consistent with trends in other jurisdictions that have or are planning to retire nuclear units,[37] we expect that doing so here would likely result in an increase in emissions relative to scenarios that keep these zero carbon resources online. Considering all of the above factors, we disagree with the Department's recommendations related to the retirement of Monticello.

b. Total carbon-free generation

As noted above, we not only examine carbon reduction by 2030, but also how much total carbon-free generation we can achieve across various scenarios. Here, we see that both the Supplement Plan and the Alternate Plan increases the overall share of carbon-free generation on our system by 2030 and 2034, relative to the Reference Case.

[37] Including, but not limited to, the California and German markets.

Figure 4-9: Generation by Fuel Type Across Scenarios



The Alternate Plan achieves higher levels of carbon-free generation in part because the Sherco CC is no longer included, and in part because – to the extent the model identified needs for firm dispatchable generation – it selected peaking resources that have a much lower capacity factor than a combined cycle facility would.[38] Whereas modeling results for Scenario 9 show the Sherco CC running at an 80 percent capacity factor, resources modeled as large-scale CTs in the Alternate Plan average 5 percent or lower throughout the planning period.

That said, just because replacement dispatchable generation has a low capacity factor does not mean that it is not needed to support the system, as we discuss further in below. Firm dispatchable generation serves an important role for reliability, including both system stability and blackstart, and its ability to support capacity and energy needs when variable renewables are not available. This is particularly true when such resources are not available at their normally expected output (such as the polar vortex of 2019 or the cold weather event our region experienced earlier this year). As such, firm dispatchable generation is crucial even if, generally throughout the year, these resources are not producing large amounts of energy.

[38] Further, we believe carbon reduction estimates in both the Supplement Plan and the Alternate Plan may actually be conservative, given our commitment to remain technology neutral on many of the firm dispatchable resource additions included in these plans. For purposes of the graphs below, however, all generation attributable to generic firm dispatchable resources are represented in the "gas" category.

4. *Risk and Reliability*

A core element of our planning principles involves evaluating our plans for potential risks to customers. As our system and the broader MISO grid includes increasing amounts of variable renewables and decreasing amounts of centralized baseload capacity, we must ensure that we are appropriately hedging customer risk with respect to the attributes of our system – capacity adequacy and resource diversity, flexibility, market exposure, and potential cost impacts. We also believe reliability is a shared responsibility; in other words, although MISO dispatches resources centrally to meet demand on the broader system,[39] we disagree with the notion that it is not any given utility's role to support reliability in the broader market. Particularly due to the Company's scale relative to MISO, and specifically in Zone 1, the choices we make about retiring or adding dispatchable generation will inevitably affect reliability and resource adequacy in the market, as well as the hedging risk borne by our own customers.

Therefore, we continue to examine the ability of our plans to meet customer needs in every hour of every day. Like our Supplement Plan, we believe our Alternate Plan appropriately balances these factors around both risk and reliability. Further, our analysis suggests that several modeling parties' alternative plans may expose customers to undue risk around capacity and energy adequacy, in part due to an overreliance on variable renewable and short duration batteries.[40]

a. The Company's plans appropriately balance energy and capacity risk.

When evaluating the risk and reliability profiles of our June 2020 proposed Supplement, we examined three key factors related to customer risk mitigation; these included measures of resource diversity, the firm generation-to-peak demand ratio of the portfolio, and the range of outcomes across sensitivities examining different levels of load and input costs (i.e. technology, fuel, carbon prices). We again examine these factors for our Alternate Plan and find that – like the Supplement Plan – this plan is robust when considering these risks.

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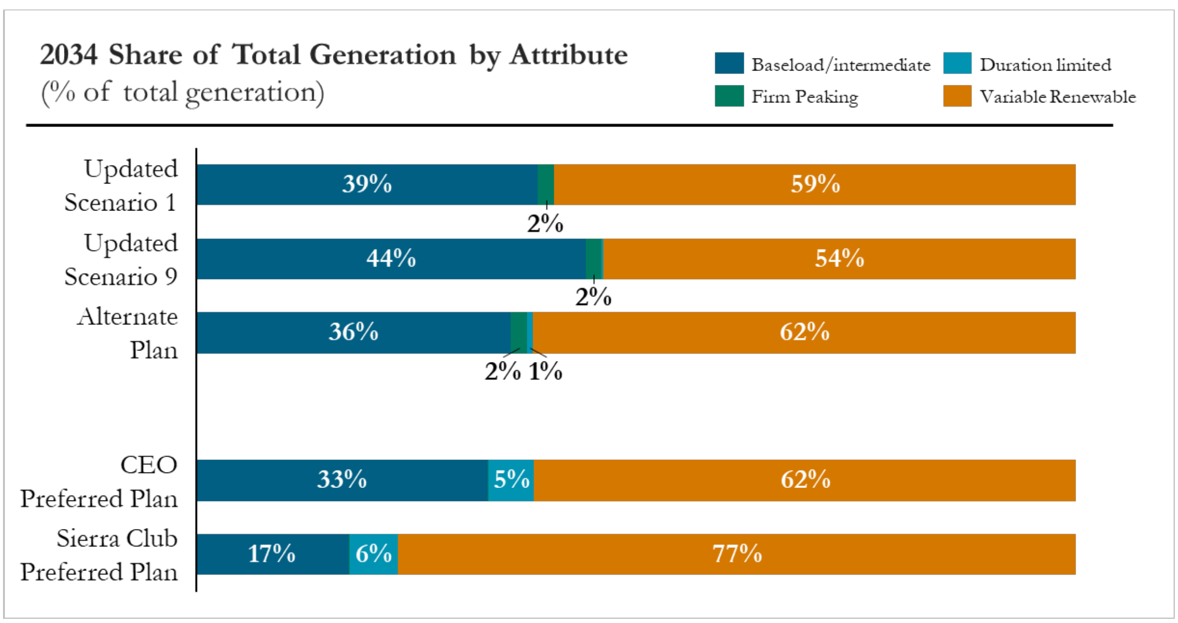
[39] Department Comments at 36.
[40] Note: For the purposes of comparative plan analysis in this section, we are primarily comparing the Sierra Club's "Clean Energy for All Plan" expansion plan and the CEO Preferred Plan (using the assumption set CEO Base Case Scenario). While we keep these plans' capacity additions consistent, we do re-evaluate resource dispatch and costs under the externality assumption used in our PVSC modeling, instead of Sensitivity K (midpoint) for a more consistent comparison to our Plans.

Generation portfolio resource diversity is an important consideration, as over-exposure to potential volatility of any one type of generation creates risk. The impact of Winter Storm Uri on the ERCOT-served portion of Texas was a severe example, where the system had significantly less capacity than expected on which to draw, due to lower than expected performance (or significant outages) across multiple resource types. This includes, but is not limited to, gas resources. While our approach to planning, weatherization, and other contributing factors differs substantially from the ERCOT market, the Company has a responsibility to ensure we manage our resource diversity and mitigate risk of unexpected events impacting reliability to the extent possible.

i. Resource diversity and firm-to-peak ratio.

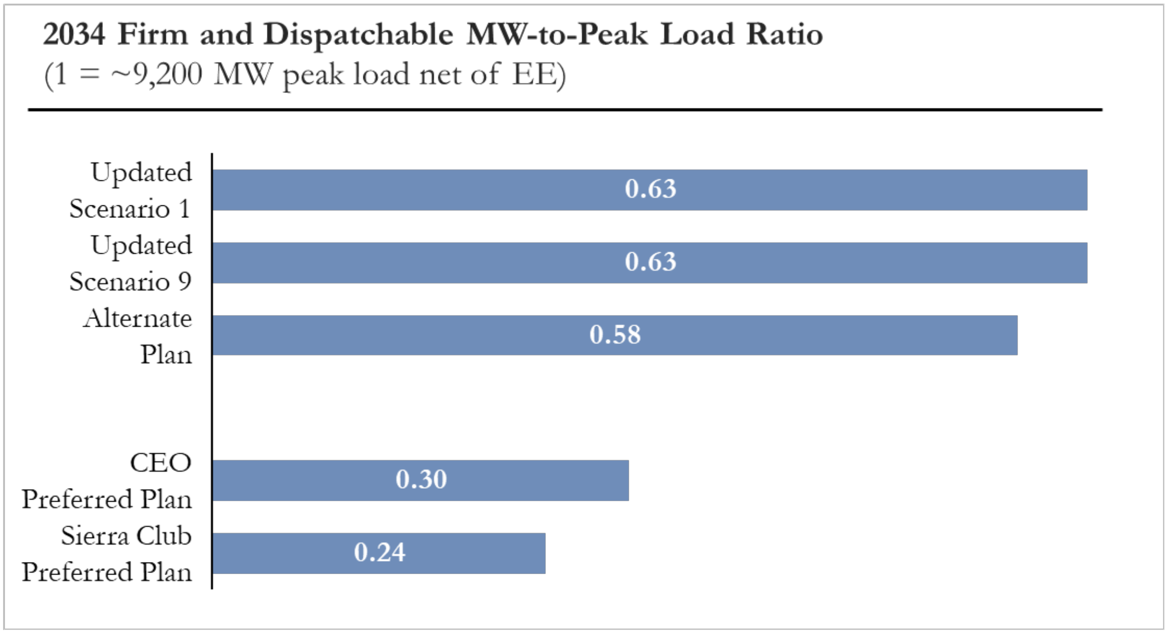
The Figures below examines our updated Reference Case, Supplement Plan and Alternate Plan, as compared to the CEOs' and Sierra Club's preferred plans,[41] on measures of generation and capacity diversity. As discussed further below, CUB's preferred plan[42] did not provide enough information for us to analyze its plan in the same way.

Figure 4-10: Share of Total Generation, by Resource Attribute Type



[41] The CEOs submitted several plans and sensitivities; for purposes of these analyses, the CEO Preferred Plan refers to the CEO Preferred Plan expansion plan and CEO Base Case Scenario.
[42] What CUB terms the "Consumers Plan."

Figure 4-11: Firm and Dispatchable Capacity-to-Peak Load Ratio, 2034



There are several important takeaways from this analysis. First, as stated previously, the Company's Alternate Plan achieves over 80 percent carbon-free generation and 85 percent carbon reduction from 2005 levels by 2030. Other modeling parties' plans also achieve high levels of carbon-free generation, in some cases higher than our Plans; however, the Company's Plans maintains substantial firm and dispatchable capacity, including carbon-free firm capacity from nuclear. Other parties' plans do not maintain this level of firm dispatchable generation. This is especially true of the Sierra Club's proposed plan.

As such we believe that the Supplement Plan (Updated Scenario 9) and the Alternate Plan reduces customer risk relative to other parties' plans, even as they achieve high levels of carbon reduction. We discuss in these comments – as well as in our initial and Supplement filings to this docket – that as the system is undergoing a shift away from traditional centralized baseload resources, we believe that ensuring we can cover a substantial portion of our peak demand (especially in winter) with firm and/or dispatchable resources will be key to mitigating risk associated with the energy transition. This has the potential to be even more critical as customers adopt beneficial electrification measures and depend more on the grid for transportation, heating, and other fuels. As we noted before, the non-baseload firm dispatchable resources shown here (such as peaking CTs) do not run at high capacity factors during normal times when renewables and other resources are performing at their expected levels. However, those peaking resources are ready to dispatch if and when they are needed to meet customer demand when it occurs; in this sense they serve as somewhat of an insurance policy against low renewable output periods. Recent winter weather events reinforce the benefit of this approach, as well as maintaining our prudent planning and operational planning practices with regard to fuel supplies and fuel diversity more generally.[43] Therefore, we believe the Alternate Plan appropriately balances the benefits of increasing variable renewable generation while maintaining a capacity hedge.

We have significant concerns with the CEOs and Sierra Club's proposed preferred plans' ability to maintain that balance. While the CEO's plan is more diverse, with a larger share of baseload generation remaining on the system and a mix of wind, solar and battery resources, it does not include very much firm dispatchable capacity overall; all of the Plan's large-scale additions are either variable renewable or duration limited resources. These concerns are compounded with the Sierra Club's preferred plan. By eliminating nuclear – the largest source of non-emitting baseload generation on our system – and attempting to replace that needed energy capacity only with renewables and batteries, it results in an energy mix that is not particularly diverse with a heavy reliance on variable renewable generation.

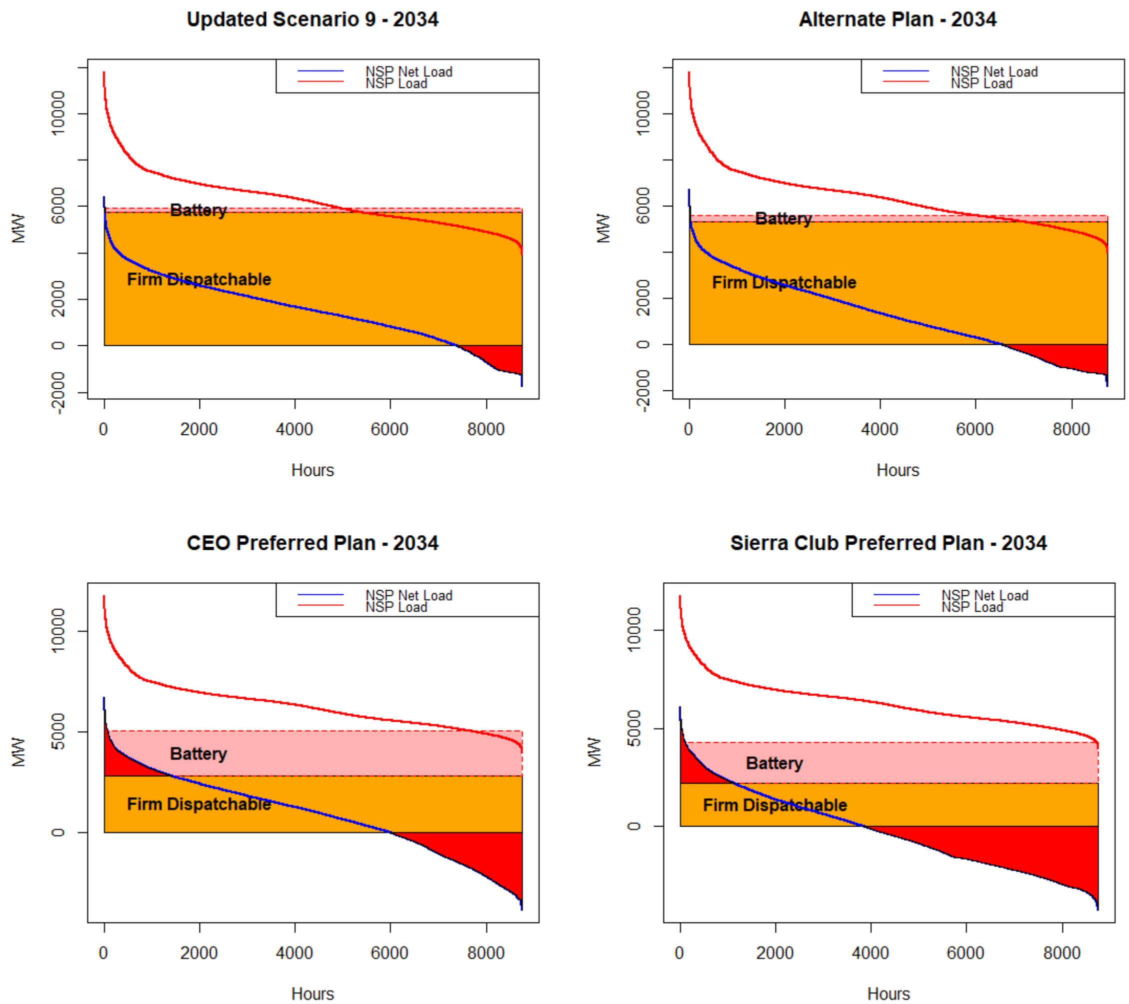
ii. Net load and market exposure.

To further examine the various plans' potential exposure to capacity and market risk, we looked at a comparison of the Company's, CEOs' and Sierra Club's plans in 2034 with respect to how net load interacts with firm and dispatchable generation.[44] Specifically, these charts show the number of load hours in which net load relies heavily on duration limited resources and/or the market, and how many hours in which there is excess generation that is expected to be absorbed by either the market or duration limited resources (i.e. storage). The red shaded areas in the charts below indicate where a plan is relying on duration limited resources or the market to either meet net load (on the left end of the chart) or absorb excess renewable generation (on the right end of the chart), relative to net load hours where customer needs are expected to be able to be matched by firm dispatchable capacity.

[43] We are able to run many of our gas plants on currently available alternatives, such as fuel oil, if needed and market conditions (such as during times of constrained gas supplies) support it. We incorporate assumptions that any new CTs included in our plans would be capable of dual fuel operations, to operate on alternate fuels if needed to maintain reliability and mitigate customer market risk.

[44] Here, shown as (Demand) – (Energy Efficiency + Renewable Generation Net of Curtailment); firm dispatchable include nuclear, CC, CT and hydro resources.

Figure 4-12: Company and Modeling Party Plans, Net Load and Firm Capacity Across Hours in 2034[45]



First, the analysis shows that all plans assume large amounts of renewable capacity is added to our system; the gap between load and net load lines in the charts below illustrate this. However, this analysis further shows that the Company's plans have sufficient firm and dispatchable capacity to match net load in far more hours of the year and customers are not exposed to the market or duration limited resources in large quantities or for very many hours. For the CEOs and Sierra Club, however, there are substantial amounts of load over many more hours that are expected to be

[45] Note that this analysis examines firm dispatchable and duration limited resources assumed to be installed and how net load falls across those hours of the year, utilizing a load duration curve approach. The reliability analyses described further below take a different approach, examining *available capacity* across each hour and whether the system as it is simulated in those hours can serve customer needs. The analyses below incorporate hourly chronological resource constraints whereas this analysis does not.

met with duration limited resources or the market, largely because their plans do not add firm dispatchable capacity and – in the case of Sierra Club – also do not extend the life of our Monticello nuclear unit. The Sierra Club plan relies on the market and/or duration limited resources the most, assuming a substantial amount of renewable generation in excess of our load across many hours of the year can be absorbed.[46]

In all, the Company agrees with modeling parties that we can integrate high levels of renewables onto our system, but we also have to carefully manage customer risk as we navigate this transition. Especially for those times when – such as the 2019 Polar Vortex or the 2021 Winter Storm Uri – renewables are not able to substantially contribute to customer needs, we believe it is not prudent to expose customers to the potential of low renewable availability with very little long-duration dispatchable capacity to hedge that risk. In addition to the robustness of the Supplement Plan – which we discussed at length in our June 2020 Supplement – the Alternate Plan maintains a better balance of firm generation capacity as compared to our winter peak load than other modeling parties' preferred plans. Other parties' plans present a concern in this regard.

Finally, it is worth noting here that, although we do maintain a prudent amount of firm capacity in our proposed plans, no plan presented by any modeling party attempts to back up variable renewable *installed capacity* MW-for-MW with gas resources, as CAE has suggested is necessary. Rather our approach provides for an appropriate hedge to ensure a substantial share of *our customer load* is "backed up" and is not subject to undue risk. CAE's assertion seems to be borne from a lack of understanding regarding our planning approach,[47] as well as capacity expansion and production cost modeling's ability to evaluating the risk around unserved energy and other key reliability metrics. We discuss our reliability analysis further below.

[46] It is further worth noting that our and other parties' modeling currently assumes 100 percent capacity accreditation for storage resources; in reality it is likely that future storage accreditation would account for some level of forced outages and a marginal declining effective load carrying capability, the latter of which is especially relevant in the quantities of storage resources added in the CEOs' and Sierra Club's plans.

[47] The Company's resource planning approach ensures that we are planning to add accredited capacity to meet our peak load plus MISO reserve obligation, including considering the accredited capacity values MISO have deemed appropriate for variable renewables' contribution to peak load. Further, we prioritize plans that maintain sufficient baseload, intermediate, and firm peaking capacity equal to a reasonably large share of winter customer load, in part because MISO has not yet introduced a seasonal RA construct that accounts for different resources' RA capabilities in winter. But capacity expansion and production cost modeling evaluates energy needs in every hour of every day, including evaluating whether there is a likelihood of unserved energy associated with a particular plan.

b. The Company's plans are reliable, and modeling parties' plans present concerns.

In addition to the risk evaluations described above, the Company conducted further reliability analyses on our Alternate Plan and other modeling parties' proposed plans. This is consistent with the analysis presented in our Supplement last June, along with some adjustments and new analyses based on feedback from parties. Our analyses suggest that the Company's Alternate Plan does not present reliability concerns; however, there is higher risk associated with the CEO and Sierra Club preferred plans. We also have more fundamental concerns with CUB's modeling, which we discuss first.

i. CUB plans do not provide an adequate basis for analysis.

We noted above that the Company aligns its resource planning with a FRAP approach which ensures that the Company is planning to add sufficient accredited resources to match our customer load, plus a planning reserve margin indicated by MISO. Any resource plan that either does not represent our full load or add sufficient accredited resources to meet it, is not an acceptable alternative to the Company's proposed plan. It is our understanding that the model used to produce CUB's alternative plan for the NSP system made a number of assumptions that are not aligned with the FRAP approach, including that it appears to exclude load and generation from NSP-W in its definition of the NSP System. Given the above, we conclude that this approach is not sufficient to ensure the Company has planned adequate generation resources to meet its capacity obligations, nor does it allow for the correct cost allocation factors for assigning regional transmission costs within MISO.[48]

Further, due to the approach it takes to assessing existing resources, this modeling does not include all of our contracted resources directly as part of the NSP System either[49]. Both the NSP-W and contracted resources issues obviously underrepresent

[48] Responses to XE IR-83 and IR-85. Additionally, obeying constraints such as Kirchhoff's Voltage and Current Laws and a 7 percent load following reserve, while correct from a scientific perspective, does not guarantee that a proposed framework automatically complies with MISO Resource Adequacy and Tariff obligations. For example, the amount of capacity in the Company's Plans presented here were optimized to meet the Company's full upper Midwest load, plus an 8.9 percent reserve margin, for each year of the 2020-2045 period. Just ensuring the model builds enough generation to ensure a 7% load following reserve (i.e., non-spinning reserve/ancillary service) for five modeled years is not enough for the Company to demonstrate compliance with MISO's FRAP process. Additionally, a 7% load following reserve is not in and of itself evidence of transmission stability or power transfer ability. Additional dynamic stability analyses would be needed, especially as the level of renewable penetration increases – the MISO Renewable Integration Impact Assessment indicated the necessity of additional reserves and transmission infrastructure for a variety of different grid conditions under high renewable penetration thresholds.

[49] Response to XE IR-73.

both the load for which our resource plan – which covers our full Upper Midwest service area – must account, as well as the full set of resources we currently use to serve that customer load[50]. Additionally, the one optimized plan CUB submitted was developed with a model and several datasets to which we were not allowed full or direct access, so we could not complete a full cost, risk or reliability analysis on this plan or compare it against a base plan that was also optimized in the same software[51]. For these reasons, we were unable to conduct deeper reliability analyses on CUB's plan, and it should not be relied upon.

ii. Initial reliability screen.

Setting aside the CUB plan, we proceeded with conducting an updated reliability analysis on the plans submitted by the CEOs and Sierra Club. As a first screen, we examined the annual amount of unserved energy – defined as the amount of customer demand (in MWh) that the plan is not able to provide for even when using all native and imported resources – in each plan, over the full 2020-2045 cost modeling period. Table 4-12 shows that both of these proposed plans had substantially more unserved energy than the Company's Plans. Although it appears that these unserved energy periods happen in the years beyond our current 2020-2034 planning period, we believe it remains relevant because the PVSC and PVRR analyses in the Resource Plan consider the full 2020-2045 modeling period.

[50] We would further note that in our originally filed July 2019 IRP, we debuted an updated approach where DR and EE bundles were created so that these resources could be treated as supply-side resources in modeling. As seen in the response to IR-87 and elsewhere, CUB nets these resources out and does not consider them as "generation". While modeling can certainly be conducted using this approach, we would note that this is not consistent with our updated approach for these resources or those of other intervening parties submitting modeling. This is particularly relevant as frameworks for optimizing distributed resources along with supply-side resources continue to develop.
[51] Responses to XE IR-1, XE IR-10, XE IR-13, XE IR-14, XE IR-16, XE-IR 19, XE IR-55, XE IR-57, XE IR-59 part a, and XE IR-89. Additionally, the response to IR-62 indicates that the software used "does not allow any loss of load"; this also precludes an equivalent reliability analysis from being completed.

Table 4-12: Comparison of Annual Unserved Energy (EUE) Between Plans

Scenario	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Supplement Plan	--	--	--	--	--	--	--	--	--	0
Alternate Plan	--	--	--	--	--	--	654	--	--	654
CEO Preferred Plan – Corrected Xcel Base Case	6,595	4,852	--	5,839	4,629	--	20,484	13,161	1,822	57,382
CEO Preferred Plan – CEO Base Case	--	--	--	--	1,995	7,605	11,121	22,137	4,317	47,175
Sierra Club Preferred Plan	2,033	2,980	--	7,840	3,551	11,768	20,316	15,485	10,489	74,462

Given the assumptions around the cost of unserved energy that are used in EnCompass, we observe that the cost of the unserved energy[52] in both the Sierra Club's and the CEO's preferred plans actually exceeds the cost of surplus capacity credits equaling at least as many MW as one generic CT. This suggests that these plans include a high level of unserved energy that would need to be mitigated by new resources the optimization itself is not selecting.

[52] The Company's modeling includes an assumed emergency energy cost of $10,000/MWh. If a generation plan is unable to serve energy, it is assessed this cost per unserved MWh.

Table 4-13: Unserved Energy Cost in Party-proposed Plans vs the Company's Plans, 2037-2045

	Supplement Plan	Alternate Plan	CEO Preferred Plans[53]	Sierra Club Preferred Plan
Net present value of EUE Occurring in 2037-2045[54] ($ million)	$0	$4	$297 - $406	$484
Surplus CT Capacity Equivalent	0	7 MW	519-709 MW	869 MW

After this initial screening, we also conducted a more thorough reliability analysis on our plans as well as the CEO and Sierra Club plans. This reliability examination is a new type of analysis the Company has introduced in the context of resource planning that we expect to continue evolving in the future, for example, to examine the impact of long duration extreme weather events. While it does not take place within the capacity expansion modeling itself, it is a means of comparing fundamentally different capacity expansion plans and provides helpful additional context regarding a plan's risks and reliability performance.

iii. Base reliability analysis.

The below analysis replicates, and builds on, the one we conducted on our Supplement Plan in our June 2020 filing. A primary objective of this analysis is to determine whether we have the ability to serve our own load – in other words, whether we have enough capacity online –under a variety of system conditions, should they arise[55]. At a high level, the analysis evaluates each plan's performance across several dimensions related to reliability, including times when both our own

[53] First value is from the CEO Preferred Plan with CEO Base Case assumptions. The higher value is from the CEO Preferred Plan using the Corrected Xcel Base Case assumptions.
[54] We observed Unserved Energy occurring in both the CEO Preferred Plan and the Sierra Club's Preferred Plan during 2037 – 2045. For each year, we calculated the cost of this unserved energy by multiplying the MWH of unserved energy by $10,000/MWH. We then took the net present value of these expenses and reported them in this table. We divide this by the net present value of what we would have paid for a single MW of surplus CT capacity for those years to show the amount of excess CT capacity that could have been secured instead.
[55] This is explained further in Appendix A – EnCompass Modeling Assumptions. The critical issue is whether the Company has enough online capacity ("available capacity") in a variety of scenarios that it ***could*** serve its own load with its own resources, should an emergency arise. What is actually dispatched, sold, or purchased in a given scenario is not the primary focus.

capacity and ability to import from MISO is insufficient to cover our load,[56] and high net load ramps. We conducted this analysis under both typical meteorological year (TMY) conditions and actual hourly conditions for 2019 (during which we experienced strained conditions during a polar vortex), in order to examine how a plan might perform under more extreme circumstances than TMY. We note that we have undertaken some refinements to this analysis that either respond to stakeholder feedback and/or expand the analysis to examine new parameters. A comprehensive documentation these revisions is included in Appendix A.

The summary results of this analysis are in Table 4-14 below; the plan(s) with the highest results are indicated in red. In summary, our analysis shows that our Supplement Plan and Alternate Plans are more robust to a variety of reliability concerns than either the CEO or Sierra Club plans. These CEO and Sierra Club plans exhibit higher levels of unserved energy and a higher level of reliance on the availability of MISO than either our Supplement Plan or Alternate Plan. Further, modeling party plans appear particularly susceptible to periods of low output from wind or solar generation, correlated outages of the few remaining gas units in operation, or small but reasonable changes to battery operational assumptions such as the application of a minimal forced outage rate.[57] Plan performance under these tests suggests that the lack of firm dispatchable capacity to supplement large amounts of variable and use-limited resources evidences a higher level of reliability risk than the Company can adopt.

[56] Five Principles of Resource Adequacy for Modern Power Systems - ESIG, and Exploring the Impacts of Extreme Events, Natural Gas Fuel and Other Contingencies on Resource Adequacy. EPRI, Palo Alto, CA: 2021. 3002019300.
[57] As discussed in footnote 12, battery storage was the only dispatchable resource type we modeled in EnCompass with a 0 percent Forced Outage Rate (FOR). For the purposes of this analysis we increased the FOR to 5 percent.

Table 4-14: Summary Results of Reliability Analysis Between Four Major Plans[58]

Plan	Hourly Conditions in Simulated for Plan Year 2034	Native Capacity Shortfall Events	Shortfall Hours Requiring Maximum MISO Imports	Average Shortfall Intensity (MW)	Longest Shortfall (Hr)	Peak Capacity Shortfall (MW)	Max Net Load Ramp[59]	LOLH	EUE (MWh)
Company Alternate Plan	TMY (Average Year)	0	0	0	0	0	4,484	0	0
	2019 Actual Hourly Load & Generation	1	2	171-205	2	213-239	4,794-4,814	0	0
Company Supplement Plan (Updated Scenario 9)	TMY (Average Year)	0	0	0	0	0	4,081	0	0
	2019 Actual Hourly Load & Generation	1-2	0-3	81-135	2	145-171	5,019-5,178	0	0
CEO Preferred Plan	TMY (Average Year) – W & X	0	0	0	2	0	5,637-5,746	0	0
	2019 Actual Hourly Load & Generation – W & X	13-17	28-42	390 - 399	5-6	1,238 – 1,531	6,037 – 7,207	0	0
Sierra Club Preferred Plan	TMY (Average Year)	3	0-4	154	2	260	7,082	0	0
	2019 Actual Hourly Load & Generation	30-47	28-140	440-484	11	1,818-2,819	7,990-9,521	0-17	0-5,767

Note: Shaded cells indicate the highest result in each category. Underlined metrics incorporate the availability of MISO resources

There are several important takeaways from the results of our reliability analyses. First, the hourly performance of all plans varies – in some cases substantially – between performance under average year ("TMY") conditions versus a recent actual

[58] CUB did not provide sufficient information to perform this analysis on its preferred plan.
[59] Over a period of three hours. See Appendix A for additional explanation of this metric.

year's hourly load and renewable shape contributions ("2019 Actual Hourly Load and Generation").[60]

The results of this analysis suggest that analyzing multiple sets of assumptions is, indeed, critical to assessing the reliability risks associated with different plans, as the 2019 Actuals analysis reveals a greater quantity and more severe events relative to the TMY analyses. For this same purpose, we also analyze plans along a variety of dimensions, including traditional reliability metrics, such as EUE or LOLH, and others that we believe provide helpful additional information to examine the risk associated with each plan (i.e. max net load ramp, or the number of hours the plan assumes it can import from MISO at or near the max transfer limit during hours when we lack enough of our own available capacity).

In combination, we believe that an expansion plan that consistently indicates a high result across several dimensions is more likely to result in risk and reliability concerns. In this case, both Sierra Club's and the CEOs' preferred plans consistently result in worse outcomes than both the Company's Plans, across every measure. Not only do they have a higher frequency of occasions where the generation portfolio would be insufficient to cover its own load ("shortfalls"), but these shortfalls are longer in duration and require more capacity assistance from MISO than shortfalls in either of the Company's plans. The CEOs' and Sierra Club's plans also max out the MISO import capability, exhibit higher levels of shortfalls, show significantly steeper net load ramps and have a higher risk of EUE. Further, as exhibited by the EUE analysis in Table 4-14 above, we would expect these concerns would only grow if we analyzed a year beyond 2034.

iv. Additional reliability tests

In addition to the above, we have also conducted supplemental analysis also see variation in the ability of these plans to perform when individual resource types face adverse circumstances. Sierra Club's Initial Comments in particular discussed its concern about reliance on natural gas resources leading plans to become susceptible to correlated outages, due to a widespread pipeline outage or other supply constraint. To examine whether correlated gas outage risk may increase risk in our plan relative to others, we tested the ability of different plans to handle a hypothetical long duration, localized gas resource outage. Specifically, we examined plan

[60] We test the plans against load and resource shapes in a specific year because it helps us understand how the plan might perform in a year with more extreme weather variation than the TMY shapes include, given the constraints of an hourly chronological dispatch production cost model.

performance using 2019 load shapes during the Polar Vortex event, and "turned off" all the existing gas CC and CT resources located in the Twin Cities metro area[61]. Table 4-15 below illustrates this finding, showing a comparison between the Sierra Club's Preferred Plan and the Company's Alternate Plan. In the case of the Sierra Club plan, even though the model has perfect foresight that the capacity bottleneck in the Twin Cities' area will occur, it lacks sufficient resources to mitigate it, and a significant amount of unserved energy still occurs in 2035[62]. In contrast, the Company's plan includes sufficient clean baseload and firm dispatchable generation to ensure the Company could withstand such an outage.

We conclude from this analysis that simply having fewer gas resources on the system does not necessarily equate to a system that is less susceptible to reliability challenges during a correlated gas outage event. If a portfolio is not sufficiently diverse, with other firm and dispatchable resources in place to support the system through that period, the system could still encounter significant challenges.

[61] For both the Sierra Club's Preferred Plan and the Company's plan, CT's and CC's are either set at 0, or at or below their minimum capacity rating (less than 10 MW). For the outage simulation in 2025, this means we actively turned off 2,606 MW of gas capacity; for 2035 we turned off 1,694 MW of gas capacity (the difference due to retirements between these years of various gas-fired plants located in the Twin Cities area)

[62] Unlike forced outages, which may occur with little advance warning, production cost models have perfect foresight of the three-day reduction in capacity of all gas generation resources in the Twin Cities' area, and will act to optimize dispatch of all other generation resources available in order to best serve native demand in the model. We chose to use 2035 resource portfolios in this analysis because that is the first year after which all of the resources within the planning period would be in-serviced.

Table 4-15: Simulated Correlated Gas Outage Test Results

	Sierra Club Preferred Plan	*Xcel Energy Alternate Plan*
2025 Simulation		
Unserved Energy Had this Outage Occurred in 2025	**0 MWh**	**0 MWh**
Total Installed Firm Capacity		
Nuclear MW	1,721	1,721
Coal MW	1,657	1,657
Gas CT/CC MW	4,256	4,198
2035 Simulation		
Unserved Energy Had this Outage Occurred in 2035	**55,205 MWh** *24% of NSP native load requirements*	**0 MWH** *0% of NSP native load requirements*
Total Installed Firm Capacity		
Nuclear MW	0	648
Coal MW	0	0
Gas CT/CC MW	2,257	5,105

c. The Company's plans are resilient to cost risk.

The Company recognizes that this is a time of significant change in the utility industry, both within markets and on a policy basis, and as a result, resource costs are relatively fluid. Although we believe our planning approach appropriately considers these cost risks, we do not have perfect foresight, and we appreciate that commenters may disagree with our assumptions. Several intervenors noted their disagreement with our assumed renewable and energy storage technology cost assumptions or other input parameters. We recognize that renewable technology prices can change quickly, and traditionally have declined faster than some forecasts would expect. Uncertainty also affects our fuel price forecasts, load forecasts, and carbon pricing policy, and other key inputs. We further recognize that our gen-tie proposals in the Alternate Plan also are a new approach that involves some inherent cost uncertainty. In fact, the only certain thing about long term forecasts is that they will be wrong at some point. This is precisely why we do sensitivity testing for inputs that are subject to significant uncertainty, to ensure that we are proposing prudent planning decisions and not putting customers at undue risk.[63]

i. Summary of sensitivity results.

A summary of these sensitivities' cost results is shown in Table 4-16 below. We believe the sensitivities we tested represent a sufficient range of outcomes to provide an indication of the potential range of cost outcomes for our plan, such as different market price, load, technology cost, and carbon price assumptions. We also have evaluated Futures Scenarios that examine how our Alternate Plan might change under a combination of these factors and selected additional sensitivities.

Table 4-16: Company Plans Cost/(Savings) Results, Across Sensitivities

Sensitivity	**Reference Case (Updated Scenario 1)** *Total NPV Cost 2020-2045 ($ millions)*	**Supplement Plan (Updated Scenario 9)** *$ million cost/(savings) relative to Reference Case*	**Alternate Plan** *$ million cost/(savings) relative to Reference Case*
PVSC	40,067	(234)	(606)
A. PVRR	37,165	96	(46)
Standard sensitivities			
B. Low Gas/Coal/Market Prices	40,888	(192)	(442)
C. High Gas/Coal/Market Prices	41,284	(313)	(849)
D. Low Load*	42,254	(236)	(553)
E. High Load*	43,667	(212)	(569)
F. Low Resource Cost	39,626	(75)	(865)
G. High Resource Cost	43,128	(447)	(345)

63 Some sensitivities are also required under Minnesota statute, such as PVSC runs that evaluate some form of externality pricing and regulatory cost of carbon. We note again here that CUB's modeling did not contain any PVSC evaluations; when asked in IR-57, CUB said it did not believe this was relevant because they did not allow new gas plants to be selected in their model in MN (although gas generation is added in other states in the model) Unfortunately, CUB misses an important point regarding PVSC, which is that existing units – including the NSP gas generators that the Consumers Plan model extends beyond their Preferred Plan retirement dates - will have associated carbon emissions, as will market purchases. Further, the Commission is required to consider PVSC when evaluating potential resource plans. Thus, it is imperative that the cost impacts of these factors are provided to the Commission and stakeholders, without which a proposed alternative plan cannot be appropriately evaluated.

Sensitivity	Reference Case (Updated Scenario 1) *Total NPV Cost 2020-2045 ($ millions)*	Supplement Plan (Updated Scenario 9) *$ million cost/(savings) relative to Reference Case*	Alternate Plan *$ million cost/(savings) relative to Reference Case*
I. Low Externality	39,086	(189)	(505)
J. Low Externality/Low Regulatory	38,035	(35)	(198)
K. Mid Externality, Mid Regulatory	39,571	(141)	(409)
L. High Externality	46,203	(1,090)	(2,163)
M. No Regulatory or Externality Cost	36,898	124	16
Futures Sensitivities and Other Special Cases			
*Future P. High DG Adoption**	40,644	(100)	(536)
*Future Q. High Electrification**	42,257	(478)	(1,638)
*Increased Planning Reserve Margin Requirement (PRMR) **	41,354	(223)	(581)
Tax Reform[64] (Alternate Plan only)	40,067	n/a	▪ PVSC: (990) ▪ PVRR: (429)
North Dakota planning standards[65]	36,458	PVRR: 239	▪ PVRR: 254 ▪ Tax reform sensitivity: (108)

* Indicates a plan that is reoptimized in capacity expansion modeling, due to changes in assumed customer load or different optimization assumptions. In all other scenarios the capacity expansion plan for each Scenario is held constant with the "base" PVSC runs.

As shown in the table above, both the Supplement Plan and the Alternate Plan show benefits under a broad range of sensitivities and futures, and a much larger range of upside (savings) potential than cost potential. Specifically, the range of outcomes above show that we could expect the Supplement Plan to achieve anywhere from $1 billion of savings to $124 million of cost, as compared to the Reference Case. But there are far more cases in which the Supplement Plan shows savings than costs, and the median sensitivity indicates expected savings of approximately $200 million. For

[64] This sensitivity adoption of proposed direct pay provisions and ITC normalization opt-out as described in Section IV.B. Note that this is intended to illustrate the potential upside benefit of certain policy changes, but does not necessarily reflect the specific provisions put forward in various bills currently moving through Congress.
[65] This sensitivity optimizes expansion plan without regulatory cost of carbon or externality costs, incremental DR, Community Solar Gardens, as required by the North Dakota PSC.

the Alternate Plan, the upside potential is even higher, while the downside potential is lower, with a range of just over $2 billion of potential savings and the highest potential cost would be $16 million. Here again, the median result shows significant savings (over $500 million).[66] The fact that both plans show customer savings, relative to the Reference Case (Updated Scenario 1), in nearly all of the sensitivity analyses, supports the conclusion we made in our Supplement – that the proposed baseload coal retirements and Monticello extension are beneficial to customers relative to a "business as usual" case.

We also examine these cases to evaluate specific issues stakeholders highlight in their comments. For example, in response to concerns raised by the Department in its Comments – that our load forecasts are consistently too high – we conducted our standard "low load" sensitivity (sensitivity D).[67] The analysis here shows that in a future where load is lower than the Company expects, plan savings are very similar to those under the primary scenario.[68] Similarly, the Supplement Plan and the Alternate Plan are able to show benefits under a range of market fuel and energy prices, as well as various future potential values of externalities and regulatory cost of carbon. In fact, the only sensitivities in which the Plans do not exhibit expected system cost savings is one in which a cost of carbon is not included (including the North Dakota Planning Standards analysis, discussed further below).

ii. Special case analyses.

In addition to the standard sensitivities discussed in the above table, the Company examined a few other test cases, consistent with our June 2020 analyses or to test other factors that may affect our plans. The first set of special cases replicates the "Futures Scenario" analyses that we included in our June 2020 Supplement. A futures scenario is intended to test a combination of assumptions changes; not necessarily ones that reflect a future we are confident will occur or actions we believe we should take, but rather the potential outcome of a confluence of multiple assumptions changes described in the standard sensitivities. They also roughly align to MISO Transmission Expansion Planning (MTEP) scenarios, as described in the table below. We also examine a sensitivity that tests a higher planning reserve margin requirement, in line with updated MISO guidance relative to our base assumptions; this is an

[66] Tax reform sensitivities and North Dakota Planning Standard sensitivities not included in these ranges.
[67] Note that we use this case to proxy high DER adoption, but it could represent a low load future resulting from various factors.
[68] In this sensitivity, the capacity expansion plan was reoptimized to reflect a lower level of additions needed to serve load. In this case, all of the plans add fewer MW of new capacity, but relative to the Reference Case, Scenario 9 and the Alternate Plan provide incremental customer savings.

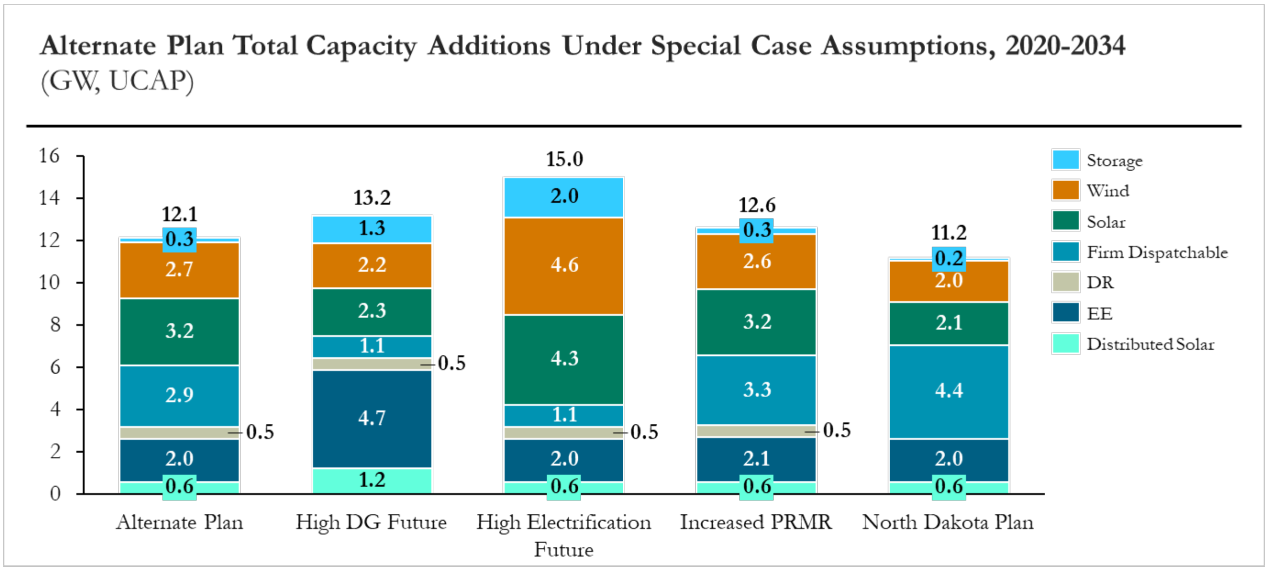
important sensitivity to test because of the FRAP alignment discussed in detail above. Finally, we also examine a plan that adheres to North Dakota planning standards, which do not allow for consideration of a regulatory cost of carbon or externality pricing. The assumptions that are tested in these scenarios are summarized in the table below.

Table 4-17: Special Case Parameters

Special Scenarios	Description	Gas/Coal/Market Prices	Load Forecast	Carbon & Externality Costs	New Resource Costs
P. High DG Adoption and Low Technology Cost Future	Similar to MISO MTEP Limited Fleet Change Scenario	Low	High DG Solar Forecast, Higher EE Levels	High/High	Low
Q. High Electrification and Low-Tech Costs Future	Similar to MISO MTEP Accelerated Fleet Change Scenario	High	High Electrification	High/High	Low
Z. Increased PRMR	Reflects higher PRMR per recent MISO guidance	Base	Base, but adjusted to reflect a 9.4% planning reserve margin and 98% coincidence factor	High/High	Base
North Dakota Planning Standards	Optimizes expansion plan based on PVRR, with no externality or regulatory cost of carbon prices included; also removes incremental DR and CSG solar	Base	Base	None	Base

As can be expected, all the above scenarios result in somewhat different expansion plans relative to the Alternate Plan optimized with base assumptions. But, noted above, nearly all cases result in savings relative to the respective Reference Cases under each set of assumptions. 2020-2034 totals for these plans are included in the Figure below.

Figure 4-13: 2020-2034 Cumulative Resource Additions Under Special Case Assumptions



In cases that assume a low technology cost trajectory, more storage is selected relative to firm dispatchable resources, although these differences occur primarily in 2030 and beyond (outside our near-term action plan window). Further, depending on load trajectories associated with these cases, the plans select more or less renewable capacity relative to the Alternate Plan, but still add a substantial quantity of new renewables over the planning period. Therefore, even if one of these futures becomes more likely than the base set of assumptions utilized for creation of the Alternate Plan, these base assumptions set us on a reasonable middle-ground path to achieving higher levels of carbon-free energy, affordably for customers.

As noted above, the increased PRMR case examines the impact of recent increases to required planning reserve margin and coincidence factors, per MISO guidance, that were not incorporated into our modeling updates. We tested this case in order to confirm that our base plans were not adding too few resources to adequately cover our expected increased obligations over time, especially in the near term.[69] The effect of this change on the expansion plan is to add incremental firm dispatchable and storage resources, relative to the Alternate Plan, but these changes do not occur until the late 2020s, which indicates that our proposed five year action plan includes sufficient accredited capacity to cover these assumed obligations.

[69] The MISO planning reserve margin for Zone 1 has been increasing over the last several years, as has the Company's coincidence factor, and these are the primary inputs into the Company's effective reserve margin.

Finally, we note that – as a company that serves multiple jurisdictions with differing views on how economic externalities should be considered – we do also examine a plan that reflects capacity expansion optimization based on PVRR, with no consideration of carbon costs. This "North Dakota Plan" shows fewer renewable additions and more firm dispatchable units overall; however, whereas in our June 2020 Supplement the North Dakota plan did not add any new renewable capacity in the near term, this updated plan does add significant solar in 2025 to capture available tax incentives. Finally we note that, while there are incremental costs associated with the Alternate Plan under these planning assumptions, our tax reform sensitivity shows significant upside potential, saving customers over $100 million relative to the Reference Case where Sherco 3 and King are kept online until their current end of financial life and the nuclear units are not extended.

iii. Nuclear retirement scenarios.

Finally, we did examine whether our Alternative Plan parameters (removing the Sherco CC and adding interconnection re-use resources at Sherco and King) were economically robust to alternate nuclear extension scenarios, consistent with Baseload Scenarios 4 (Early Coal; No Nuclear Extension) and Scenario 12 (Early Coal; Extend All Nuclear). The results of these cases continue to show that extending the lives of both nuclear plants is beneficial to customers on both a PVSC and PVRR basis; i.e. the highest levels of savings are achieved under Scenario 12. Therefore, despite the Department's recommendations to retire Monticello early, we reiterate here that our economic modeling does not support such an action for either the Supplement Plan or the Alternate Plan, and Monticello extension is needed in order to achieve the incremental savings indicated under Scenario 12.[70] Further, our modeling results show that carbon reduction achievement under Scenario 4 is consistently less favorable than either of the cases where nuclear units are extended. This occurs in part due to the loss of Monticello's carbon-free generation capabilities – rated at over 640 MW, and operating at well over a 90 percent capacity factor – and in part because the model selects incremental firm dispatchable capacity (modeled as gas CTs) to fill the capacity need Monticello's retirement would create.

[70] Further, from a transmission stability perspective, the Sherco gen-tie MW limits and stability needs in the Alternate Plan were not studied without Monticello in operation.

Table 4-18: Scenario 4 and 12 Economic Modeling Results

PVSC Deltas *$ million cost/(savings) relative to Reference Case*			
Baseload Scenario	**Scenario 9 (Preferred)** (Early Coal; Extend Monti)	**Scenario 4** (Early Coal; No Nuclear Extension)	**Scenario 12** (Early Coal; Extend All Nuclear)
Updated Inputs	(234)	(210)	(636)
Updated Inputs + Alternate Plan Parameters	(606)	(543)	(965)
PVRR Deltas *$ million cost/(savings) relative to Reference Case*			
Baseload Scenario	**Scenario 9 (Preferred)** (Early Coal; Extend Monti)	**Scenario 4** (Early Coal; No Nuclear Extension)	**Scenario 12** (Early Coal; Extend All Nuclear)
Updated Inputs	96	55	(163)
Updated Inputs + Alternate Plan Parameters	(46)	(84)	(277)

d. The Alternate Plan mitigates risk associated with relying on the MISO generator interconnection queue.

We noted above that, despite arguments presented by Sierra Club and CUB in particular, we have not revised our assumed transmission interconnection cost assumptions for greenfield resources. As discussed, we have observed the queue becoming increasingly more constrained, especially for wind projects, and thus resulting in very high assigned interconnection upgrade costs in recent DPP phases. We are concerned that the Sierra Club uses out of date analyses to argue that we should assume lower interconnection costs that would not fully represent the queue issues we face today. Further, we are concerned that the CUB analysis does not accurately account for the level of system-wide cost that would be assigned to the Company in the event of a regional transmission expansion. We discuss these issues below.

i. 2017 MISO queue analysis.

As noted in previous filings to this docket, the Company bases its interconnection cost assumptions on observed trends from recent queue studies. The Sierra Club used information provided by CUB in modeling and cited an out of date analysis from a

Lawrence Berkeley National Lab (LBNL) report in its comments that is now several DPP cycles out of date. When asked if there were updated analyses available to show how the queue had changed since the LBNL report was published,[71] Sierra Club was unable to produce them. We have included our own analysis and discussion here.

We examined the most recent 2017 queue tranche to understand whether it would be appropriate to either increase or reduce the costs associated with greenfield interconnection. We do not believe the results of this study supports reducing these cost assumptions, in part because costs vary widely and are uncertain, and in part because of the simplifying assumptions we need to make for modeling purposes.

Below is a table that shows each phase of queue study results from the August 2017 group of projects (the most recent set of studies completed). While in some cases, we observe a few projects navigating the MISO queue process to interconnect with lower costs than we assume in our modeling, other projects are assigned substantially higher costs and end up dropping out of the queue entirely. In recent studies, this is particularly true for projects requesting Network Resource Interconnection Service (NRIS) interconnections, in DPP phase 2 or 3 when Southwest Power Pool affected system study costs are incorporated. In future DPPs, large costs could be triggered in either RTO's system as the remaining transmission capacity is used.

[71] In response to XE IR No. 46.

Table 4-19: Interconnection Costs for DPP West Aug-2017 MISO Interconnection Queue[72]

DPP Phase	All Resources	Wind	Solar
Phase 1			
Average Cost ($/kW)	$177.5	$208.0	$131.2
Total Active Projects	34	23	10
Total MW	4,980	3,997	983
Phase 2			
Average Cost ($/kW)	$631.4	$755.7	$399.3
Number of Active Projects	27[73]	18	8
Total MW	4,127	3,217	908
Delta in MW from Phase 1	*-17%*	*-20%*	*-8%*
Phase 3			
Average Cost ($/kW)	$113.0	$156.7	$96.6
Number of Active Projects	13 *(3 NRIS, 10 ERIS)*	7 *(0 NRIS, 7 ERIS)*	6 *(3 NRIS, 3 ERIS)*
Total MW	2,208	1,400	808
Delta in MW from Phase 1	*-56%*	*-65%*	*-18%*

First, the table shows that a substantial quantity of projects dropped out of the queue across study phases, most of them after DPP Phase 2 wherein the largest costs are identified. In addition to MISO re-study of transmission needs between Phase 1 and 2, this is the stage at which SPP affected system study costs are added. Overall, the costs were prohibitively high for a large share of the projects, especially for wind generation.

Second, while the table does shows that average integration costs of $130/kW will be realized by the 13 projects remaining across the MISO West region, we noted that 10 of the 13 projects that have completed Phase 3 studies are not guaranteed to receive full capacity accreditation. Rather they are designated as Energy Resource Interconnection Service (ERIS) requests, which *could* receive some capacity credit but the timing and magnitude and potential incremental cost to achieve this credit cannot be known in advance[74] and further costs could be assigned later for the projects to be

[72] Data available at www.misoenergy.org.
[73] Includes one non-renewable project not reflected in the remainder of the table.
[74] ERIS resources must request long term Network Integrated Transmission Service (NITS) in order to qualify as a capacity resource for the Company which are granted through the MISO Transmission Service Request (TSR) queue process. The Company believes it is possible – if not likely – that as greater number of projects and MW use the TSR queue process, the TSR queue may begin to exhibit the same cost and schedule risks as currently observed in the MISO Generator Interconnection queue.

able to earn capacity credit, on top of the costs identified here. For the three projects that did request NRIS service, all were solar projects, and their interconnection upgrade costs per project vary widely, from $60-260/kW.

ii. Incorporating appropriate queue costs into modeling.

The above findings are important observations for our modeling process. The model requires us to determine an appropriate representation of interconnection costs over a number of years into the future, which inevitably introduces two challenges; 1) how to evaluate an appropriate representative cost for an unconstrained pool of MW the model can choose if some projects can make it through the queue at relatively low cost, but others are forced out entirely due to extremely high costs, and 2) how to determine an appropriate cost to include in our modeling for resources that will have transmission certainty (i.e. NRIS designation). If we were to model an unconstrained level of accredited MW at a low average interconnection cost – as the Sierra Club and CUB seem to suggest – we would vastly overestimate the magnitude of guaranteed accredited capacity that can successfully navigate the queue and, ostensibly, be placed into service in the future. Further, while procuring resources that provide energy, but not capacity, in a time when we will need capacity resources to fully hedge our MISO requirements would not align with our practices around mitigating risk to customers.

Therefore, to appropriately address this issue in modeling, we need to impose some constraint related to queue issues. Theoretically, this could either limit the total MW the model can choose in a given year, based on some assumption of how to translate queue results to annual available MW limits, or increase the assumed cost of interconnection for all generic greenfield wind and solar resources. Ultimately, we believe increased average interconnection costs – assumed at $500/kW for greenfield wind and $200/kW for greenfield solar, consistent with our June 2020 Supplement assumptions – are a more appropriate and simpler approach to represent these real-world constraints. If the Company has a capacity need in a given year and it has already exhausted an artificially imposed MW threshold, the plan would likely result in an unserved energy or capacity need when, in reality, we would procure least cost resources available to us at the time.

Further, it is worth noting here that CUB's analysis does not appropriately reflect the way that MISO assigns cost in interconnections studies or regional transmission expansion, and as a result their locational co-optimization cannot be relied upon to formulate an alternative plan for the Company. As we noted before, this modeling does not account for the Company's full upper Midwest load as a single entity, and it also makes adjustments to account for our load in North and South Dakota by "moving it into" the Minnesota boundary for purposes of locational modeling. These locational distinctions are not particularly relevant in the Company's modeling; but, as CUB's analysis claims to co-optimize transmission and distribution resources with location considered, this is problematic, as it fails to account for specific interconnection costs that could vary widely based on the location of a generator (i.e. within the span of a few counties), or for transmission projects involving 69 kV infrastructure, as it considers this to be exclusively on the distribution system. Further, it appears that CUB has assumed that transmission investments across the region would be partially allocated to the Company at a far lower percentage than would likely be reflected in such a regional buildout. Whereas CUB assumed that the Company was assigned only 5.4-5.6 percent of costs[75], the Company comprises 7 percent of MISO-wide load and over 50 percent in Zone 1. In addition, the cost allocation method for future transmission investment is presently being discussed in the MISO stakeholder process and has not been settled. It is possible that the Company would be assigned a higher share of costs, if projects indicated in MISO's planning were focused more in our region than others. Finally, we note that constraints in other regions affect interconnection cost upgrades in MISO, as evidenced above in the DPP studies; ignoring interconnection cost implications in neighboring regions like SPP will lead to fundamentally underestimated costs associated with bringing new renewable generation online.

iii. Gen-tie benefits compared to queue constraints.

Given the relatively high costs to interconnect greenfield renewables evidenced by the latest completed DPP study cycle, and the fact that we expect constraints to continue for some time, the re-use of interconnection rights the Company currently holds at Sherco and King is a hedge against the interconnection queue in MISO. If the proposed gen-tie lines can be constructed for reasonable costs and enable substantial renewable additions (ad we believe they can be), we can reduce the average cost/MW relative to the queue and make use of these valuable interconnection rights to the benefit of customers. Because we currently hold these rights, we want to ensure we make the best use of this opportunity to reutilize them to the benefit of our customers, bringing significant new renewables online at an equal or lower average cost/MW than the broader MISO queue can offer for resources coming online before 2030, and possibly beyond. Therefore, we believe that the proposed option to build gen-ties at Sherco and King to connect resources with those existing interconnections offers us those opportunities.

[75] Response to XE IR-85.

e. Additional transmission considerations and impact on the Alternate Plan.

There are two other key transmission-related considerations we note here, related to the benefits of the Alternate Plan. To our knowledge, this would be the first major generator interconnection reuse proposal in MISO that incorporates a hybrid of different resource types behind the POI. As such, MISO is continuing to develop its guidelines related to accreditation of hybrid resources. Further, the gen-tie concept – in particular for the length of route proposed for Sherco POI re-use – is at an early stage and subject to modifications that will come with more complete project and route design. We address these considerations below.

i. MISO hybrid resource accreditation and seasonal construct.

MISO is currently in the process of proposing a capacity accreditation methodology for hybrid resources. Hybrids are defined as generators that combine more than one type of Electric Facility for the production and/or storage for later injection of electricity. In a recent Resource Adequacy Subcommittee meeting, MISO indicated that they plan to accredit hybrid resources based on a "sum of the parts" approach. As proposed, MISO will take the accredited capacity for each of the respective resource types that make up the hybrid facility and sum them up to a level not to exceed the amount of firm interconnection service at the site. Initially this will be calculated using assumed unforced capacity values for each resource type behind the POI, but as operating data is collected, MISO will incorporate it into its determination for resource accreditation.

Given the MISO proposal, the Company anticipates that it will receive full accreditation for all resources proposed to be added on the Sherco gen-tie, and we have modeled the resources consistent with this understanding. This is the case despite the fact that the total installed capacity on the line will far exceed the approximately 2,000 MW of owned injection/interconnection rights. Our understanding is that this is feasible, without significant interconnection re-study, because the accredited capacity of each resource totals to less than 2,000 MW; in fact, the cumulative accredited value is expected to be up to approximately 1,425 MW. As such, it may be possible to add more capacity interconnecting at the site in the future beyond what was modeled here – potentially in the form of storage – particularly if that capacity further supports renewable integration. We include an example calculation below, based on the resources added in the Alternate Plan by 2034.

Table 4-20: Example Hybrid Resource Accreditation

Resource	Modeled Installed Capacity (MW)	Example Accreditation Multiplier[76]	Estimated Accredited Capacity (MW)
Wind	2,150	0.16	344
Solar	1,450	0.30-0.50[77]	435-725
Combustion Turbine	375	0.95	356
Total	**3,975**		**1,135-1,425**

Further, we are aware of – and support – MISO's examination of the potential need for different reserve requirements and/or resource specific RA values on a seasonal basis. We currently expect that MISO will formally propose a new seasonal construct in late summer or early autumn of this year. While these changes certainly could affect our planning, it is too soon to know what the ultimate proposal will be, what construct FERC will accept, and when implementation would start. Thus, we have not included modeling that specifically addresses the potential for a seasonal construct here, but we will evaluate this proposal and update the Commission if we determine there are any material changes as that process moves forward.

ii. Transmission routing cost.

The Company appreciates that we are proposing an early conceptual idea with initial cost estimates that – while consistent with past project experience – are subject to some uncertainty. To address that uncertainty, the company investigated the customer savings impact of increasing the line mileage from the approximately 140 miles to 175 miles; this would increase the modeled cost of the Sherco gen-tie from $578 million to $713 million. We note this sensitivity – while discussed here to represent an extension in line miles – could apply to any number of factors that would increase costs above the amount accounted for in our Alternate Plan. This sensitivity would reduce customer savings on a net present value basis by approximately $132 million; generally, on par with the Supplement Plan on a PVRR basis, but still generating significant incremental customer benefits on a PVSC basis. Therefore, we believe that the Plan presented here is resilient when considering potential transmission cost risk.

[76] Represented as Effective Load Carrying Capability (ELCC) or UCAP values.
[77] As discussed in our June 2020 Supplement, solar is currently accredited at 50 percent of its installed capacity. Our EnCompass modeling incorporates assumptions consistent with MISO Transmission Expansion Planning, which assumes a declining solar ELCC through the early 2030s after which it holds steady at 30 percent. Because we do not know what the average ELCC for solar resources will be by the end of our planning period, we have shown a range here.

E. Lessons Learned and Recommendations for Future Resource Plans

The Company appreciates that we, and the industry more broadly, are undergoing a significant transition, not only regarding the types of resources we consider, but also the way in which planning is conducted. There is increasing emphasis on stakeholder participation, alignment between generation, transmission, and distribution planning, and incorporating more detailed analyses of resource attributes. We appreciate the robust engagement of other parties, examining modeling and presenting alternate plans. Ultimately, we believe some of the proposed modifications and different approaches these parties presented will require ongoing work for our next resource plan. In this section, we discuss some lessons learned and frameworks for ensuring all parties participate in a way that helps the Commission consider our resource plans with the best information possible, as well as a discussion of proposed future improvements to our modeling and processes.

1. Proposed Minimum Information Requirements for Parties Submitting Alternative Plans

This resource plan was the first in which several other parties besides the Department conducted full-scale modeling efforts to either validate or test alternate proposed plans for the Commission to consider. We have also responded to substantial levels of requests for information from modeling parties and others; ultimately totaling nearly 1,000 requests spanning nearly two years, many of which directly supported parties completing their own alternative modeling.

Overall, this process has raised valuable issues for consideration, and pressed us to consider new and different approaches than we had previously. We appreciate the engagement from other parties and believe that there are valuable contributions for the Commission to consider in the context of evaluating the Company's plans. However, not every modeling party in this docket has adhered to the basic planning principles the Company must follow or been equally forthcoming with information supporting their proposed alternative plans. These factors make alternative plans difficult for us and other interested parties to fully evaluate, much less for the Commission to adopt outright as a preferred alternative to the Company's proposed plans. The Company is subject to many requirements when submitting its Resource Plans, and we would not propose all other parties be subject to all of those requirements as well; however, we believe some additional structure around the IRP process and party participation may be helpful, both in keeping future resource planning processes on track, and providing the Commission all the information it needs to make decisions.

For example, the Company has a statutory requirement to evaluate "a set of resource options that a utility could use to meet the service needs of its customers over a forecast period, including an explanation of the supply and demand circumstances under which, and the extent to which, each resource option would be used to meet those service needs."[78] For our service area, this means evaluating the expected loads (plus our required MISO planning reserve margin) *annually* over the 15 years of the planning period, and accounting for our full five-state upper Midwest service area. We also ensure our planning process takes a full account of the resources already available to us to serve customers, which includes both owned and PPA resources. One simple summary we use to evaluate our plan on these measures is a Load and Resources Table, such as the ones provided in Appendix B. A model that does not evaluate these basic inputs at a bare minimum – and from which the submitting party cannot, or is unwilling to, provide a basic load and resources table – should not be considered a viable alternative to the Company's proposed plan.

In order to more easily evaluate the merits of a plan that *does* meet these basic minimum requirements, we believe there are a few other components that are reasonable to request of parties for the record. These include:

- A load and resources table, as described above, that reflects the Company's load plus MISO reserve margin requirements, the Company's full set of existing resources and the modeling party's proposed expansion plan, on an annual basis
- An evaluation of the proposed alternative plan's PVRR, as well as its PVSC. The Commission is required by Minnesota statutes[79] to use a CO_2 environmental cost value when evaluating and selecting resource options in all proceedings before the Commission, including resource plan and certificate of need proceedings. Thus, an alternate plan that provides no such measure cannot be further evaluated. We would also propose that – at a minimum – the modeling party provide PVSC values under the same externality/regulatory cost of carbon sensitivity that the Company presents in its primary plan, although we agree that testing other values is appropriate. Any comparison of PVRR values should be between plans that are calculated using a similar methodology to the Company's (if not in the same type of modeling software).
- A quantitative bill and/or rate impact analysis of the proposed plan, including whether the plan results in significant differential bill impacts to different

[78] Per Minn. Stat. § 216B.2422, subd.1(d).
[79] Minn. Stat. § 216B.2422, subd. 3.

customers within a customer class (i.e. participating and non-participating customers).

- An analysis of whether the proposed plan results in unserved energy or other significant reliability concerns within the modeled construct.
- A reasonably comprehensive documentation of input assumptions, to the extent they are different than the Company's inputs.
- Discussion of how its proposed alternative plan achieves the Commission's public interest analysis requirements for approving a resource plan, as outlined in Minn R. 7843.0500, subp. 3.

We believe setting forth basic requirements, including but not limited to the above, would support better analysis of any plans submitted as proposed alternatives to the Company's plan and ultimately help the Commission make a determination regarding our five-year action plans.

2. Distributed Solar as an Optimized Resource

We also recognize that there are some improvements we can make to our future analyses. One such improvement is the inclusion of distributed solar as a selectable resource in our planning, which was a topic of discussion across several parties' comments. We acknowledge that – partially for reasons related to legacy Strategist capabilities (or lack thereof) – we have more work to do to fully incorporate distributed solar as a selectable demand-side resource in our generation planning. Rather, our plan contains substantial solar additions and, to the extent incremental distributed solar above what our forecasts indicate is adopted, it could reduce the need for larger-scale solar additions in the future. In short, the Company will, of course, continue to integrate distributed solar that customers choose to adopt, and we are open to working on a modeling construct that enables identification of economic distributed solar additions as part of our next resource plan.

That said, we have significant concerns with the approach the Distributed Solar Coalition took to modeling only the "incremental cost" to the utility to incentivize certain levels of distributed solar generation, saying that this approach was similar to how bundles of energy efficiency and demand response were modeled. We believe this approach would not fully consider all system costs associated with treating distributed solar as an optimized resource.[80] The present value of societal costs and revenue requirements associated with resource additions in our Resource Plan do not just represent incremental cost to incentivize, rather it is intended to represent the costs associated with the resources selected to serve our system. In other words, if an "optimal amount" of customer-procured resource is going to be identified through modeling in the context of the broader system, then either the full cost of that resource must be evaluated through modeling, or the bundles of distributed solar would need to be assessed through an alternative cost effectiveness test and reflect achievable potential levels – like the EE bundles in our modeling were – before the model could select them.[81]

In this context, it is further important to note that – while resource planning does not directly contemplate ratemaking structures and equity between customers – the cost of net metering compensation and the value of solar tariff are passed through to non-participating customers, in a similar fashion to the way the cost of a large-scale resource PPA is passed through to customers through the fuel clause. These cost and equity concerns must also be considered when discussing a vast expansion of rooftop or community-scale solar development, such as the DSC, CUB and others have proposed. Further, modeling economic distributed solar additions requires further

[80] In response to XE IR 81, DSC confirmed that it intended for these incentive payments to apply to all MWh produced by the distributed solar resource, not only excess generation; this appears essentially equivalent to proposing a production credit for distributed solar.

[81] As detailed in our original July 2019 IRP filing, EE bundles were derived from data provided by the Center for Energy and the Environment's potential study or by the Company. As part of the economic potential portion of the CEE analysis, energy efficiency measures were screened using the societal cost-effectiveness test: *Minnesota Energy Efficiency Potential Study*. Available at Minnesota Energy Efficiency Potential Study: 2020–2029 (mn.gov). The consideration of energy efficiency measures in a portfolio also incorporates the measure's cost to a customer, via the Societal Test. While not every measure is required to pass this test, the portfolio as a whole is expected to pass it. Therefore, we disagree with the suggestion that the only relevant cost is the cost to the utility to acquire the resource, whether for EE or for other distributed resources. Moreover, all three bundles of EE reflect achievable potential (the amount of economic energy efficiency that is achievable given barriers to participation and utility budgets), not just what is economic (economic potential) or technically possible (technical potential). This differs from the DG Solar bundle approach proposed by the DSC, which uses an economic adoption model without any further adjustment for the amount of DG solar that is achievable. The Company believes that comparable treatment to EE could be possible, but the DSC proposal is not fully consistent with the analytical rigor that is applied to energy efficiency scenarios. For example, when determining the potential for energy savings from a measure like water heating, a research team will consider technical factors beyond cost such as availability of the efficient option at distributors, the prevalence of the measure in homes and businesses, the lifetime of the equipment, and customers' awareness of the technology as an option to save energy. Applying this same methodology to distributed rooftop solar, for example, would need to consider factors such as available roof area, presence of roof obstructions, age of roof, load bearing capacity of roofs, customer acceptance of any risks involved in on-site solar installations, and others. Further information about each type of potential can be found here: Guide for Conducting Energy Efficiency Potential Studies (epa.gov) (page 2-4). The model the DG Solar method is based on can be found here: Eric Williams, Rexon Carvalho, Eric Hittinger, and Matthew Ronnenberg. *Renewable Energy*. May 2020. "Empirical development of parsimonious model for international diffusion of residential solar".

coordination between the resource planning and distribution planning processes. We recognize the coordination between these processes needs to be stronger and have begun that work (for example, through aligning distributed resource adoption forecasts), but there is still much to be done.

In sum, we are open to working with stakeholders to model distributed solar as a selectable resource but believe the framework by which we appropriately assess the cost of these resources and potential benefits to the system requires further work; we are not comfortable adopting the DSC's proposed analysis at this stage. We would propose the Commission allow additional time for us to work with parties to develop that framework and address selectable distributed solar in the next Resource Plan.

F. Conclusion and Looking Forward

The Company has worked to propose an Alternate Plan that is responsive to stakeholder feedback with regard to the Sherco CC, reutilizing our coal interconnection rights to bring on more clean renewable generation earlier than would otherwise be indicated in the Supplement Plan. While both plans are beneficial on a cost and carbon reduction basis, while also appropriately balancing risk and reliability factors, we do think the Alternate Plan is the appropriate next step in the energy transition. The Alternate Plan achieves high levels of customer cost savings (relative to the Reference, or "business as usual" case) while also enabling significant upside benefits if contemplated tax credit reform is adopted. The Alternate plan is robust under a wide variety of commodity and technology cost and load futures and mitigate substantial downside reliability risk relative to modeling parties' plans. That said, we recognize that – as the transition of our fleet continues – there are improvements we can make to our analysis and modeling approach to better incorporate a broader set of resources and integrate planning across our system. We look forward to continuing that work with stakeholders and the Commission in future resource plans, to responsibly manage Xcel Energy's transition to a cleaner portfolio with the best interest of our customers in mind.

SECTION 5: CUSTOMER RATE AND BILL IMPACTS

Minn. R. 7843.0500, subp. 3, requires the Commission to evaluate resource plans on, among other things, their ability to "keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints." Our June 2020 Supplement Preferred Plan (the Supplement Plan) included a customer cost analysis that showed our Preferred Plan continued to achieve our carbon goals and reliability objectives while maintaining affordability. In these Reply Comments, we present a new customer cost analysis of the Alternate Plan and a comparison to the Supplement Plan.[1]

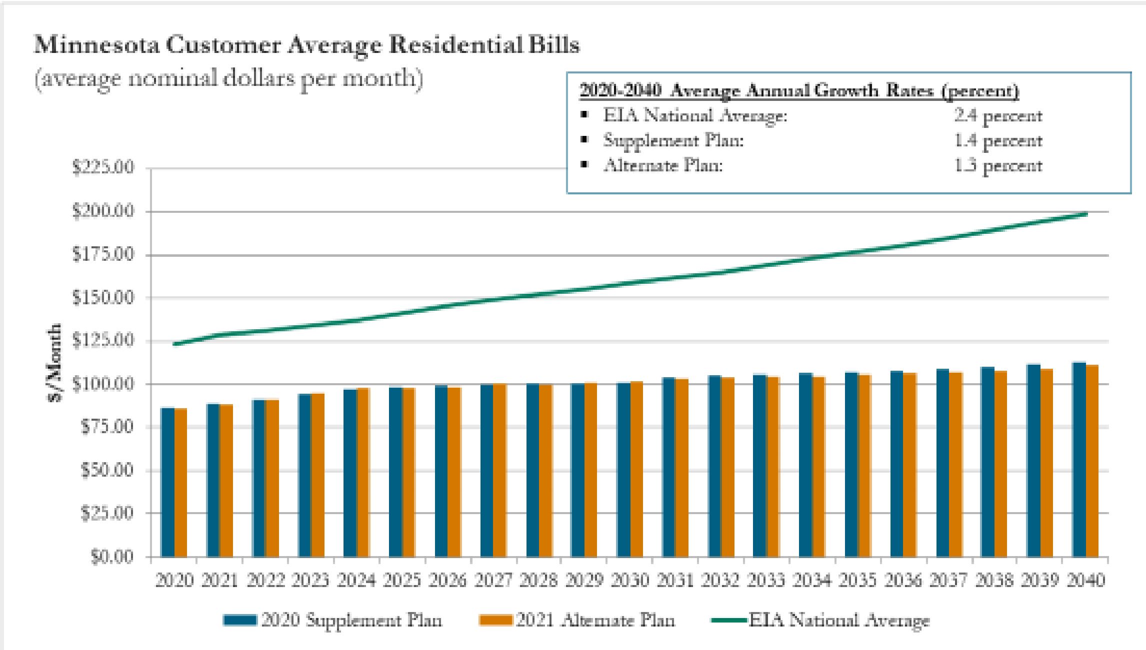
Our refreshed customer cost impact analysis finds that our recommended Alternate Plan continues to keep average residential customer bills well below the national average. Additionally, our projected average bill and rate growth remains below inflation and is over a full percentage point below national averages for bill and rate growth. That said, we do note that both the Alternate Plan and the Supplement Plan project slightly higher rates when compared to national average rate estimates, and we discussed key drivers of these differences in our Supplement filing. These main drivers, our lower sales forecast, revenue requirements related to renewable expansion and EIA's lower forecast, have similar impacts for both the Supplement Plan and the Alternate Plan. When reviewed as a whole, however, we believe these metrics show that the Alternate Plan, like the Supplement Plan, continues to maintain affordability while achieving substantial carbon reduction benefits relative to our Reference Case, while also keeping customer bills and our rates as low as practicable.

A. Residential Bill Analysis

As shown in Figure 5-1 below, NSP System residential customers – on average – pay substantially less per month than the national average in both Plans. We also continue to expect our average bill levels will grow more slowly than the national average, by approximately a full percentage point per year. The Alternate Plan results in a slightly lower total bill over the term of the analysis, but both plans are largely comparable, especially through the planning period.

[1] While much of the modeling evaluation in these reply comments is the Alternate Plan as compared the updated Supplement Plan, we note that the rate design comparison provided here does not account for the additional renewable additions we have added to our system since our June 2020 filing. In other words, the Supplement Plan rate impact is the original rate impact we filed in June 2020. Ultimately we determined it was a more simplistic look to compare the Alternate Plan to the customer impact view that stakeholders last saw.

Figure 5-1: Minnesota Average Residential Bills



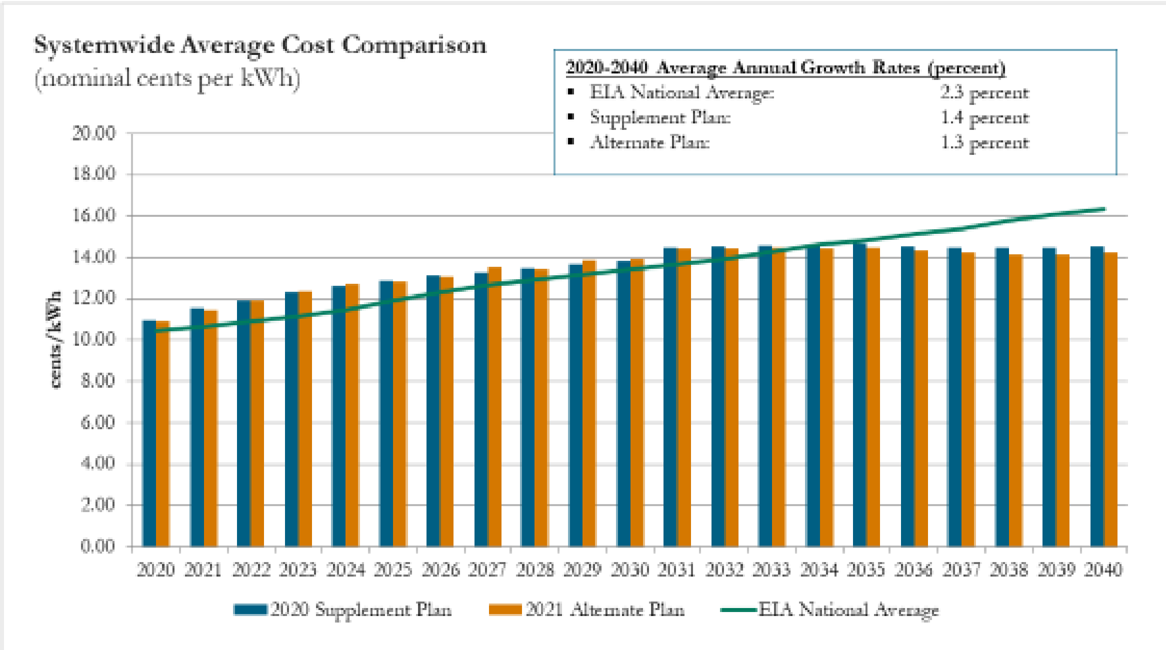
B. Rate Impacts and Key Drivers

In addition to reviewing average residential bill impacts, we believe it is important to consider the impacts of the Alternate Plan on our rates. In this Section, we present the Alternate Plan's forecasted cost impacts relative to the Supplement Plan, at both a total system and Minnesota-only level. Overall, our Alternate Plan results in slightly lower rates as compared to the Supplement Plan, although they are similar in most years of the analysis

We project that the Alternate Plan would result in rate increases of approximately 1.3 percent per year through 2040 as compared to the Supplement Plan's growth rate of 1.4 percent, on a system-wide basis. We note that this estimated rate increase, on an average annual basis, is nearly one percentage point lower than the national average rate increase, as projected by the Energy Information Administration (EIA),[2] and lower than the rate of inflation. In other words, we can achieve either Plan's significant carbon emissions reductions with cost impacts that are significantly less than the expected national average increase in electricity prices. This rate of increase is also less than the rate of inflation.

[2] See Energy Information Administration. *Annual Energy Outlook 2020*. (January 2020). Available at: https://www.eia.gov/outlooks/aeo/index.php

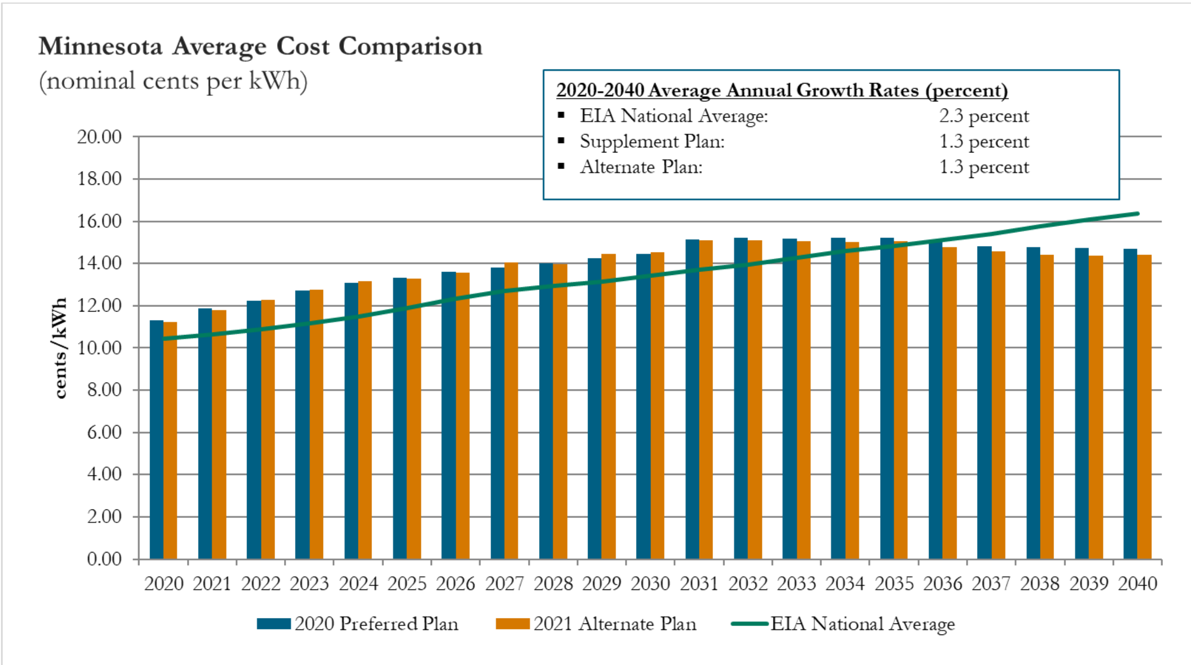
Figure 5-2: Systemwide Nominal Cost Comparison



When we look at Minnesota customers' projected rate impact, again the rate grows at a very similar rate, well below the national average, and both Plans have similar average costs. That said, the average annual growth projected for Minnesota-specific rates is marginally lower than the NSP System overall, and the rates for the Alternate Plan are marginally lower than for the Supplement Plan[3]. This is driven by more growth in the underlying energy sales forecasts relative to the system overall, which spreads Minnesota-specific revenue requirements over a broader base of consumption. Again here, we note that the expected growth rate attributable to both Plans is substantially lower than expected national average rate growth.

[3] The data block in Figure 5-3 is rounded to one significant digit. The Supplement Preferred Plan is actually 1.32% and the Alternate Plan is 1.25%

Figure 5-3: Minnesota Customers Nominal Cost Comparison



Based on the totality of these metrics, we believe our Alternate Plan, as well as the Supplement Plan, keeps customer bills and rates as low as practicable while achieving the substantial carbon reduction benefits we anticipate as a result of this Integrated Resource Plan.

SECTION 6: FORECASTING AND RENEWABLE ENERGY SITING

In the following sections, the Company provides additional detail on our robust approach to demand and energy forecasting as well as our thorough due diligence processes to mitigate the environmental impacts of renewable energy development. We address specific comments filed by the Department of Commerce and The Nature Conservancy below.

I. DEMAND AND ENERGY FORECAST

In Comments, the Department conducted a high-level assessment of the Company's demand and energy forecast and concluded it has a systematic bias and adjusted our forecast to evaluate capacity expansion plans. As the Department noted in its Comments, its review was limited: "For this IRP, the Department neither reviewed the technical details of Xcel's forecast nor tested all the Company's previous or current statistical models."[1] Additionally, the Department's analysis did not account for assumptions that were made and determined to be reasonable at the time that the forecasts were developed. These assumptions include levels of energy efficiency, loss of wholesale loads, loss of large customer loads, the addition of customer-owned combined heat and power operations, and weather.

As we detail below, after accounting for these variables, the variance between the Company's forecasts and actual results is much smaller than the Department's limited analysis portrays. The forecast we submitted in this proceeding is reasonable and based on sound statistical models and the best assumptions available at the time regarding factors that may impact future demand and energy. That said, it is likely that future demand will be different than the forecast used for this Resource Plan or any other proceeding – as the only thing certain about any forecast is that it will be wrong. We account for this in our Resource Plan modeling by testing a wide range of potential future sensitivities that examine both lower- and higher-than-expected loads.

We minimize risks to customers by adopting Preferred Plans that are robust across a wide range of futures that include other variables, such as electrification and resource adequacy, or other important constructs. And we note that, before any resources are actually procured, there likely will be additional procedural steps that involve refreshing the forecasts, where they are subjected to additional scrutiny by parties and the Commission. Finally, we note that we use the same statistical models and assumptions for our forecasts in rate cases as we do in resource planning proceedings. And while parties reviewing resource plans claim – like the Department did here –

[1] Minnesota Department of Commerce, Comments (Docket No. E002/RP-19-368), February 11, 2021, page 11.

that our forecasts overstate future customer loads, parties in rate case proceedings often claim that we are understating future customer loads. In summary, our statistical models are solid, our assumptions are reasonable, and the Company and the Commission have appropriate guardrails in place to ensure that our actions are appropriately aligned with the best interests of our customers.

Below we explain the major factors that, in hindsight, contributed to what appears now as historical over-forecasting of energy and demand. As we demonstrate below, there is no systemic issue in our current statistical models that is causing an over-forecasting bias, and there is no need for the Company to use a forecast from an independent consultant in future regulatory proceedings.

A. Historical Forecast Variance Contributors

There are several factors that contribute to the variance between the Company's forecast and actual usage over the past 15 years. These factors were not known at the time the forecasts were developed and can be analyzed and quantified without testing the Company's previous or current statistical models. Rather, as we note above, these factors reflect assumptions that were made and determined to be reasonable at the time the forecasts were developed. Below we provide greater detail on each of these below.

1. Energy Efficiency

Prior to the Company's October 2008 forecast, the Company made no adjustments to the demand and energy forecasts for future energy efficiency. The Company's forecasts assumed that future energy efficiency impacts would be similar to the impacts embedded in the historical energy and demand values used to develop the forecast. To the extent that expected future impacts were greater than the historical impacts, the future energy efficiency impacts were reflected in the Resource Planning process as a resource.

Beginning with the October 2008 forecast, the Company incorporated an adjustment to the demand and energy forecast to account for future energy efficiency amounts that were projected to be higher than historical achievements. Because the Company changed its forecast process in 2008, we focus our comments on the forecast variances beginning with the October 2008 forecast.

The incorporation of an adjustment to the forecast to account for future energy efficiency amounts improved the accuracy of the forecast. However, actual energy efficiency achievements have consistently been greater than forecasted, and, when compounded over time, this has contributed to actual energy and demand being lower than forecast, or a positive/over-forecast variance.

In recent years, this exceedance of forecasted energy efficiency achievements has been largely driven by the rapid adoption of LED lighting technologies at a higher rate than forecast. Given that LED lighting can help customers cost-effectively and systematically reduce their energy bills, the Company has worked aggressively to help accelerate the adoption of LEDs throughout our service territory.

However, there are indications that this LED lighting achievement is beginning to slow. Based on a recent survey of the Company's business customers, approximately 40 percent of the energy savings potential from LED lighting was installed by the end of 2019. And given 2020 actual and 2021-2023 expected goal achievements included in the Company's forecast from business lighting programs, we expect approximately 90 percent of the energy savings potential from LED lighting will be installed by the end of 2023. For residential customers, a biennial survey estimated that 46 percent of current residential sockets have LEDs installed as of Fall 2020. LED bulbs are expected to be installed in the sockets with the highest hours of annual usage, meaning that the remaining sockets without LEDs (54 percent) represent an energy savings potential much less than the count of sockets. The 2021-2023 energy efficiency goal achievements included in the Company's residential load forecast are primarily from LED lighting installations, significantly reducing the remaining potential at the end of 2023. Given this reduction in LED potential beyond 2023, there is a significantly diminished likelihood of having actual energy efficiency achievements exceed forecast achievements.

2. *Wholesale Load*

Between 2009 and 2013, all of the Company's contracts with firm wholesale customers expired. However, until notified by the wholesale customer that its contract would not be extended, it was reasonable and necessary for the Company to include the customer's forecasted energy and demand in its long-term forecast. The July 2012 forecast was the first forecast to include no additional load for firm wholesale customers. Therefore, all forecasts prior to July 2012 were overstated by the amount of wholesale load that ultimately was not served by the Company.

3. Large Customer Load Changes and Combined Heat and Power (CHP) Operations

There have been several significant changes in large customer loads that have contributed to the over-forecasting of energy and demand. Beginning in September 2011, the Company adjusted the forecast for the announced shutdown of the **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. All forecasts prior to this time assumed that this load would be served.

In addition, beginning in September 2011, the forecast included an adjustment for a **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. Therefore, all forecasts prior to this time were overstated due to assuming that some, if not all, of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** load would be served.

[PROTECTED DATA BEGINS PROTECTED DATA ENDS] began serving part of its load from CHP operations in 2017. The Company adjusted the long-term demand and energy forecast for this load reduction beginning with the August 2014 forecast. All forecasts prior to August 2014 were overstated for the period beginning in 2017 due to the loss of this load.

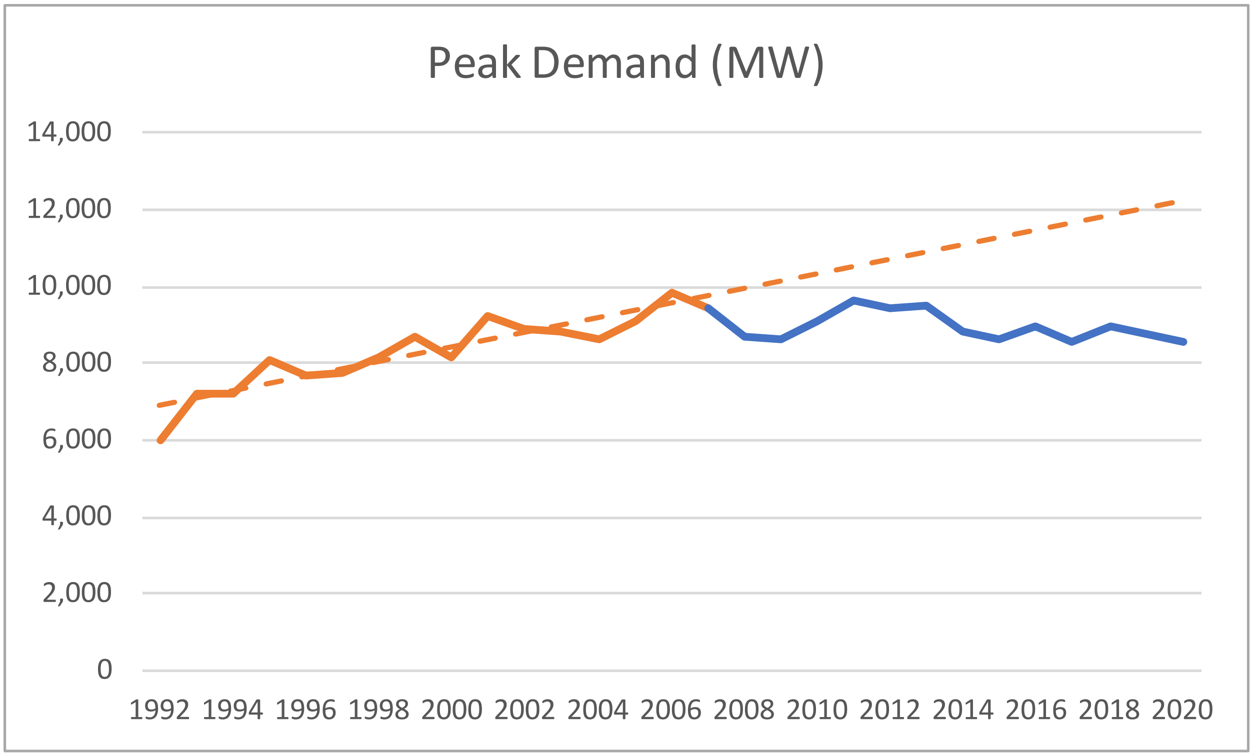
4. Weather

Weather can be a significant contributor to forecast variance, particularly for peak demand. The Company's forecast is based on normal weather, and actual weather can contribute to actual demand being higher or lower than forecast.

The variance analysis provided in the Department's comments compared actual peak demand to forecasted demand. During the 15-year period of 2004-2018, weather impacting the peak day was cooler than normal in eight years and hotter than normal in seven years. In years when it was cooler than normal weather conditions, the positive forecast variance was exacerbated because actual weather resulted in less demand than expected.

In sum, the forecast we submitted in this proceeding is reasonable and based on sound statistical models and the best assumptions available regarding factors that may impact future demand and energy. As demonstrated in Figure 6-1, the Company's demand increased for many years, and forecasts reasonably reflected the expectation that demand would continue to increase. However, as discussed above and also shown in Figure 6-1, the recession of 2008-2009, more rapid energy efficiency adoption, and unexpected loss of significant loads have resulted in a flattening to slightly declining demand over the past ten years, leading to larger forecast variances.

Figure 6-1: Xcel Energy Peak Electricity Demand (1992-2020)



B. Variance Analysis

In this section, we update the analysis presented in the Department's Comments to account for the factors discussed above. The updated analysis of Demand is provided in Table 6-1 and the updated analysis of Energy is provided in Table 6-3. We note that, after accounting for these factors, there still is a slight tendency for our forecasts to result in positive forecast to actual variances, but these are generally well within the Department's ±5 percent band it used to assess the reasonableness of the uncertainty inherent in future demand requirements.[2]

We also provide for reference, as Table 6-2 below, the Department's demand summary table from their Comments. We note that, in our adjusted demand forecast view, the greatest variances reflected in this table reduced significantly after accounting for the hindsight impacts unknown at the time of the forecasts.

[2] *See* Department Comments at page 13.

Table 6-1: Adjusted Percentage Variance of Demand

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Forecast Vintage	**Oct-08**					4.1%	8.5%	4.8%	6.6%	4.1%	7.0%	7.5%	9.1%	10.0%	12.1%	12.0%
	Apr-09						5.8%	4.6%	3.9%	1.1%	3.7%	3.9%	5.2%	6.0%	8.0%	7.7%
	Oct-09						-3.1%	3.2%	3.2%	1.0%	3.5%	3.7%	4.8%	5.4%	7.2%	6.7%
	Apr-10							1.2%	1.5%	-0.4%	2.8%	3.6%	5.2%	6.0%	7.9%	7.7%
	Jul-10							1.6%	3.7%	0.3%	2.9%	3.3%	4.4%	4.8%	6.2%	5.5%
	Apr-11								1.5%	-1.4%	0.5%	0.5%	1.9%	2.5%	4.2%	3.7%
	Sep-11								8.7%	-1.3%	0.1%	0.3%	1.5%	2.1%	3.6%	3.2%
	Mar-12									-3.2%	-1.8%	-1.8%	-0.7%	-0.1%	1.5%	1.2%
	Jul-12									2.3%	1.2%	1.2%	2.3%	2.6%	4.2%	3.5%
	Mar-13										1.1%	0.6%	1.4%	1.6%	3.1%	2.5%
	Jul-13										2.4%	2.2%	3.2%	3.5%	4.7%	3.9%
	Sep-13										1.0%	0.7%	1.1%	1.5%	3.1%	2.5%
	Mar-14											1.6%	2.1%	2.4%	3.8%	3.2%
	Aug-14											-3.2%	1.9%	2.6%	4.2%	3.6%
	Mar-15												1.3%	2.1%	3.8%	3.1%
	Jul-15												0.8%	1.7%	3.4%	2.6%
	Mar-16													-0.1%	1.6%	0.7%
	Aug-16													-0.4%	1.1%	0.1%
	Nov-16														1.0%	0.0%
	Mar-17														1.6%	0.5%
	Jul-17														1.1%	0.5%
	Mar-18															-0.9%
	Jul-18															-0.2%

Table 6-2: Department's Percentage Variance of Demand

Table 4b: Xcel's Demand Forecast Error, October 2008 to Present (percent)

Forecast Vintage	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Oct-08					10.0%	12.2%	6.7%	2.0%	4.8%	5.3%	14.5%	18.6%	14.7%	21.8%	17.3%
Apr-09						9.2%	3.1%	-1.7%	0.3%	0.4%	8.6%	12.1%	8.1%	14.5%	9.9%
Oct-09						0.1%	1.6%	-2.4%	0.3%	0.3%	8.4%	11.7%	7.5%	13.6%	8.9%
Apr-10							0.2%	-3.0%	0.3%	1.5%	11.0%	15.4%	12.0%	19.3%	15.3%
Jul-10							0.6%	-2.8%	0.4%	1.0%	10.1%	14.0%	10.1%	16.9%	12.4%
Apr-11								-5.0%	-2.4%	-2.4%	6.4%	10.5%	7.0%	13.8%	9.6%
Sep-11								1.8%	-2.8%	-3.3%	5.1%	9.0%	5.4%	12.0%	8.0%
Mar-12									-5.4%	-5.4%	2.7%	6.4%	2.9%	9.5%	5.6%
Jul-12									0.0%	-3.2%	4.9%	8.7%	4.9%	11.4%	7.2%
Mar-13										-3.7%	4.0%	7.5%	3.6%	10.0%	5.9%
Jul-13										-2.4%	5.7%	9.4%	5.5%	11.8%	7.3%
Sep-13										-3.7%	4.1%	7.2%	3.5%	10.0%	5.9%
Mar-14											5.0%	8.2%	4.4%	10.7%	6.6%
Aug-14											0.0%	7.9%	4.5%	10.9%	6.7%
Mar-15												7.2%	4.0%	10.5%	6.2%
Jul-15												6.6%	3.6%	10.0%	5.8%
Mar-16													1.5%	8.1%	3.6%
Aug-16													1.3%	7.4%	3.0%
Nov-16														7.4%	2.9%
Mar-17														7.5%	2.8%
Jul-17														6.9%	2.9%
Mar-18															1.3%
Jul-18															2.0%

We provide an updated analysis of the Energy forecasts in 6-3 below. This updated analysis also demonstrates a similar reduction to forecast variance after accounting for the factors discussed above. We have provided the comparable energy summary table from the Department's comments as Table 6-4 for ease of reference.

Table 6-3: Adjusted Percentage Variance of Energy

Forecast Vintage	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Oct-08					-0.4%	3.0%	1.9%	2.0%	2.4%	3.4%	3.2%	4.4%	4.2%	5.9%	5.5%
Apr-09						2.8%	1.7%	1.9%	2.5%	3.9%	4.0%	5.4%	5.5%	7.5%	7.5%
Oct-09						0.5%	-0.7%	0.2%	1.3%	2.9%	3.1%	4.2%	4.2%	6.2%	6.3%
Apr-10							-0.9%	-0.4%	0.8%	2.2%	2.6%	3.8%	3.9%	5.6%	5.4%
Jul-10							-0.7%	-0.2%	0.8%	2.0%	2.4%	3.8%	4.0%	5.6%	5.4%
Apr-11								0.0%	0.7%	1.1%	1.3%	2.8%	3.0%	4.5%	4.0%
Sep-11								-0.4%	-0.2%	0.5%	0.4%	1.6%	1.5%	3.0%	2.5%
Mar-12									-0.4%	-0.7%	-1.3%	-0.3%	-0.3%	1.1%	0.5%
Jul-12									-0.8%	-0.8%	-1.4%	-0.5%	-0.6%	0.6%	0.1%
Mar-13										-0.3%	-1.3%	-0.5%	-0.7%	0.5%	0.0%
Jul-13										-0.3%	-1.3%	-0.5%	-0.7%	0.5%	0.0%
Sep-13										-0.3%	-1.7%	-1.2%	-1.5%	-0.4%	-1.0%
Mar-14											-1.0%	-0.6%	-1.0%	0.1%	-0.6%
Aug-14											-0.3%	1.1%	1.2%	2.8%	2.4%
Mar-15												1.6%	1.9%	3.6%	3.2%
Jul-15												0.7%	1.0%	2.5%	2.2%
Mar-16													0.3%	1.8%	0.7%
Aug-16														0.3%	-0.8%
Nov-16														0.2%	-0.9%
Mar-17														0.5%	-0.7%
Jul-17															-0.8%
Mar-18															-1.5%
Jul-18															

Table 6-4: Department's Percentage Variance of Energy

Table 6b: Xcel's Energy Forecast Error, October 2008 to Present (Percent)

Forecast Vintage	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Oct-2008					0.1%	4.5%	2.3%	3.4%	5.7%	7.7%	8.8%	11.5%	11.3%	14.7%	12.3%
Apr-2009						4.1%	1.0%	2.2%	4.6%	6.7%	8.0%	10.8%	10.7%	14.2%	12.0%
Oct-2009						1.7%	-1.4%	0.5%	3.4%	5.8%	7.1%	9.6%	9.4%	12.9%	10.8%
Apr-2010							-1.7%	-0.2%	2.6%	4.6%	6.0%	8.5%	8.5%	11.7%	9.4%
Jul-2010							-1.5%	-0.7%	1.9%	3.8%	5.3%	7.9%	8.0%	11.1%	8.8%
Apr-2011								-0.7%	1.6%	2.6%	3.9%	6.7%	6.7%	9.8%	7.3%
Sep-2011								-1.1%	0.2%	0.9%	1.9%	4.4%	4.2%	7.1%	4.7%
Mar-2012									-0.8%	-0.8%	-0.3%	1.8%	1.6%	4.5%	2.0%
Jul-2012									-1.2%	-1.7%	-1.3%	0.7%	0.5%	3.2%	0.8%
Mar-2013										-1.5%	-1.4%	0.5%	0.2%	2.8%	0.4%
Jul-2013										-1.5%	-1.4%	0.5%	0.2%	2.8%	0.4%
Sep-2013										-1.5%	-1.8%	-0.2%	-0.6%	1.9%	-0.5%
Mar-2014											-1.3%	0.3%	-0.4%	2.2%	-0.3%
Aug-2014											-0.6%	1.9%	1.8%	4.6%	2.2%
Mar-2015												2.4%	2.5%	5.2%	2.7%
Jul-2015												1.5%	1.5%	4.2%	1.8%
Mar-2016													0.7%	3.2%	0.2%
Aug-2016														1.8%	-1.4%
Nov-2016														1.7%	-1.4%
Mar-2017														1.7%	-1.4%
Jul-2017															-1.5%
Mar-2018															-2.7%
Jul-2018															

Table 6-5 below summarizes the average forecast error for Forecast Year 1, Forecast Year 2, Forecast Year 3, and so on, for both the Company's updated analysis and the Department's analysis. As noted above, there still is a slight tendency for our forecasts to result in positive forecast to actual variances, but the Company updated analysis generally results in variances within the Department's ±5 percent band it used to assess the reasonableness of the uncertainty inherent in future demand requirements.[3]

Table 6-5: Average Forecast Error (percent)

		Average Demand Forecast Error		**Average Energy Forecast Error**	
Forecast Year	**Number of Observations**	**Xcel Energy Update**	**Department's High-Level Analysis**	**Xcel Energy Update**	**Department's High-Level Analysis**
1	23	1.1%	2.1%	0.0%	-0.1%
2	21	1.6%	2.8%	0.1%	0.1%
3	19	1.6%	3.6%	0.4%	1.4%
4	16	2.3%	4.9%	1.0%	2.4%
5	14	3.0%	7.1%	1.4%	3.7%
6	11	3.7%	8.7%	2.2%	4.9%
7	9	4.6%	11.0%	3.2%	7.3%
8	7	5.9%	12.6%	4.5%	9.5%
9	5	7.7%	14.1%	5.7%	11.3%
10	3	8.9%	13.5%	6.6%	12.5%
11	1	12.0%	17.3%	5.5%	12.3%

C. Conclusion

As we have noted, future demand will be different than the forecast for this Resource Plan. There are many factors at play, some of which we have discussed above – and likely others – including faster than expected penetrations of distributed energy resources, or adoption of electric vehicles and other types of beneficial electrification. Reducing the load forecast significantly, as the Department suggests we should in this proceeding, may lead to under forecasting our future resource adequacy requirements – especially in light of potential beneficial electrification growth and an increasing reserve margin.

It is essential to keep the role of load and energy forecasts in context when considering whether they should be adjusted for the purposes of resource planning.

[3] *See* Department Comments at page 13.

The load forecast discussed here is an input into our overall resource adequacy position, which – as the Department discussed at length in its Comments – we plan to fully cover, in alignment with a Fixed Resource Adequacy Planning approach. This means that we plan native resources to cover our full expected customer load, plus the Company's share of MISO's determined reserve margin for Zone 1, which is reevaluated each year. The MISO required reserve margin has been increasing across recent years, including the years in which this Resource Plan has been pending – and is now higher than it has been for any year since at least 2011.[4] For purposes of these Reply Comments, we have not updated our base reserve margin assumption, in order to minimize the amount of new modeling inputs the Commission and parties will need to consider. However, we note that slightly higher load forecasts serve to partially mitigate the impact of an increasing reserve margin on our near-term resource adequacy position.

Finally, potential forecast variances and changes in future load requirements are two important reasons the Company conducts modeling on a wide range of potential future sensitivities – examining both lower and higher than expected loads. We minimize risks to customers by selecting Preferred Plans that are robust across a wide range of potential futures. Scenario 9 – the basis of our Initial and Supplement Plan – showed savings across low load sensitivities that examined low load, as well as sensitivities that examined higher load due to beneficial electrification. We again conducted low and high load sensitivities on the Alternate Plan presented in this reply,[5] and our Alternate Plan continues to show benefits under each sensitivity. Because both our Supplement Plan and Alternate Plan show benefits across these load sensitives, and for the reasons described above, we believe it is appropriate to continue using our own load forecasts – including low and high load sensitivities – to examine our future plans.

In conclusion, it is not necessary for the Company to retain an independent expert to provide a forecast for future regulatory proceedings. Our statistical models are solid, our assumptions are reasonable, and the Company and the Commission have appropriate guardrails in place to ensure that any actions resulting from this or other regulatory proceedings where forecasts are an integral input are appropriately aligned with our customers' interests.

[4] https://cdn.misoenergy.org/PY%202021%2022%20LOLE%20Study%20Report489442.pdf (at page 26)
[5] In addition to the high and low load sensitivities, we also conducted sensitives that consider an updated planning reserve margin as discussed in the Modeling discussion in Section 4.

II. RENEWABLE ENERGY SITING

In this section, the Company addresses comments from The Nature Conservancy (TNC) on mitigating and managing the environmental impacts of renewable resource additions.

A. Comments from The Nature Conservancy

TNC filed comments urging the Company to consider – in view of the substantial wind and solar resource additions proposed in this plan – how impacts to sensitive ecosystems can be avoided, minimized, or offset during renewable siting and development. Overall, TNC strongly supports the Company's IRP – in particular its commitment to carbon reduction, transition from coal generation, and expansion of utility-scale wind and solar – all of which TNC sees as critical to address climate change and help Minnesota achieve its economy-wide emission reduction goals. TNC also recognizes these investments will generate economic benefits across the region, in which TNC operates three chapters with 55,000 members.

While recognizing that the Company often invests in renewable projects after developers have already completed siting and interconnection steps, TNC believes utilities can set standards for renewable procurement that send a clear signal to developers to minimize and mitigate ecosystem impacts. Specifically, TNC requests the Company: 1) publicly share, and include in future RFPs, criteria for procurement of low-impact renewable energy projects, including requiring consultation with wildlife and habitat agencies throughout project development; 2) include wildlife and habitat criteria in transmission planning and solicitations, driving transmission to less sensitive ecosystems, and 3) support research to address scientific uncertainties around wildlife and habitat impacts of utility-scale renewables.

B. Mitigating the Impacts of Renewable Energy Development

Xcel Energy appreciates and shares TNC's concerns regarding the protection of sensitive ecosystems during the siting and development of wind and solar projects. The Company follows a robust screening and due diligence process when reviewing prospective projects for development and/or acquisition. This includes applying the U.S. Fish and Wildlife Service's Land-Based Wind Energy Guidelines (WEGs), as well as periodic and ongoing engagement with federal, state, Tribal, and jurisdictional regulatory and wildlife agencies to identify and mitigate any potential environmental and cultural impacts or risks associated with renewable energy development. Our due diligence and siting process includes, but is not limited to, wind capacity optimization, environmental and natural resource protection, and cultural and archeological mitigation. We follow similar practices as highlighted in TNC's Site Wind Right tools, proposed RFP guidance and due diligence questionnaire. We ensure our contractors are aligned with our processes and follow these guidelines and protocols while developing our renewable energy sites. This allows Xcel Energy to have a fully engaged process which is consistent with industry guidelines, engages stakeholders and is protective of the environment.

Xcel Energy has also partnered with the American Wind Wildlife Institute (AWWI) and the American Clean Power Association to support the development of technology for protection of the environment in development and construction activities. This includes avian and biological impacts, cultural and archaeological issues, federal and state endangered and threatened species, and species of concern. We agree with TNC on the need to broaden the evaluation of environmental impacts from solar development; while the WEGs establish a due diligence framework for wind resource development that can generally be applied to solar, Xcel Energy has identified the need to fully understand the potential unique environmental impacts solar development brings. For this reason, we have approached AWWI to partner in establishing a Solar Working Group and made a significant financial and resource contribution to help establish this working group to understand what impacts large-scale solar may have and assist in avoiding and mitigating these impacts.
With regard to TNC's recommendation on applied research, the Company has provided renewable host sites for projects being funded by AWWI's Wind and Wildlife Research Fund. Promoting the advancement of these technologies and developing new technologies and strategies that are protective of the environment while promulgating renewable development will help in renewable siting and mitigation efforts. In 2020, Xcel Energy partnered with the University of North Dakota's Biology Department on research and development of drone technology to improve the efficacy of post-construction mortality monitoring in determining wind turbine impacts on avian and bat species. We piloted this technology at our Foxtail Wind Farm in North Dakota, and plan to expand this study into our Colorado service territory in 2021.

C. Conclusion

In summary, Xcel Energy appreciates having the opportunity to review the tools TNC has assembled. Our approach to renewable energy development aligns with those TNC has recommended. From the requirements put in place to hold developers accountable, to the due diligence practices and research described previously, Xcel

Energy is meeting or exceeding the standards in TNC's proposed RFP guidance and due diligence questionnaire. With Xcel Energy's goals of 80 percent carbon-free by 2030, and 100 percent carbon-free by 2050, it is imperative that we stay ahead of any environmental challenges or impacts that may delay this generation shift, and do so in a way that provides long-term, sustainable environmental benefit.

MODELING ASSUMPTIONS & INPUTS

I. ENCOMPASS INPUTS AND ASSUMPTIONS

As discussed in Section 4, the Company has made a limited set of updates to our modeling assumptions for the purposes of this Reply. We provide a summary of major changes and new modeling inputs and assumptions, relative to the modeling in our June 2020 Supplement below, followed by further details regarding assumptions used in this round of modeling.

Topic	Assumption	Change from Supplement Filing	Rationale for Change
Generic wind and solar cost assumptions	▪ Extended federal Production Tax Credits (PTC) and Investment Tax Credits (ITC) to their current dates	▪ Previous Production Tax Credit and Investment Tax Credit schedule	▪ The federal Consolidated Appropriations Act of 2021 extended the qualification period for tax credits
Generic wind, solar and battery size	▪ 50 MW generic sizes for all wind, solar and battery resources	▪ Wind: 750MW ▪ Solar: 500MW ▪ Battery: 321 MW	▪ Better accounts for the modularity of these resources
Wind and solar resource production	▪ Include costs for curtailed generation of renewable resources	▪ Did not assign costs to curtailed generation of renewable resources	▪ Better reflects the costs of curtailment
Black Start Resources	▪ Add specific resources to represent near term black start resource needs in Alternate Plan	▪ Included placeholder capacity and associated life extension costs for black start resources	▪ Replace the placeholders with specific black start unit assumptions in Alternate Plan

Topic	Assumption	Change from Supplement Filing	Rationale for Change
Sherco and King gen-ties	▪ In Alternate Plan, include revenue requirements of 345 kV transmission lines to reutilize generation interconnection opening at Sherco and King when they retire	▪ None	▪ To incorporate costs for gen-ties that enable primarily renewables to reutilize interconnection rights at Sherco and King
Approved new and repowered resources	▪ Mower, Deuel Harvest, Elk Creek, St Cloud Hydro, Heartland Divide, Border, Nobles, GrandMeadow, Pleasant Valley, Ewington.	▪ Resources were not included in June 2020 Supplement because they were not yet approved as of our assumptions lock-in date	▪ Reflects expected lives and costs of recently approved resources
Resource adequacy sensitivity	▪ Increased effective reserve margin to 7.21 percent, based on a 9.4 percent planning reserve margin and 98 percent coincidence factor in one sensitivity	▪ No sensitivity conducted	▪ Reflects increasing reserve margin needs per recent MISO guidance

A. Discount Rate and Capital Structure

The discount rate used for levelized cost calculations and the present value of modeled costs is 6.47 percent. The rates shown below were calculated by taking a weighted average of each NSP jurisdiction's last allowed/settled electric retail rate case.

Table 1: Discount Rate and Capital Structure

Discount Rate and Capital Structure				
	Capital Structure	Allowed Return	Before Tax Electric WACC	After Tax Electric WACC
Long-Term Debt	45.72%	4.79%	2.19%	1.58%
Common Equity	52.39%	9.25%	4.85%	4.85%
Short-Term Debt	1.89%	3.55%	0.07%	0.05%
Total			**7.10%**	**6.47%**

B. Inflation Rates

The inflation rates are used for existing resources, generic resources, and other costs related to general inflationary trends in the modeling and are developed using long-term forecasts from Global Insight. The general inflation rate of 2% is from their long-term forecast for "Chained Price Index for Total Personal Consumption Expenditures" published in the second quarter of 2018.

C. Reserve Margin

The reserve margin at the time of MISO's peak is 8.9 percent from the 2020-2021 Loss Of Load Expectation Study Report, published November 2019. The coincidence factor between the NSP System and MISO system peak is 95 percent. Therefore, the effective reserve margin is:

$$(95\,percent\ coincidence\ factor)x\ (1 + 8.9\,percent) - 1 \\ = \mathbf{3.46}\,percent\ effective\ reserve\ margin\ for\ NSP$$

We also examined a sensitivity scenario using increased effective reserve margin to reflect recent MISO guidance:

$$(98\,percent\ coincidence\ factor)x\ (1 + 9.4\,percent) - 1 \\ = \mathbf{7.21}\,percent\ effective\ reserve\ margin\ for\ NSP$$

D. CO_2 Costs

The PVSC Base Case CO2 values are based on the high environmental cost values for CO2 through 2024 (page 31 of the Minnesota Public Utilities Commission's Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.). All prices are converted to 2018 real dollars using the 2017 Gross Domestic Product Implicit Price Deflator (GDPIPD) of 113.416 and then escalate at general inflation thereafter.

The PVSC Base Case values starting in 2025 are based on the "high" end of the range of regulated costs (see page 12 of MPUC Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs in Dockets No.E999/CI-07-1199 and E-999/DI-17-53 issued June 11, 2018). All prices escalate at general inflation.

The Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs requires four alternative scenarios to be run in addition to the PVSC Base Case. The Order Extending Deadline for Filing Next Resource Plan issued January 30, 2019 also requires a scenario using the midpoint of the Commission's most recently approved externalities and regulatory costs of carbon. The values in the PVSC Base Case and alternative scenarios are set out below.

Table 2: CO2 Costs

CO2 Costs ($ per short ton)						
Year	Low Environmental Cost	High Environmental Cost	Low Environmental/ Regulatory Costs	Mid Environmental/ Regulatory Costs	PVSC - High Environmental/ Regulatory Costs	PVRR - Omitting CO2 Cost Considerations
2018	$9.09	$42.76	$9.09	$25.92	$42.76	$0.00
2019	$9.49	$44.58	$9.49	$27.04	$44.58	$0.00
2020	$9.90	$46.45	$9.90	$28.18	$46.45	$0.00
2021	$10.32	$48.39	$10.32	$29.35	$48.39	$0.00
2022	$10.77	$50.38	$10.77	$30.57	$50.38	$0.00
2023	$11.22	$52.43	$11.22	$31.82	$52.43	$0.00
2024	$11.69	$54.55	$11.69	$33.12	$54.55	$0.00
2025	$12.16	$56.72	$5.00	$15.00	$25.00	$0.00
2026	$12.67	$58.97	$5.10	$15.30	$25.50	$0.00
2027	$13.17	$61.29	$5.20	$15.61	$26.01	$0.00
2028	$13.70	$63.67	$5.31	$15.92	$26.53	$0.00
2029	$14.24	$66.12	$5.41	$16.24	$27.06	$0.00
2030	$14.80	$68.64	$5.52	$16.56	$27.60	$0.00
2031	$15.37	$71.24	$5.63	$16.89	$28.15	$0.00
2032	$15.97	$73.91	$5.74	$17.23	$28.72	$0.00
2033	$16.57	$76.67	$5.86	$17.57	$29.29	$0.00
2034	$17.21	$79.50	$5.98	$17.93	$29.88	$0.00
2035	$17.85	$82.41	$6.09	$18.28	$30.47	$0.00
2036	$18.52	$85.41	$6.22	$18.65	$31.08	$0.00
2037	$19.20	$88.50	$6.34	$19.02	$31.71	$0.00
2038	$19.91	$91.68	$6.47	$19.40	$32.34	$0.00
2039	$20.62	$94.96	$6.60	$19.79	$32.99	$0.00
2040	$21.38	$98.32	$6.73	$20.19	$33.65	$0.00
2041	$22.14	$101.78	$6.86	$20.59	$34.32	$0.00
2042	$22.94	$105.34	$7.00	$21.00	$35.01	$0.00
2043	$23.74	$109.00	$7.14	$21.42	$35.71	$0.00
2044	$24.58	$112.76	$7.28	$21.85	$36.42	$0.00
2045	$25.43	$116.63	$7.43	$22.29	$37.15	$0.00
2046	$26.33	$120.61	$7.58	$22.73	$37.89	$0.00
2047	$27.23	$124.71	$7.73	$23.19	$38.65	$0.00
2048	$28.17	$128.92	$7.88	$23.65	$39.42	$0.00
2049	$29.12	$133.24	$8.04	$24.13	$40.21	$0.00
2050	$30.12	$137.69	$8.20	$24.61	$41.02	$0.00
2051	$31.14	$142.26	$8.37	$25.10	$41.84	$0.00
2052	$32.18	$146.97	$8.53	$25.60	$42.67	$0.00
2053	$33.26	$151.80	$8.71	$26.12	$43.53	$0.00
2054	$34.36	$156.76	$8.88	$26.64	$44.40	$0.00
2055	$35.50	$161.87	$9.06	$27.17	$45.28	$0.00
2056	$36.66	$167.11	$9.24	$27.71	$46.19	$0.00
2057	$37.86	$172.51	$9.42	$28.27	$47.11	$0.00

E. All Other Externality Costs

The values of the criteria pollutants are derived from the high and low values for each of the 3 locations, as determined in the Minnesota Commission Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018. The midpoint externality costs are the average of the low and high values. All prices are escalated to 2018 real dollars using the 2017 (GDPIPD) of 113.416. The high, low and midpoint externality costs will be used in the CO2 sensitivities as described above.

Table 3: Externality Costs

MPUC Low Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$6,116	$4,829	$3,643	$0
NOx	$2,934	$2,622	$2,110	$28
PM2.5	$10,697	$6,856	$3,654	$872
CO	$1.65	$1.17	$0.31	$0.31
Pb	$4,857	$2,562	$624	$624

MPUC High Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$15,288	$12,030	$8,878	$0
NOx	$8,390	$7,798	$6,771	$158
PM2.5	$26,721	$17,091	$8,973	$1,327
CO	$3.51	$2.08	$0.63	$0.63
Pb	$6,011	$3,094	$695	$695

MPUC Midpoint Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$10,702	$8,430	$6,261	$0
NOx	$5,662	$5,210	$4,441	$93
PM2.5	$18,709	$11,974	$6,313	$1,099
CO	$2.58	$1.63	$0.47	$0.47
Pb	$5,434	$2,828	$659	$659

F. Demand and Energy Forecast

The Company's fall 2019 load forecast is used as the base assumption and assumes that EV impacts growth continues throughout the forecast period. The energy efficiency (EE) forecast included in the base forecast developed by the Company's Load Forecasting Department assumes somewhat less energy efficiency (EE) savings levels than those included in our initial Resource Plan's Preferred Plan.

The "Load Forecast with EE" shown in Table 4 below is the starting point for the load inputs. In all modeling scenarios, the "EE" is removed - the removal of these EE program effects, which have a 14-year life, impacts the load forecast through 2048. In the initial filing, the three EE Bundles (discussed below) were optimized as Proview Alternatives. For this supplemental filing, the first two EE Bundles are locked in all scenarios. The resulting forecast, before the optimized EE bundles are added, is shown below in Table 4 as

"Forecast Without EE." The forecasts shown do not include the impact of DG solar, as DG solar is modeled as a resource, not a load modifier.

Table 4: Demand and Energy Forecast

Demand and Energy Forecast				
	Demand (MW)		Energy (GWh)	
Year	Forecast with EE	Forecast without EE	Forecast with EE	Forecast without EE
2018	9,152	9,152	43,914	43,914
2019	9,084	9,084	43,558	43,558
2020	9,099	9,230	43,170	43,806
2021	9,079	9,312	42,741	44,018
2022	9,126	9,462	42,628	44,549
2023	9,165	9,604	42,440	45,004
2024	9,184	9,728	42,339	45,555
2025	9,238	9,849	42,324	45,976
2026	9,311	9,992	42,470	46,565
2027	9,414	10,164	42,757	47,296
2028	9,504	10,327	43,221	48,216
2029	9,525	10,416	43,006	48,432
2030	9,605	10,566	43,224	49,093
2031	9,679	10,710	43,420	49,734
2032	9,775	10,880	43,903	50,678
2033	9,979	11,058	44,532	51,299
2034	10,190	11,246	45,426	52,203
2035	10,343	11,269	46,158	52,299
2036	10,502	11,325	47,028	52,527
2037	10,673	11,393	47,647	52,503
2038	10,803	11,420	48,209	52,422
2039	10,936	11,449	48,833	52,394
2040	11,073	11,518	49,603	52,729
2041	11,209	11,585	50,055	52,737
2042	11,338	11,645	50,635	52,873
2043	11,467	11,701	51,267	53,048
2044	11,614	11,780	52,023	53,374
2045	11,722	11,818	52,468	53,375
2046	11,839	11,865	53,010	53,473
2047	11,951	11,903	53,545	53,547
2048	12,021	11,998	54,150	54,160
2049	12,045	12,045	54,202	54,202
2050	12,097	12,097	54,407	54,407
2051	12,149	12,149	54,611	54,611
2052	12,199	12,199	54,947	54,947
2053	12,252	12,252	55,022	55,022
2054	12,305	12,305	55,226	55,226
2055	12,357	12,357	55,431	55,431
2056	12,409	12,409	55,765	55,765
2057	12,461	12,461	55,840	55,840

The low load sensitivity includes high customer-adoption-based DG/DER growth and higher EE savings, which reduces load. The high load sensitivity includes high electrification load. These assumptions are shown in Table 5 and Table 6 and are incremental/decremental to the forecast shown in Table 4.

Table 5: High Load Sensitivity

High Electrification		
Year	Energy (GWh)	Demand (MW)
2018	35	8
2019	46	6
2020	59	7
2021	166	20
2022	276	33
2023	390	47
2024	507	62
2025	592	65
2026	692	77
2027	812	85
2028	939	98
2029	1,202	118
2030	1,578	162
2031	2,028	205
2032	2,538	251
2033	3,137	305
2034	3,857	367
2035	4,716	438
2036	5,657	515
2037	6,672	596
2038	7,741	679
2039	8,851	766
2040	9,996	854
2041	11,114	940
2042	12,199	1,025
2043	13,241	1,118
2044	14,229	1,796
2045	15,159	2,520
2046	16,037	3,173
2047	16,877	3,796
2048	17,696	4,647
2049	18,660	4,908
2050	19,530	5,407
2051	20,634	5,947
2052	21,645	6,418
2053	22,656	6,896
2054	23,666	7,384
2055	24,677	7,877
2056	25,688	8,352
2057	26,699	8,840

**Demand values are coincident to system peak*

Table 6: Low Load Sensitivity

High DER Growth		
Year	Energy (GWh)	Demand (Nameplate MW)
2018	0	0
2019	0	0
2020	0	0
2021	207	122
2022	180	106
2023	159	94
2024	270	159
2025	258	152
2026	423	250
2027	423	250
2028	635	374
2029	641	379
2030	740	437
2031	826	487
2032	913	538
2033	996	588
2034	1,082	639
2035	1,167	689
2036	1,256	739
2037	1,338	790
2038	1,423	840
2039	1,509	891
2040	1,598	941
2041	1,631	963
2042	1,580	933
2043	1,529	903
2044	1,482	872
2045	1,425	842
2046	1,350	797
2047	1,296	765
2048	1,245	733
2049	1,187	701
2050	1,131	668
2051	1,063	628
2052	1,009	594
2053	932	550
2054	872	515
2055	807	476
2056	742	437
2057	671	396

G. Energy Efficiency Bundles

The EE "Program" and "Maximum" Bundles are based on the Minnesota Department of Commerce's Minnesota Energy Efficiency Potential Study: 2020-2029 published December 4, 2018. The "Optimal" Bundle was developed by the Company. The bundles are decremental (reducing energy and demand) to the "Forecast without EE" shown in Table 4.

Table 7: Energy Efficiency Bundles

	Energy(MWh)			Demand (MW)			Costs ($000)		
Year	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max
2018	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0
2020	621	43	231	97	18	36	100,989	12,598	148,331
2021	1,326	91	493	207	38	77	113,525	13,905	167,221
2022	1,913	148	702	301	60	113	121,239	21,425	177,197
2023	2,555	211	928	407	86	154	133,614	23,931	196,474
2024	3,094	279	1,110	520	116	197	148,406	26,120	217,388
2025	3,629	346	1,289	635	146	241	152,433	26,077	223,293
2026	4,330	414	1,533	759	176	289	160,445	26,236	233,779
2027	5,054	482	1,785	886	206	338	167,718	26,637	242,963
2028	5,785	551	2,040	1,012	235	387	174,161	27,018	249,373
2029	6,454	606	2,280	1,127	259	432	162,170	23,442	233,114
2030	7,110	659	2,516	1,241	283	477	162,170	23,442	233,114
2031	7,753	710	2,748	1,354	307	522	162,170	23,442	233,114
2032	8,339	760	2,960	1,460	329	564	162,170	23,442	233,114
2033	8,909	808	3,168	1,564	352	605	162,170	23,442	233,114
2034	9,464	857	3,370	1,667	374	646	162,170	23,442	233,114
2035	9,250	846	3,294	1,648	370	638	0	0	0
2036	8,739	835	3,073	1,579	366	600	0	0	0
2037	8,088	789	2,829	1,470	347	557	0	0	0
2038	7,450	741	2,590	1,369	327	517	0	0	0
2039	6,841	685	2,372	1,267	304	475	0	0	0
2040	6,197	626	2,144	1,154	278	430	0	0	0
2041	5,543	562	1,919	1,036	250	384	0	0	0
2042	4,871	499	1,685	916	221	337	0	0	0
2043	4,220	434	1,457	796	191	291	0	0	0
2044	3,561	377	1,218	678	165	245	0	0	0
2045	2,912	318	990	562	139	201	0	0	0
2046	2,276	265	761	451	116	156	0	0	0
2047	1,746	212	573	349	93	117	0	0	0
2048	1,216	159	384	248	70	79	0	0	0
2049	686	106	195	146	46	40	0	0	0
2050	156	53	7	45	23	1	0	0	0
2051	0	0	0	0	0	0	0	0	0
2052	0	0	0	0	0	0	0	0	0
2053	0	0	0	0	0	0	0	0	0
2054	0	0	0	0	0	0	0	0	0
2055	0	0	0	0	0	0	0	0	0
2056	0	0	0	0	0	0	0	0	0
2057	0	0	0	0	0	0	0	0	0

***Demand values are coincident to system peak*

H. Demand Response Forecast

The base demand response forecast was developed by the Company and is included in all scenarios and sensitivities. The three demand response "Bundles" are from the Brattle Potential Study provided as Appendix G2 of the initial filing to this docket. The Bundles are incremental to the base demand response forecast. In the initial filing, the three DR Bundles were optimized as Proview Alternatives. Similar to this supplemental filing, the first DR Bundle is locked in all scenarios.

Table 8: Demand Response Forecast

Demand (MW) Adjusted For Reserve Margin					Costs ($000)		
Year	Base Demand Response Forecast	Bundle 1	Bundle 2	Bundle 3	Bundle 1	Bundle 2	Bundle 3
2018	852	0	0	0	0	0	0
2019	928	0	0	0	0	0	0
2020	1012	33	107	90	1,752	7,659	11,311
2021	1027	165	112	98	8,917	8,150	12,587
2022	1041	232	117	107	12,748	8,676	14,016
2023	1055	294	121	110	16,489	9,137	14,758
2024	1066	341	133	101	19,512	10,277	13,829
2025	1072	382	145	92	22,305	11,459	12,858
2026	1077	394	152	93	23,475	12,207	13,326
2027	1078	407	159	95	24,786	13,080	13,845
2028	1077	423	168	97	26,245	14,086	14,418
2029	1071	440	178	99	27,859	15,231	15,047
2030	1059	458	190	102	29,637	16,522	15,734
2031	1048	478	202	104	31,551	17,926	16,467
2032	1037	499	215	107	33,612	19,451	17,251
2033	1026	521	228	110	35,832	21,109	18,088
2034	1016	545	243	113	38,224	22,911	18,984
2035	1005	570	259	116	40,802	24,870	19,943
2036	995	596	275	120	43,582	26,999	20,971
2037	985	624	293	123	46,580	29,313	22,072
2038	976	654	312	127	49,814	31,829	23,253
2039	966	686	332	132	53,305	34,564	24,522
2040	957	720	353	136	57,073	37,537	25,884
2041	948	720	353	136	58,215	38,288	26,402
2042	939	720	353	136	59,379	39,054	26,930
2043	930	720	353	136	60,566	39,835	27,468
2044	922	720	353	136	61,778	40,632	28,018
2045	914	720	353	136	63,013	41,444	28,578
2046	906	720	353	136	64,274	42,273	29,150
2047	898	720	353	136	65,559	43,118	29,733
2048	890	720	353	136	66,870	43,981	30,327
2049	882	720	353	136	68,208	44,860	30,934
2050	875	720	353	136	69,572	45,758	31,552
2051	868	720	353	136	70,963	46,673	32,183
2052	860	720	353	136	72,382	47,606	32,827
2053	853	720	353	136	73,830	48,558	33,484
2054	847	720	353	136	75,307	49,530	34,153
2055	840	720	353	136	76,813	50,520	34,836
2056	833	720	353	136	78,349	51,531	35,533
2057	827	720	353	136	79,916	52,561	36,244

**Demand values are coincident to system peak.*

I. Fuel Price Forecasts

The natural gas prices are developed using a blend of market information (New York Mercantile Exchange futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, Cambridge Energy Research Associates (CERA) and Petroleum Industry Research Associates (PIRA).

Coal price forecasts are developed using two major inputs: the current contract volumes and prices combined with current estimates of required spot volumes and prices to cover non-contracted coal needs. Typically coal volumes and prices are under contract on a plant by plant basis for a one to five-year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed from price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent Request for Proposal (RFP) responses for coal supply. Added to the spot coal forecast, which is just for the coal commodity, are: transportation charges, SO_2 costs, freeze control and dust suppressant, as required.

In addition to resources that exist within the NSP System, the Company is a participant in the MISO Market. Electric power market prices are developed from fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA using a similar methodology as is used for the gas price forecast. Table 9 below shows the market prices under zero CO_2 cost assumptions. The market purchases and sales limit for transaction volume between the Company and MISO is 1,350 MWh/h in 2018, 1,800 MWh/h from 2019-2022, and 2,300 MWh/h for 2023 and beyond.

High and low price sensitivities were performed by adjusting the growth rate up and down by 50 percent from the base forecast starting when the long-term fundamentally-based forecasts are blended with the market information (New York Mercantile Exchange futures prices).

Table 9: Fuel and Market Price Forecasts

	Base Price Forecast				Low Price Forecast				High Price Forecast			
	Fuel Price ($/mmBTu)		Market Price ($/MWh)		Fuel Price ($/mmBTu)		Market Price ($/MWh)		Fuel Price ($/mmBTu)		Market Price ($/MWh)	
Year	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak
2018	$2.19	$2.74	$28.60	$21.61	$2.19	$2.74	$28.60	$21.61	$2.19	$2.74	$28.60	$21.61
2019	$2.08	$2.60	$26.93	$20.98	$2.08	$2.60	$26.93	$20.98	$2.08	$2.60	$26.93	$20.98
2020	$2.11	$2.26	$25.78	$20.13	$2.11	$2.26	$25.78	$20.13	$2.11	$2.26	$25.78	$20.13
2021	$2.14	$2.23	$25.32	$19.06	$2.14	$2.23	$25.32	$19.06	$2.14	$2.23	$25.32	$19.06
2022	$2.19	$2.33	$26.92	$20.45	$2.17	$2.28	$26.33	$20.00	$2.24	$2.38	$27.52	$20.90
2023	$2.25	$2.45	$29.31	$22.19	$2.19	$2.34	$27.96	$21.17	$2.36	$2.57	$30.68	$23.23
2024	$2.30	$2.58	$30.00	$23.20	$2.22	$2.40	$27.94	$21.60	$2.46	$2.76	$32.16	$24.87
2025	$2.35	$2.79	$31.47	$24.36	$2.24	$2.50	$28.17	$21.80	$2.57	$3.11	$35.04	$27.12
2026	$2.40	$2.98	$32.30	$24.99	$2.27	$2.58	$28.01	$21.67	$2.69	$3.42	$37.09	$28.70
2027	$2.45	$3.12	$33.35	$26.71	$2.29	$2.64	$28.28	$22.64	$2.81	$3.66	$39.16	$31.36
2028	$2.51	$3.26	$34.09	$26.97	$2.32	$2.71	$28.25	$22.35	$2.93	$3.92	$40.92	$32.38
2029	$2.57	$3.44	$35.21	$28.25	$2.34	$2.78	$28.42	$22.79	$3.07	$4.24	$43.38	$34.80
2030	$2.62	$3.70	$38.27	$30.69	$2.37	$2.88	$29.83	$23.92	$3.20	$4.71	$48.76	$39.09
2031	$2.68	$3.87	$39.33	$32.07	$2.40	$2.95	$29.97	$24.44	$3.35	$5.04	$51.22	$41.77
2032	$2.75	$4.02	$39.75	$33.14	$2.43	$3.01	$29.71	$24.77	$3.51	$5.34	$52.76	$43.99
2033	$2.81	$4.10	$39.93	$33.46	$2.45	$3.03	$29.58	$24.79	$3.67	$5.48	$53.47	$44.80
2034	$2.87	$4.20	$41.13	$34.56	$2.48	$3.07	$30.08	$25.28	$3.83	$5.70	$55.76	$46.86
2035	$2.94	$4.35	$42.15	$35.66	$2.51	$3.13	$30.32	$25.65	$4.00	$6.00	$58.12	$49.17
2036	$2.99	$4.47	$42.79	$36.60	$2.53	$3.17	$30.37	$25.97	$4.14	$6.24	$59.80	$51.13
2037	$3.07	$4.65	$44.00	$38.21	$2.56	$3.24	$30.61	$26.58	$4.36	$6.63	$62.69	$54.44
2038	$3.14	$4.86	$44.95	$39.45	$2.60	$3.31	$30.60	$26.85	$4.58	$7.08	$65.43	$57.42
2039	$3.23	$5.04	$45.82	$40.48	$2.63	$3.37	$30.63	$27.06	$4.83	$7.47	$67.88	$59.98
2040	$3.31	$5.22	$46.61	$41.48	$2.66	$3.43	$30.61	$27.25	$5.06	$7.87	$70.25	$62.53
2041	$3.37	$5.32	$46.52	$41.48	$2.69	$3.46	$30.27	$26.99	$5.26	$8.10	$70.79	$63.12
2042	$3.45	$5.47	$47.61	$42.64	$2.72	$3.51	$30.57	$27.38	$5.51	$8.43	$73.40	$65.74
2043	$3.53	$5.62	$48.37	$43.71	$2.75	$3.56	$30.64	$27.69	$5.77	$8.78	$75.56	$68.28
2044	$3.62	$5.78	$49.72	$44.99	$2.79	$3.61	$31.04	$28.09	$6.05	$9.17	$78.79	$71.29
2045	$3.70	$5.99	$51.23	$46.37	$2.82	$3.68	$31.45	$28.46	$6.31	$9.65	$82.57	$74.73
2046	$3.78	$6.17	$52.49	$47.53	$2.85	$3.73	$31.74	$28.74	$6.59	$10.09	$85.85	$77.73
2047	$3.86	$6.29	$53.27	$48.57	$2.88	$3.77	$31.89	$29.08	$6.88	$10.40	$87.98	$80.22
2048	$3.95	$6.46	$54.39	$49.88	$2.91	$3.82	$32.15	$29.49	$7.20	$10.80	$90.96	$83.42
2049	$4.04	$6.66	$55.69	$50.92	$2.95	$3.88	$32.43	$29.65	$7.53	$11.30	$94.52	$86.43
2050	$4.13	$6.77	$56.64	$51.71	$2.98	$3.91	$32.70	$29.85	$7.87	$11.60	$96.97	$88.53
2051	$4.22	$6.96	$58.23	$53.16	$3.01	$3.96	$33.16	$30.27	$8.21	$12.08	$101.05	$92.24
2052	$4.31	$7.13	$59.62	$54.42	$3.04	$4.01	$33.56	$30.63	$8.57	$12.51	$104.64	$95.53
2053	$4.41	$7.29	$61.00	$55.68	$3.08	$4.06	$33.94	$30.99	$8.94	$12.95	$108.29	$98.85
2054	$4.50	$7.46	$62.38	$56.95	$3.11	$4.10	$34.33	$31.34	$9.33	$13.39	$111.97	$102.21
2055	$4.60	$7.62	$63.76	$58.21	$3.14	$4.15	$34.71	$31.69	$9.73	$13.83	$115.69	$105.61
2056	$4.69	$7.79	$65.15	$59.47	$3.17	$4.19	$35.09	$32.03	$10.12	$14.28	$119.45	$109.05
2057	$4.79	$7.95	$66.53	$60.73	$3.21	$4.24	$35.46	$32.37	$10.52	$14.74	$123.26	$112.52

**Coal prices are delivered prices, while gas and market prices are hub prices.*

J. Baseload Retirement "Leave Behind" Costs

Based on the MISO Y2 retirement studies performed on existing coal and nuclear resources, the Company developed transmission reinforcement or "leave behind" estimates, which reflect costs required to mitigate localized grid impacts of the retirement of major baseload resources. The reinforcement costs are included as a one-time charge based on the timing of the resource retirement.

Specifically, we have included the following proxy leave behind costs related to our baseload resource retirements as estimated from the MISO studies. We applied these costs in the modeling as soon as the resource is retired, over a three-year period, to reflect the estimated local transmission reinforcement costs assumed to be required upon retirement. All numbers below are in real dollar terms ($2020).

- King: $48 million
- Sherco 3: $48 million
- Monticello: $96 million
- Prairie Island 1: $96 million
- Prairie Island 2: $96 million

K. Surplus Capacity Credit

The surplus capacity credit of up to 500 MW is applied for all twelve months of each year and is priced at the avoided capacity cost of a generic brownfield H-Class combustion turbine on an economic carrying charge basis.

Table 10: Surplus Capacity Credit

Surplus Capacity Credit																				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
$/kw-mo	4.57	4.66	4.75	4.85	4.95	5.05	5.15	5.25	5.35	5.46	5.57	5.68	5.80	5.91	6.03	6.15	6.27	6.40	6.53	6.66
	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057
$/kw-mo	6.79	6.93	7.07	7.21	7.35	7.50	7.65	7.80	7.96	8.12	8.28	8.44	8.61	8.79	8.96	9.14	9.32	9.51	9.70	9.89

L. Effective Load Carrying Capability (ELCC) Capacity Credit for Wind, Solar, and Battery Resources

The ELCC for existing wind units is based on current MISO accreditation. The ELCC for generic wind is equal to 16.7 percent of their nameplate rating per MISO 2020/2021 Wind Capacity Report. The ELCC for generic solar is based on the values provided in MISO's

Transmission Energy Planning Report 2019, (MTEP) in Appendix E,[1] and is 50 percent of the AC nameplate capacity through 2023, declining 2 percent annually to 30 percent by 2033 where it remains for the remainder of the forecast period. The ELCC assigned for a generic 4-hour battery is equal to 100 percent of the alternating current (AC) equivalent capacity. The ELCC used for hybrid options are the same as the individual components.

M. Spinning Reserve Requirement

Spinning reserve is the online reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. The level of spinning reserve modeled is 137 MW and is based on a 12-month rolling average of spinning reserves carried by the NSP System within MISO.

N. Emergency Energy

Emergency energy is used to cover events where there are not enough native resources or market purchase energy.available to meet system energy requirements. In Encompass, we use the default value of $10,000/MWh. Emergency energy is a "soft constraint" in EnCompass modeling that allows emergency energy to "dispatch" as a last resort resource, in order for the model to find a feasible solution. The EnCompass price is set to a high level to ensure that all other available resources – including those that may have a very high effective $/MWh cost resulting from startup costs spread over a very small required run time – are utilized before emergency energy.

O. Transmission Delivery Costs and Interconnection Costs

Transmission delivery costs for generic resources were developed by the Company. They are based on evaluation of recent and historical MISO studies and queue results. These costs represent "grid upgrades" to ensure deliverability of energy from these facilities to the overall bulk electric system.

We note additionally that interconnection costs for generic resources are included in the costs provided in Part U of this Appendix and represent "behind the fence" costs associated with substation and representative gen-tie construction.

[1] Available at: https://cdn.misoenergy.org//MTEP19%20Appendix%20E-Futures%20Assumptions382958.pdf

Table 11: Transmission Delivery Costs

Transmission Delivery Costs				
	CC	CT	Wind	Solar
$/kw	500	200	500	200

In the Alternate Plan, we propose to build transmission tie-lines from Sherco and King sites that can interconnect incremental wind and resource resources. The total costs of the tie lines include capital costs plus VAR support such as installing synchronous condensers and series compensation of the lines; and while these are general cost estimates and subject to change as we would undertake detailed project design, they are in line with the Company's experience on other projects. The total capacities of generator reuse are based on the existing interconnection rights at Sherco and King.

Table 12: Sherco and King Gen-tie Assumptions

	Total Costs (in 2021 Dollars)	Interconnection Rights
Sherco gen-tie	$528 million	1996 MW
King gen-tie	$ 36 million	591 MW

Table 13: Retiring Coal Units and Selection Windows for Gen-tie Resources

Retiring Unit	Open Interconnection	Modeled Replacement Resource Window	Replacement Resources Allowed
Sherco 2	720 MW	2024-2026	Solar only
Sherco 1	710 MW	2027-2029	Solar, and Wind + ~400 MW of CTs (2028-2029)
Sherco 3	566 MW	2030-2032	Solar + Wind
AS King	591 MW	2028-2030	Solar only

P. Integration and Congestion Costs

Integration costs are taken from studies conducted by Enernex and apply to new wind and solar resources only. Congestion costs were not included in the model.

Table 14: Integration Costs

Integration Costs ($/MWh)		
Year	Wind	Solar
2018	0.00	0.00
2019	0.00	0.00
2020	0.41	0.41
2021	0.42	0.42
2022	0.43	0.43
2023	0.44	0.44
2024	0.45	0.45
2025	0.46	0.46
2026	0.47	0.47
2027	0.48	0.48
2028	0.49	0.49
2029	0.49	0.49
2030	0.50	0.50
2031	0.51	0.51
2032	0.53	0.53
2033	0.54	0.54
2034	0.55	0.55
2035	0.56	0.56
2036	0.57	0.57
2037	0.58	0.58
2038	0.59	0.59
2039	0.60	0.60
2040	0.62	0.62
2041	0.63	0.63
2042	0.64	0.64
2043	0.65	0.65
2044	0.67	0.67
2045	0.68	0.68
2046	0.69	0.69
2047	0.71	0.71
2048	0.72	0.72
2049	0.74	0.74
2050	0.75	0.75
2051	0.77	0.77
2052	0.78	0.78
2053	0.80	0.80
2054	0.81	0.81
2055	0.83	0.83
2056	0.84	0.84
2057	0.86	0.86

Q. Distributed Generation and Community Solar Gardens

The distributed solar and Community Solar Gardens inputs are based on the most recent Company forecasts. Distributed Solar is modeled assuming a degradation of half a percent annually in generation. Community Solar Gardens are modeled assuming a degradation of half a percent annually in generation, and a twenty-five-year service life. After a "vintage" of additions reach end of life, it is assumed 90% of the capacity is replaced at then-current costs.

Table 15: Distributed Solar Forecast

Distributed Solar (Nameplate MW)			
Year	Solar Rewards	Community Gardens	Total
2018	29	246	274
2019	61	504	565
2020	80	658	738
2021	95	714	809
2022	109	787	897
2023	123	841	964
2024	138	852	989
2025	152	853	1,005
2026	166	854	1,020
2027	180	855	1,035
2028	194	857	1,050
2029	208	858	1,066
2030	222	859	1,080
2031	236	860	1,095
2032	249	861	1,110
2033	263	862	1,125
2034	276	863	1,140
2035	290	864	1,154
2036	303	866	1,169
2037	317	867	1,184
2038	330	868	1,198
2039	343	869	1,212
2040	357	870	1,227
2041	370	871	1,241
2042	383	869	1,252
2043	396	852	1,247
2044	409	830	1,239
2045	421	818	1,239
2046	434	814	1,248
2047	447	808	1,255
2048	460	805	1,264
2049	472	805	1,277
2050	491	806	1,297
2051	504	807	1,311
2052	518	808	1,326
2053	531	809	1,340
2054	545	810	1,355
2055	559	811	1,369
2056	572	812	1,384
2057	586	812	1,398

R. Owned Unit Modeled Operating Characteristics and Costs

Company owned units are modeled based upon their tested operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each company owned resource.

a. Retirement Date
b. Maximum Capacity
c. Current Unforced Capacity (UCAP) Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and particulate matter (PM)
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

S. Thermal Power Purchase Agreement (PPA) Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Below is a list of typical operating and cost inputs for each thermal PPA.

a. Contract term
b. Maximum Capacity
c. Minimum Capacity Rating
d. Seasonal Deration
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and Particulate Matter
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

T. Renewable Energy (PPAs and Owned) Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Company owned units are modeled based upon their tested operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each renewable energy unit.

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Wind and solar hourly patterns are developed through a "Typical Meteorological Year" process where individual months are selected from the years 2017-2019 to develop a representative typical year. Actual generation data from the selected months is used to develop the profile for each unit. For units where generation data is not complete or not available, data from a nearby similar unit is used.

U. Generic Assumptions

Generic resources are modeled based upon their expected operating characteristics and projected costs. Generic thermal costs are developed by the Company. For the modeling of our Alternate Plan, we also added cost and operational assumptions for smaller reciprocating engines and aeroderivative turbines that support black start. Generic renewable and battery costs are from National Renewable Energy Laboratory's 2019 *Annual Technology Baseline* data. Utility-scale wind and solar costs shown below include transmission costs from Table 11, while distributed solar costs do not.

In addition to base cost data for renewables, low and high costs are used for various sensitivities. Low and high wind, solar, and battery costs are based on the National Renewable Energy Laboratory's 2019 *Annual Technology Baseline* data.

The costs for wind and solar in base, low and high levels are now updated to incorporate recent federal extensions to the Production and Investment Tax Credit. The costs of wind and solar resources selected to replace the interconnection capacity of Sherco and King are calculated based on the Company's owned revenue requirements under current tax law[2] and remove incremental transmission costs (as the gen-tie costs are already accounted for elsewhere in the model). For the capacity above the interconnection threshold at Sherco and King, we consider them as PPA resources and apply the costs from the National Renewable Energy Laboratory's 2019 *Annual Technology Baseline* data without incremental transmission costs (shown in Table 24).

Below is a list of typical operating and cost inputs for each generic resource.

Thermal

a. Retirement Date
b. Maximum Capacity
c. UCAP Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

Renewable

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

[2] We already use the Company's general financing assumptions in our evaluation of generic resource costs. Differences between generic and owned revenue requirements primarily reflect differences in how the Company is able to utilize ITCs and PTCs, from solar and wind projects respectively. Firm dispatchable units included in these tranches of resource additions reflect generic pricing, as there is no inherent difference between our assumed revenue requirements for owned dispatchable units vs contracted units.

Table 12: Thermal Generic Information (Costs in 2018 Dollars)

Thermal Generic Information					
Resource	**Sherco CC**	**Generic CC**	**Generic CT**	**Generic CT**	**Generic CT**
Technology	7H	7H	7H	7F	7H
Location Type	Brownfield	Greenfield	Brownfield	Brownfield	Greenfield
Cooling Type	Wet	Dry	Dry	Dry	Dry
Book life	40	40	40	40	40
Nameplate Capacity (MW)	835	901	374	232	374
Summer Peak Capacity (MW)	750	856	331	206	331
Capital Cost ($000) 2018$	$837,068	$906,588	$174,700	$114,766	$193,500
Electric Transmission Delivery ($000) 2018$	NA	$410,505	NA	NA	$74,804
Ongoing Capital Expenditures ($000-yr) 2018$	$6,200	$6,200	$1,784	$892	$1,784
Gas Demand ($000-yr) 2018$	$31,725	$19,058	$2,165	$1,342	$2,165
Capital Cost ($/kW) 2018$	$1,002	$1,006	$467	$495	$517
Electric Transmission Delivery ($/kW) 2018$	NA	$455	NA	NA	$200
Ongoing Capital Expenditures ($/kW-yr) 2018$	$7.42	$6.88	$4.77	$3.85	$4.77
Gas Demand ($/kW-yr) 2018$	$37.98	$21.14	$5.79	$5.79	$5.79
Fixed O&M Cost ($000/yr) 2018$	$6,592	$6,592	$1,253	$1,203	$1,253
Variable O&M Cost ($/MWh) 2018$	$1.04	$1.04	$0.99	$1.03	$0.99
Levelized $/kw-mo (All Fixed Costs) $2018	$15.26	$16.06	$5.91	$6.22	$8.06
Summer Heat Rate 100% Loading (btu/kWh)	6,359	6,848	9,264	10,025	9,264
Summer Heat Rate 75% Loading (btu/kWh)	6,547	6,874	9,738	10,581	9,738
Summer Heat Rate 50% Loading (btu/kWh)	6,985	7,334	11,120	12,515	11,120
Summer Heat Rate 25% Loading (btu/kWh)	8,004	8,404	11,558	13,430	11,558
Forced Outage Rate	3%	3%	3%	3%	3%
Maintenance (weeks/yr)	5	5	2	2	2
CO2 Emissions (lbs/MMBtu)	118	118	118	118	118
SO2 Emissions (lbs/MWh)	0.00	0.00	0.00	0.00	0.00
NOx Emissions (lbs/MWh)	0.05	0.05	0.90	0.32	0.90
PM10 Emissions (lbs/MWh)	0.02	0.02	0.03	0.03	0.03
Mercury Emissions (lbs/MMWh)	0.00	0.00	0.00	0.00	0.00

Table 17. New Thermal Unit Information (Costs in 2018 Dollars)

Resource	Reciprocating Engine	Aeroderivative Turbine
Book life	30	30
Nameplate Capacity (MW)	9	30
Summer Peak Capacity (MW)	9	27
Capital Cost ($000) 2018$	$21,898	$47,818
Electric Transmission Delivery ($000) 2018$	N/A	N/A
Ongoing Capital Expenditures ($000-yr) 2018$	$16	$457
Gas Demand ($000-yr) 2018$	N/A	N/A
Capital Cost ($/kW) 2018$	$2,433	$1,594
Electric Transmission Delivery ($/kW) 2018$	NA	NA
Ongoing Capital Expenditures ($/kW-yr) 2018$	$1.74	$15.23
Gas Demand ($/kW-yr) 2018$	$0.00	$0.00
Fixed O&M Cost ($000/yr) 2018$	$208	$47
Variable O&M Cost ($/MWh) 2018$	$6.16	$0.63
Levelized $/kw-mo (All Fixed Costs) $2018	$26.33	$18.52
Summer Heat Rate 100% Loading (btu/kWh)	8,438	10,087
Summer Heat Rate 75% Loading (btu/kWh)	8,802	10,937
Summer Heat Rate 50% Loading (btu/kWh)	9,663	13,122
Summer Heat Rate 25% Loading (btu/kWh)	10,190	15,338
Forced Outage Rate	3%	2%
Maintenance (weeks/yr)	Varies based on fired hours	Varies based on fired hours
CO_2 Emissions (lbs/MMBtu)	118	118
CO Emissions (lbs/MWh)	0.27	0.56
SO_2 Emissions (lbs/MWh)	0.00	0.00
NO_x Emissions (lbs/MWh)	0.18	0.92
PM10 Emissions (lbs/MWh)	0.00	0.00
Mercury Emissions (lbs/MMWh)	0.00	0.00

Table 18: Renewable Generic Information (Costs in 2018 Dollars)

Renewable Generic Information				
Resource	**Wind**	**Utility Scale Solar**	**Distributed Solar Commercial**	**Distributed Solar Residential**
ELCC Capacity Credit (%)	16.7%	50% declines to 30%		
Capacity Factor	50.0%	22.0%	18.0%	18.0%
Book life	25	25	25	25
Electric Transmission Delivery ($/kW)	500	200	0	0

Table 139: Storage Generic Information (Costs in 2018 Dollars)

Storage Generic Information	
Resource	**Battery**
Technology	Li Ion
Location Type	NA
Book life	40
Nameplate Capacity (MW)	50
Summer Peak Capacity (MW)	50
Storage Volume (hrs)	4
Cycle Efficiency (%)	1
Equivalent Full Cycles per Year	250
Electric Transmission Delivery ($000) 2018$	0
Levelized $/kw-mo (All Fixed Costs) $2023	$18.18

Table 20: Levelized Capacity Costs by Year

Levelized Capacity Costs by In-Service Year ($/kw-mo)								
COD	CT - 7H Greenfield	CT - 7F Brownfield	CT - 7H Brownfield	CC	Sherco CC	Base Battery	Low Battery	High Battery
2018	$8.06	$6.22	$5.91	$16.06	$15.26			
2019	$8.22	$6.34	$6.02	$16.38	$15.56			
2020	$8.38	$6.47	$6.15	$16.71	$15.87	$20.04	$17.86	$22.94
2021	$8.55	$6.60	$6.27	$17.05	$16.19	$19.44	$16.81	$23.19
2022	$8.72	$6.73	$6.39	$17.39	$16.51	$18.82	$15.73	$23.45
2023	$8.89	$6.86	$6.52	$17.73	$16.85	$18.18	$14.62	$23.71
2024	$9.07	$7.00	$6.65	$18.09	$17.18	$17.52	$13.47	$23.97
2025	$9.25	$7.14	$6.78	$18.45	$17.53	$16.84	$12.30	$24.24
2026	$9.44	$7.28	$6.92	$18.82	$17.88	$16.63	$11.75	$24.51
2027	$9.63	$7.43	$7.06	$19.20	$18.23	$16.41	$11.18	$24.78
2028	$9.82	$7.58	$7.20	$19.58	$18.60	$16.19	$10.60	$25.06
2029	$10.02	$7.73	$7.34	$19.97	$18.97	$15.95	$10.00	$25.34
2030	$10.22	$7.88	$7.49	$20.37	$19.35	$15.71	$9.38	$25.62
2031	$10.42	$8.04	$7.64	$20.78	$19.74	$15.83	$9.38	$26.06
2032	$10.63	$8.20	$7.79	$21.19	$20.13	$15.94	$9.37	$26.50
2033	$10.84	$8.36	$7.95	$21.62	$20.53	$16.04	$9.36	$26.94
2034	$11.06	$8.53	$8.11	$22.05	$20.94	$16.15	$9.35	$27.40
2035	$11.28	$8.70	$8.27	$22.49	$21.36	$16.26	$9.33	$27.86
2036	$11.50	$8.88	$8.44	$22.94	$21.79	$16.36	$9.31	$28.32
2037	$11.73	$9.05	$8.60	$23.40	$22.23	$16.46	$9.28	$28.80
2038	$11.97	$9.24	$8.78	$23.87	$22.67	$16.56	$9.25	$29.28
2039	$12.21	$9.42	$8.95	$24.34	$23.12	$16.65	$9.21	$29.78
2040	$12.45	$9.61	$9.13	$24.83	$23.59	$16.74	$9.17	$30.27
2041	$12.70	$9.80	$9.31	$25.33	$24.06	$16.83	$9.13	$30.78
2042	$12.96	$10.00	$9.50	$25.83	$24.54	$16.76	$9.00	$30.97
2043	$13.22	$10.20	$9.69	$26.35	$25.03	$16.66	$8.85	$31.12
2044	$13.48	$10.40	$9.88	$26.88	$25.53	$16.55	$8.70	$31.25
2045	$13.75	$10.61	$10.08	$27.42	$26.04	$16.42	$8.53	$31.35
2046	$14.02	$10.82	$10.28	$27.96	$26.56	$16.26	$8.35	$31.41
2047	$14.30	$11.04	$10.49	$28.52	$27.09	$16.08	$8.16	$31.44
2048	$14.59	$11.26	$10.70	$29.09	$27.64	$15.88	$7.95	$31.42
2049	$14.88	$11.48	$10.91	$29.68	$28.19	$15.65	$7.73	$31.35
2050	$15.18	$11.71	$11.13	$30.27	$28.75	$15.39	$7.49	$31.23
2051	$15.48	$11.95	$11.35	$30.88	$29.33	$15.70	$7.64	$31.85
2052	$15.79	$12.19	$11.58	$31.49	$29.91	$16.01	$7.79	$32.49
2053	$16.11	$12.43	$11.81	$32.12	$30.51	$16.33	$7.95	$33.14
2054	$16.43	$12.68	$12.05	$32.76	$31.12	$16.66	$8.10	$33.80
2055	$16.76	$12.93	$12.29	$33.42	$31.75	$16.99	$8.27	$34.48
2056	$17.10	$13.19	$12.54	$34.09	$32.38	$17.33	$8.43	$35.17
2057	$17.44	$13.45	$12.79	$34.77	$33.03	$17.68	$8.60	$35.87

Table 21: Base Renewable Levelized Costs by Year

Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial*	Distributed Solar Residential*
2023	$40.91	$46.52	$60.46	$84.12
2024	$36.03	$46.62	$59.99	$81.21
2025	$35.78	$48.51	$62.70	$82.40
2026	$50.28	$53.97	$71.70	$91.23
2027	$50.32	$53.99	$71.00	$87.23
2028	$50.36	$54.01	$70.26	$83.07
2029	$50.41	$54.00	$69.47	$78.75
2030	$50.46	$53.98	$68.64	$74.26
2031	$51.13	$54.60	$69.31	$74.25
2032	$51.81	$55.21	$69.97	$74.23
2033	$52.50	$55.83	$70.64	$74.17
2034	$53.19	$56.45	$71.31	$74.08
2035	$53.89	$57.07	$71.98	$73.96
2036	$54.60	$57.70	$72.65	$73.81
2037	$55.31	$58.32	$73.32	$73.62
2038	$56.03	$58.96	$73.98	$73.40
2039	$56.76	$59.59	$74.65	$73.15
2040	$57.49	$60.23	$75.31	$72.86
2041	$58.23	$60.94	$75.87	$73.52
2042	$58.98	$61.66	$76.42	$74.18
2043	$59.73	$62.38	$76.97	$74.84
2044	$60.49	$63.10	$77.51	$75.49
2045	$61.26	$63.83	$78.04	$76.15
2046	$62.03	$64.57	$78.56	$77.43
2047	$62.81	$65.31	$79.08	$78.73
2048	$63.60	$66.05	$79.58	$80.05
2049	$64.39	$66.80	$80.08	$81.40
2050	$65.19	$67.55	$80.56	$82.76

**Distributed Solar costs represent at the meter values before grossing up for losses.*

Table 22: Low Renewable Levelized Costs by Year

Low Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial*	Distributed Solar Residential*
2023	$36.12	$38.99	$49.46	$82.47
2024	$30.57	$38.49	$48.30	$76.99
2025	$29.69	$39.29	$47.11	$71.34
2026	$43.59	$42.57	$45.87	$65.52
2027	$43.05	$41.82	$44.59	$59.54
2028	$42.55	$41.04	$43.26	$53.38
2029	$42.07	$40.23	$41.89	$47.05
2030	$41.62	$39.40	$40.48	$40.54
2031	$42.10	$39.43	$40.22	$40.29
2032	$42.57	$39.45	$39.94	$40.02
2033	$43.05	$39.46	$39.63	$39.73
2034	$43.53	$39.45	$39.30	$39.41
2035	$44.01	$39.43	$38.95	$39.06
2036	$44.50	$39.59	$38.57	$38.69
2037	$44.98	$39.74	$38.16	$38.29
2038	$45.47	$39.88	$37.72	$37.86
2039	$45.96	$40.01	$37.25	$37.41
2040	$46.45	$40.14	$36.75	$36.92
2041	$46.94	$40.51	$37.10	$37.03
2042	$47.43	$40.89	$37.46	$37.13
2043	$47.92	$41.26	$37.81	$37.22
2044	$48.41	$41.63	$38.17	$37.31
2045	$48.90	$42.01	$37.15	$37.38
2046	$49.40	$42.47	$37.76	$37.91
2047	$49.89	$42.93	$38.38	$38.45
2048	$50.38	$43.40	$39.01	$39.00
2049	$50.88	$43.87	$39.65	$39.55
2050	$51.37	$44.34	$40.30	$40.11

**Distributed Solar costs represent at the meter values before grossing up for losses.*

Table 23: High Renewable Levelized Costs by Year

High Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial*	Distributed Solar Residential*
2023	$47.16	$50.92	$88.34	$126.50
2024	$43.38	$51.94	$90.11	$129.03
2025	$44.24	$55.12	$91.91	$131.61
2026	$59.88	$62.79	$93.75	$134.24
2027	$61.08	$64.04	$95.63	$136.93
2028	$62.30	$65.32	$97.54	$139.67
2029	$63.55	$66.63	$99.49	$142.46
2030	$64.82	$67.96	$101.48	$145.31
2031	$66.11	$69.32	$103.51	$148.22
2032	$67.43	$70.71	$105.58	$151.18
2033	$68.78	$72.12	$107.69	$154.20
2034	$70.16	$73.56	$109.85	$157.29
2035	$71.56	$75.03	$112.04	$160.43
2036	$72.99	$76.53	$114.28	$163.64
2037	$74.45	$78.07	$116.57	$166.91
2038	$75.94	$79.63	$118.90	$170.25
2039	$77.46	$81.22	$121.28	$173.66
2040	$79.01	$82.84	$123.70	$177.13
2041	$80.59	$84.50	$126.18	$180.67
2042	$82.20	$86.19	$128.70	$184.29
2043	$83.85	$87.91	$131.28	$187.97
2044	$85.52	$89.67	$133.90	$191.73
2045	$87.23	$91.47	$136.58	$195.57
2046	$88.98	$93.30	$139.31	$199.48
2047	$90.76	$95.16	$142.10	$203.47
2048	$92.57	$97.06	$144.94	$207.54
2049	$94.43	$99.01	$147.84	$211.69
2050	$96.31	$100.99	$150.79	$215.92

**Distributed Solar costs represent at the meter values before grossing up for losses.*

Table 24: Sherco and King Gen-tie Renewable Levelized Costs by Year[3]

Levelized Costs by In-Service Year $/MWh (LCOE)						
COD	Wind	Utility Scale Solar	Low Wind	Low Utility Scale Solar	High Wind	High Utility Scale Solar
2023	$25.27	$33.71	$20.47	$26.19	$31.51	$38.12
2024	$20.07	$33.56	$14.61	$25.43	$27.41	$38.88
2025	$19.50	$35.19	$13.41	$25.97	$27.96	$41.80
2026	$33.67	$40.38	$26.98	$28.98	$43.27	$49.20
2027	$33.38	$40.14	$26.12	$27.96	$44.14	$50.18
2028	$33.09	$39.87	$25.27	$26.90	$45.02	$51.19
2029	$32.79	$39.58	$24.45	$25.81	$45.92	$52.21
2030	$32.49	$39.28	$23.65	$24.69	$46.84	$53.25
2031	$32.80	$39.59	$23.76	$24.43	$47.78	$54.32
2032	$33.11	$39.91	$23.87	$24.15	$48.73	$55.40
2033	$33.43	$40.22	$23.98	$23.85	$49.71	$56.51
2034	$33.74	$40.53	$24.07	$23.53	$50.70	$57.64
2035	$34.05	$40.83	$24.17	$23.20	$51.72	$58.80
2036	$34.36	$41.13	$24.25	$23.03	$52.75	$59.97
2037	$34.67	$41.43	$24.33	$22.85	$53.81	$61.17
2038	$34.97	$41.73	$24.41	$22.65	$54.88	$62.40
2039	$35.28	$42.01	$24.47	$22.44	$55.98	$63.64
2040	$35.58	$42.30	$24.53	$22.21	$57.10	$64.92
2041	$35.88	$42.65	$24.59	$22.23	$58.24	$66.21
2042	$36.18	$43.00	$24.63	$22.23	$59.41	$67.54
2043	$36.48	$43.35	$24.67	$22.23	$60.59	$68.89
2044	$36.78	$43.70	$24.69	$22.23	$61.81	$70.27
2045	$37.07	$44.04	$24.71	$22.21	$63.04	$71.67
2046	$37.36	$44.38	$24.72	$22.28	$64.30	$73.11
2047	$37.64	$44.71	$24.72	$22.34	$65.59	$74.57
2048	$37.92	$45.05	$24.71	$22.39	$66.90	$76.06
2049	$38.20	$45.37	$24.69	$22.44	$68.24	$77.58
2050	$38.47	$45.70	$24.66	$22.49	$69.60	$79.13

V. Market Purchases and Sales Carbon Rate

In order to estimate emissions rates associated with market purchases, the Company assumes an annual average carbon emissions pounds/MWh rate, as shown in the table below. These estimates were developed using MISO's MTEP Futures modeling results.

[3] The costs provided in this table are based on the National Renewable Energy Laboratory's 2019 Annual Technology Baseline data without incremental transmission costs. For the first 2000 MW of renewable additions at Sherco site and the first 600 MW of renewable additions at King site, we further adjust costs based on an estimate of the Company's owned revenue requirements.

Market sales emissions rates reflect an average emissions rate for our system resources, and vary according to each individual scenario and sensitivity capacity expansion portfolio.

Table 25: Market Purchase Carbon Rate

Market Purchase CO2 Rate																				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
lbs/MWh	1372	1307	1241	1176	1110	1045	1042	1039	1036	1034	1031	1018	1006	993	980	968	955	943	930	917
	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057
lbs/MWh	905	892	880	867	854	842	829	817	804	792	779	766	754	741	729	716	703	691	678	666

II. RELIABILITY ANALYSIS – STAKEHOLDER INPUT, ASSUMPTIONS AND MODELING SCENARIOS

The Initial Comments submitted by several parties indicated concerns with the Company's approach to analyzing the relative reliability of various potential generation portfolios modeled in the June 2020 Supplement. In general, concerns were focused in two areas: 1) that such an analysis inappropriately ignored the presence and availability of the MISO market; and 2) detailed methodological concerns, i.e. around the generic wind shapes chosen for the analysis.

As we outline in Section 2 – Reliability of this Reply there are times when MISO's import capability may not be available, and the number of MISO-declared emergencies has risen in the past few years. As such, studying whether the Company has enough available capacity to serve its own load for all hours of a year in an hourly chronological dispatch model is valuable for our customers. It shows us whether we have the technical capability to cover the equivalent of our load with our own resources in the case of severe underavaialbility of other resources, and as such is an indication of potential reliability and/or risk concerns[4]. Additionally, while many of the metrics evaluate the ability of the Company's system generation to cover its own load under different constraints, EnCompass production cost modeling underlying this analysis does incorporate purchases and sales. Furthermore, three of the metrics evaluated directlyconsider the ability to access resources in the broader MISO market, given the relevant transmission constraints.

[4] Some of the feedback in the Initial Comments from external parties focused on which generation was economic to dispatch during different time intervals, instead of the level of available capacity. This focus misses the point of these reliability analyses, which is to evaluate, in an hourly chronological model, whether the company has enough online capacity that it can technically serve all of its load with its own resources, should it need to do so for emergency purposes.We believe this provides helpful data points for considering comparative reliability between plans.

The table below outlines the reliability tests conducted in this Reply. We then further discuss how we addressed feedback from parties' Initial Comments and include a definition of terms in subsequent sections.

Table 26: Three Scenarios Investigated For Each Capacity Expansion Plan in the Reliability Analysis

Scenario	Battery Forced Outage Rate (Percent)	Shapes for Generic Wind Units	All Other Assumptions
TMY Hourly Load & Generation	0	TMY	No change from those used in the June 2020 Supplement
2019 Actual Hourly Load & Generation (Low End of Range)	0	Same as the Reliability Analysis in the IRP Supplement	No change from those used in the June 2020 Supplement
2019 Actual Hourly Load & Generation (High End of Range)	5	"Highest" Observed NCF	No change from those used in the June 2020 Supplement

A. Response to methodological feedback

Regarding methodological concerns about the reliability analysis, we examined the feedback provided in the Initial Comments and discuss our findings below. Additionally, the Company adds a few concerns and updates as well.

Table 27: Reliability Analysis Initial Comments Topics

Concern raised	How the Company addresses this concern in this Reply
Intervenor plans had not been evaluated using actual 2019 hourly load data	The CEO's and Sierra Club's Preferred Plans were tested with the 2019 actual hourly load and renewable shapes in addition to TMY shapes. Results appear in Section 4 of this Reply, in Table 4-14.
Capacity factors for wind and solar generic units were too low	CEO Initial Comments indicated a concern with the net capacity factor (NCF) assumption for generic wind units in some of reliability scenarios in the IRP Supplement. In particular, the concern was that for the 2019 actual year conditions, the generic unit wind NCF was significantly lower than what the Company used in its standard PVSC and PVRR production cost modeling. Since a main objective of the reliability analysis was to test each plan with different, "non-TMY" hourly data, the NCFs will differ by default. However, to address this concern, as a "bookend" reflecting the best possible outcome, we used the highest observed wind NCF for the year 2019 for the shape of all generic wind resources in a set of reliability runs. These runs complemented another set of runs with the original wind NCF chosen. Where results between the two sets of runs differ in Table 4-14 in Section 4, a range is now presented. No changes are made to the choice of solar shape used in "2019 Actual Hourly Load and Generation" scenarios. This is because the reliability analysis provided in the IRP Supplement was already using the solar unit with the highest observed solar NCF for the year 2019.
The Demand Response resource contains an extra cost adder	The Company's response to CEO IR-130 describes why this approach was taken in our modeling. This adder is discussed further below; we do not remove it from the EnCompass models we used to conduct the main reliability analysis.[5]

[5] While removing this adder certainly increases DR dispatch throughout the modeled year, it does not largely impact the reliability results because most of the reliability analysis deals with the level of available capacity relative to our demand, not the level or type of generation actually dispatched. Since EnCompass considers DR to be available capacity in scenarios both with and without the DR cost adder, changing this setting does not alter the number or characteristics of capacity shortfalls. Some of the feedback in the Initial Comments from external parties focused on which generation was economic to dispatch during different time intervals, instead of the level of available capacity. This focus misses the point of these reliability analyses, which is to evaluate, in a hourly chronological model, whether the company has enough online/available capacity that it can technically serve all of its load with its own resources.

Concern raised	How the Company addresses this concern in this Reply
All generic wind and solar units use the same shape	The concern expressed in the Initial Comments was that using the same NCF shape for all generic units may impact the reliability analysis by underrepresenting the benefits of geographic diversity. Using the Sierra Club's Preferred Plan we randomly simulated generic unit wind shapes for the entire year of 2034 and conducted 50 separate production cost runs for the month of December. We evaluate the reliability results for each run in the footnote below.[6] The results of the simulation do not differ greatly from our "high" and "low" interval estimates we show for the Sierra Club Preferred Plan in Table 4-14 of Section 4. In some cases the simulated shapes perform better on average, in other cases worse or in between our "high" and "low" interval estimates. Simulating wind shapes for only 8 generic wind units for only a single year produced a large volume of data; based on the results of this exercise its not yet clear that simulated data in and of itself produces different or better outcomes for this analysis.
Hours with high amounts of MISO imports may not signify a reliability issue, but rather an economic issue	We appreciate this feedback and modified our metric in response. The metric now studies the amount of MISO market purchases only during hours in which a capacity shortfall is occurring. In this way, it more appropriately represents periods in which Company would not have access to sufficient capacity regardless of dispatch economics. We examine the number of hours in which MISO imports are within 5 percentof the 2,300 MW import limit to indicate reliability risk.

[6] The table below includes sample reliability results for the 50 production cost runs with simulated wind shapes for generic wind units, compared to the reliability results from using observed 2019 wind shapes for generic wind units. The least reliable plan in each category is underlined and in bold. We note that that there is not a systematic trend or change in overall outcome associated with varying the wind shapes.

	Number of Native Capacity Shortfalls	Average Shortfall Intensity (MW)	Peak Capacity Shortfall (MW)	Longest Shortfall (Hrs)
Sierra Club Preferred Plan - *Using Different Observed 2019 Wind Shapes*	**7-9**	407-448	1,281 – **1,683**	3-4
Sierra Club Preferred Plan - *Average of Results from 50 Runs with Simulated Wind Shapes*	4	**664**	1,534	**6**

Concern raised	How the Company addresses this concern in this Reply
High net load ramps may not signify a reliability issue, but rather a economic issue	Feedback from intervenors indicated a focus on which resources were actually dispatched during net load ramps, whereas our intention with this metric is to study whether the Company has enough available capacity that it could theoretically meet the entire ramp with its own resources. This is discussed further in the footnote below[7]. No change was made this metric for the reliabilyt analysis included in Section 4 of this Reply.
LOLH and EUE were not examined using stochastic analysis	In Initial Comments, parties claimed that that these metrics were less meaningful because these events are most typically recorded at the ISO/RTO level and because they "are based on deterministic and not stochastic simulations with enough iterations to demonstrate convergence."[8] The Company disagrees with this interpretation. These metrics can be also be used to provide important information about future plans, including moments when it might be most at risk even with the availability of RTO/ISO resources. Additionally LOLH and EUE calculations do not necessarily need to be stochastic simulations to provide meaningful insights and context. As one example, the ELCC update made by the Company for the most recent Public Service Company of Colorado Energy Resource Plan uses historical observed data, which fully preserves the hourly relationship between load and resource variability that has occurred in recent years. While simulations of hourly load can also provide helpful information, the ability of each plan to meet all hourly electrical needs during conditions the Company faced recently is an appropriate basis for measuring reliability.
Lack of forced outage rate (FOR) assumption for batteries	While not raised by intervenors, we determined that it would be appropriate to examine a 5 percent FOR to batteries in "Battery FOR" scenarios in Table 4-14 in Section 4. We note that batteries were the only resource assigned a UCAP of 100 percent, or in other words, a 0 percent FOR. Given the amount of standalone storage and hybrid solar and storage units selected in several plans, we examine a FOR similar to that of other dispatchable generation.

[7] Net load ramps help us evaluate potential hourly chronological reliability risks, rather than just examining a total number of hours a native capacity shortfall could be expected to occur. Whether EnCompass dispatches available capacity or imports it from MISO during the actual reliability test is irrelevant to the test; we are simply examining the relative ability of given plans to meet the steepest net load ramp with native resources, if this became necessary. Given recent net load ramp events observed in MISO – like the April 2021 event discussed in the Reliability section – and CAISO's inclusion of Flexible Ramp requirements – we believe it is appropriate to examine this metric. This is especially true because it is possible that – as more variable generation is adopted across MISO – other load-serving entities in the MISO region may be relying on the market at the same time.

[8] EFG Attachment to CEO Initial Comments 15-21, submitted February 11, 2021. Page 31.

B. Characteristics studied in the reliability analyses

Native Capacity Shortfall: A count of the hours when Company does not have enough available/online generation capacity to cover its full need. As outlined in Section 4, we believe it is important to examine the ability of different plans to cover our full load under a variety of assumptions. This metric looks at the amount of available capacity that that Company has each hour, versus the demand for that hour. Regardless of whether available capacity is dispatched for that hour, this metric reveals whether the Company has enough available capacity to even be capable of covering its full load if needed.

Average Intensity of Shortfall Events: On average, the amount of native capacity – in MW – by which the plan was short during native capacity shortfalls.

Peak Capacity Shortfall: The maximum amount of native capacity – in MW – by which the plan was short during an hour of the modeled year.

Longest Shortfall: This is longest period of time – in hours – in each plan where there is insufficient native capacity available to serve the Company's load.

Max 3 Hour Upward Ramp: Maximum three-hour net load ramp observed by each scenario, where net load equals load minus renewable generation. This ramp is compared against the amount of other available/online generation the Company has at each given hour. The objective of this metric is to see whether the Company simply has enough generation capacity available to serve a rapid increase in net load with its own resources, regardless of whether those resources are ultimately dispatched by the model. See footnote 7 for a further discussion.

LOLH and EUE: Standard industry metrics - Loss-of-Load Hours and Expected Unserved Energy – that quantify the number of hours with loss of load and the amount of energy "unmet." These occur when there is not enough energy – etiher generated or imported by the Company – to provide power to all customers we serve.

Table 1: Updated Scenario 1 (Reference Case) Load and Resources, 2020-2034

Load and Resource Summary	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Obligation[1]	9,430	9,380	9,416	9,426	9,406	9,381	9,370	9,385	9,393	9,341	9,354	9,362	9,404	9,459	9,523
Existing and Approved Resources	10,826	11,253	11,524	11,556	10,881	9,668	9,368	8,426	8,383	8,350	7,711	7,128	6,828	6,225	5,740
Net Position	1,396	1,873	2,108	2,131	1,475	287	-1	-959	-1,011	-991	-1,643	-2,234	-2,576	-3,234	-3,783
Resources - Future	0	0	0	0	0	460	440	1,148	1,128	1,429	1,823	2,295	2,639	3,363	3,892
Planning Position	**1,396**	**1,873**	**2,108**	**2,131**	**1,475**	**747**	**439**	**189**	**117**	**437**	**179**	**61**	**63**	**129**	**109**

Existing and Approved Resources	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Coal	2,295	2,295	2,295	2,295	1,647	1,647	1,647	994	994	994	994	994	994	994	994
Nuclear	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,019	1,019	1,019	498	0
Combined Cycle	2,078	2,078	2,078	2,078	2,078	2,078	1,787	1,551	1,551	1,551	1,551	1,551	1,275	1,275	1,275
Combustion Turbine	1,781	1,781	1,781	1,781	1,635	1,325	1,325	1,280	1,280	1,280	1,280	737	737	737	737
Hydro	881	1,001	999	999	999	168	168	168	168	168	168	168	162	158	158
Biomass	110	110	110	86	86	61	61	61	29	29	29	19	19	19	19
Wind	500	624	733	680	755	681	676	675	672	650	649	633	630	565	561
Solar	495	531	614	647	632	612	591	570	548	526	503	480	456	431	435
Demand Response	1,045	1,192	1,273	1,349	1,407	1,454	1,470	1,485	1,499	1,511	1,518	1,526	1,536	1,547	1,560
Total Existing and Approved	**10,826**	**11,253**	**11,524**	**11,556**	**10,881**	**9,668**	**9,368**	**8,426**	**8,383**	**8,350**	**7,711**	**7,128**	**6,828**	**6,225**	**5,740**

Resource Additions	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Sherco CC	0	0	0	0	0	0	0	728	728	728	728	728	728	728	728
Firm dispatchable	0	0	0	0	0	0	0	0	0	321	321	642	963	1,605	1,925
Wind	0	0	0	0	0	0	0	0	0	0	0	42	117	251	384
Solar	0	0	0	0	0	460	440	420	400	380	774	884	832	780	855
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Future Resources	**0**	**0**	**0**	**0**	**0**	**460**	**440**	**1,148**	**1,128**	**1,429**	**1,823**	**2,295**	**2,639**	**3,363**	**3,892**

[1] Includes the Company's customer load and effective planning reserve margin.

Table 2: Supplement Plan (Updated Scenario 9) Load and Resources, 2020-2034

Load and Resource Summary	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Obligation	9,430	9,380	9,416	9,426	9,406	9,381	9,370	9,385	9,393	9,341	9,354	9,362	9,404	9,459	9,523
Existing and Approved Resources	10,826	11,253	11,524	11,556	10,881	9,668	9,368	8,426	8,383	7,867	7,339	6,756	6,457	5,853	5,369
Net Position	1,396	1,873	2,108	2,131	1,475	287	-1	-959	-1,011	-1,474	-2,015	-2,605	-2,947	-3,606	-4,155
Resources - Future	0	0	0	0	0	460	440	1,148	1,128	1,657	2,107	2,742	3,129	3,901	4,243
Planning Position	**1,396**	**1,873**	**2,108**	**2,131**	**1,475**	**747**	**439**	**189**	**117**	**182**	**93**	**137**	**181**	**295**	**88**

Existing and Approved Resource	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	2,295	2,295	2,295	2,295	1,647	1,647	1,647	994	994	511	0	0	0	0	0
Nuclear	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,120	622
Combined Cycle	2,078	2,078	2,078	2,078	2,078	2,078	1,787	1,551	1,551	1,551	1,551	1,551	1,275	1,275	1,275
Combustion Turbine	1,781	1,781	1,781	1,781	1,635	1,325	1,325	1,280	1,280	1,280	1,280	737	737	737	737
Hydro	881	1,001	999	999	999	168	168	168	168	168	168	168	162	158	158
Biomass	110	110	110	86	86	61	61	61	29	29	29	19	19	19	19
Wind	500	624	733	680	755	681	676	675	672	650	649	633	630	565	561
Solar	495	531	614	647	632	612	591	570	548	526	503	480	456	431	435
Demand Response	1,045	1,192	1,273	1,349	1,407	1,454	1,470	1,485	1,499	1,511	1,518	1,526	1,536	1,547	1,560
Total Existing and Approved	**10,826**	**11,253**	**11,524**	**11,556**	**10,881**	**9,668**	**9,368**	**8,426**	**8,383**	**7,867**	**7,339**	**6,756**	**6,457**	**5,853**	**5,369**

Resource Additions	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Sherco CC	0	0	0	0	0	0	0	728	728	728	728	728	728	728	728
Firm dispatchable	0	0	0	0	0	0	0	0	0	321	642	1,284	1,605	2,246	2,246
Wind	0	0	0	0	0	0	0	0	0	0	0	0	8	167	309
Solar	0	0	0	0	0	460	440	420	400	608	738	731	688	660	810
Storage	0	0	0	0	0	0	0	0	0	0	0	0	100	100	150
Total Future Resources	**0**	**0**	**0**	**0**	**0**	**460**	**440**	**1,148**	**1,128**	**1,657**	**2,107**	**2,742**	**3,129**	**3,901**	**4,243**

Table 3: Alternate Plan Load and Resources, 2020-2034

Load and Resource Summary	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Obligation	9,430	9,380	9,416	9,426	9,406	9,381	9,370	9,385	9,393	9,341	9,354	9,362	9,404	9,459	9,523
Resources - Existing, Approved	10,826	11,253	11,524	11,556	10,841	9,628	9,160	7,998	7,954	7,438	6,910	6,756	6,457	5,853	5,369
Net Position	1,396	1,873	2,108	2,131	1,435	247	-210	-1,387	-1,439	-1,903	-2,443	-2,605	-2,947	-3,606	-4,155
Resources - Future	0	0	0	0	336	598	850	1,397	1,453	1,918	2,585	2,642	2,987	3,608	4,162
Planning Position	**1,396**	**1,873**	**2,108**	**2,131**	**1,771**	**845**	**641**	**10**	**14**	**15**	**141**	**37**	**40**	**2**	**8**

Existing and Approved Resource	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Coal	2,295	2,295	2,295	2,295	1,647	1,647	1,647	994	994	511	0	0	0	0	0
Nuclear	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,120	622
Combined Cycle	2,078	2,078	2,078	2,078	2,078	2,078	1,787	1,551	1,551	1,551	1,551	1,551	1,275	1,275	1,275
Combustion Turbine	1,781	1,781	1,781	1,781	*1,595*	*1,285*	*1,117*	*852*	*852*	*852*	*852*	*737*	*737*	*737*	*737*
Hydro	881	1,001	999	999	999	168	168	168	168	168	168	168	162	158	158
Biomass	110	110	110	86	86	61	61	61	29	29	29	19	19	19	19
Wind	500	624	733	680	755	681	676	675	672	650	649	633	630	565	561
Solar	495	531	614	647	632	612	591	570	548	526	503	480	456	431	435
Demand Response	1,045	1,192	1,273	1,349	1,407	1,454	1,470	1,485	1,499	1,511	1,518	1,526	1,536	1,547	1,560
Total Existing and Approved	10,826	11,253	11,524	11,556	10,841	9,628	9,160	7,998	7,954	7,438	6,910	6,756	6,457	5,853	5,369

Resource Additions	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Sherco CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm dispatchable	0	0	0	0	0	0	278	599	599	920	1,241	1,241	1,562	2,204	2,525
Wind	0	0	0	0	0	0	0	0	33	67	225	284	359	359	443
Solar	0	0	0	0	336	598	572	798	820	931	918	867	816	795	945
Storage	0	0	0	0	0	0	0	0	0	0	200	250	250	250	250
Total Future Resources	**0**	**0**	**0**	**0**	**336**	**598**	**850**	**1,397**	**1,453**	**1,918**	**2,585**	**2,642**	**2,987**	**3,608**	**4,162**

Table 1: Net Present Value Results for Scenarios and Sensitivities Presented

Scenario label	PVSC	_A	_B	_C	_D	_E	_F	_G	_I	_J	_K	_L	_M	_P	_Q	_Z	ND Plan
Scenario	PVSC	PVRR	Low Gas/Coal/Mkts	High Gas/Coal/Mkts	Low Load	High Load	Low Resource Cost	High Resource Cost	Low Externality	Low Externality, Low Regulatory	Mid Externality, Mid Regulatory	High Externality	No Reg or Externality Costs	Low Load Low Gas/Coal/Mkts Low Resource Cost	High Load High Gas/Coal/Mkts Low Resource Cost	Reserve Margin	North Dakota Plan
Scenario 1 - Updated Reference Case	41,067	37,165	40,888	41,284	42,254	43,667	39,626	43,128	39,086	38,035	39,571	46,203	36,898	40,644	42,257	41,354	36,458
Scenario 9 - Updated Supplement Plan	40,833	37,261	40,696	40,971	42,019	43,455	39,551	42,680	38,897	38,000	39,429	45,113	37,022	40,544	41,779	41,131	36,696
Sceanrio 9 - Alternate Plan	40,461	37,120	40,446	40,435	41,702	43,099	38,762	42,783	38,580	37,838	39,161	44,040	36,914	40,108	40,574	40,772	36,712
Scenario 4 - Updated	40,856	37,220															
Scenario 4 - Alternate	40,524	37,081															
Scenario 12 - Updated	40,431	37,002															
Scenario 12 - Alternate	40,102	36,888															

Table 2: Net Present Value Deltas (Relative to Scenario 1) for Scenarios and Sensitivities Presented

Scenario label	PVSC	_A	_B	_C	_D	_E	_F	_G	_I	_J	_K	_L	_M	_P	_Q	_Z	ND Plan
Scenario	PVSC	PVRR	Low Gas/Coal/Mkts	High Gas/Coal/Mkts	Low Load	High Load	Low Resource Cost	High Resource Cost	Low Externality	Low Externality, Low Regulatory	Mid Externality, Mid Regulatory	High Externality	No Reg or Externality Costs	Low Load Low Gas/Coal/Mkts Low Resource Cost	High Load High Gas/Coal/Mkts Low Resource Cost	Reserve Margin	North Dakota Plan
Scenario 1 - Updated Reference Case	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Scenario 9 - Updated Supplement Plan	(234)	96	(192)	(313)	(236)	(212)	(75)	(447)	(189)	(35)	(141)	(1,090)	124	(100)	(478)	(223)	239
Sceanrio 9 - Alternate Plan	(606)	(46)	(442)	(849)	(553)	(569)	(865)	(345)	(505)	(198)	(409)	(2,163)	16	(536)	(1,683)	(581)	254
Scenario 4 - Updated	(210)	55															
Scenario 4 - Alternate	(543)	(84)															
Scenario 12 - Updated	(636)	(163)															
Scenario 12 - Alternate	(965)	(277)															

Morgan Stanley

Biden Infrastructure Proposal Underscores Support for Clean Energy

"Path" to 100% Carbon-Free Electricity by 2035

- President Biden's infrastructure package includes significant support for wind, solar, storage, carbon capture, fuel cells and EV infrastructure
- If passed, the proposal would create meaningful tailwinds for clean energy development in the U.S.

Key Areas of Support for Clean Energy

1.	10-year extension and phase-down of investment tax credit and production tax credit for wind, solar and fuel cells
2.	Introduction of new tax credit for energy storage
3.	"Direct pay" of tax credits to developers to accelerate monetization of projects
4.	Support for electric vehicle deployment and infrastructure
5.	Create a more resilient electric transmission system through targeted investment tax credits that incentivize investments in the grid
6.	Support for carbon capture and sequestration in the form of "reformed and expanded" 45Q tax credit

Source: American Jobs Plan, Capital Alpha

Probability of Success

Low **Medium** **High**

CERTIFICATE OF SERVICE

I, Mustafa Adam, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket No. E002/RP-19-368

Dated this 25th day of June 2021

/s/
____
Mustafa Adam
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Ross	Abbey	ross.abbey@us-solar.com	United States Solar Corp.	100 North 6th St Ste 222C Minneapolis, MN 55403	Electronic Service	No	OFF_SL_19-368_19-368_Official
Gary	Ambach	Gambach@slipstreaminc.org	Slipstream, Inc.	8973 SW Village Loop Chanhassen, MN 55317	Electronic Service	No	OFF_SL_19-368_19-368_Official
Ellen	Anderson	eanderson@mncenter.org	Minnesota Center for Environmental Advocacy	1919 University Ave W Ste 515 Saint Paul, MN 55104	Electronic Service	No	OFF_SL_19-368_19-368_Official
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_19-368_19-368_Official
Susan	Arntz	sarntz@mankatomn.gov	City Of Mankato	P.O. Box 3368 Mankato, MN 560023368	Electronic Service	No	OFF_SL_19-368_19-368_Official
Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy	414 Nicollet Mall Fl 5 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-368_19-368_Official
Jessica L	Bayles	Jessica.Bayles@stoel.com	Stoel Rives LLP	1150 18th St NW Ste 325 Washington, DC 20036	Electronic Service	No	OFF_SL_19-368_19-368_Official
David	Bender	dbender@earthjustice.org	Earthjustice	1001 G Street NW Suite 1000 Washington, District of Columbia 20001	Electronic Service	No	OFF_SL_19-368_19-368_Official
Tracy	Bertram	tbertram@ci.becker.mn.us		12060 Sherburne Ave Becker City Hall Becker, MN 55308-4694	Electronic Service	No	OFF_SL_19-368_19-368_Official
James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-368_19-368_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Jessica	Beyer	jbeyer@greatermankato.com	Greater Mankato Growth	1961 Premier Dr Ste 100 Mankato, MN 56001	Electronic Service	No	OFF_SL_19-368_19-368_Official
Melissa E	Birchard	mbirchard@keyesfox.com	KEYES & FOX LLP	18 Loudon Rd PO Box 1391 Concord, NH 03302	Electronic Service	No	OFF_SL_19-368_19-368_Official
Michael J.	Bull	mbull@mncee.org	Center for Energy and Environment	212 Third Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-368_19-368_Official
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-368_19-368_Official
Thomas	Carlson	thomas.carlson@edf-re.com	EDF Renewable Energy	10 2nd St NE Ste. 400 Minneapolis, Minnesota 55413	Electronic Service	No	OFF_SL_19-368_19-368_Official
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_19-368_19-368_Official
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-368_19-368_Official
Jean	Comstock	jean.comstock.dbcc@gmail.com	St. Paul 350	729 6th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_19-368_19-368_Official
Riley	Conlin	riley.conlin@stoel.com	Stoel Rives LLP	33 S. 6th Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-368_19-368_Official
Brooke	Cooper	bcooper@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_19-368_19-368_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_19-368_19-368_Official
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, 401-8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-368_19-368_Official
Scott F	Dunbar	sdunbar@keyesfox.com	Keyes & Fox LLP	1580 Lincoln St Ste 880 Denver, CO 80203	Electronic Service	No	OFF_SL_19-368_19-368_Official
Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota St Ste W1360 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_19-368_19-368_Official
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	2720 E. 22nd St Institute for Local Self-Reliance Minneapolis, MN 55406	Electronic Service	No	OFF_SL_19-368_19-368_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_19-368_19-368_Official
Mike	Fiterman	mikefiterman@libertydiversified.com	Liberty Diversified International	5600 N Highway 169 Minneapolis, MN 55428-3096	Electronic Service	No	OFF_SL_19-368_19-368_Official
Lucas	Franco	lfranco@liunagroc.com	LIUNA	81 Little Canada Rd E Little Canada, MN 55117	Electronic Service	No	OFF_SL_19-368_19-368_Official
Amy	Fredregill	afredregill@environmental-initiative.org	Environmental Initiative, MN Sustainable Growth Coalition	211 First St N Ste 250 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-368_19-368_Official
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	OFF_SL_19-368_19-368_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Janet	Gonzalez	Janet.gonzalez@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 55101	Electronic Service	No	OFF_SL_19-368_19-368_Official
Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP	Suite 1750 220 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_19-368_19-368_Official
J Drake	Hamilton	hamilton@fresh-energy.org	Fresh Energy	408 St Peter St Saint Paul, MN 55101	Electronic Service	No	OFF_SL_19-368_19-368_Official
Meghan K	Hassett	mhassett@ucsusa.org	Union of Concerned Scientists	1 N Lasalle Ave CHICAGO, IL 60602	Electronic Service	No	OFF_SL_19-368_19-368_Official
Kim	Havey	kim.havey@minneapolismn.gov	City of Minneapolis	350 South 5th Street, Suite 315M Minneapolis, MN 55415	Electronic Service	No	OFF_SL_19-368_19-368_Official
Philip	Hayet	phayet@jkenn.com	J. Kennedy and Associates, Inc.	570 Colonial Park Drive Suite 305 Roswell, GA 30075-3770	Electronic Service	No	OFF_SL_19-368_19-368_Official
Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_19-368_19-368_Official
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_19-368_19-368_Official
Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.	445 Etna Street Ste. 61 St. Paul, MN 55106	Electronic Service	No	OFF_SL_19-368_19-368_Official
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2950 Yellowtail Ave. Marathon, FL 33050	Electronic Service	No	OFF_SL_19-368_19-368_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-368_19-368_Official
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-368_19-368_Official
Mark J.	Kaufman	mkaufman@ibewlocal949.org	IBEW Local Union 949	12908 Nicollet Avenue South Burnsville, MN 55337	Electronic Service	No	OFF_SL_19-368_19-368_Official
William D	Kenworthy	will@votesolar.org	Vote Solar	332 S Michigan Ave FL 9 Chicago, IL 60604	Electronic Service	No	OFF_SL_19-368_19-368_Official
Samuel B.	Ketchum	sketchum@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-368_19-368_Official
Thomas	Koehler	TGK@IBEW160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	OFF_SL_19-368_19-368_Official
Frank	Kohlasch	frank.kohlasch@state.mn.us	MN Pollution Control Agency	520 Lafayette Rd N. St. Paul, MN 55155	Electronic Service	No	OFF_SL_19-368_19-368_Official
Brenda	Kyle	bkyle@stpaulchamber.com	St. Paul Area Chamber of Commerce	401 N Robert Street Suite 150 St Paul, MN 55101	Electronic Service	No	OFF_SL_19-368_19-368_Official
Carmel	Laney	carmel.laney@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-368_19-368_Official
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_19-368_19-368_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Rachel	Leonard	rachel.leonard@ci.monticello.mn.us	City of Monticello	505 Walnut St Ste 1 Monticello, MN 55362	Electronic Service	No	OFF_SL_19-368_19-368_Official
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_19-368_19-368_Official
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_19-368_19-368_Official
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_19-368_19-368_Official
Emily	Marshall	emarshall@mojlaw.com	Miller O'Brien Jensen, PA	120 S. 6th Street Suite 2400 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_19-368_19-368_Official
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-368_19-368_Official
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_19-368_19-368_Official
Taylor	McNair	taylor@gridlab.org		668 Capp Street San Francisco, CA 94110	Electronic Service	No	OFF_SL_19-368_19-368_Official
Brian	Meloy	brian.meloy@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-368_19-368_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Joseph	Meyer	joseph.meyer@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St Paul, MN 55101-2131	Electronic Service	No	OFF_SL_19-368_19-368_Official
Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis	350 S. 5th Street Room M 301 Minneapolis, MN 55415	Electronic Service	No	OFF_SL_19-368_19-368_Official
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_19-368_19-368_Official
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-368_19-368_Official
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_19-368_19-368_Official
Alan	Muller	alan@greendel.org	Energy & Environmental Consulting	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_19-368_19-368_Official
Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-368_19-368_Official
J	Newberger	Jnewberger1@yahoo.com	State Rep	14225 Balsam Blvd Becker, MN 55308	Electronic Service	No	OFF_SL_19-368_19-368_Official
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_19-368_19-368_Official
M. William	O'Brien	bobrien@mojlaw.com	Miller O'Brien Jensen, P.A.	120 S 6th St Ste 2400 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-368_19-368_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Ric	O'Connell	ric@gridlab.org	GridLab	2120 University Ave Berkeley, CA 94704	Electronic Service	No	OFF_SL_19-368_19-368_Official
Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_19-368_19-368_Official
Jessica	Palmer Denig	jessica.palmer-Denig@state.mn.us	Office of Administrative Hearings	600 Robert St N PO Box 64620 St. Paul, MN 55164	Electronic Service	No	OFF_SL_19-368_19-368_Official
J. Gregory	Porter	greg.porter@nngco.com	Northern Natural Gas Company	1111 South 103rd St Omaha, NE 68124	Electronic Service	No	OFF_SL_19-368_19-368_Official
Greg	Pruszinske	gpruszinske@ci.becker.mn.us	City of Becker	PO Box 250 12060 Sherburne Ave Becker, MN 55308	Electronic Service	No	OFF_SL_19-368_19-368_Official
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_19-368_19-368_Official
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_19-368_19-368_Official
Nathaniel	Runke	nrunke@local49.org		1765 County Hwy 16 Rochester, MN 55902	Electronic Service	No	OFF_SL_19-368_19-368_Official
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_19-368_19-368_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Larry L.	Schedin	Larry@LLSResources.com	LLS Resources, LLC	332 Minnesota St, Ste W1390 St. Paul, MN 55101	Electronic Service	No	OFF_SL_19-368_19-368_Official
Jacob J.	Schlesinger	jschlesinger@keyesfox.com	Keyes & Fox LLP	1580 Lincoln St Ste 880 Denver, CO 80203	Electronic Service	No	OFF_SL_19-368_19-368_Official
Douglas	Seaton	doug.seaton@umwlc.org	Upper Midwest Law Center	8421 Wayzata Blvd Ste 105 Golden Valley, MN 55426	Electronic Service	No	OFF_SL_19-368_19-368_Official
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-368_19-368_Official
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	Yes	OFF_SL_19-368_19-368_Official
Andrew R.	Shedlock	Andrew.Shedlock@KutakRock.com	Kutak Rock LLP	60 South Sixth St Ste 3400 Minneapolis, MN 55402-4018	Electronic Service	No	OFF_SL_19-368_19-368_Official
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	OFF_SL_19-368_19-368_Official
Joshua	Smith	joshua.smith@sierraclub.org		85 Second St FL 2 San Francisco, California 94105	Electronic Service	No	OFF_SL_19-368_19-368_Official
Beth H.	Soholt	bsoholt@windonthewires.org	Wind on the Wires	570 Asbury Street Suite 201 St. Paul, MN 55104	Electronic Service	No	OFF_SL_19-368_19-368_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Anna	Sommer	ASommer@energyfuturesgroup.com	Energy Futures Group	PO Box 692 Canton, NY 13617	Electronic Service	No	OFF_SL_19-368_19-368_Official
Mark	Spurr	mspurr@fvbenergy.com	International District Energy Association	222 South Ninth St., Suite 825 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_19-368_19-368_Official
Benjamin	Stafford	bstafford@cleanenergyeconomymn.org	Clean Energy Economy Minnesota	400 South 4th St Ste 401-202 Minneapolis, MN 55415	Electronic Service	No	OFF_SL_19-368_19-368_Official
Byron E.	Starns	byron.starns@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-368_19-368_Official
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-368_19-368_Official
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_19-368_19-368_Official
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_19-368_19-368_Official
Thomas	Tynes	jjazynka@energyfreedomcoalition.com	Energy Freedom Coalition of America	101 Constitution Ave NW Ste 525 East Washington, DC 20001	Electronic Service	No	OFF_SL_19-368_19-368_Official
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_19-368_19-368_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julie	Voeck	julie.voeck@nee.com	NextEra Energy Resources, LLC	700 Universe Blvd Juno Beach, FL 33408	Electronic Service	No	OFF_SL_19-368_19-368_Official
Samantha	Williams	swilliams@nrdc.org	Natural Resources Defense Council	20 N. Wacker Drive Ste 1600 Chicago, IL 60606	Electronic Service	No	OFF_SL_19-368_19-368_Official
Laurie	Williams	laurie.williams@sierraclub.org	Sierra Club	Environmental Law Program 1536 Wynkoop St Ste 200 Denver, CO 80202	Electronic Service	No	OFF_SL_19-368_19-368_Official
Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine	225 South Sixth Street, Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-368_19-368_Official
Tim	Wulling	t.wulling@earthlink.net		1495 Raymond Ave. Saint Paul, MN 55108	Electronic Service	No	OFF_SL_19-368_19-368_Official
Patrick	Zomer	Pat.Zomer@lawmoss.com	Moss & Barnett a Professional Association	150 S. 5th Street, #1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-368_19-368_Official