February 11, 2021

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

VIA E-FILING

Re: **In the Matter of Xcel Energy's 2020-2034 Upper Midwest Resource Plan**
PUC Docket No. E002/RP-19-368
Sierra Club Initial Comments – Public Version

Dear Mr. Seuffert:

Sierra Club respectfully submits its Initial Comments – Public Version in *In the Matter of Xcel Energy's 2020-2034 Upper Midwest Resource Plan* in Docket No. E002/RP-19-368.

These comments and attachments contain information Xcel Energy considers to be Trade Secret. Sierra Club believes this filing comports with the Minnesota Public Utilities Commission's Notice relating to Revised Procedures for Handling Trade Secret and Privileged Data, pursuant to Minn. Rule 7829.0500.

Please contact me at (303) 454-3358 or laurie.williams@sierraclub.org if you have any questions regarding this filing.

Sincerely,

/s/Laurie Williams
Staff Attorney
Sierra Club
1536 Wynkoop St. Suite #200
Denver, CO 80202

Enclosures

STATE OF MINNESOTA

BEFORE THE PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Joseph Sullivan	Vice Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

In the Matter of Xcel Energy's 2020-2034
Upper Midwest Resource Plan **PUC Docket No. E002/RP-19-368**

SIERRA CLUB INITIAL COMMENTS

Drafted with the assistance of

Applied Economics Clinic

Grid Strategies LLC

Synapse Energy Economics, Inc.

FEBRUARY 11, 2021

PUBLIC DOCUMENT - NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED

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I. SUMMARY AND OVERVIEW

This IRP process represents one of Minnesota's biggest opportunities to align our energy future with our values. As the thousands of public comments in the record show, Minnesotans want clean, affordable, reliable energy that will support a resilient economy while reducing carbon emissions, responsibly setting us on a trajectory to reach 100% carbon-free electricity by 2040, if not sooner. With only 10 years remaining to avert climate catastrophe[1], now is the time for a "no regrets" energy strategy that retires expensive, carbon-intensive coal plants and rapidly builds out proven low-cost renewable technologies – wind, solar, and battery storage – that will save customers money while also diversifying our energy supply through a commitment to both utility scale and distributed generation.

Xcel's proposed plan includes several promising actions that are vital to achieving this vision: retiring its remaining coal-fired units by 2030, building an additional 3,500 megawatts (MW) of utility scale solar by 2030 and 2,250 MW of new wind by 2034, and dramatically expanding its investments in the cleanest and cheapest energy resources, energy efficiency and demand response.

Unfortunately, Xcel's proposal also includes some significant missed opportunities. Most critically, Xcel has refused to reconsider its ill-advised proposal to build a new 800 MW combined-cycle methane gas plant in 2027 ("Sherco CC"). Sierra Club's experts' analysis, using the same modeling platform as Xcel, shows that building the Sherco CC leads to a resource plan that is $200 million more expensive for customers. (Section V.) Moreover, one of our experts, Telos Energy, conducted an independent analysis of Xcel's engineering power flow studies that Xcel used to justify a reliability need for the Sherco CC, and found that the proposed gas plant provides *no* reliability benefit to Xcel's system. (Section VI.)

Sierra Club contracted with Synapse Energy Economics, Applied Economics Clinic, and Grid Strategies to review Xcel's EnCompass capacity expansion modeling assumptions and correct identified errors. Our experts' review found various ways in which Xcel has biased its modeling inputs to lead the model to build more gas and fewer renewables. (Section V.) They also found that Xcel has minimized the buildout of distributed generation as part of its plan. Moreover, although the Commission ordered Xcel to look at the possibility of decreasing the size of the Sherco CC and investigate the potential for hybrid renewables, Xcel did not fully comply with the Commission's order. (Section V.B.) When Sierra Club's experts corrected these issues and conducted modeling using more reasonable assumptions, they developed a plan that will save customers more than **<u>$2.2 billion</u>** over the planning period compared to Xcel's Preferred Plan. Sierra Club's plan ("Clean Energy for All" Plan) would set the Company on a trajectory to reduce its carbon emissions by 100% by 2040, a "no regrets" strategy that includes no new methane gas plants (including no Sherco

[1] According to the United Nations Intergovernmental Panel on Climate Change, the world must reduce its greenhouse gas emissions by about half by 2030, and net zero by around 2050. Report available at https://www.ipcc.ch/sr15/

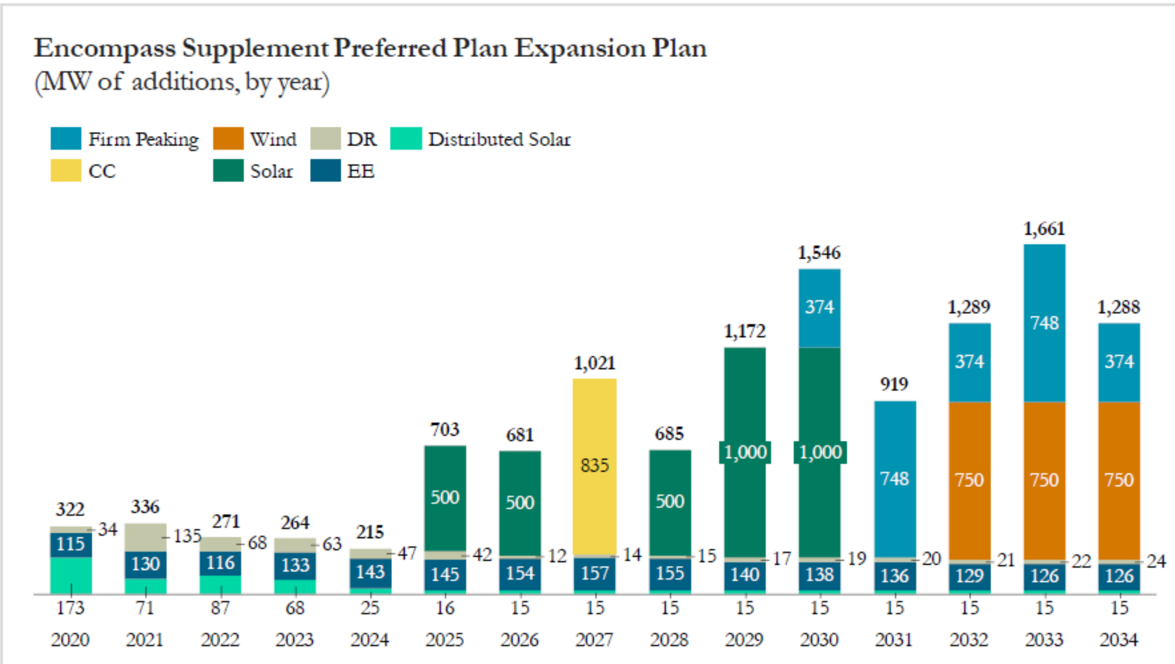
CC), more utility scale wind and solar – including over 4,000 MW of solar paired with storage – dramatically higher levels of distributed solar and community solar, standalone battery storage, and no extension of the Monticello nuclear license. (Section V.D-F.) A full comparison of our plan with Xcel's is summarized in Table 1, below.

Table 1: Comparison of Resource Additions Under Xcel's Preferred Plan vs Sierra Club's "Clean Energy For All" Plan

Resource Type	Xcel's Preferred Plan	Sierra Club's Clean Energy For All Plan
Coal	Sherco 1 in 2026 Sherco 2 in 2023 + seasonal dispatch Sherco 3 by 2030 King in 2028	-Same-
Combined Cycle Gas	Sherco 800 MW CC in 2027	None
Other Potential Gas	2,600 MW new firm peaking 2030-2034 (modeled as generic CTs)	No new CTs
Utility Scale Renewables	3,500 MW new utility scale solar 2025-2030 2,250 MW new wind by 2034	1,350 MW new utility scale solar by 2034 4,320 MW new wind by 2034
Utility Scale Paired Solar-Plus-Storage ("hybrid solar")	None	4,070 MW solar 1,080 MW battery
Distributed Solar	863 MW Community Solar 276 MW DG solar	2,050 MW Community Solar 1,851 MW DG solar
Battery Storage	None	1,020 MW by 2034
Nuclear	Monticello license extension through 2040	Monticello license ends 2030 (no license extension)
Demand Side Management	780 GWh/year savings through 2034 400 MW new DR by 2023	-Same-

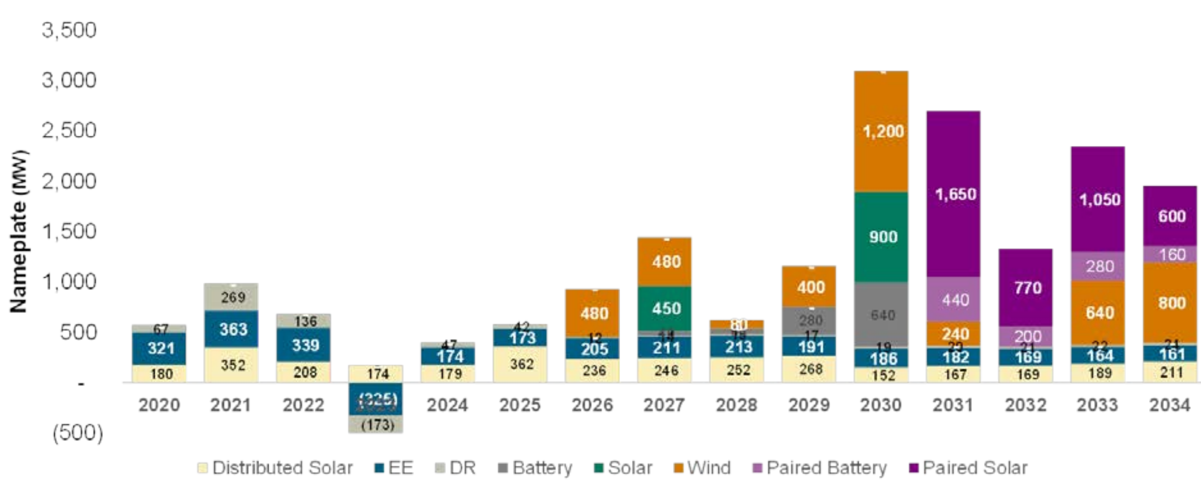
Figures 1 and 2 show the differences between our preferred plan and Xcel's by year.

Figure 1: Xcel's Preferred Plan (Incremental Resource Additions Per Year)



Source: XcelEnergy "Upper Midwest Integrated Resource Plan 2020-2034: Supplement," Figure 3-2 at p. 62.

Figure 2: Sierra Club's Clean Energy For All Plan (Incremental Resource Additions Per Year)[2]



[2] As explained in Section V.E, below, an error in the most recent version of EnCompass caused it to double count energy efficiency between 2020 and 2022, and also caused incremental energy efficiency to appear negative in 2023. Because this error did not impact the capacity expansion results or the cost delta between scenarios, and given time and resource constraints, we did not attempt to correct this issue.

Sierra Club's Clean Energy For All plan would not only save customers **$2.2 billion** over the planning period; it also can meet customers' needs reliably. Xcel asserts that scenarios high in renewable energy are less reliable than those with gas. Our expert Grid Strategies reviewed Xcel's reliability arguments and found Xcel has overstated the reliability concerns with renewables. Many recent studies have found that high renewables scenarios are equally capable of delivering reliable energy. (Section VI.) Studies by Vibrant Clean Energy – including its report in this docket, sponsored by Citizens Utility Board – demonstrate that traditional resource planning tools neglect the significant reliability and diversity benefits of distributed generation. In addition, Xcel has in part justified its proposed Sherco CC on grounds of a "critical reliability need," citing Y-2 studies; our expert Telos Energy conducted an engineering-level review of those studies and found that the proposed gas plant is not needed to address reliability issues. (Section VI.F.)

Moreover, our plan delivers greater socioeconomic and environmental benefits than Xcel's by supporting higher levels of local community investment and job creation – both key to an equitable and just energy transition and to our state's recovery from the COVID crisis – while also setting Xcel on a path to delivering 100% carbon free energy by 2040, consistent with Minnesota's statutory greenhouse gas reduction goals and Governor Walz's energy plan. (Section VII.) Our plan also better preserves the Company's flexibility and limits risk by avoiding commitment to a new massive and expensive gas plant that will likely become stranded long before its costs are recovered. Stranded costs would amount to **[PROTECTED DATA BEGINS…PROTECTED DATA ENDS]** if the plant were retired by 2040, consistent with Governor Walz' policy objectives. (Section VII.A.)

Because Sierra Club's Clean Energy For All plan will deliver clean, reliable energy at significantly lower cost, Sierra Club respectfully requests that the Commission take the following actions in this docket:

1. Approve Xcel's proposed retirement dates for Sherco Unit 3 by no later than 2030 and A.S. King by no later than 2028, with instructions that Xcel should evaluate whether those units should be retired earlier in its next IRP; and approve moving Sherco 2 to seasonal dispatch and King to seasonal dispatch until 2023 and economic commitment thereafter;

2. Disappove the need for the Sherco CC in 2027;

3. Approve the need for 1,350 MW of utility scale solar and 4,320 MW of new wind beginning in years 2027 and 2026, as well as an additional 4,070 MW of utility scale solar paired with 1,080 MW of battery storage starting in 2031, and 1,020 MW of standalone battery storage beginning in 2027;

4. Approve Xcel's proposal to achieve 780 GWh/year savings from energy efficiency programs through 2034 and 400 MW of new demand response by 2023;

5. Approve the need for 2,050 MW of community solar and 1,851 MW of distributed generation solar, and order Xcel to bring forward a proposal by January 2022 for programs that could incentivize the growth of solar distributed generation within its territory at levels consistent with Sierra Club's Clean Energy For All Plan, and in a manner that would advance the goals of equity and access;

6. Disapprove the need for the Monticello license extension through 2040; and

7. Order Xcel in its next IRP to include a discussion of potential options for exiting its contract with the HERC incinerator, as well as the costs and benefits of declining to renew its contract with the incinerator.

II. EXPERT REVIEW PROCESS

Sierra Club contracted with four experts to conduct a review of Xcel's IRP and underlying analyses. Xcel's IRP is built around three main areas of analysis: 1) its capacity expansion and production cost modeling through EnCompass and Strategist; 2) its "reliability analyses," largely concentrated in Section XI of Attachment A of its IRP Supplement, and 3) its Y-2 or power flow analyses supporting its purported reliability need for the Sherco gas plant.

Tyler Comings, Senior Researcher at Applied Economics Clinic (formerly of Synapse Energy Economics), reviewed the Company's EnCompass modeling assumptions and its methodology for modeling existing resources and new resource options in the IRP. Mr. Comings has issued IRP comments and testified on resource planning issues in many jurisdictions. He has also consulted on issues of regulatory compliance, wholesale electricity markets, utility finance, and economic impact analyses. Rather than attaching a separate expert report, Mr. Comings directly contributed to drafting Section V of Sierra Club's comments. His resume is attached in Attachment B.

Rachel Wilson, Principal Associate at Synapse Energy Economics, Inc., conducted the EnCompass modeling underlying Sierra Club's comments, including processing modeling inputs and outputs and identifying issues with Xcel's modeling methodologies. Ms. Wilson has direct experience with a number of electric sector capacity optimization and dispatch models and has utilized them in a number of proceedings across the country relating to utility resource planning and power plant economics. Rather than attaching a separate expert report, Ms. Wilson directly contributed to drafting Section V of Sierra Club's comments. Her resume is attached in Attachment B.

Michael Goggin, Vice President at Grid Strategies, reviewed the Company's filing and assisted with developing EnCompass modeling assumptions, with a particular focus on assumptions related to transmission and interconnection, capacity value, and electric reliability. Mr. Goggin has testified before state regulatory commissions and the Federal Energy Regulatory Commission (FERC) more than 20 times on IRP, transmission, renewable integration, and reliability issues. Rather than attaching a separate expert report, Mr. Goggin directly contributed to drafting Sections V and VI of Sierra Club's comments. His resume is attached in Attachment B.

Matthew Richwine, a founding partner at Telos Energy, Inc., conducted a review on behalf of Sierra Club and the Clean Energy Organizations ("CEOs") of the Y-2 studies underlying Xcel's claimed reliability need for the Sherco CC addition. His findings are summarized in Section VI below and his report is attached to these comments as Attachment C.

III. SUMMARY OF XCEL'S PLAN AND PROPOSED 5-YEAR PLAN

A. Summary of Xcel's preferred plan

Xcel's preferred plan includes the following:

- Coal resources: retire A.S. King in 2028 and Sherco 3 by 2030; Sherco 1 and 2 in 2026 and 2023; move Sherco 2 to seasonal dispatch.
- Nuclear: operate Monticello through 2040, operate Prairie Island through end of current licenses (Unit 1 – 2033, Unit 2 – 2034)
- Renewables: add over 3,500 MW of utility scale solar by 2030, starting in 2025, and 2,250 MW of wind by 2034.
- Combined cycle gas: 800 MW CC in 2027
- 2,600 MW of firm peaking added between 2030-2034 (modeled as combustion turbines ("CTs")
- Demand side management: EE programs achieving energy savings levels from 2-2.5%, 780 GWh savings annually through 2034, and 400 MW of incremental DR by 2023 for a total of over 1,500 MW DR by 2034.

B. Xcel's 5-year action plan

While Xcel's 5-year action plan does not include any incremental capacity additions through 2024, it does include construction and planning activities for several resource additions.[3] Xcel would need to undertake planning for its coal retirements. It would also continue to plan "development activities associated with the Sherco CC during the next five years."[4] During the 5-year plan, Xcel would also plan to initiate a Certificate of Need proceeding and a Supplemental License Renewal process with the Nuclear Regulatory Commission for the Monticello nuclear plant, both of which Xcel plans to initiate in 2021.[5]

[3] "Xcel Energy Upper Midwest Integrated Resource Plan 2020-2034: Supplement," docket no. E002/RP-19-368, filed June 30, 2020 (hereafter IRP Suppl.) at 65.
[4] *Id.* at 66.
[5] *Id.* at Attachment A, p. 127.

In terms of renewable energy, Xcel recently proposed to repower 720 MW of wind in docket E002/M-20-620, which the Commission subsequently approved. Xcel's preferred plan also includes the addition of 500 MW of solar in 2025 which, though outside the 5-year action plan window, would require Xcel to begin construction in 2023-2024.[6] Xcel notes that it has proposed the addition of up to 460 MW of solar additions at the Sherco substation as part of its Covid Economic Recovery Proposal in docket E,G999/CI-20-492. "If approved, this would largely fill the need projected in 2025 in the Supplement Preferred Plan."[7] Xcel would also add 400 MW of demand response by 2023, as well as significantly increase investment in energy efficiency. Lastly, Xcel states that it will "continue to plan sufficient supporting infrastructure to facilitate our fleet transformation, ensure grid resilience and reliability, and to enable greater DER and DR resources on our system."[8]

IV. STANDARD OF REVIEW

An integrated resource plan generally details the projected need for electricity in its service territory for a forecasted planning period, and the utility's plans for meeting projected need, including the actions it will take in the next five years.[9] A resource plan contains a set of demand- and supply-side resource options that the utility could use to meet the forecasted needs of retail customers.[10]

One of the "standard resource-planning tasks" in an IRP is "analyzing the size, type, and timing of the new resources required to meet need over the planning period."[11] Where a utility proposes a new fossil generation resource as part of its preferred plan in its IRP, it bears a high burden of proof: the utility must show that a renewable alternative to meet the need is "not in the public interest," considering cost-effectiveness, reliability and the state's greenhouse gas reduction goals. Minn. Stat. § 216B.2422, subd. 4.

As this Commission has noted, the IRP "process is iterative because analyzing future energy needs and preparing to meet them is not a static process; strategies for meeting future needs are always evolving in response to changes in actual conditions in the service area. When demographics, economics, technologies, or environmental regulations change, so do a utility's resource needs and its strategies for meeting them."[12]

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[6] *Id.* at 66.
[7] *Id.*
[8] *Id.* at 67.
[9] Minn. Stat. § 216B.2422; Minn. R. Chap. 7843.0400.
[10] Minn. Stat. § 216B.2422, subd. 1(d).
[11] *See,* e.g., Order Asking Commission of Commerce to Seek Funding for Specialized Technical Professional Investigative Services Under Minn. Stat. Section 216B.62, Subd. 8, In the Matter of Xcel Energy's 2016-2030 Integrated Resource Plan, Docket No. E-002/RP-15-21, (April 15, 2016); see also Minn. R. 7850.2600, subp. 2 (size, type, and timing are elements of need).
[12] Order Approving Plan with Modifications and Establishing Requirements for Future Resource Plan Filings, In the Matter of Xcel Energy's 2016–2030 Integrated Resource Plan, Docket No. E-002/RP-15-21, (January 11, 2017).

It is the Commission's duty to approve, reject or modify the plans, "consistent with the public interest." Minn. Stat. § 216B.2422, subd. 2. "The public interest determination must include whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02." Id. subd. 2c. To evaluate whether a resource plan is in the public interest, the Commission assesses plans based on their ability to:

> A. maintain or improve the adequacy and reliability of utility service;
>
> B. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;
>
> C. minimize adverse socioeconomic effects[13] and adverse effects upon the environment;
>
> D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and
>
> E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

Minn. R. 7843.0500, subp. 3. Under the Commission's rules, "parties…may file proposed resource plans different from the plan proposed by the utility. When a plan differs from that submitted by the utility, the plan must be accompanied by a narrative and quantitative discussion of why the proposed changes would be in the public interest, considering the factors listed in part 7843.0500, subpart 3."[14]

V. COST: TO KEEP CUSTOMERS' BILLS AND UTILITY'S RATES AS LOW AS PRACTICABLE, THE COMMISSION SHOULD APPROVE SIERRA CLUB'S CLEAN ENERGY PLAN AS THE LEAST COST RESOURCE PLAN.

The primary tools used in utility integrated resource planning are capacity expansion optimization and production cost modeling. These tools are essential to developing a least-cost resource plan. Minimizing total resource plan costs is in turn a key component to keeping customers' bills and the utility's rates as low as practicable, as required to demonstrate a resource plan is in the public interest.[15]

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[13] "Socioeconomic effects" in defined as "changes in the social and economic environments, including, for example, job creation, effects on local economies, geographical concentration of persons and structures, concentrations of investment capital, and the ability of low-income and rental households to receive conservation services." Minn. R. 7843.0100 subp. 10.
[14] Minn. R.7843.0300 subp. 11
[15] Minn. R. 7843.0500, subp. 3(B) and Minn. Stat. § 216B.2422, subd. 2.

While Xcel initially used Strategist as its capacity expansion modeling tool, as part of its Supplemental IRP, Xcel also filed updated modeling using EnCompass.[16] Sierra Club strongly supported this update because EnCompass is a more accurate modeling tool for assessing the value of portfolios containing high levels of renewable energy penetration.[17] Strategist utilizes a load-duration curve when dispatching resources, arranging loads by descending magnitude. EnCompass, on the other hand, uses hourly chronological dispatch and thus is able to capture daily variations in load, and also "better reflects grid operations and values a more complete range of resource attributes than Strategist modeling."[18] As an hourly chronological dispatch model, EnCompass "assign[s] value to capacity, energy and flexibility according to the grid's needs across each hour in an average day – or a full year" while Strategist "primarily values capacity adequacy at an annual peak and a more "averaged" value for energy."[19] Because Strategist does not dispatch resources at the hourly or sub-hourly level, it does not fully capture the benefits of flexible resources, particularly battery storage. Lastly, Strategist's "typical week" methodology repeats the generation patterns of intermittent resources for one week in each month. These patterns are carried forward to future years, and do not capture any variation between different weeks in a month or between different future years. EnCompass is thus better suited to represent the characteristics and capture the benefits of renewable and storage resources. As a result, EnCompass's results are far more informative than Strategist's when it comes to modeling scenarios with high levels of renewable energy. For this reason, Sierra Club's experts focused their review on Xcel's EnCompass modeling.

Sierra Club employed Synapse, the Applied Economics Clinic, and Grid Strategies to review Xcel's EnCompass capacity expansion modeling assumptions and correct identified errors. As discussed in detail below, their review found various ways in which Xcel has biased its modeling inputs to lead the model to select more gas and fewer renewable resources (including utility scale and distributed resources, as well as battery storage). Moreover, although the Commission ordered Xcel to look at the possibility of decreasing the size of the Sherco CC and investigate the potential for hybrid renewables, Xcel did not allow the model to optimally determine whether or not to add the Sherco CC or hybrids; rather, Xcel only tested those resources in pre-determined sensitivities.

When issues with Xcel's assumptions were corrected and more reasonable modeling assumptions were used, our experts developed a plan that would save customers $2.2 billion more over the planning period than would Xcel's. When the model was allowed to fully optimize in determining whether to add the Sherco gas plant, it never chose to add it. Optimization also resulted in significant additions of hybrid and standalone battery storage. Sierra Club's plan ("Clean Energy For

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16 Order Suspending Procedural Schedule and Requiring Additional Findings, In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy at 1-2 (Nov. 12, 2019).
17 Letter Regarding Issues Presented at October 17th Agenda Meeting & Request for an Extension of the Comment Deadline (October 15, 2019).
18 IRP Suppl. at 29.
19 *Id.*

All Plan") would set the Company on a trajectory to reduce its carbon emissions by 100% by 2040, a "no regrets" strategy that includes no new methane gas plants (including no Sherco CC), more utility scale wind and solar – including over 4,000 MW of solar paired with storage – dramatically higher levels of distributed solar and community solar, standalone battery storage, and no Monticello nuclear license extension.

A. Summary of Xcel's EnCompass Modeling Process

The Company's resource planning process focused on decisions for the future of its coal and nuclear units. To do this, the Company modeled 15 "scenarios" which varied coal retirement and nuclear licensing dates.[20]

In its scenarios, Xcel fixed its existing resources in place, as well as a new resource, the Sherco CC, and then used the "capacity expansion" capability of the Company's chosen models to optimize other resource builds. Xcel's "reference" scenario ("Scenario 1") assumed that coal and nuclear units retired at their "current dates." For nuclear units in the reference case, Monticello retires in 2030 and Prairie Island retires in 2033. For coal units in the reference case, Sherco 1 retires in 2026, Sherco 2 retires in 2023, Sherco 3 retires in 2034, and King retires in 2038; Sherco 2 and King also do not operate in the spring or fall through 2023 (i.e., are dispatched seasonally).[21] Subsequent scenarios tested combinations of earlier coal unit retirements and nuclear license extensions.

AEC, Synapse, and Grid Strategies reviewed the Company's modeling methodology and assumptions in detail, with a focus on new resource decisions and the potential for a lower-cost alternative to the Company's preferred plan. As discussed in detail below, our analysis found myriad flaws in the Company's methodology and assumptions that led it to choosing more gas resources and fewer renewable resources than is reasonable.

B. Some of Xcel's Encompass modeling assumptions were unreasonable, resulting in modeling outcomes that were biased towards natural gas and against additional renewables.

First, there are several aspects of Xcel's methodology and assumptions that were reasonable. For the reasons discussed above, our experts were pleased that the Company is moving towards a state-of-the-art model like EnCompass, which can more accurately and comprehensively evaluate the benefits of renewable resources. It was also appropriate for the Company to evaluate earlier retirement of its coal-fired units, given the increasingly challenging economics of burning coal. Finally, the Company's primary source of renewable and storage resource costs, the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB), is a reliable industry standard source for this data.

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[20] *Id.* at 28.
[21] *Id.* at 17.

As discussed in greater detail in this section, while some of Xcel's assumptions and findings were reasonable, our review found that there are many steps in the Company's methodology that stacked the deck against adding renewable and battery resources in its modeling. One of Xcel's key errors was its decision to include the Sherco CC in all of its modeling runs, preventing the model from determining whether adding the unit was an optimal resource addition. Xcel's modeling assumptions also included several artificial and arbitrary barriers to building wind, solar, and battery storage, which in turn compelled the model to instead select new generic natural gas replacement. The flaws in Xcel's modeling of new resource alternatives include:

1. Hard-wiring Sherco CC into all modeling runs, without regard to whether it was an optimal resource addition;
2. Only allowing the model to build unreasonably massive renewable and storage projects, which prevented it from making smaller incremental supply additions;
3. Inflating the costs of solar PV and battery storage despite the use of a reasonable starting point (the NREL ATB);
4. Inconsistent modeling of wind capacity factors;
5. Assuming excessive interconnection costs for solar PV and wind projects;
6. Largely ignoring battery storage, despite it being an increasingly attractive resource option;
7. Understating the potential for future distributed and community solar adoption;
8. Ignoring Power Purchase Agreement (PPA) contract extensions and re-powering;
9. Failing to adequately assess hybrids, as required by Commission order;
10. Failing to adequately analyze smaller sizes of the Sherco CC, contrary to Commission order.

These flaws are described in more detail below.

1. Xcel hardwired the Sherco gas plant into all of its modeling runs, preventing the model from determining whether it is a reasonable, least cost resource addition.

The Company's preferred plan, in both its original and supplemental filing, includes the construction of the Sherco 835 MW nameplate natural gas combined cycle plant ("Sherco CC") for operation in

2027 at a capital cost of $837 million.[22] The Company's modeling does not justify the Sherco CC project. Xcel hard-wired the Sherco CC addition into its EnCompass resource baseline, circumventing the point of conducting capacity expansion modeling: developing the optimal least cost portfolio. Existing units should be allowed to retire and new resources should be selected on an economic basis to ensure a least-cost plan. It is a common technique in modeling to justify a resource decision by comparing it to the next best alternative—i.e., by allowing for the model to choose optimal resource additions. Yet the Company has only modeled portfolios that include the Sherco CC resource rather than let the model determine an optimal resource. Even if one agreed with all of the Company's other assumptions and methodology (which we do not), Xcel has provided no evidence in its IRP or IRP Supplement that the Sherco CC investment is an optimal resource addition because Xcel baked it into all of its model runs.

It is worth noting that Xcel's discussion of the Sherco CC with respect to its modeling assumptions is disingenuous. In Table 2-1 of its IRP Supplement, Xcel presents a summary of its "Existing and Approved NSP System Resources."[23] The table includes 4,740 MW of natural gas and oil. In a footnote to that entry, Xcel states that this "does not include the Sherco CC, which is expected to come online by 2027."[24] Similarly, Xcel states that "[o]ur baseline includes all owned, contracted, or otherwise available resources on the system or resources that have received regulatory approval as of January 31, 2020."[25] From this, one might think that Xcel did not include the Sherco CC in its baseline modeling. But Table 2-2 of the IRP Supplement shows that Xcel includes it as an "existing and approved resource,"[26] and in Attachment A to its IRP Supplement, Xcel finally notes that "the planned Sherco CC is also included in our baseline modeling, given that the unit is provided for via Minnesota statute."[27] As discussed in Section IX.A, below, we disagree with Xcel's assertion that Minnesota law exempts it from having to demonstrate a need for the Sherco CC under the IRP statute.

2. **Xcel limited its EnCompass resource inputs to massive solar, wind and battery projects, artificially and arbitrarily preventing the model from selecting portfolios that included more reasonably sized renewable additions**.

Xcel's EnCompass modeling assumes all new utility-scale solar PV, wind and battery storage options are only available in massive and unreasonable project sizes. Because the model could only add these resources in extremely large chunks, this prevented the model from adding smaller, more reasonably sized additions.

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22 IRP Suppl. at 69 of Attach A, Table IV-14.
23 *Id.* at 23.
24 *Id.* at FN 17.
25 *Id.* at 22-23.
26 *Id.* at 25.
27 *Id.* at 80 of Attach A, citing Minnesota Session Laws -2017 Ch. 5. H.F. No. 113.

- Solar PV: Xcel set a minimum size of 500 MW for utility-scale solar PV, meaning that the model did not have the option of adding utility-scale solar in smaller increments.[28] This limitation was arbitrary and unreasonable. The Lawrence Berkley National Lab (LBNL) provides a summary of solar PV projects installed nationally. For 2019, the most recent year available, this dataset shows that more than half of the utility-scale solar projects were below 50 MW and none were above 200 MW.[29] The largest solar project in the U.S. is 579 MW, and that project came online in phases over nearly two years.[30] The latest *Lazard Levelized Cost of Energy*—which is an industry standard—only reports the cost of utility-scale solar for 150 MW installations.[31]

- Wind: Xcel set a minimum size of 750 MW for new wind projects.[32] This minimum size is arbitrary and without basis. In LBNL's sample of 81 wind farms across the U.S., installed in 2018 and 2019, more than half of the projects were below 200 MW in size.[33] A 750 MW wind project would be the sixth largest in the United States, and the larger projects were typically built in phases over several years.[34] The *Lazard Levelized Cost of Energy* only reports the cost of onshore wind for 175 MW installations.[35]

- Battery Storage: Xcel set a minimum size of 321 MW for new battery storage.[36] This minimum size is also arbitrary and unreasonable. The Company claimed the size was set to match the size of its generic combustion turbine (CT) in the model.[37] A 321 MW battery would be largest installation in the world, larger than a 300 MW battery project that came online in December 2020.[38] The *Lazard Levelized Cost of Storage* reports large-scale battery installations in 10, 50, and 100 MW sizes.[39]

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28 *Id.* at 88 of Attach A.
29 Mark Bolinger et al., *Utility-Scale Solar Data Update: 2020 Edition*, Lawrence Berkeley National Laboratory (November 2020), https://emp.lbl.gov/utility-scale-solar/
30 California Energy Commission, *The World's Largest Utility Scale Solar Project is Located in California,* CA.gov, https://ww2.energy.ca.gov/title24/tour/solarstar/index.html
31 *Lazard Levelized Cost of Energy Analysis – Version 14.0.*, Lazard (October 2020), https://www.lazard.com/media/451419/lazards-levelized-cost-of-energy-version-140.pdf
32 IRP Suppl. at 87 of Attach A.
33 Ryan Wiser et at., *Wind Energy Technology Data Update: 2020 Edition*, Lawrence Berkeley National Laboratory (August 2020), https://emp.lbl.gov/publications/wind-energy-technology-data-update
34 *Largest U.S. Wind Power Projects Beginning in 2021, by Installed Capacity,* Statista (November 2020), https://www.statista.com/statistics/193246/largest-us-wind-power-projects/
35 Lazard, *supra.*
36 IRP Suppl. at 89 of Attach A.
37 *Id.* at 87-89 of Attach A.
38 Vistra Corp., *Vistra Brings World's Largest Utility-Scale Battery Energy Storage System Online,* PR Newswire (January 6, 2020), https://www.prnewswire.com/news-releases/vistra-brings-worlds-largest-utility-scale-battery-energy-storage-system-online-301202027.html
39 Lazard*, supra.*

Xcel did not offer any reasonable justification for imposing these minimum project sizes.[40] The model should be allowed to select more typical project sizes in seeking a least-cost plan—which may include combinations of resources such as solar-battery hybrids. By limiting the model's selection to these massive minimum sizes, the Company has forced it to make lumpy investments that are oversized relative to the incremental capacity or energy need in any year. The Company's modeling thus overlooks one of the significant advantages of renewable and storage projects relative to conventional generators: the ability to shape a modular portfolio of wind turbines, solar arrays, and battery containers customized to exactly meet their needs.

3. Xcel's EnCompass solar PV and battery storage cost assumptions are unreasonably inflated.

The Company's EnCompass modeling overstates the costs of both solar PV and battery storage, which further reduces the likelihood that the model will select these resources when optimizing portfolios. Xcel's cost for utility-scale solar is inflated because it does not account for economies of scale that occur with large projects, despite the fact that Xcel only modeled large projects. The costs for batteries are inflated because the Company assumed a 10-year project life (rather that a more typical 15 or 20-year life) and miscalculated the financing of capital costs.

Moreover, the Company developed levelized costs of solar PV using the 2019 NREL ATB levelized cost, which is a reasonable starting point, but it also adjusted the solar capacity factor and added its own calculation of interconnection costs that unreasonably and significantly increased those levelized costs. (We describe the interconnection costs further in the next section.)

Despite only modeling large utility-scale solar PV projects, the Company did not account for the lower costs per kilowatt that come with larger solar PV installations (i.e., economies of scale). The Company's source for $/kilowatt solar PV costs is the 2019 NREL ATB, an industry standard resource.[41] The 2019 NREL ATB cost estimate assumes a 23 MW installation size, yet Xcel uses this cost for a 500 MW project.[42] Solar projects do not have to reach 500 MW to achieve cost savings. According to data from the Lawrence Berkeley National Laboratory, for utility-scale solar projects installed in the U.S. in 2018, the costs of projects between 100 and 200 MW in size were 15 percent cheaper than projects between 20 and 50 MW (such as the 23 MW hypothetical used by NREL), and 23 percent cheaper than projects between 5 and 20 MW, as shown in Figure 3.[43] This effect was even more pronounced in LBNL's recently released 2019 data: the 100 to 200 MW solar PV projects

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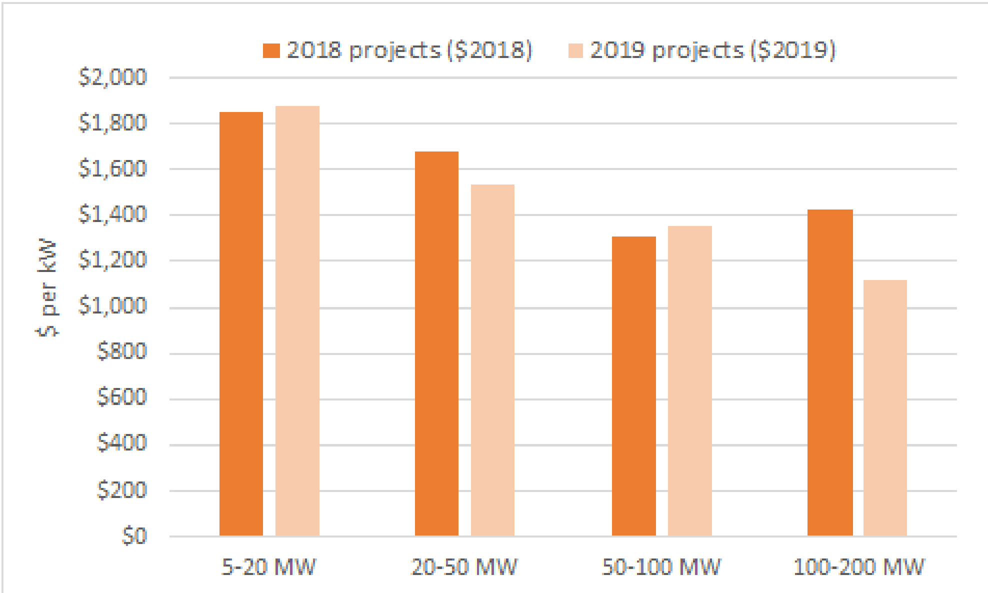
[40] *See* response to SC-35 Supp, response to SC-69 Supp.
[41] IRP Suppl. at 134 of Attach A.
[42] 19-0368 Sierra Club-097_Attachment A NREL ATB Renewable – Base; NREL Annual Technology Baseline 2019. NREL Solar - Utility PV. Available at: https://atb.nrel.gov/electricity/2019/data.html
[43] Mark Bolinger et al., *Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States –2019 Edition*. Figure 11. Lawrence Berkeley National Laboratory (December 2019), https://emp.lbl.gov/utility-scale-solar/

were 17 percent and 40 percent cheaper, compared to the smaller size categories, respectively.[44] The data below show the pronounced effect of economies of scale with project size.

Figure 3: Solar PV Economies of Scale ($ per kW by size)[45]



In our modeling, as discussed further in Section V.C below, we both updated and corrected Xcel's assumptions by: 1) using the more recent NREL 2020 ATB to update Xcel's levelized costs, and 2) incorporating economies of scale for large solar PV projects, which reduced the costs for larger projects, as shown in the Technical Appendix. For instance, the Company's final levelized cost for solar PV is $54 per MWh in 2025.[46] Our updated NREL 2020 cost for a 150 MW system is $48 per MWh; and our Corrected RE Base cost is $41 per MWh (prior to any changes to interconnection costs, as described later).

The Company used the same source for the upfront costs of battery storage as it did for solar PV, the NREL 2019 ATB, which again is a reasonable source of data and an industry standard.[47] But at the time of our analysis, the NREL 2020 ATB was available, and so we updated the cost assumptions in our modeling runs, as presented in the Technical Appendix.

Apart from this, the Company inflated its estimate of levelized costs for battery storage by using faulty financing assumptions. First, the Company assumed a 10-year life for a battery storage project, rather than a more typical 15 or 20-year life. The 10-year life assumption means that the capacity needs to be replaced more frequently, and all of the initial capital costs have to be recovered over a

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[44] Bolinger, *Update*, *supra*.
[45] Bolinger, *Empirical, supra*; Bolinger, *Update, supra*.
[46] 19-0368 Sierra Club-097_Attachment A NREL ATB Renewable – Base, Solar by Year.
[47] 19-0368 Sierra Club-097_Attachment A NREL ATB Renewable – Base.

compressed time period. The Company's own source, NREL ATB, assumes a 15-year life for batteries;[48] and Lazard assumes a 20-year life.[49] In recent procurement cases, a 20-year life has been the industry standard. Using a more reasonable lifespan for battery storage lowers the levelized costs of the resource substantially.

Second, the fixed charge rate (FCR) factor Xcel used to calculate the levelized capital costs for battery storage was too high. The Company presented levelized costs in real (or constant dollar) terms, but it used a nominal discount rate (i.e., nominal weighted average cost of capital or WACC) rather than the real discount rate (i.e., real WACC) to calculate the FCR factor.[50] This treatment inflates the costs of batteries. The levelized costs from the NREL ATB that the Company uses for wind and solar PV calculates a real levelized cost using a real WACC.[51] Thus, Xcel's method for calculating the real levelized costs of batteries is inconsistent with how the Company calculated the levelized costs for other resources in its modeling. This, along with the unreasonably short life of battery projects in the model, made battery resources appear more costly. In our analysis, we modeled both a 15-year and a 20-year battery life. These adjustments, along with corrections discussed above, reduced the costs of battery storage substantially, as shown in the Technical Appendix. For instance, in 2025, Xcel's assumed levelized cost of battery storage is $16.84 per kw-month for a 10-year resource life, whereas our costs are $11.28 per kw-month for a 15-year project (in our NREL 2020 costs) and $9.72 per kw-month for a 20-year project (in our Corrected RE Base costs).

4. Xcel's modeling of wind capacity factors is inconsistent.

As with other renewable resources, Xcel used the NREL 2019 ATB to develop levelized costs for wind. Xcel used the NREL 2019 assumption of a 45 percent capacity factor in its EnCompass modeling.[52] The NREL 2020 ATB updated this capacity factor to 47 percent. In Attachment A to the IRP Supplement, which summarizes Xcel's modeling assumptions and inputs, Xcel states that it assumed a 50 percent capacity factor for wind. [53] However, Xcel's actual EnCompass modeling input files reflect that Xcel in fact used a 45 percent capacity factor. In our NREL 2020 costs, we updated Xcel's assumption to the 47 percent capacity factor from NREL 2020; and in our Corrected RE

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48 19-0368 Sierra Club-097_Attachment D NREL ATB Battery; NREL Annual Technology Baseline 2019. Storage. Available at: https://atb.nrel.gov/electricity/2019/data.html
49 Lazard, *supra.*
50 19-0368 Sierra Club-184 Attachment.xlsx. Curiously, when asked about this in discovery, the Company claimed that the "WACC does not affect this calculation," but its own workbook shows that it indeed used the nominal WACC to calculate the FCR. Id. Xcel response to SC 184(b)
51 See: 19-0368 Sierra Club-097_Attachment A NREL ATB Renewable – Base, NREL Solar - Utility PV tab, rows 241, 247, and 291.
52 See: 19-0368 Sierra Club-097_Attachment A NREL ATB Renewable – Base, Wind by Year tab, row 5.
53 IRP Suppl. at 69 of Attach A.

Base, we assumed a 50 percent capacity factor for wind. (We also updated Xcel's wind resource costs to use the NREL 2020 ATB data; these are shown in the Technical Appendix).

The Company's final levelized cost for wind is $50 per MWh in 2025.[54] Our updated NREL 2020 cost is $48 per MWh; and our Corrected Base cost is $38 per MWh (prior to any changes to interconnection costs, as described later).

5. Xcel has assumed prohibitively high interconnection costs through the analysis period, creating another barrier to the model selecting renewable energy.

Xcel's assumed interconnection costs for solar PV and wind are unreasonably inflated, introducing an artificial barrier to adopting those resources. First, Xcel treats interconnection costs separately from other capital costs by taking the levelized costs from NREL ATB and then layering on a separate calculation for the interconnection costs that assumes a different financing mechanism. This treatment does not comport with how a power purchase agreement (PPA) would work, where the developer would finance the interconnection costs along with the other capital costs. Our Corrected RE Base costs incorporate this correction but our NREL 2020 costs do not.

Xcel's upfront interconnection costs are also inflated. In its EnCompass modeling, Xcel assumes that utility-scale solar projects have an interconnection cost of $200/kW, while wind projects are assigned an interconnection cost of $500/kW. These interconnection costs are not adequately justified. Xcel states that "the $/kW transmission interconnection cost assumptions are estimates based on a number of different studies, historical Resource Plan assumptions, and recent MISO queue study results."[55] In response to interrogatories from Sierra Club, Xcel admits that its assumed interconnection costs are a rough estimate without a solid analytic foundation,[56] and do not account for changes in transmission system flows due to generation retirements and additions that may alleviate some transmission constraints.[57] Moreover, the Company's analysis did not account for a range of technological solutions it could use to interconnect new wind and solar resources at low cost.

Xcel's interconnection cost assumptions are much higher than those that were found in a recent analysis of MISO interconnection study results by Lawrence Berkeley National Laboratory (LBNL). LBNL analyzed 194 wind and solar projects comprising 27 GW that have applied to interconnect to MISO. LBNL found that the average completed MISO wind project paid interconnection costs of only $66/kW, while the average completed solar project paid $70/kW.[58] These costs are markedly

[54] 19-0368 Sierra Club-097_Attachment A NREL ATB Renewable – Base, Solar by Year.
[55] IRP Suppl. at FN 23.
[56] Xcel response to SC 100.
[57] Xcel response to SC 101.
[58] Will Gorman et al., *Improving Estimates of Transmission Capital Costs for Utility-Scale Wind and Solar Projects to Inform Renewable Energy Policy,* Lawrence Berkeley National Laboratory at 10 (October 2019), , https://eta-publications.lbl.gov/sites/default/files/td_costs_formatted_final.pdf

lower than the $500/kW and $200/kW interconnection costs Xcel assumed for wind and solar, respectively. For wind and solar projects that have applied to interconnect but have not yet been completed, LBNL found average wind interconnection costs of $317/kW and $53/kW for solar.[59] The higher cost for proposed wind projects relative to completed projects likely reflects that wind project developers often submit speculative applications to interconnect to the grid, and only choose to move forward with projects that come in with lower costs. Thus, remaining projects are likely to have higher interconnection costs. Regardless, even the $317/kW average interconnection cost for all proposed wind projects is markedly lower than Xcel's assumption of $500/kW. For solar, Xcel's proposed assumption of $200/kW is 3-4 times greater than reality.

Vibrant Clean Energy (VCE) conducted modeling on behalf of the Citizens Utility Board (CUB) in this docket that confirms that Xcel's interconnection costs are unreasonably high. VCE's modeling shows that co-optimized generation and transmission expansion results in average interconnection costs of only $146/kW.[60] VCE has used the same tool to provide similar co-optimized generation and transmission planning analysis for the State of Minnesota, MISO, and other stakeholders in the state.[61] VCE's model includes detailed representation of MISO's transmission topology, transmission constraints, potential transmission additions, and the location of renewable resources, none of which can be accounted for in the EnCompass tool used for all of the Company's modeling, and thus presents a more analytically robust basis for an interconnection cost estimate. As a result, in some of our EnCompass modeling scenarios, we use VCE's result of $146/kW for interconnection costs, instead of the $200/kW for solar and $500/kW for wind that Xcel assumed. This more reasonable interconnection cost assumption increases wind and solar deployment in EnCompass, relative to Xcel's results.

VCE's modeling also demonstrates how batteries can reduce renewable interconnection costs, which Xcel also admits it did not account for in its modeling.[62] Battery storage resources can be strategically sited to reduce or even eliminate interconnection upgrade costs. For example, a battery located on the same side of a transmission constraint as a renewable generator can charge using

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59 *Id.*
60 CUB Initial Comments, filed February 11, 2021, in E-002/RP-19-368, attached VCE Report, "A 'Consumers Plan' for Clean Energy Across NSPM by 2035," at 36. Note that this number changed slightly as VCE made adjustments to its model after providing us with the $146/kw number; VCE's final transmission cost adder number is $149/kw, which is small enough that it should not be material to our modeling results.
61 For example, *see* Vibrant Clean Energy, LLC, *Minnesota's Smarter Grid, Pathways Toward a Clean, Reliable and Affordable Transportation and Energy System,* (July 31, 2018), https://www.vibrantcleanenergy.com/wp-content/uploads/2018/07/Minnesotas-SmarterGrid_FullReport.pdf; Minnesota Energy Storage Strategy Workshop Final Report, *Modernizing Minnesota's Grid: An Economic Analysis of Energy Storage Opportunities,* Vibrant Clean Energy (July 11, 2017), https://www.vibrantcleanenergy.com/wp-content/uploads/2017/07/Modernizing_Minnesotas_Grid_LR.pdf; and Vibrant Clean Energy, *MISO High Penetration Renewable Energy Study for 2050,* Vibrant Clean Energy (January 2016), https://www.vibrantcleanenergy.com/wp-content/uploads/2016/05/VCE_MISO_Study_Report_04252016.pdf
62 Xcel response to SC 102.

energy that would have exceeded the available transmission capacity, and release that energy later once the transmission constraint is no longer present. Because periods of very high renewable output are not typically sustained for long periods of time, even short-duration batteries can significantly reduce the amount of transmission upgrades that are needed to interconnect new wind and solar resources. VCE's model has the geographic resolution to model this benefit of battery storage, while EnCompass does not. That Xcel did not account for this benefit may partly explain why VCE's modeling deploys significantly more battery storage than Xcel's. Moreover, as discussed later in our comments, VCE's model is better able to capture the value of batteries' fast flexible response than EnCompass, as VCE's model runs at a 5-minute chronological resolution instead of hourly. Batteries can also instantly regulate power flow and voltage, potentially preventing overloads, stability concerns, or other reliability concerns that would trigger a need for costly transmission upgrades.

This transmission cost adder issue emphasizes the importance of timely regional transmission planning. Xcel should be proactively pursuing solutions to alleviate transmission congestion and reduce renewable interconnection costs. Most importantly, Xcel should push MISO to build on the Multi-Value Projects' success in delivering large net benefits to all MISO customers[63] by using the same approach to plan for another round of transmission expansion. As a large transmission owner, Xcel has considerable influence in MISO's stakeholder processes that determine which transmission projects make it through MISO's planning and cost allocation process.

Despite the success of MISO's Multi-Value Projects, MISO has more recently primarily relied on the generator interconnection process to plan and pay for large-scale network transmission elements, instead of a multi-value approach through the MTEP regional planning process. That approach is far less efficient than the multi-value planning approach, as it misses the ability to plan transmission that simultaneously meets reliability, economic, and generator interconnection needs. The generator interconnection process also results in less transmission being built than the regional planning process, due to the "free rider" problem that stifles the incentive for interconnecting generators to pay for network transmission upgrades.[64]

Xcel and Minnesota's other utilities are already behind the ball on planning for new transmission, but, if Xcel and others prioritize action, new transmission lines – and more importantly the large amounts of low-cost renewable resources they will interconnect – will be available to meet Xcel's future energy and capacity needs. If Xcel moves quickly to address transmission bottlenecks, those wind, solar, and hybrid resources can even be accessed before federal tax credits phase down.

[63] *A 2017 Review of the Public Policy, Economic, and Qualitative Benefits of the Multi-Value Project Portfolio,* MISO (September 2017), https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf

[64] Jay Caspary et al., *Disconnected: The Need for a New Generator Interconnection Policy,* Americans for a Clean Energy Grid at 16 (January 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.pdf

Federal tax credits for wind, solar, and hybrid resources were recently extended to allow qualifying projects to come online through the end of 2025, and further extensions are possible under the new Administration and Congress. For reference, through the Competitive Renewable Energy Zone projects, Texas built enough transmission to add 11,500 MW of new wind capacity in about five years.[65]

It is important that Xcel not take actions that could limit the benefits of building new transmission to access renewable generation. In particular, building the Sherco CC could limit the ability to build transmission west from the Sherco site to access high quality wind in the Dakotas. The Sherco CC would use up a significant share of the transmission capacity between the Sherco site and the Twin Cities load center, reducing the ability to deliver newly accessed wind across that segment.

In the interim, Xcel can pursue many highly cost-effective solutions to interconnect more wind and solar generation onto its existing 5,000 miles of transmission lines by increasing their capacity and utilization.

First, dynamic line ratings, power flow control devices, topology optimization techniques, and similar technologies can be deployed in a matter of months and allow new renewable resources to interconnect at low cost.[66] Recent analysis by the Brattle Group found that 2,670 MW of additional wind capacity could be added in SPP by adopting dynamic line ratings, power flow control devices, and topology optimization, more than doubling the amount of wind capacity that can be added while keeping curtailment at an acceptable level.[67] Brattle found a one-time investment of $85 million in these technologies would yield annual production cost savings of $175 million.

Dynamic line ratings allow more power to safely flow on transmission lines by accounting for how ambient weather conditions affect the thermal limits of those lines. Transmission line ratings are typically based on worst case weather assumptions: hot weather with full sun and no wind cooling the line. Dynamic line rating devices measure the actual thermal limit of transmission lines, which under most weather conditions are much higher than the limits based on those worst-case assumptions. Dynamic line rating devices are particularly effective for increasing transmission capacity in wind-producing areas, as high wind speeds cool transmission lines at the same time they drive high wind plant output. At a minimum, Xcel could use seasonal line ratings instead of its current practice of using year-round ratings that are based on worst-case summer weather

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[65] Dan Woodfin, *CREZ Transmission Optimization Study Summary,* ERCOT (April 15, 2020), http://www.ercot.com/meetings/board/keydocs/2008/B0415/Item_6_-_CREZ_Transmission_Report_to_PUC_-_Woodfin_Bojorquez.pdf

[66] Rob Gramlich, *Bringing the Grid to Life: White Paper on the Benefits to Customers of Transmission Management Technologies,* Working for Advanced Transmission Technologies Coalition (March 2018), https://watttransmission.files.wordpress.com/2018/03/watt-living-grid-white-paper.pdf

[67] https://watt-transmission.org/2021/02/05/line-ratings-and-the-future-of-renewable-energy/; study to be posted at https://watt-transmission.org/industry-publications/

conditions. This would significantly increase transmission line limits during the cooler fall, winter, and spring periods when wind output is highest.

Power flow control devices, also known as Flexible Alternating Current Transmission Systems (FACTS) devices, can also be deployed quickly to increase interconnection capacity on the existing transmission system. As noted in the CapX2050 report, these are "a collection of power electronics-based devices used to adjust the power transfer capabilities of the system and/or improve stability or controllability of the system, particularly at critical conditions. Essentially, FACTS devices help make the most of existing resources' distributing power, reducing transmission system losses and improving the efficiency of the transmission system." Topology optimization plays a similar role by taking specific transmission lines out of service to redirect power flow away from congestion transmission elements and onto more optimal paths.

Second, over the next several years, Xcel could take steps that will add capacity to existing transmission rights-of-way. These improvements can typically be completed more quickly than new transmission lines because they do not typically require new land acquisition and permitting and regulatory proceedings. For example, the CapX2020 transmission projects were presciently built with towers that allow the addition of a second circuit, but most only carry a single circuit today. Xcel could work with its CapX2020 partners to add a second Alternating Current circuit to these paths, which would likely roughly double their transfer capacity. This could add around 2,500 MW of additional transmission capacity from high-quality wind resource areas.[68] An even more ambitious option would be to add a Direct Current conductor as the second circuit for some of the longer existing lines, like the Fargo 345-kiloVolt line. While this would require the time and expense of adding Direct Current converters at either end of the line, it would yield an even larger increase in transfer capacity and access to even more low-cost wind generation. There may be similar opportunities to double circuit existing transmission lines elsewhere on Xcel's transmission system.

Other options for increasing transmission line capacity on existing rights-of-way include reconductoring existing lines with advanced conductors that can operate at a higher capacity, and replacing transmission towers with new towers that can support more circuits or higher-capacity circuits. Series compensation devices can also be added to existing transmission lines to increase transfer capacity and improve power flow.

In other cases, substation equipment may be a limiting factor for transfer capacity. Transformers, switches, and other substation equipment can be upgraded to overcome these constraints. Because they do not require new right-of-way, these upgrades can typically be made more quickly than building new transmission lines.

[68] Estimated based on the 3,600 MW of transfer capacity provided by the four CapX2020 projects, minus around 1,100 MW for the Brookings line, which was built mostly double circuit.

Independent of action by Xcel, solutions being developed by other parties may significantly alleviate transmission congestion in western MISO over the next several years. For example, planned long-distance Direct Current transmission lines to deliver wind generation from western MISO to load centers to the east, like the proposed Soo Green transmission project, could drastically alleviate transmission congestion affecting wind deliveries to Xcel's footprint. The Soo Green underground Direct Current transmission project would deliver 2,100 MW of wind generation from the Killdeer substation near Mason City, Iowa, to Chicago, significantly alleviating the transmission congestion caused by wind generation moving west to east across MISO.[69] The pick-up substation is 30 miles south of the Minnesota border, and strongly connected to Xcel's grid via the completed MVP #3 and MVP #4 lines and the under-construction Huntley-Wilmarth line. By exporting existing wind generation across MISO's west-to-east transmission congestion, the line would greatly alleviate congestion for new wind in Xcel's territory and all of western MISO.

6. Xcel has not given battery storage sufficient consideration despite it being an increasingly cost-effective peaking capacity option.

The Company's EnCompass modeling does not select new battery storage prior to 2035 in any of its 15 scenarios.[70] This result is due in part to the Company inflating the costs of batteries and limiting projects to an unrealistic minimum size of 321 MW, as discussed previously in this section. The costs of storage are expected to continue to decline and, as a result, there are substantial battery storage projects planned in the U.S.: according to the EIA, there will be 3,616 MW of new installations between 2020 and 2023.[71] In reporting this number, the EIA stated that this is likely an underestimate: "Given the short planning period required to install a storage facility, the reported planned capacity does not necessarily reflect all the possible builds during this period, but the reported planned capacity can be used as an indicator of trends."[72]

Battery storage has only recently become a prominent replacement resource and this trend is only expected to accelerate in the future given declining costs. Xcel's utility in Colorado[73] and other utilities in MISO[74] are making significant investments in storage and hybrid resources as a result of these cost declines. The Company should consider storage as a viable peaking capacity resource. Moreover, as discussed later in our comments, battery storage offers reliability services that gas

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[69] Steve Frenkel, *PJM Special Session,* SOO Green HVDC Link (May 22, 2020), https://www.pjm.com/-/media/committees-groups/committees/mrc/2020/20200528/20200528-item-03-1-soo-green-hvdc-link-presentation.ashx

[70] IRP Suppl. at 31, Figure 2-7.

[71] U.S. Energy Information Administration, *Battery Storage in the United States: An Update on Market Trends,* U.S. Dept. of Energy, at 26 (July 2020) https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

[72] *Id.*

[73] https://www.greentechmedia.com/articles/read/xcel-retire-coal-renewable-energy-storage

[74] https://www.nipsco.com/our-company/news-room/news-article/nipsco-announces-new-indiana-based-solar-projects-to-power-270-000-homes-by-2023

generators are unable to provide, but that will become increasingly important as renewable penetrations increase. This includes the ability to charge using excess renewable generation and to quickly ramp output as supply and demand fluctuate on the power system.

7. Xcel's distributed solar and Community Solar Garden (CSG) deployment forecasts are too conservative.

Xcel modeled distributed solar and community solar as a fixed supply-side forecast, rather than allowing the model to dynamically select additional amounts as part of a least-cost, optimized resource plan.[75] Xcel's forecasts are overly conservative and do not reflect the Company's ability to facilitate accelerated adoption, and its cost assumption for community solar is inflated.

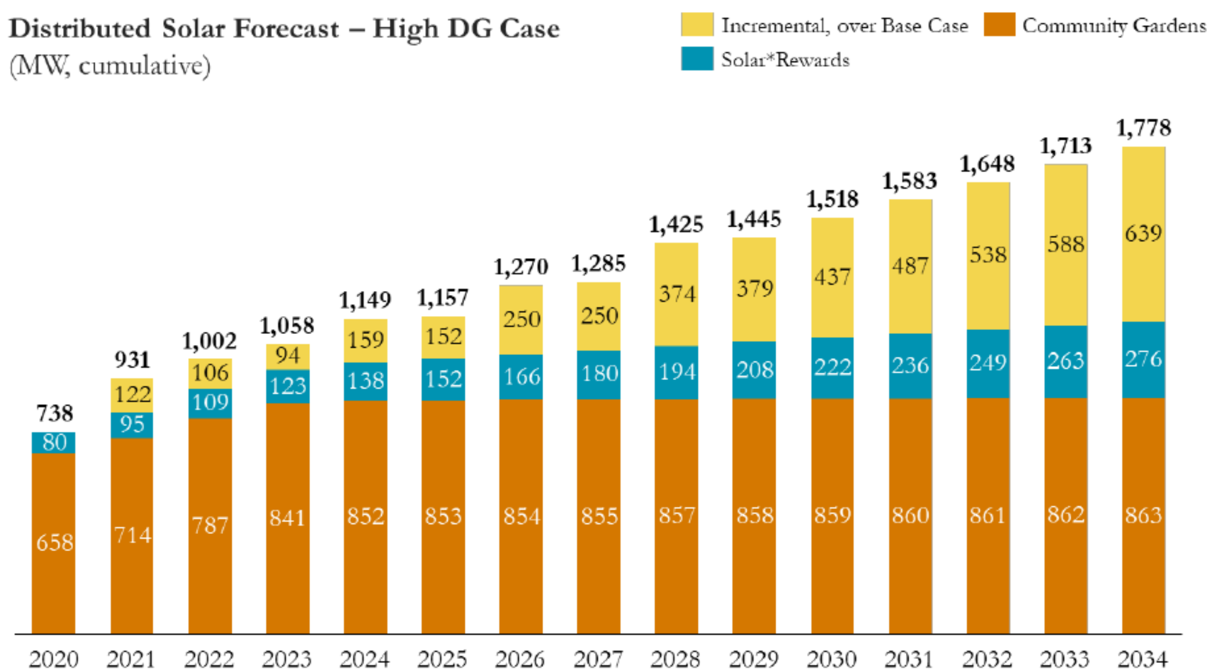
a. Xcel's distributed solar forecast is too low and ignores Xcel's ability to encourage additional DG adoption.

After 2023, Xcel assumes that only around 15 MW of new distributed solar (including CSG solar) is added per year.[76] Xcel asserts that this forecast is based on 2017 legislation that eliminated new Solar*Rewards funding after 2021, with final installations by 2023.[77] Xcel's solar forecast thus assumes distributed solar nearly stops after 2023.

Xcel also conducted a "High Distributed Solar" sensitivity, under which the Company forecasted potential additional adoption using a "payback adoption model" that assumes a 10 percent reduction to the solar installation cost curve, relative to the base case, starting in 2020. This resulted in a "high adoption case" forecast of around 1,778 MW of total installed distributed solar by 2034, or approximately 640 MW more than under its base case.[78] Figure III-2, copied below, shows both Xcel's base case and high distributed solar adoption forecasts.

[75] IRP Suppl. at 37-38 of Attach A.
[76] *Id.* at 37, 65 of Attach A, Table IV-13.
[77] *Id.* at 37.
[78] *Id.* at 38 of Attach A.

Figure 4: Xcel's Base Case and High Distributed Solar Forecasts[79]



With respect to Xcel's High Distributed Solar sensitivity (one of its "Futures Scenarios"), Xcel included the following disclaimer:

> [T]hese Futures Scenarios are intended to examine the resiliency of each baseload scenario under a combination of assumptions changes that we believe are plausible future states. They are not intended to show us which future is overall least cost for our system; we do not have full control over the level of distributed solar or electrification growth on our system, and we have no control over variables such as fuel prices and new resource capital costs.[80]

There are several problems with Xcel's distributed solar forecasting methodology. Xcel incorrectly assumes it has no control over distributed solar levels. This ignores its ability to incentivize additional DG installations even without the Solar*Rewards program. While the statutorily-created program may be expiring, this does not mean Xcel cannot propose additional programs for this Commission's approval. Programs that incentivize customers to use their private capital to build a resource to the benefit of all of Xcel's customers are well within this Commission's jurisdictional authority to approve. Xcel's own forecasting in its High Distributed Solar Adoption forecast shows that a 10% cost reduction incentive is able to stimulate significantly more customer investment in distributed generation. Thus, distributed solar is similar to energy efficiency: while the utility does not have complete control over the amount customers will add, there is sufficient data available to

[79] *Id.* at 39 of Attach A.
[80] *Id.* at 35.

forecast how various incentive levels will lead customers to adopt the societally beneficial energy resource.

Xcel's financial interests of course run counter to incentivizing customer-owned solar resources, as the utility does not secure a guaranteed rate of return on the capital costs of those projects. Xcel tries to argue that distributed generation is more expensive and thus does not make sense to make available as selectable resource in the modeling. In discovery, Xcel stated: "Distributed solar was not selected in the optimization results at any point in the preliminary modeling leading up to the IRP filing as the cost assumptions from NREL indicate that distributed solar has lower capacity factor and higher LCOE than utility scale solar."[81] Xcel's levelized costs for solar reflect this perspective: as presented in Table IV-18 of Attachment A, Xcel assumes that utility scale solar's levelized cost starts at $46/MWh, while the levelized cost of residential distributed solar starts at $92/MWh.[82] However, it would be inappropriate to use the levelized cost of distributed solar in the modeling, because this is not the cost paid by the utility and the utility's ratepayers. Instead, most of the capital cost of distributed solar is borne by the individual purchasing the system (e.g., the homeowner installing solar on their roof). Distributed solar can also provide other high-value benefits such as reducing the need for distribution system upgrades and avoiding the need for new transmission.

It appears, however, that rather than using the levelized cost assumptions for distributed generation that Xcel presents in Table IV-18, Xcel instead assumed in its modeling that distributed generation costs **[PROTECTED DATA BEGINS…PROTECTED DATA ENDS]**. It would be appropriate to use the Solar*Rewards incentive level to model the utility's costs for distributed generation, which, as discussed further in the next section, would be consistent with the method used in Synapse's modeling.

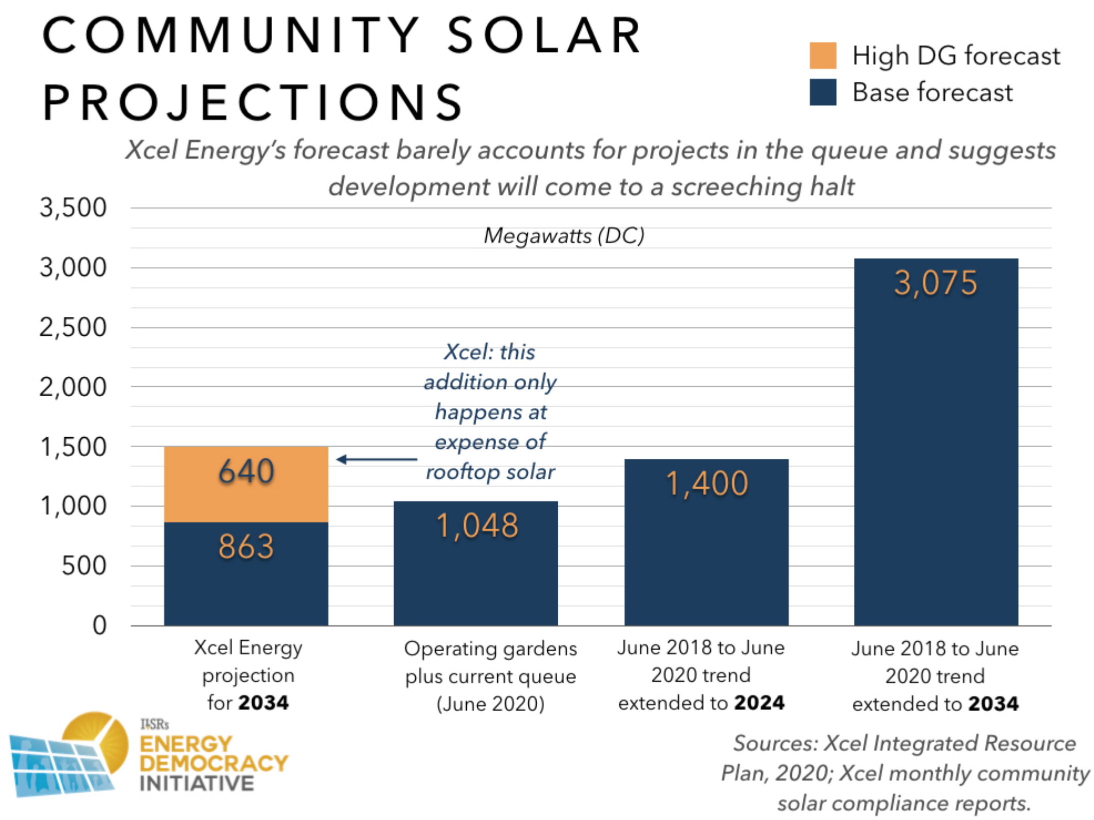
b. Xcel's treatment of community solar is unreasonable.

As with distributed solar, Xcel also uses a fixed forecast for community solar in its modeling. As shown in Figure 4, above, Xcel's community solar forecast essentially flattens in 2023, reaching 863 MW in 2034 – only 22 MW more than the level forecasted for 2023. A report by the Institute for Local Self Reliance (also discussed in detail in the Initial Comments of the Solar Coalition in this docket) explains why this forecast is unreasonable.[83] As explained in that report and in the Distributed Solar Coalition's Initial Comments[84], as of December 1, 2020, operational community solar capacity in Minnesota was 757 MW. Over the last two years, community solar in Minnesota has been growing at a rate of approximately 167 MW per year. Another 483 MW of community

[81] Xcel Response to IR SC 37.
[82] IRP Suppl. at 72 of Attach A, Table IV-18.
[83] John Farrell, *Utility Distributed Energy Forecasts: Why utilities in Minnesota and other states need to plan for more competition,* Institute for Local Self-Reliance (July 2020), https://cdn.ilsr.org/wp-content/uploads/2020/07/distributed-energy-forecasts-report-2020.pdf
[84] "Distributed Solar Coalition" refers to VoteSolar, ILSR, Earthjustice, Cooperative Energy Futures, and ELPC.

solar projects are in Xcel's queue.[85] Just the addition of the projects in the existing queue would far exceed Xcel's community solar forecast for 2034. If community solar projects continue to grow at the same rate as in the last two years, Xcel could be expected to reach 1,400 MW of community solar by 2024, and over 3,000 MW by 2034. ILSR's forecast is replicated in the chart below, and an updated forecast is included in the Distributed Solar Coalition's comments.

Figure 5: ILSR community solar forecast for Xcel based on historical trends and existing queue[86]



The amount of community solar that can be added is limited by the availability of interconnection points to distribution feeders in Xcel's territory ("hosting capacity"). Xcel reported 1,308 MW of available hosting capacity for community solar as of August 2020.[87] The combination of existing installations and available hosting capacity leads to a maximum of 2,046 MW of community solar potential, which is still more than double Xcel's community solar projection for 2034.

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85 *See* Distributed Solar Coalition's Initial Comments, February 11, 2021, docket no. 19-368.
86 *Id.* at 15
87 Docket No. E002/M-19-685, Compliance Filing, Attachment A, p. 1 of 13.

Xcel also overstates the cost of community solar in its modeling. Xcel states that it uses the market rate of energy as its community solar cost assumption.[88] The EnCompass modeling input files show Xcel's community solar cost starts at **[PROTECTED DATA BEGINS… PROTECTED DATA ENDS]** in 2019, reaching **[PROTECTED DATA BEGINS …PROTECTED DATA ENDS]** in 2034. This market rate incorporates a whole list of costs that Xcel must recover through rates, including capital costs, fuel costs, operations and maintenance costs (O&M), distribution costs, and transmission costs. The EnCompass model, in contrast, only optimizes resource plans based on capital, fuel, and O&M costs (while Xcel has also included transmission cost adders for certain resources as a proxy, EnCompass does not optimize transmission build out). Xcel's cost assumption for community solar should therefore only include the cost components reflecting avoided capacity and energy costs, i.e., the avoided cost of resources that would otherwise be needed.

One way to value this avoided cost is to simply look at the cost of the portfolio that would be built if community solar were entirely removed as a resource addition. As discussed in Section V.C below, this is the methodology used in Synapse's modeling.

A comparison to how this Commission assesses the Value of Solar may be useful. While community solar customers used to receive a credit equivalent to the Applicable Retail Rate, the Commission has since transitioned to using a value of solar (VOS) methodology. The value of solar is made up of avoided fuel cost, fixed and variable O&M, generation capacity cost, reserve capacity cost, transmission capacity cost, environmental cost, voltage control, and integration costs.[89] One arguably could use the value of solar and subtract those elements that EnCompass cannot account for to develop an EnCompass input cost assumption. The EnCompass model does not account for either the costs or the benefits of the distribution and transmission system, and so the distribution and transmission capacity costs should be removed. EnCompass also models environmental costs as a separate value; using this component of the Value of Solar in the community solar cost would thus double count these costs. Thus, for purposes of EnCompass modeling, one could take the Value of Solar and subtract both the environmental cost component and the distribution capacity cost component. As shown in the Distributed Solar Coalition's Initial Comments, the 2021 value of solar can be broken down as follows:

25 Year Levelized Values	Distributed ($/kWh) PV Value
Avoided Fuel Cost	0.0301
Avoided Plant O&M - Fixed	0.0014
Avoided Plant O&M - Variable	0.0014
Avoided Generation Capacity Cost	0.0197
Avoided Reserve Capacity Cost	0.0016
Avoided Transmission Capacity Cost	0.0175
Avoided Distribution Capacity Cost	0.0041

[88] Xcel Response to IR SC 189.
[89] *See* docket no. 13-867.

Avoided Environmental Cost	0.03940
Avoided Voltage Control Cost	0
Solar Integration Cost	0
TOTAL	**0.1152**

Source: November 6, 2019 supplemental filing in docket13-867 and approved in the March 2020 Order in the same docket

Subtracting the avoided distribution and transmission capacity costs and avoided environmental cost yields a resource value of $54.20/MWh. This is **[PROTECTED DATA BEGINS… PROTECTED DATA ENDS]** of Xcel's community solar cost assumption for 2019.

8. **Xcel ignores the likelihood that it will be able to extend many of its existing PPAs, thus overstating its capacity and energy needs**.

Xcel assumes in its EnCompass modeling that it will not extend any of its existing PPAs,[90] arguing that for contract negotiation purposes it would not be beneficial to assume the extension of any single PPA. Historically, Xcel has extended a significant share of expiring PPAs, and for planning purposes it is reasonable to assume that some share of these PPAs will be extended. For example, in the last 10 years, for four of six wind projects with expiring PPAs, Xcel either extended the PPA or purchased the facility, accounting for 174 MW of those 250 MW.[91] During that time period, Xcel also extended or purchased the majority of biomass and hydropower capacity facing expiring PPAs.[92] The 350 MW diversity sharing agreement with Manitoba Hydro that Xcel assumes expires in 2025 was extended when the predecessor agreements expired in 2015, which in turn had been in place since 1987 and 1991.[93] These existing PPAs are large sources of energy and capacity, and Xcel admits that extending these contracts would provide large amounts of capacity and energy that reduces the need for other resources such as the Sherco CC.[94] At a minimum, Xcel should assume that a reasonable share of these expiring contracts are extended, which would avoid Xcel's concern about assuming the extension of any one contract.

Xcel's supplemental application documents the significant capacity associated with these expiring PPAs. Specifically, Xcel's loads and resources table shows hydropower's peak capacity contribution drops 831 MW, from 993 MW to 162 MW, in 2025,[95] triggered mostly by the expiration of contracts with Manitoba Hydro. Xcel also shows a drop of over 1,000 MW in existing gas and oil peaking capacity between 2023 and 2027, driven mostly by expirations of existing PPAs.[96] Wind, solar, and biomass experience similar drops during that period as existing PPAs expire, contributing an

90 Xcel response to SC 112.
91 Xcel response to SC 164.
92 Xcel response to SC 166, 167.
93 Xcel response to SC 168.
94 Xcel response to SC 116 and SC 117.
95 IRP Suppl. 129 of Attach A.
96 *Id.* at 81 of Attach A.

additional loss of peaking capacity of around 200 MW, or around 500 MW of nameplate capacity.[97] Xcel's assumption that all of these contracts expire causes it to overstate its need for new peaking capacity resources by around 2,000 MW, and also overstate its need for energy.

In its supplemental application, Xcel also acknowledges that its analysis did not account for wind additions that have since been approved, including 100 MW at the Deuel Harvest and 98.9 MW at the Mower County project.[98] These two resources, and the 80 MW Elk Creek solar project, were included in all of our modeled scenarios, as discussed in the next section. However, neither we nor Xcel included the repowering of 720 MW of wind capacity that was approved by the Commission in late December 2020, as our modeling had been initiated by that time.[99] Moreover, the extension of the wind PTC in late 2020 also offers an opportunity to Xcel to pursue other repowering opportunities with placed in service dates through the end of 2025, at least. These approved and potential extensions and expansions further reduce the need for energy and capacity from resources like the proposed Sherco CC.

9. Xcel failed to adequately assess whether hybrid resources should be included in their plan, as required by Commission order.

Despite using a new model with added capabilities and having additional time to conduct modeling, the Company has failed to seriously consider hybrid resources such as solar/battery projects. In its order extending the schedule of the IRP, the Commission stated that it "would like to see additional consideration of generators powered by renewable sources of energy combined with technology for storing energy."[100] The Commission continued: "Renewable generators plus storage is a versatile combination. Given the potential benefits to be derived from combining renewable generators and storage technology, the Commission will direct Xcel to more thoroughly evaluate this combination in its revised resource plan filing."[101] However, the Company's supplemental modeling only explored hybrids as limited sensitivities. This approach short-changed hybrids from being a candidate for the preferred plan, and failed to comply with the spirit of the Commission's order.

Rather than allowing EnCompass to select hybrid resources as part of its capacity expansion optimization, Xcel only evaluated whether a hybrid option was an economic alternative to standalone renewables by manually replacing some of the standalone wind and solar additions with

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[97] *Id.* at 130 of Attach A.
[98] *Id.* at 84 of Attach A.
[99] *PUC Signs Off on $750 Million Xcel Wind Energy Project,* AP News (December 24, 2020), https://apnews.com/article/technology-utilities-minneapolis-minnesota-08f1812bc6cbaf2164ebbba959d23f48
[100] Order Suspending Procedural Schedule and Requiring Additional Findings, In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy at 4 (Nov. 12, 2019).
[101] *Id.*

hybrids.[102] Xcel's sensitivity modeling of hybrids was limited to substituting in one solar and battery or one wind and battery resource into a resource portfolio that had already undergone optimization. Xcel swapped the hybrids in for a solar PV standalone resource in 2025. This substitution led to higher present value of social costs (PVSC) and present value of revenue requirements (PVRR) results. However, contrary to Xcel's assertion, this result does not mean that hybrids are not economic. First, the same errors with Xcel's assumptions for solar PV and battery resources, individually, were replicated in their testing of hybrid resources. The Company's modeling inflated solar and battery costs, only allowed for massively scaled project sizes, and assumed inflated interconnection costs. Second, the Company's modeling of hybrids is limited to one year, 2025, but the costs of wind, solar, and battery technologies are expected to continue to decrease over time; Xcel does not test whether adding hybrids in later years would be cost-effective. Even though the Company's solar and battery storage costs were inflated, it might have found hybrid resources to be the optimal replacement at a later date if it had used the model's capability to optimize these resources.

The only reason Xcel offered for its failure to include hybrids in the optimization phase of its modeling was increased model run times. Synapse found that adding hybrids as a resource option in the optimization process did not noticeably increase its own modeling run times.

As we discuss in the next section, in our modeling, we offered hybrids to EnCompass throughout the modeling period and allowed the model to choose to add these resources as part of the optimization process. Ultimately, our modeling found that over 4,000 MW of solar paired with 1,080 MW of battery storage was a component of our lowest-cost plan. Our plan begins to add hybrids in year 2031.

We note that, in discovery, Xcel acknowledged the importance of conducting an all source RFP to their decision to propose hybrid resources in Colorado.[103] Xcel has not conducted a similar RFP or RFI in Minnesota since the early 2000s.[104] Given Xcel's resistance to reasonably assessing hybrids in its IRP, the Commission should consider ordering Xcel to conduct an all source RFP or RFI to assess hybrid costs and availability in its territory.

10. Xcel failed to adequately analyze smaller sizes of the Sherco CC, contrary to Commission order.

In its November 2019 Order, the Commission found that "Xcel proposes to build a plant capable of generating approximately 800 MW, but provides insufficient support for building a plant of that size. Consequently the Commission will direct Xcel to provide additional modeling exploring a range of

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[102] IRP Suppl. at 52.
[103] *See* Xcel response to SC-134.
[104] Xcel Response to SC-186.

sizes for the proposed Sherco CC."[105] However, the limited sensitivity analysis conducted by Xcel is inadequate to demonstrate the need for the Sherco CC, as required by the Commission.

First, the Strategist modeling results filed in the initial IRP indicate that a smaller size would be more optimal with higher levels of renewable energy. As Xcel notes:

> Strategist results showed that the 592 MW size option yielded the most favorable PVSC outcome, at approximately $45 million in savings relative to the Strategist-modeled Scenario 9 capacity expansion plan. The smallest and largest size options both yielded added cost in Strategist modeling. This difference is likely attributable to the different mix of capacity expansion portfolios in the base Scenario 9 modeling in EnCompass versus Strategist. Strategist simulations yielded a much more solar-heavy Scenario 9 portfolio that erodes some of the energy value of the default-sized Sherco CC option.[106]

As explained in Section V.D-F below, our own EnCompass modeling results found that – once the flawed assumptions discussed above that limit renewable and storage deployment are corrected – there is no need for any Sherco CC capacity. The most cost-effective size of the Sherco CC is 0 MW. If only some of Xcel's flawed assumptions were corrected, resulting in a more modest deployment of renewables and storage, modeling would likely indicate a smaller version of the Sherco CC is optimal, consistent with the results from Xcel's Strategist modeling. As discussed later, an oversized Sherco CC can particularly impair the economics of renewable generation, due to the inflexibility of combined cycle generators relative to batteries and other resources forcing the curtailment of renewable output.

Moreover, Xcel's sensitivity analysis was flawed. First, Xcel repeated the same flawed modeling process it used in its hybrid sensitivity: it only swapped out different sizes of the Sherco CC in a particular year, rather than allowing the model to optimize based on different size options. Xcel also made inconsistent assumptions for the technology used for the Sherco CC, making it difficult to conduct an apples-to-apples comparison of the economics of the different projects. Xcel modeled the larger Sherco CC option using on older 7F turbine technology, rather than state-of-the-art 7H technology assumed for the other project sizes. This results in a substantially lower capital cost for the resource of $783/kW, relative to costs of over $1000/kW for the other size options, that is likely not just due to economies of scale but rather the use of older technology. In addition, these technologies offer different levels of flexibility, which as discussed later was not fully accounted for in Xcel's analysis because of the lack of sub-hourly modeling in EnCompass. This need for flexibility is particularly important at higher renewable penetrations. As a result, both the cost and value of these technologies are different, making it difficult to determine the optimal choice.

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105 Order Suspending Procedural Schedule and Requiring Additional Findings, In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy at 4 (Nov. 12, 2019).
106 IRP Suppl. at 56.

Xcel also assumed the use of duct-firing for the smaller and larger Sherco CC options, but not the 835 MW nameplate capacity version.[107] This results in a much larger summer capacity de-rate for this option of 10.2%, versus 2.5-2.7% for the other sizes. As a result, it is possible that smaller and larger options without duct-firing, or the 835 MW option with duct-firing, would be more optimal than the options Xcel evaluated.

C. <u>When problems with Xcel's modeling assumptions were corrected, Synapse's modeling shows that there are many lower-cost alternatives to Xcel's preferred plan.</u>

Overall, as described further in this section, Synapse's modeling corrected the issues with Xcel's modeling discussed in the prior section in the following ways:

- We updated the Company's source data by using the more recent NREL 2020 ATB, instead of the 2019 ATB used by Xcel.
- We allowed the model to select smaller solar PV, wind, and battery installations, based on more typical and reasonable project sizes (shown in Table 3, below).
- We offered hybrid solar+battery and wind+battery options to the model as part of the optimization process. We used a ratio of 40 MW battery storage to 150 MW solar, which was as close as we could get to Xcel's ratio of 125:500 using our project sizes.
- We applied the lowest percent decrease in solar PV costs per kW, 15 percent, for 100 MW solar PV installations to the updated NREL ATB costs, which was a conservative way to account for economies of scale for utility scale solar PV.
- We modeled both 15- and 20-year life for batteries, instead of the 10-year life assumed by Xcel.
- We corrected the real levelized costs for batteries to use the real discount rate.
- We used the Distributed Solar Coalition's forecast for community solar additions, and used their modeling methodology for distributed generation additions.
- We added two wind projects and one solar project that were approved after Xcel began its modeling in January 2020, but not the 720 MW of wind repowering projects approved in December 2020.
- In some of our runs, we used interconnection costs from VCE's modeling.

Synapse modeled all alternative scenarios using the latest version of the EnCompass capacity expansion and dispatch model, Version 5.0. The same scenario, run in different versions of EnCompass, may result in differences to the resource selection, the unit dispatch, and the revenue requirement. Because Xcel's analysis was done using Version 4.1 of the EnCompass model, the PVSC value of any Company scenario modeled by Synapse in Version 5.0 will be slightly different than that presented by Xcel in its IRP. In order to provide a direct cost comparison between

[107] Xcel response to IR SC-190.

scenarios, Synapse also re-ran Xcel's preferred plan in Version 5.0. (It is worth noting that simply re-running Xcel's preferred plan in Version 5.0 resulted in a slightly different resource plan, including the addition of 321 MW of battery storage, as presented in the Technical Appendix.)

Xcel selected its Scenario 9 as its Preferred Plan, concluding that it "represents a path forward to achieving our carbon reduction goals affordably and reliably."[108] Synapse therefore used Scenario 9 as its starting point for its modeling, with each of our scenarios adjusting specific Xcel assumptions.

Xcel's base PVSC scenario calculation uses its high regulatory and externality cost forecast.[109] We instead calculated the PVSC for all modeled scenarios under Xcel's Sensitivity K, which offers Mid Regulatory Cost and Externality costs, because it represents the mid-point of each of the costs associated with various pollutants. As a result, our PVSC is more conservative. The scenarios modeled by Synapse on behalf of Sierra Club are presented in Table 2, below, along with the Xcel input assumptions that were adjusted in each scenario.

Table 2. Summary of Sierra Club Modeled Resource Scenarios and Accompanying Assumption Adjustments

Scenario	Sherco CC	Renewable Energy Costs	Renewable Capacity Increments	Hybrid Build Year	Interconnection Cost	DG Solar	Monticello License
Xcel Scenario 9 (Xcel's preferred plan) (1)	Fixed in 2027	Xcel Defaults	Xcel Defaults	No Hybrids	Xcel Defaults	Xcel Defaults	Extended
Xcel Scenario 9 + Approved Projects (2)	Fixed in 2027	Xcel Defaults	Xcel Defaults	No Hybrids	Xcel Defaults	Xcel Defaults	Extended
NREL2020 + Unforce Sherco CC (3)	Allow model to select if optimal	NREL 2020	Lower increments	All Years	Xcel Defaults	Xcel Defaults	No Extension
Corrected RE Base, Unforce Sherco CC (4)	Allow model to select if optimal	Corrected RE Base	Lower increments	All Years	Xcel Defaults	Xcel Defaults	Both Extended and No Extension
Corrected RE Base, Force Sherco CC (5)	Fixed in 2027	Corrected RE Base	Lower increments	All Years	Xcel Defaults	Xcel Defaults	Both Extended and No Extension

[108] IRP Suppl. at 12.
[109] IRP Suppl. at 50-51 of Attach A.

Corrected RE Base, Increased DG (6)	Allow model to select if optimal	Corrected RE Base	Lower increments	All Years	Xcel Defaults	Increased DG	Both Extended and No Extension
Corrected RE Base, Increased DG+CSG (7)	Allow model to select if optimal	Corrected RE Base	Lower increments	All Years	Xcel Defaults	Increased DG and CSG	Both Extended and No Extension
Corrected RE Base, VCE Interconnection (8)	Allow model to select if optimal	Corrected RE Base	Lower increments	All Years	VCE Interconnection	Xcel Defaults	Both Extended and No Extension
Corrected RE Base, DG+CSG+VCE Interconnection (9) **("Sierra Club Clean Energy for All Plan")**	Allow model to select if optimal	Corrected RE Base	Lower increments	All Years	VCE Interconnection	Increased DG and CSG	Both Extended and No Extension
Corrected RE Base, Increased DG+VCE Interconnection only (10)	Allow model to select if optimal	Corrected RE Base	Lower increments	All Years	VCE Interconnection	Increased DG	Both Extended and No Extension

Except for the Approved Projects scenario, Synapse modeled all its scenarios with and without the extension of the Monticello nuclear license.

1. Key changes to input assumptions

<u>Addition of approved resources</u>

In all scenarios other than our re-run of Xcel's Scenario 9, Synapse added three additional resources, shown in Table 3, that were not included in Xcel's modeling but have since been approved by the Commission. As discussed in the next section, the result of these resource additions is a $98 million decline in the resulting PVSC relative to Xcel's modeled scenario. As noted above, the 720 MW of wind repowering projects approved by the Commission in December 2020 were not reflected in either our analysis or Xcel's analysis.

Table 3. Approved Projects Added to All of Sierra Club Modeled Scenarios[110]

Name	Type	Capacity (MW)
Elk Creek	Solar	80
Deuel Harvest	Wind	100
Mower County Repower	Wind Repowering	98.9

Changes to renewables assumptions

Sierra Club's experts made several changes to correct issues with Xcel's assumptions around new build renewable and storage resources. The first of those changes was to lower the size of the new-build renewable and storage resources offered to the EnCompass model for optimization to more reasonable project sizes. A comparison of Xcel's assumed project sizes and those included in Synapse's modeling is shown in Table 4. These smaller resource sizes were included in Sierra Club runs 3 through 10.

Table 4. Comparison of new build resource increments (MW)

Resource	Xcel Increments (MW)	Start Build Date	Synapse Increments (MW)	Start Build Date
Solar	500	2023	20 & 150	2023
Wind	750	2026	80	2023
Storage	321	2023	20	2023
Paired Storage	N/A	N/A	20	2023
Behind-the-meter Solar	N/A	N/A	1	2021

We offered utility scale solar projects to the model in two different sizes, a 20 MW unit and a 150 MW unit, with the costs of the larger unit reflecting the economies of scale described above. For example, in 2025, our cost assumption for a 20 MW solar unit is $52.95/MWh compared to $48.23/MWh for a 150 MW unit. A year-by-year comparison of costs is shown in the Technical Appendix.

In contrast to Xcel, which only included hybrid resources in one of its modeled scenarios and only as a sensitivity (i.e., it did not allow the model to select hybrids as part of an optimized plan, but only substituted hybrids in for other resources in plans that had already been optimized), Synapse also

[110] Project specific information and costs for the Elk Creek, Deuel Harvest, and Mower County projects were provided in EnCompass format as part of the response to CEO 113.

offered a paired-solar-storage resource option to the EnCompass model in all scenarios, starting in 2023. This resource paired 40 MW of battery storage with the larger 150 MW solar unit.

Xcel did not allow new wind resources to come online until 2026, citing transmission constraints. Synapse lowered the online date to 2023, reflecting the ability of the Company to bring an 80 MW wind farm online much faster than a 750 MW wind farm. (This change did not end up impacting our modeling results, as our preferred plan does not add wind until 2026.)

Renewable energy cost adjustments

Using the Company's framework for calculating the levelized costs of solar PV, wind and battery storage, in addition to the changes described above, we modeled two alternative renewable and battery cost pathways: "NREL 2020" and "Corrected RE Base."

The "NREL 2020" cost forecast includes the following adjustments and was used in Sierra Club Scenario 3:

- For all resources:
  - We updated the Company's source for solar PV, wind, and battery costs—NREL 2019 ATB—to use the more recent 2020 ATB.
  - Xcel had applied the Investment Tax Credit (ITC) to the entire levelized cost of solar and solar battery hybrid projects. But these credits should only apply to capital costs of the project, which are still a major portion of the costs. Therefore, where applicable, we only applied the ITC to capital costs, rather than the entire levelized cost as Xcel did. Note: this adjustment slightly increased levelized costs, all else equal.
- For solar and wind resources:
  - The NREL 2020 ATB increased the project life from 25 to 30 years—which would lower the levelized costs. However, in order to be conservative and consistent with Xcel, we kept the project life to 25 years.
  - We kept the capacity factor for solar PV and wind constant, whereas the NREL 2020 ATB assumed they would increase—again in the interest of being conservative.
- For battery storage:
  - We assumed a 15-year project life, rather than Xcel's 10-year assumption.
  - We corrected the real levelized cost calculation to use the real WACC instead of the nominal WACC.
  - Xcel improperly levelized the fixed O&M of future installations in its calculations. We corrected this by taking the annual fixed O&M costs from the NREL 2020 ATB, rather than the levelized cost of future fixed O&M. Note: this adjustment slightly increases levelized costs, all else equal.

The Corrected RE Base starts with the adjustments above from the NREL 2020 costs, but in addition:

- For solar and wind resources:
  - Rather than treating interconnection costs separately from other capital costs by taking the levelized costs from NREL ATB and then layering on a separate calculation for the interconnection costs that assume a different financing mechanism (as Xcel incorrectly did), we included Xcel's interconnection cost assumptions in the NREL ATB calculation, financed in the same manner as the rest of the capital costs.
  - Xcel did not account for a PTC and ITC provision that allows developers several years to bring their projects online once they start construction and qualify for the federal tax credits. In order to adjust for this, we accounted for the fact that the safe harbor provision extends the placed-in-service deadline for facilities that qualify for tax credits by two years, relative to Xcel's assumption (*e.g.*, we model a 22 percent ITC for solar projects placed in service in 2023, rather than 2021 under Xcel's assumptions). Note: this adjustment did not change our results because none of our scenarios built renewable capacity prior to 2025. However, our modeling was initiated before the extension of the renewable and hybrid tax credits at the end of December 2020. As a result, projects coming online through 2025 can now take advantage of the higher value PTC and ITC credits, so our results conservatively understate the near-term opportunity to add those resources.
- For battery storage:
  - We assumed a 20-year project life, instead of the 15 years in our "NREL 2020" case or the 10 years assumed by Xcel.
- For wind:
  - We used the 50 percent capacity factor that Xcel presents in the IRP, instead of the 47 percent it used in calculating levelized costs.[111]

The Corrected RE Base cost assumptions correct all errors identified by our experts with Xcel's cost assumptions and so represent the most reasonable set of cost assumptions, in our experts' opinions. As a result, these costs were used in Sierra Club Scenarios 4 through 10.

<u>VCE interconnection costs</u>

Synapse conducted some runs (8, 9, and 10) using the interconnection cost assumption that resulted from VCE's modeling, $146/kW, instead of Xcel's assumption of $200/kW for solar and $500/kW for wind. As explained above, VCE's model better represents the ability to co-optimize transmission

[111] IRP Suppl. at 69.

and generation expansion, and to use battery storage to reduce renewable interconnection costs. Notably, VCE's interconnection cost result is higher than the interconnection cost LBNL found for recently completed wind and solar projects in MISO, and so our assumption may be conservative.

The levelized costs of solar PV, wind, and battery storage that Synapse modeled are shown in the Technical Appendix.

Optimization of Sherco CC

In Xcel's Scenario 9 (and all of Xcel's other modeling runs), Xcel hardcoded the Sherco CC resource addition in the year 2027. That is, Xcel forced the model to include the Sherco CC in all of its runs, regardless of cost. Synapse's modeling, in contrast, allowed the EnCompass model to choose whether to add the Sherco CC as part of its capacity optimization process, depending on whether the model found it to be a least cost resource addition. Synapse made the Sherco CC a resource option that the model could select in every run. Because none of our runs selected the Sherco CC, Synapse conducted an additional run (Sierra Club Scenario 5) in which it forced the model to select the Sherco CC in order to isolate the impact of the gas plant addition on total resource plan costs.

Distributed generation (DG) and community solar

In several of Sierra Club's modeling runs, Synapse used distributed generation and community solar forecasts that were developed by the Distributed Solar Coalition. Rather than modeling distributed generation as a static supply side forecast as Xcel did, the Coalition instead developed a methodology comparable to Xcel's methodology for modeling energy efficiency, wherein "bundles" of efficiency were made available for selection at different price points. This methodology is further described in the Distributed Solar Coalition's Initial Comments. The Coalition used existing models to estimate the amount of DG adoption that could be spurred depending on the amount of incentive offered by the utility (expressed in dollars per MWh). For example, their forecast estimates that 33 MW of additional DG solar (on top of Xcel's base DG forecast) will be built in Minnesota in 2021 if no incentive is offered, and that an additional 14 MW of DG could be built with a $10/MWh incentive, 17 MW with a $20/MWh incentive, etc. These numbers are incremental additions as the incentive level is increased, meaning that while 33 MW would be added with no incentive, a total of 47 MW of additional DG would be built in 2021 with a $10 MW incentive (33 MW + 14 MW). EnCompass was allowed to select the economic amount of DG to add in a given year based on program incentive level, which ensures that the volume of DG included in the resource portfolio is optimized. In this manner, the forecast can be thought of as offering mini DG PPAs, with a limited amount of DG available at each price point. The Distributed Solar Coalition's "Increased DG" forecast is shown in Table 5.

Table 5. "Increased DG" Forecast: Cumulative Distributed Generation Resource Options, by Price (MW AC) – Incremental Additions, from left to right

Year	$0/MWh	$10/MWh	$20/MWh	$30/MWh	$35/MWh	$40/MWh
2021	33	14	17	21	12	14
2022	60	26	33	40	23	26
2023	65	33	41	51	29	33
2024	74	40	51	63	37	41
2025	89	49	62	77	45	50
2026	109	60	75	94	55	61
2027	136	72	90	112	66	73
2028	169	86	108	134	78	86
2029	211	102	127	158	92	101
2030	262	120	149	184	107	118
2031	322	140	174	214	124	137
2032	393	163	201	247	143	157
2033	476	188	231	283	163	179
2034	572	215	265	322	185	203

Synapse used this "Increased DG" methodology in Sierra Club runs 6, 7, 9, and 10.

In certain runs, we used an "Increased CSG" assumption in which we substituted ILSR's community solar forecast for Xcel's community solar forecast. As discussed further in the Distributed Solar Coalition's Initial Comments, this "Increased CSG" forecast is based on the trend in recent community solar installations reported by Xcel.[112] From the end of 2018 through July 2020 (19 months), on average, there were 140 MW of new community solar installations, on an annual basis. Xcel also reported 1,308 MW of available hosting capacity for community solar as of August 2020.[113] The combination of existing installations and available hosting capacity leads to a maximum of 2,046 MW of community solar potential.[114] Therefore, we modeled 140 MW of incremental community solar per year until that potential maxed out the hosting capacity in 2030. After that point, we assumed no new community solar installations. This approach is still conservative because it assumes no increase in hosting capacity in the next nine years. This revised community solar forecast is shown in the Appendix.

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[112] Xcel response SC 181 reports actual installations for 2018 through July 2020. The annual average from the end of 2018 through July 2020 is 140 MW per year.
[113] Docket No. E002/M-19-685, Compliance Filing- Hosting Capacity Results_Attachment A, p. 13.

Synapse used this "Increased CSG" forecast in Sierra Club runs 7 and 9.

Rather than using Xcel's market energy cost as the CSG cost assumption, Synapse instead calculated the value of community solar based on the cost of avoided capacity and energy from alternative resource additions. This approach approximates the avoided generation and transmission costs of CSG because Synapse modeled both: 1) a portfolio where additional CSG is built and 2) a portfolio where other resources are built instead, as optimized by the model. For example, Sierra Club runs 6 and 7 are identical except that run 7 uses ILSR's community solar forecast and run 6 uses Xcel's. (Similarly, runs 9 and 10 use VCE's interconnection cost assumption and are otherwise identical, except run 9 includes ILSR's community solar forecast, while run 10 uses Xcel's.) In run 7, Synapse modeled ILSR's increased CSG forecast at a $0/MWh cost. The cost differential between run 6 and 7 is the avoided cost from increased community solar. In its total PVSC chart below, Synapse therefore substituted in the cost of run 7 for run 6. Similarly, the total PVSC for run 10 was substituted in as the total PVSC for run 9. Use of this avoided cost as the cost of community solar translates into a cost of **[PROTECTED DATA BEGINS**…**PROTECTED DATA ENDS]**. It is reasonable that this avoided cost is lower than the avoided cost component pulled from the 2020 Value of Solar calculation because added CSG is mainly displacing new utility-scale solar in Synapse's modeling runs, and the costs of that resource are expected to decline in the future. Thus, a cleaner, lower-cost portfolio should eventually lead to lower avoided costs. In addition, this analysis does not account for distributed solar's ability to provide local transmission and distribution spending deferral benefits, as EnCompass does not account for those benefits.

D. Synapse modeling results

Synapse's modeling results show that Xcel's preferred plan is not the least cost option for its customers. Although Synapse made the Sherco CC an option for the model to choose in all of its runs, the model never selected it. By forcing the modeling to add the Sherco CC, Synapse was able to compare the cost of plans with and without the new gas plant, and found that not building the Sherco CC would save customers approximately $150-$200 million. Even under renewable energy cost assumptions that simply updated Xcel's assumption from the NREL 2019 to NREL 2020 database, the model chose not to add the Sherco CC, indicating that it is not a cost-effective resource addition.

Synapse's modeling also shows that, when the NREL 2020 cost assumptions are used, it is slightly more expensive (by $30 million) not to relicense the Monticello nuclear plant; once other corrections to Xcel's renewable energy cost assumptions are made, using the "Corrected RE Base" cost assumptions, the license extension becomes the more expensive choice by approximately $200 million. Moreover, when more reasonable renewable energy cost assumptions are employed (under both the "NREL 2020" and "Corrected RE Base" cost assumptions), the model does not select any new CC or CT gas plants, but instead selects portfolios containing higher levels of renewable energy, hybrids, and battery storage. Finally, the model views adding distributed generation as an attractive choice, and the portfolios with high levels of distributed generation (including community solar) are by far the most cost effective. In total, Sierra Club's preferred plan saves customers more than $2.2 billion.

1. Summary of Synapse Modeling Results

A summary of the resulting PVSC values for each of the Sierra Club scenarios is shown in Table 6. The Sherco CC is a forced addition in Scenarios 1, 2, and 5. For all other scenarios, the Sherco CC was a resource option that was made available to EnCompass; however, the EnCompass model did not choose to add the Sherco CC as part of the least-cost resource portfolio in any of our scenarios.

Table 6. Summary PVSC Results for Sierra Club Scenarios, Relative to Xcel's Preferred Plan

Scenario	Extended Monti NPV ($million)	No Monti Extension NPV ($million)
Xcel's Preferred Plan ("Scenario 9") (1)	$39,790	N/A
Xcel's Preferred Plan + Approved Projects (2)	$39,693	N/A
NREL2020 + Unforce Sherco CC (3)	$38,255	$38,289
Corrected Base RE Base/Unforce Sherco CC (4)	$36,685	$36,516
Corrected RE Base + Force Sherco CC (5)	$36,890	$36,673
Corrected RE Base + Increased DG (6)	$36,277	$36,076
Corrected RE Base + Increased DG+CSG (7)	$36,277	$36,076
Corrected RE Base + VCE Interconnection (8)	$35,833	$35,556
Corrected RE Base + Increased DG+CSG+VCE Interconnection (9) (Sierra Club Preferred Plan or "Clean Energy For All Plan")	**$35,465**	**$35,190**
Corrected RE Base + Increased DG+VCE Interconnection (10)	$35,465	$35,190

Sierra Club's preferred plan is its scenario 9, which represents the culmination of all of the corrections made by our experts: the Corrected RE Base cost assumptions, ILSR's "Increased DG" forecast and community solar forecast, and VCE's interconnection costs. We call the results from this modeling scenario "Sierra Club's Clean Energy For All Plan."

Note again that the PVSC values for the resource portfolios that add both new DG and new CSG are the same as the resource portfolios that include new DG only. As explained above, the CSG resources were offered to the EnCompass model at zero cost, and we made the assumption that the avoided cost of those resources represents the cost to add them to the resource portfolio. For this reason, the PVSC value of the DG/CSG resource portfolios are assumed to be the same as in the DG only resource portfolios.

With the exception of the "Xcel's Preferred Plan" and "Xcel's Preferred Plan + Approved Projects" scenario, each of the Sierra Club scenarios included adjustments to Xcel's input assumptions—most notably, corrections that resulted in lower renewable and storage costs. Therefore, the "delta" NPV relative to Xcel's preferred plan is in part due to modeling lower costs of these new resources than were assumed by Xcel. Because these corrected renewable costs were not included when Synapse remodeled Xcel's Preferred Plan, one cannot get an "apples to apples" comparison by comparing the cost of the "Xcel's Preferred Plan" run to the costs in the other runs.

In order to provide such an "apples to apples" comparison of Xcel's Preferred Plan and Sierra Club's Clean Energy For All Plan, Synapse modeled an additional sensitivity that assessed the cost of the resource buildout under Xcel's Preferred Plan under our "Corrected RE Base" cost assumptions and VCE's interconnection costs. Under these corrected assumptions, Xcel's Preferred Plan results in a revenue requirement of approximately $37.4 billion, compared to $35.5 billion under Sierra Club's Corrected RE Base + DG/CSG/VCE Interconnection scenario that extends the Monticello license. The value of eliminating the Sherco CC and the firm peaking resources is thus the difference between these scenarios – approximately $1.9 billion, as shown in Table 7. Sierra Club's Clean Energy for All Plan, which does not extend the Monticello nuclear license, results in a revenue requirement of $35.2 billion, for another $300 million in customer savings as a result of that retirement. In total, Sierra Club's plan saves customers more than $2.2 billion.

Table 7. Comparison of Xcel Preferred Plan and Sierra Club Preferred Plan Under Corrected Assumptions

Scenario	Extended Monti NPV ($million)	No Monti Extension NPV ($million)
Xcel's Preferred Plan ("Scenario 9") Under Sierra Club Corrected Base RE + VCE Transmission Cost Assumptions	$37,395	N/A
Sierra Club Clean Energy For All Plan (Corrected RE Base + DG/CSG/VCE Interconnection)	$35,465	$35,190
Delta from Xcel's Preferred Plan	($1,930)	($2,205)

The following subsections highlight key findings from Synapse's modeling.

2. Synapse's modeling identifies significant cost savings from not building the Sherco CC.

In Sierra Club's first alternative run to Xcel's Preferred Plan, run 3 ("NREL2020 + Unforce Sherco CC") includes updated NREL 2020 resource costs and allows the EnCompass model to determine whether the Sherco CC is an optimal addition to the resource portfolio. Other than using the new version of EnCompass, no other changes were made to Xcel's assumptions. When given the choice, EnCompass did not select the Sherco CC, but instead added additional solar and storage resources, both paired and on a standalone basis, as a substitute for the combined cycle unit. EnCompass also did not select the additional gas-fired combustion turbines (or "firm peaking" resources, as Xcel says) that appear in Xcel's Scenario 9.

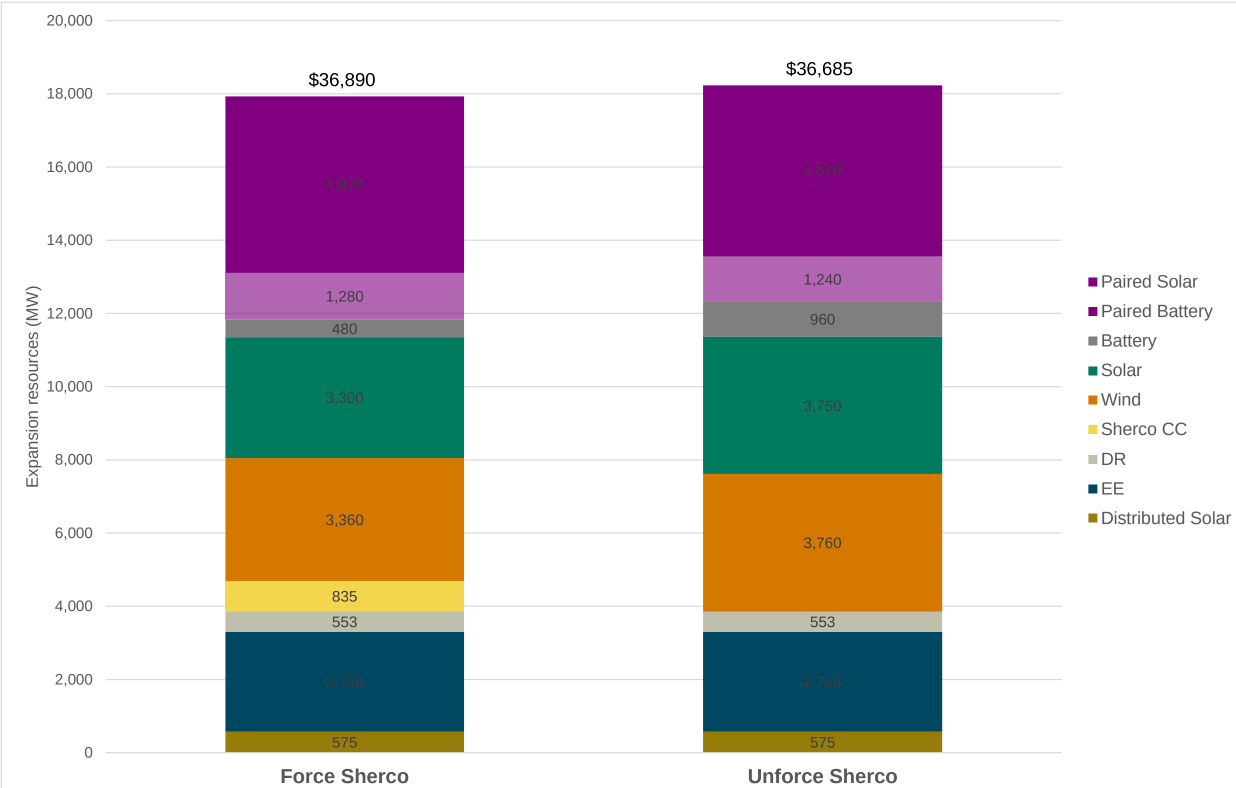
In order to isolate the cost impact of adding the Sherco CC, Synapse conducted one scenario where we first allowed the model to decide whether to add the gas plant (the "Corrected RE Base/Unforce Sherco CC" run), using the Corrected RE Base cost assumptions, i.e., the set of renewable energy cost assumptions that corrected all errors our experts identified with Xcel's cost estimates. The model chose not to add the gas plant, and so we forced the model to choose the Sherco CC in a second run ("Corrected RE Base/Force Sherco" run), as Xcel did in its modeling, as opposed to letting the model choose the optimal resource. Comparing the results of the two runs shows that forcing the Sherco CC into the scenario adds a cost of $205 million (with the Monticello extension) or $157 million (without the Monticello extension) under the "Corrected RE Base" assumptions. Those results are shown in Table 8, below.

Table 8. Comparison of Forced and Unforced Sherco under Corrected RE Base Assumptions

Scenario	Extended Monti NPV ($million)	No Monti Extension NPV ($million)
Corrected RE Base/Unforce Sherco CC (4)	$36,685	$36,516
Corrected RE Base + Force Sherco CC (5)	$36,890	$36,673
Delta	($205)	($157)

A comparison of the new-build resources selected by the EnCompass model in the Corrected RE Base scenarios with Sherco Forced and Unforced (with the Monticello extension) is shown in Figure 6. Neither scenario adds additional combustion turbines. While a slightly higher number of MW are added in the Unforce Sherco scenario, the total revenue requirement of that scenario is lower than in the Force Sherco scenario.

Figure 6. Comparison of Expansion Resources (MW), Corrected RE Base/Unforce Sherco CC (4) versus Corrected RE Base + Force Sherco CC (Extend Monti) (5)



3. **Synapse's modeling finds that the Monticello license extension is not in customers' interests.**

Synapse modeled most of its scenarios both with and without the Monticello license extension to assess the reasonableness of including the extension in the preferred plan. In the NREL2020/ Unforce Sherco CC scenario, when the license was allowed to expire, the EnCompass model chose to replace Monticello with carbon-free resources, adding additional amounts of wind, solar, and battery storage. This scenario also results in a lower PVSC than Xcel's Scenario 9, shown in Table 9, and is only slightly more expensive (approximately $34 million) than the NREL2020/Unforce Sherco CC scenario with the Monticello license extension.

Synapse modeled every subsequent scenario both with and without extending the Monticello license. In every other scenario, it is cheaper to retire the Monticello unit than to extend the operating license. When all identified issues with Xcel's renewable energy assumptions were corrected ("Corrected RE Base"), it was always cheaper for EnCompass the replace the Monticello unit in 2030 with new wind, solar, and battery storage resources and no new gas-fired capacity. The economics of continuing to operate the Monticello unit depend on the price and availability of new renewables and storage: if these replacement resources are available at costs lower than was assumed by Xcel in its IRP, as Sierra Club's experts believe is reasonable to assume, it becomes more economic for Xcel to retire Monticello at the end of its current operating license.

Table 9. Comparison of Revenue Requirements Associated with Sherco CC Optimization and Monticello Extension

Scenario	Extended Monti NPV ($million)	Delta from Xcel Scenario 9	No Monti Extension NPV ($million)	Delta from Xcel Scenario 9
Xcel's Scenario 9 (Xcel's preferred plan) (1)	$39,790	-		
NREL 2020 + Unforce Sherco CC (3)	$38,255	($1,535)	$38,289	($1,501)
Corrected RE Base, Unforce Sherco CC (4)	$36,685	($3,105)	$36,516	($3,275)
Corrected RE Base, Force Sherco CC (5)	$36,890	($2,900)	$36,673	($3,118)
Corrected RE Base, Increased DG (6)	$36,277	($3,513)	$36,076	($3,714)
Corrected RE Base, Increased DG/CSG (7)	$36,277	($3,513)	$36,076	($3,714)
Corrected RE Base + VCE Interconnection (8)	$35,833	($3,957)	$35,556	($4,235)
Corrected RE Base + DG/CSG/VCE Interconnection (9) (Sierra Club Clean Energy for All Plan)	**$35,465**	**($4,325)**	**$35,190**	**($4,600)**
Corrected RE Base + DG/VCE Interconnection (10)	$35,465	($4,325)	$35,190	($4,600)

4. Synapse's modeling does not add any new gas capacity in any scenario.

In addition to the fixed Sherco CC, Xcel's Preferred Plan adds 2,244 MW of new combustion turbines by 2034. As discussed further in the next section, Xcel's modeling results show that these resources operate at capacity factors of **[PROTECTED DATA BEGINS…PROTECTED DATA ENDS]** during the analysis period, demonstrating that these resources are seldom called upon for energy generation. The Sierra Club scenarios, in contrast, consistently selected battery storage resources, both standalone and paired solar-plus-storage, in lieu of new gas capacity.

Xcel notes that its Preferred Plan "includes cost assumptions that reflect an estimate of the amount of investments required to extend the lives of our existing black start generating facilities beyond their existing planned retirement dates to 2030" and that some of the firm peaking resources (new CTs) added in that Plan from 2030 to 2034 could also provide black start services.[115] The Synapse modeling preserved Xcel's input value that represents the cost of extending the lives of existing resources. However, future CT additions in 2030 and beyond were not selected by the EnCompass model and were thus not part of a least-cost plan. Because these units are not added until 2030, if they are indeed necessary for black start capability, this need is more appropriately addressed in future IRP proceedings.

E. Sierra Club's Clean Energy For All Plan is significantly lower in cost than Xcel's Preferred Plan.

Sierra Club's Scenario 9 is the least cost option and represents Sierra Club's Preferred Plan ("Clean Energy For All" Plan). This scenario corrects all issues identified with Xcel's renewable cost and size assumptions, uses VCE's interconnection costs and ILSR's community solar forecast, and optimizes solar DG in accordance with the values developed by Vote Solar and ILSR. Relative to Xcel's Scenario 9, Sierra Club's Clean Energy For All Plan has:

- almost twice the amount of wind,
- over 5,400 MW of utility scale solar (including more than 4,000 MW paired with 1,000 MW of battery storage),
- an additional 1,020 MW of standalone battery storage,
- more than double the amount of community solar and seven times more distributed solar, and
- less than one-third of the amount of gas capacity on a firm basis.

Resource additions and retirements in both the Xcel Preferred Plan and Sierra Club's Clean Energy For All Plan are shown in Table 10.

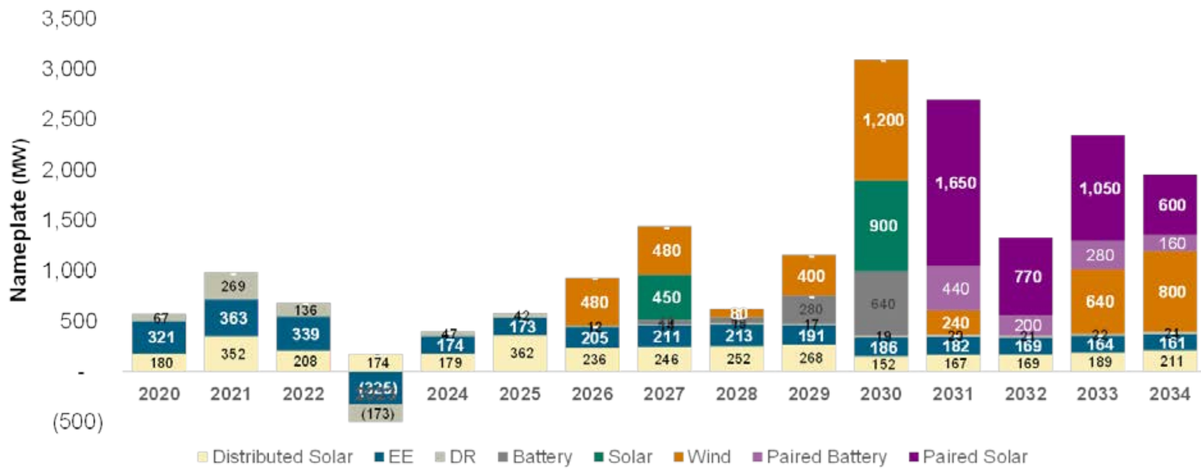
115 IRP Suppl. at 5.

Table 10. Comparison of Resource Additions Under Xcel's Preferred Plan and Sierra Club's Clean Energy For All Plan

Resource Type	Xcel's Preferred Plan	Sierra Club's Clean Energy For All Plan
Coal	Sherco 1 in 2026 Sherco 2 in 2023 + seasonal dispatch Sherco 3 by 2030 King in 2028	Same
Combined Cycle Gas	Sherco 800 MW CC in 2027	None
Other Potential Gas	2,600 MW cumulative new firm peaking 2030-2034	No new CTs
Utility Scale Renewables	3,500 MW new utility scale solar 2025-2030 2,250 MW new wind by 2034	1,350 MW new utility scale solar by 2034 4,320 MW new wind by 2034
Paired solar-plus-storage ("hybrid solar")	None	4,070 MW solar 1,080 MW battery
Distributed Solar	863 MW CSG 276 MW DG solar	2,050 MW CSG 1,851 MW DG solar
Battery Storage	None	1,020 MW by 2034
Nuclear	Monticello license extension through 2040	Monticello through 2030 (no license extension)
Demand Side Management	780 GWh/year savings through 2034 400 MW new DR by 2023	Same

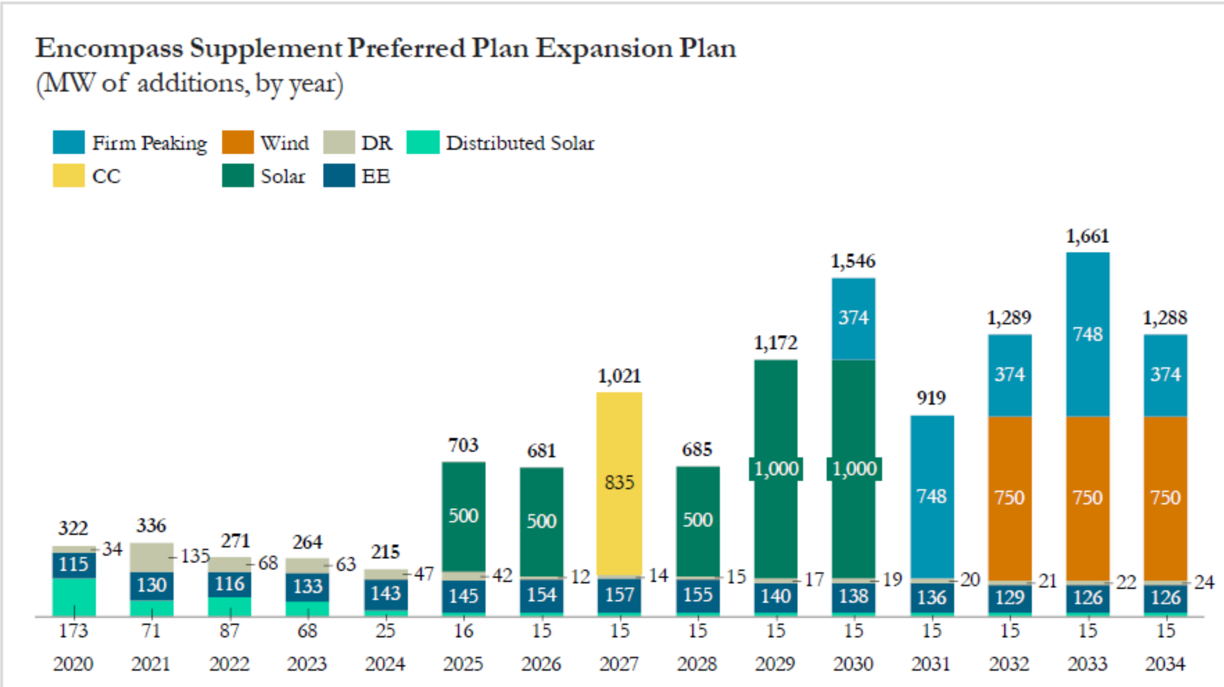
Annual incremental resource additions, by technology type, are shown in Figure 7 for Sierra Club's Clean Energy for All Plan and in Figure 8 for Xcel's Preferred Plan. The data underlying Figure 7 is also included in the Technical Appendix.

Figure 7. Annual Incremental Resource Additions, Sierra Club's Clean Energy For All Plan[116]



116 Xcel's modeling methodology incorporates two modeling runs for each of its scenarios. The first model run is a capacity optimization run, the "parent run," which generates the future resource portfolio and begins in 2023. The second model run begins in 2020 and dispatches the resources that were added in the parent run. Certain of Xcel's EE resources are added from 2020-2022, however. The Company's resource modeling was conducted using EnCompass Version 4.3.1, which contained a problem in which the dispatch runs (that began in 2020) that used the parent run expansion plan (that began in 2023) were not including these EE resources added between 2020 and 2022. The workaround proposed by Anchor Power affected all model runs in Version 4.1.6 and later, such that the results double count the EE_OPT and EE_PROG resources between 2020 and 2022. It also causes the annual additions for EE in 2023 to appear negative when these MW values disappear. This occurs in all our modeled scenarios and was discovered too late in the process to correct. Because it occurs in every scenario, and only between 2020 and 2022, the cost delta between scenarios should not be affected, nor should it materially impact the capacity expansion results.

Figure 8. Annual Incremental Resource Additions, Xcel's Preferred Plan



Sierra Club's Clean Energy For All Plan builds just over 300 more megawatts (on a firm basis) by 2034 than does Xcel's Preferred Plan. Low variable cost energy from these resources is replacing the energy that would have been generated in Xcel's Preferred Plan from the Sherco CC and the new CT units, and displacing a portion of the generation from Xcel's existing CCs. Capacity factors for Xcel's gas-fired units in 2034 are shown in Table 11 – Trade Secret. The ability of renewables to displace generation from existing fossil-fueled resources lowers the CO_2 emissions from Xcel's resource portfolio and moves the Company closer to its emission reduction goals.

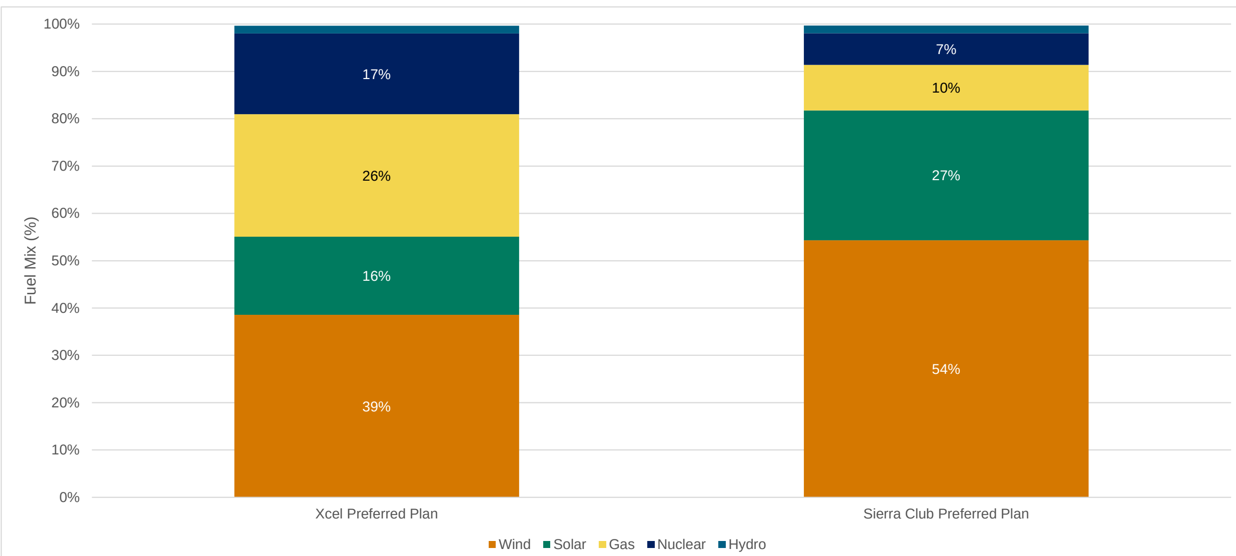
Table 11. Capacity factors of Xcel's gas-fired resources, 2034 – TRADE SECRET

Resource	Xcel's Preferred Plan, Capacity factor (%)	Sierra Club Preferred Plan, Capacity factor (%)
	[PROTECTED DATA BEGINS…	
Angus Anson 2		
Angus Anson 3		
Angus Anson 4		
Black Dog 6		
Blue Lake 7		
Blue Lake 8		
New CT		
High Bridge 2x1		
Mankato Energy Center 2		

Riverside 2x1		
Sherco CC		**…PROTECTED DATA ENDS]**

Wind and solar generation make up a greater percentage of the fuel mix in 2034 under Sierra Club's Clean Energy For All Plan than in Xcel's Scenario 9, making up 81 percent of total generation when the Monticello license is allowed to expire. In Xcel's Preferred Plan, wind and solar generation make up 55 percent of total generation. Fuel mix in 2034 is shown in Figure 9.

Figure 9. Comparison of Fuel Mix as a Percent of Generation, Xcel's Preferred Plan vs. Sierra Club's Preferred Plan (no Monti license extension) ("Clean Energy For All" Plan), 2034



In Xcel's preferred plan, generation from gas makes up 26 percent with the addition of the Sherco CC and 2,244 MW of additional gas-fired combustion turbines. The EnCompass model did not build any of these additional gas-fired resources in Sierra Club's Clean Energy For All Plan, and thus gas makes up 10 percent of generation in 2034.

Minnesota customers save a significant amount of money under Sierra Club's Clean Energy For All Plan relative to Xcel's Preferred Plan. As shown in Table 12, the net present value of Xcel's Preferred Plan (as modeled in EnCompass Version 5.0 and using our Corrected RE Base and VCE transmission cost assumptions) is approximately $37.4 billion. Sierra Club's Clean Energy For All Plan has a revenue requirement of approximately $35.2 billion, resulting in savings to customers of $2.2 billion.

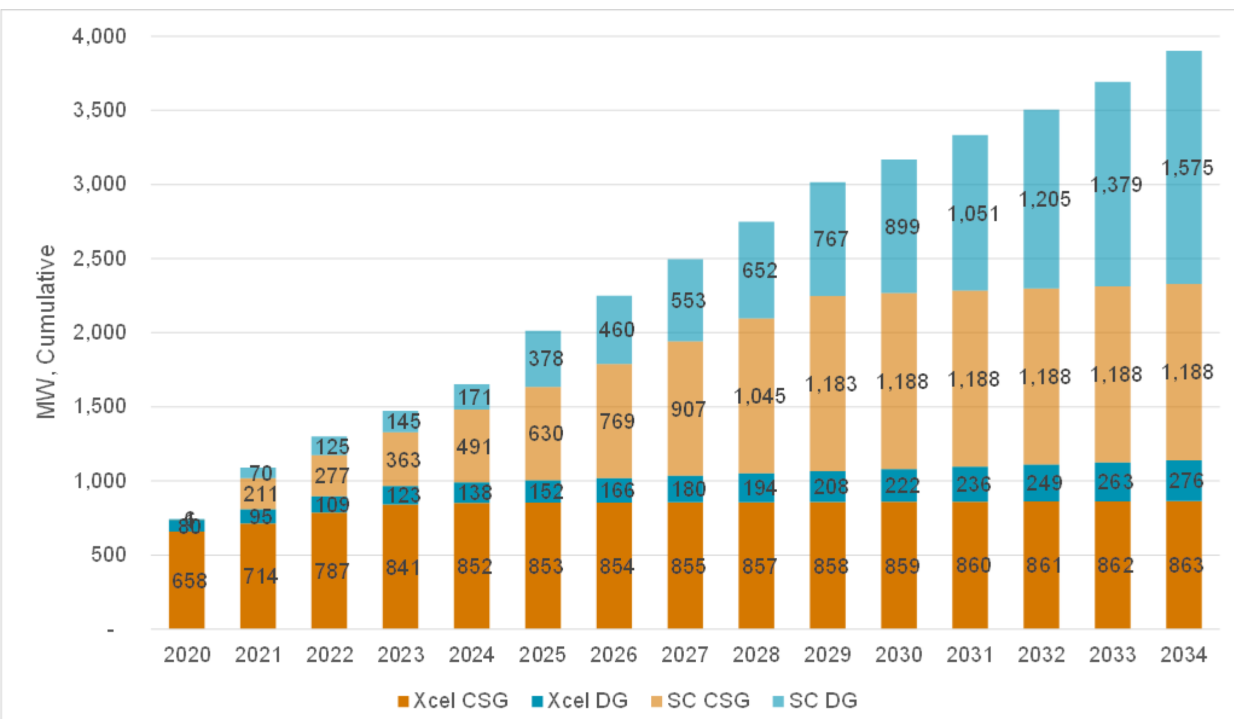
Table 12. Total PVSC of Xcel's Preferred Plan versus Sierra Club's Clean Energy For All Plan

Scenario	Extended Monti NPV ($million)	No Monti Extension NPV ($million)
Xcel's Preferred Plan ("Scenario 9") Under Sierra Club's Corrected Assumptions	$37,395	N/A
Sierra Club Clean Energy For All Plan (Corrected RE Base + DG/CSG/VCE Interconnection)	$35,465	$35,190
Delta from Xcel's Preferred Plan	($1,930)	($2,205)

These savings result from several factors. Sierra Club's Clean Energy For All Plan selects additional utility-scale renewables that operate at low to no variable cost, displacing existing resources with higher operating costs as well as the new fossil additions (the Sherco CC and more than 2,000 MW of new CT) in Xcel's Preferred Plan.

Our plan also adds significantly more smaller scale solar in the form of DG and CSG resources relative to Xcel's Preferred Plan, as shown in Figure 10.

Figure 10 Comparison of Distributed generation (DG) and Community Solar Generation (CSG) Additions – Xcel's Preferred Plan vs Sierra Club's Clean Energy For All Plan



Sierra Club's Clean Energy For All Plan is lower cost even without carbon costs

Xcel tested high, low, and no CO_2 cost sensitivities in order to examine the effect of CO2 pricing on its resource portfolios.[117] Xcel refers to the no CO_2 cost sensitivity as its "PVRR" or "No Externality or Regulatory."[118] Synapse modeled a similar sensitivity as part of our analysis, modeling both Xcel's Preferred Plan (under our corrected cost assumptions) and Sierra Club's Clean Energy For All under Xcel's Sensitivity A, which uses a value of zero for carbon and externality costs.[119] The results from that sensitivity are shown in Table 13.

Table 13. Comparison of PVRR (No Carbon), Xcel's Preferred Plan and Sierra Club's Preferred Plan

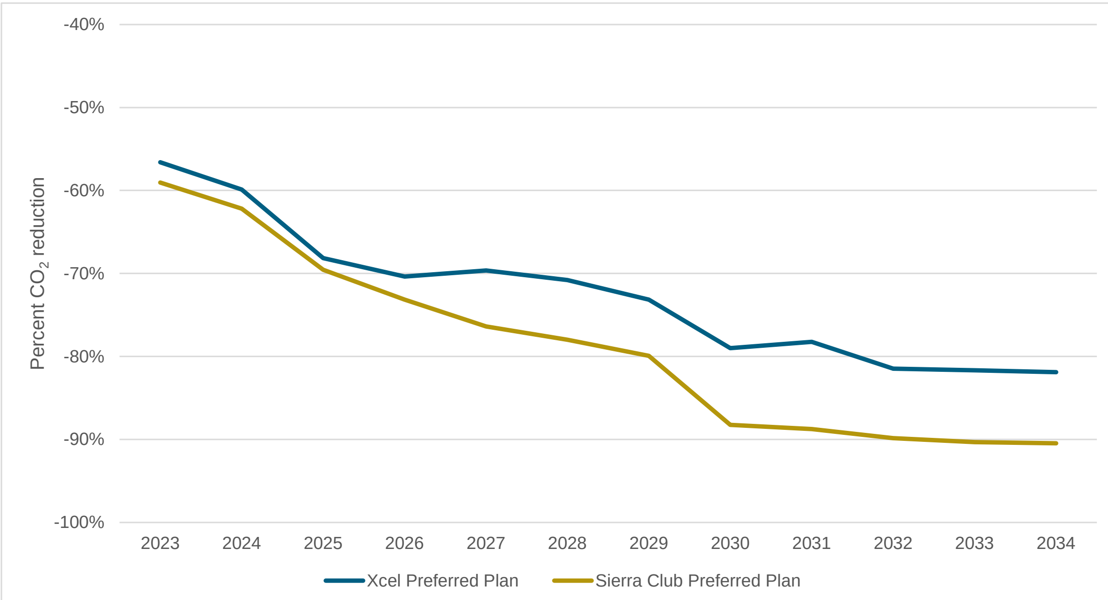
Scenario	Extended Monti NPV ($million)	No Monti Extension NPV ($million)
Xcel's Preferred Plan (using Corrected RE Base and VCE interconnection cost assumptions) (No Carbon)	$35,385	N/A
Sierra Club Clean Energy For All (No Carbon)	$34,119	$33,821
Delta	($1,266)	($1,564)

When carbon costs are stripped out, Sierra Club's Clean Energy For All Plan is still significantly lower in cost than Xcel's, by more than **$1.5 billion**.

Total CO_2 emissions reductions are also lower under Sierra Club's Preferred Plan. The comparison between Xcel's and Sierra Club's Preferred Plans is shown in Figure 11.

117 IRP, page 133
118 IRP, page 134
119 The optimization period for Xcel's "PVRR" modeling runs (which do not use CO_2 pricing as part of the dispatch) begins in 2023. The optimization period in the Clean Energy For All scenario begins in 2021, as the model is allowed to select the optimal amounts of additional DG and CSG starting in that year. The difference in optimization periods means that these two scenarios cannot be compared on a PVRR basis, which is why we chose to use Sensitivity A as the means of comparison with a CO_2 and externality cost of zero.

Figure 11. Carbon Dioxide Reduction, Xcel's Preferred Plan Compared to Sierra Club's Clean Energy For All Plan



Emissions in 2027, the year in which the Sherco CC comes online in Xcel's Preferred Plan, are 6 percent lower in Sierra Club's preferred plan because that unit is displaced by renewable and battery storage resources. By 2034, emissions in the Sierra Club's Clean Energy For All Plan are almost 10 percent lower than in Xcel's Plan. While neither scenario reaches 100 percent carbon-free energy by 2045, the end of the extended analysis period, CO_2 emissions reductions are at 93 percent in Sierra Club's Clean Energy For All Plan, compared to an 85 percent reduction in Xcel's Plan, and better sets the Company on a trajectory to achieve 100% carbon-free energy by 2040.

F. <u>Key conclusions from Synapse modeling</u>

In short, Synapse's modeling results show that moving forward with the Sherco CC is not in the best financial interest of customers. The Company's assumed renewable prices came from NREL's 2019 ATB; simply updating the input prices to reflect the values from the updated NREL 2020 ATB led the EnCompass model to select new renewable and storage resources in 2027 rather than the gas-fired Sherco CC.

Fully correcting all of the errors identified with Xcel's renewable resource cost assumptions, adjusted interconnection costs, and an improved modeling methodology for community solar and distributed generation led the model to create Sierra Club's Preferred Plan, which adds wind, solar (utility scale, hybrids, and distributed) and battery storage in lieu of new gas-fired generating capacity. These lower cost additions result in cost savings to customers of more than $2.2 billion relative to Xcel's Preferred Plan on a PVSC basis (and more than $1.5 billion with carbon costs removed).

Synapse's modeling results also demonstrate that extension of the Monticello nuclear plant license is not in customers' interests. In every scenario using fully corrected renewable energy resource costs (and all but one scenario that used only updated NREL 2020 costs), retirement of Monticello is less expensive than extending the license of that unit. For this reason, Sierra Club's Clean Energy For All Plan does not include the extension of the Monticello nuclear license.

G. The King, Sherco 1, and Sherco 3 coal units should be considered for even earlier retirement

Xcel has provided compelling evidence that the "early coal" future is preferable to the current retirement dates. The Company's modeling shows that early retirements would result in a lower PVSC.[120] In the Company's reference case, Sherco 1 retires in 2026, Sherco 2 retires in 2023, Sherco 3 retires in 2034, and King retires in 2038; Sherco 2 and King are also do not operate in the spring or fall through 2023 (i.e. are dispatched seasonally).[121] Xcel's preferred plan (scenario 9) includes an "early coal" future where the units are retired earlier, and the Monticello plant's license is extended. In the "early coal" future, Sherco 1 retires in 2026, Sherco 2 retires in 2023, Sherco 3 retires in 2030 (instead of 2034), and King retires in 2028 (instead of 2038). This "early coal" future alone (scenario 4) saves $291 million in PVSC relative to the Company's reference case; and it is lower cost in most of the sensitivities run by Xcel.[122] For this reason, we used the "early coal" retirement dates in all of our modeling runs.

While we agree with the Company's broad finding that earlier retirement of the coal units should be a component of a preferred plan, the IRP only explores one set of early retirement dates for the Company's coal units. The dates for the reference case and "early coal" futures are hard-coded into the model, rather than letting the model economically select retirement dates based on cost. Thus, given the framework set up by the Company it is impossible to know whether it might be economical to retire the coal units at an even earlier date. This is unfortunate because the IRP is an appropriate forum to explore the myriad options for existing units, especially if there are indications that they are not economically viable.

While Xcel's preferred plan (scenario 9) assumes that all coal units retire by 2030, it may be in ratepayers' interests to retire them even earlier. Based on the Company's modeling of these units in the IRP, the King unit appears to be the **[PROTECTED DATA BEGINS…PROTECTED DATA ENDS]** of any of the coal units. The capacity factor for the unit in the preferred plan is often below **[PROTECTED DATA BEGINS…PROTECTED DATA ENDS]**; indeed, under Xcel's Scenario 9 assumptions, it is expected to operate at roughly **[PROTECTED DATA BEGINS… PROTECTED DATA ENDS]** capacity factor in 2025 through 2028—shown below in Figure 12. In "sensitivity A" where there is no carbon price, the unit still operates

[120] IRP Suppl. at 138 of Attach A.
[121] *Id.* at 17.
[122] *Id.* at 138-139 of Attach A.

[PROTECTED DATA BEGINS… PROTECTED DATA ENDS] capacity factor. It is unlikely that operating the **[PROTECTED DATA BEGINS…PROTECTED DATA ENDS]**, but Xcel has fixed the unit's retirement date in the modeling, preventing the model from determining whether earlier retirement would be optimal.

Figure 12: King Capacity Factor (%) TRADE SECRET[123]

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

The capacity factors for Sherco units 1 and 3 are shown below. These units are expected to operate more frequently than King but still could be considered for earlier economic retirement in future modeling.

[123] DC 101 TRADE SECRET, "EO - Base Expansion PVSC PVRR"

Figure 13: Sherco Unit 1 Capacity Factor (%) TRADE SECRET[124]

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

Figure 14: Sherco Unit 3 Capacity Factor (%) TRADE SECRET[125]

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

Recent federal tax credit extensions make it possible for Xcel to add large amounts of very low-cost renewable and hybrid resources in the near term. This opportunity should put additional economic pressure on these uneconomic coal units to retire sooner so they can be replaced by lower-cost renewable and hybrid sources of energy and capacity. In addition, inflexible fossil generators impede the transition to high levels of variable wind and solar generation, as their slow ramp rates and limited ability to turn down output increase curtailment of wind and solar.

Sierra Club explored the possibility of modeling earlier retirements of these units—the King in particular—but we were limited by Xcel's methodology in two ways. First, Xcel calculated capital revenue requirements for the coal units using the Strategist model and input those hard-coded values into EnCompass. We only had a license for EnCompass and thus could not re-calculate the capital revenue requirements with alternative retirement dates. This barrier should be avoided in the future as parties should not be expected to fund the license for two models. Second, alternative retirement dates should change the trajectory of capital costs because units that plan for retirement are able to reduce investments that are no longer viable (except those needed for safety and/or reliability). However, when we asked for capital costs with alternative retirement dates, Xcel did not provide such data because it had not done that analysis and stated that it did not possess the requested information.[126] In the future, Xcel should identify capital costs that could be avoided with alternative retirement dates.

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124 *Id.*
125 *Id.*
126 Xcel response to SC 155 d, e, and f.

VI. RELIABILITY: XCEL OVERSTATES THE RELIABILITY BENEFITS OF ITS PREFERRED PLAN, AND UNDERSTATES THE ABILITY OF HIGH RENEWABLES SCENARIOS TO PROVIDE RELIABLE ENERGY.

At various points throughout its IRP Supplement, Xcel asserts that the Sherco CC and additional 2,600 MW of "firm, peaking" resources (modeled as generic gas CTs) are needed for reliability purposes. Xcel also expresses reservations about portfolios containing high levels of renewables, noting, for instance, that "[w]hen we developed our Initial Preferred Plan, we recognized that, as we added increasing variable renewable resources to our generation mix, maintaining reliability would become increasingly complex."[127] Based on Xcel's assessment, Xcel identified "potential risks associated with portfolios that rely more heavily on variable renewables and use-limited resources."[128]

As explained in detail in this section, none of Xcel's reliability arguments stands up to scrutiny. Xcel's reliability analysis is biased towards gas generators and against renewable and storage resources in many ways. First, Xcel generally understates the contribution of wind, solar, and storage to meeting peak demand. Second, by ignoring correlated outages of conventional generators and particularly gas generators, Xcel misses a key threat to reliability from increasing its dependence on gas generation. Third, with regard to other grid reliability services, including ancillary services like flexibility and black start, Xcel again understates the capabilities of renewable and storage resources and overstates the need for conventional generators like the Sherco CC.

Moreover, Xcel asserts it needs the Sherco CC to address critical reliability needs, pointing to its Y-2 studies associated with its proposed coal unit retirements.[129] However, as summarized below in subsection VI.F and as detailed in the attached report, Attachment C, our expert Telos Energy reviewed the Y-2 studies and conducted updated power flow analyses to assess the reliability benefits of the Sherco CC. Telos' report concludes that there is no reliability benefit from the proposed gas plant.

A. Xcel generally understates the contribution of wind, solar and storage to meeting peak electricity demand.

In its resource planning modeling, Xcel understated the value of wind, solar, and storage for meeting electric reliability needs, and overstated the value of non-renewable resources. By understating the ability of renewable and storage resources to provide reliability services, Xcel biased its analysis against these resources and towards other options like the proposed Sherco Combined Cycle plant.

[127] IRP Suppl. at 4.
[128] IRP Suppl. at 58.
[129] IRP Suppl. at 64.

Understating the contribution of renewables and storage resources to reliability services also overstates the need for these other resources.

Xcel's modeling assumptions understate the contribution of wind and solar generation to meeting peak electricity demand. This artificially creates the appearance of a capacity need and, combined with overstating the contribution of gas generators to meeting peak demand, also biases Xcel's IRP analysis against renewable resources and towards gas generators. A resource's contribution to peak demand is typically measured by capacity value, which refers to the share of a resource's nameplate capacity that can be relied on to meet demand needs. Capacity value should not be confused with capacity factor, which measures the energy production of a resource.

In its EnCompass modeling, Xcel assumes that wind's accredited capacity value is 16.7% of nameplate capacity, which is the capacity credit MISO assigned to wind in MISO's Zone 1 (which includes Minnesota, the Dakotas, and western Wisconsin) in its 2019 wind capacity credit report. Solar additions are assumed to receive a 50% capacity value through the year 2023, and then decline by 2 percentage points per year after that, reaching 30% capacity value by 2033.[130]

1. Xcel has undervalued the capacity value of wind

MISO's December 2020 wind capacity report found that the capacity value of wind in Zone 1 has increased from 16.7% to 18.2% of nameplate capacity.[131] With Xcel's 4,200 MW of installed wind capacity,[132] this 1.5 percentage point change increases the accredited capacity of the Company's wind fleet by 63 MW, and an additional 35 MW across other parts of MISO Zone 1.

Xcel assumes that wind's capacity value remains constant at 16.7% throughout the planning period, even though technological advances have caused it to steadily increase over the last decade. MISO's fleetwide average accredited capacity value for wind has increased from 12.9% in 2011 to 16.3% in 2021, even as wind penetration has increased from 7.6% to 18.8%. Using the average capacity value of the entire wind fleet understates the marginal capacity value contribution of wind resources that have recently been added, as the fleetwide average capacity value is weighed down by older vintages of turbines with outdated technology.

Wind plant technology improvement is expected to drive continued capacity value increases. Multiple studies have documented how taller wind turbines with longer turbines blades provide higher capacity value by increasing output during periods when older vintages of turbines had lower

[130] IRP Suppl. at 9.
[131] *Planning Year 2021-2022: Wind and Solar Capacity Credit,* MISO (December 2020), https://cdn.misoenergy.org/DRAFT%202021%20Wind%20&%20Solar%20Capacity%20Credit%20Report503411.pdf
[132] IRP Suppl. at 130 of Attach A.

output.[133] Larger turbines are able to access higher quality, more consistent winds higher above the earth's surface. The increasing length of turbine blades have caused the wind energy captured by turbines to increase much more quickly than the turbines' rated capacity, also driving more consistent output by disproportionately increasing output during periods of lower wind speeds.[134] New wind turbines also have different output profiles from the existing fleet, reducing the correlation in their output and increasing capacity value. As new wind plants are built in new locations, this increases the geographic diversity of the wind fleet and increases its capacity value because the output of these new wind installations is inherently less than perfectly correlated with that of existing plants.

These factors, as well as the capacity value complementarity among wind, solar, and storage discussed below, are likely to continue to outpace the decline in wind's capacity value as penetrations increase. MISO's large size and diverse wind resources also slow the decline in wind's capacity value. MISO's Renewable Integration Impact Assessment (RIAA) has modeled that wind's capacity value starts at over 22% and then gradually declines before stabilizing in the 13% range, even at wind penetrations five times higher than current levels.[135]

While Sierra Club's EnCompass modeling also uses the 16.7% wind capacity value assumption used by Xcel, a more reasonable assumption for wind's capacity value going forward for purposes of EnCompass modeling, including wind's diversity benefits with solar and storage, is likely over 20%. Increasing from 16.7% to 20% alone would increase the accredited capacity value of Xcel's 4,200 MW wind fleet by 139 MW.

<u>Wind Reliability During Extreme Cold Events</u>

Xcel's initial and supplemental IRP filings express a concern that, even where its modeling results indicate sufficient resource adequacy, "increasing levels of renewable adoption and baseload retirements mean that modeling and evaluating future resource plans using only [capacity expansion] modeling only is no longer sufficient to ensure energy adequacy in every hour of every day."[136] Xcel argues:

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[133] *See* for example, See for example, Ryan Wiser et al., *The Hidden Value of Large-Rotor, Tall-Tower Wind Turbines in the United States,* Lawrence Berkeley National Laboratory (July 2020), https://emp.lbl.gov/publications/hidden-value-large-rotor-tall-tower; Lion Hirth & Simon Müller, *System Friendly Wind Power: How Advanced Wind Turbine Design Can Increase the Economic Value of Electricity Generated Through Wind Power,* Energy Economics (March 3, 2016), https://neon.energy/Hirth-Mueller-2016-System-Friendly-Wind-Power.pdf

[134] Wiser, *Wind, supra* at 37.

[135] Jordan Bakke, *Renewable Integration Impact Assessment (RILA),* MISO at 7 (April 18, 2018), https://cdn.misoenergy.org/20180418%20PAC%20Item%2003d%20RIIA174068.pdf

[136] IRP Suppl. at 104 of Attach A.

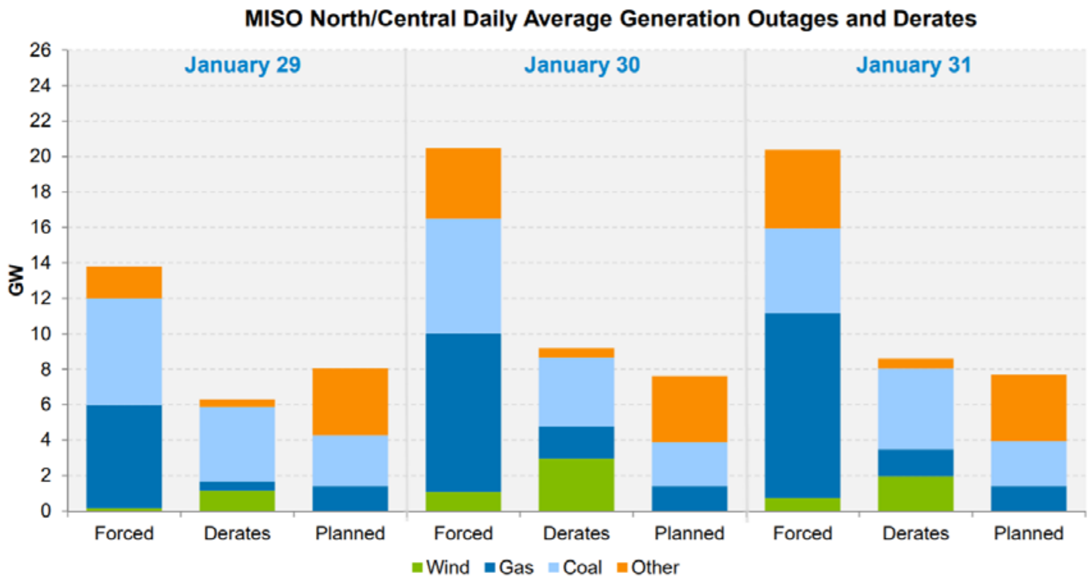
> As we add more variable renewables to our system going forward, capacity adequacy and energy adequacy begin to decouple, increasing the risk that a portfolio could appear capacity sufficient – given existing [resource adequacy] constructs – but result in flexibility or energy availability shortfalls… variable renewables are also weather dependent, and an annual peak measure still does not indicate these resources' contributions to ensuring our system has sufficient energy to serve customers in all hours of the year.[137]

However, MISO's ELCC methodology does in fact account for wind's availability to meet load in all hours of the year, as Xcel acknowledged when asked in discovery.[138] Thus, wind's contribution in all hours of the year, including winter peak demand events, is reflected in the MISO ELCC results showing wind's capacity value, so no adjustment to those figures is needed.

To support its argument, Xcel points to an event in which a significant share of MISO wind capacity was unavailable during an extreme cold snap in January 2019 because record low temperatures fell below the minimum operating temperature of some turbines.[139]

This 2019 Polar Vortex event was an extremely unusual event, with many locations experiencing record or near-record cold temperatures and generators of *all* types experiencing outages and derates. About 25% of MISO North and Central total generating capacity was unavailable during the event, with gas and coal accounting for the vast majority of outages. The following MISO chart shows that fossil generators accounted for 5 times more outages and derates than wind generators.[140] Specifically, 4 GW of wind capacity experienced outages and derates, compared to 21 GW for gas and coal capacity. As a share of total capacity across MISO North and Central, wind and fossil experienced failures at comparable rates. However, most of MISO's wind capacity is located in the northwest part of the footprint that was most severely affected by the extreme cold, while most of the fossil generation is located in areas that were less affected. As a result, it appears that in the most affected region, wind capacity actually fared better than fossil capacity.

[137] *Id.*
[138] See Xcel response to SC 51(a).
[139] *See* IRP Suppl. at 106 of Attach A, Figure VI-3.
[140] *MISO January 30-31 Maximum Generation Event Overview,* MISO (February 27, 2019), https://cdn.misoenergy.org/20190227%20RSC%20Item%2004%20Jan%2030%2031%20Max%20Gen%20Event322139.pdf



Source:
https://cdn.misoenergy.org/20190227%20RSC%20Item%2004%20Jan%2030%2031%20Max%20Gen%20Event322139.pdf at 5

MISO noted that this was an historic event, so such an extreme event is unlikely to be repeated for some time. Power system planners, like all infrastructure engineers, do not design the system to be perfectly reliable during all conceivable events, as the cost of building such a system would be prohibitive and outweigh the benefits. Despite such an extreme event, MISO had more than enough generation supply to meet demand throughout the event, and never had to resort to rolling outages.

Moreover, the unexpected wind outage is unlikely to be repeated due to steps MISO and others took following the event. The primary problem during that event was that MISO's wind forecast did not include detailed parameters for the minimum operating temperatures of turbines, so grid operators were caught off guard when wind output fell below what had been expected the day before. MISO notes that it immediately addressed that problem by incorporating plant-specific low temperature operating limits into MISO's wind forecast.[141] If MISO ever experiences a similarly severe cold snap, grid operators will be prepared and commit additional generating resources and imports the day before if there is a risk of temperature-related outages.

Said another way, the 2019 event was a grid operating concern and not a grid planning problem. Utilities and grid operators typically distinguish between the operational timescale (deciding how to dispatch power plants hours and days ahead of real-time to meet demand) and the planning timescale (deciding which power plants to build so they will be ready to meet periods of high demand several years from now). The 2019 event was a real-time operational challenge, and not a planning challenge. Wind output was lower than grid operators had been expecting a day in advance

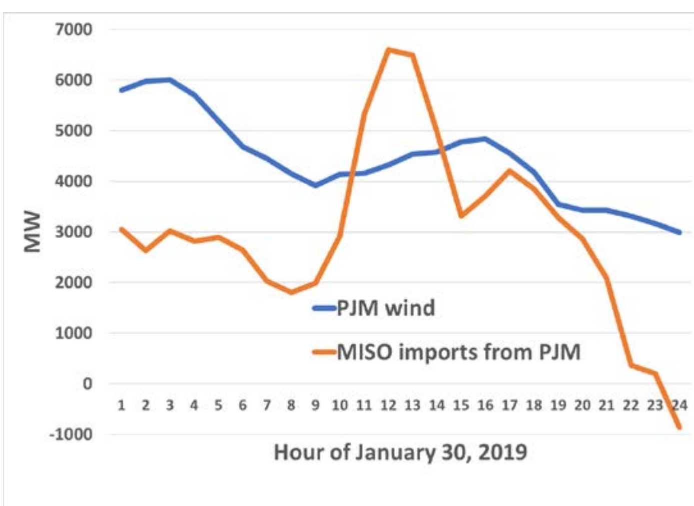
[141] *Id.* at 4, 12.

due to the flaw in the forecasting methodology that has since been corrected. However, from a planning perspective, which is the matter addressed in IRPs, wind still produced well above its accredited and expected capacity value.[142]

If utilities and wind plant operators want to further reduce the risk of such an event in the future, that can be achieved by taking steps like purchasing extreme low temperature packages for wind turbines that include additional heaters, insulation, and materials that are less susceptible to failure in extreme cold, just as utilities improved weatherization at conventional generators after the 2019 event.

Transmission ties to neighboring power systems are probably the most important tool for addressing extreme weather events, as they were during the 2019 event. The extreme temperatures necessary to cause generator failures will not affect a large geographic area simultaneously, and so any local drops in output can be addressed with imports from other parts of MISO, or other regions. For example, wind output surged in neighboring PJM during the 2019 event, allowing MISO to rely on imports from PJM, as shown in the chart below. PJM wind output and exports to MISO were very high during the late morning of January 30, 2019, the most challenging period for MISO. For reference, PJM's hourly wind output averaged 2,734 MW across all of 2019,[143] so wind output was well above average throughout this day. In fact, PJM's high wind output on the morning of January 30 more than offset the 4 GW of MISO wind capacity that was unavailable due to extreme cold.

Figure 15: PJM wind output and MISO imports from PJM during Polar Vortex event, January 30, 2019



142 Michael Goggin, *How Transmission Helped Keep the Lights on During the Polar Vortex,* Into the Wind the AWEA Blog (February 14, 2020), https://www.aweablog.org/transmission-helped-keep-lights-polar-vortex/
143 Wind Generation, PJM, https://dataminer2.pjm.com/feed/wind_gen

Xcel argues that it cannot count on imports from other MISO utilities, and therefore Xcel treats them as non-firm and excludes them from some of the reliability analysis presented in the IRP Supplement. In particular, Xcel argues that "broader regional weather events" can cause shortfalls for neighboring utilities.[144] However, while there may be positive correlations in weather across large areas, extreme weather is never perfectly correlated across an area as large as MISO's footprint. Rather, as was seen in the 2019 event, the most extreme cold was only experienced in a relatively confined area that gradually moved across the MISO footprint. This allows individual utilities to rely on imports from other utilities when they are experiencing the worst of the event, and then in turn provide exports to those other utilities once the worst has passed to those areas. MISO has calculated that the ability to transfer power within MISO provides between $2.2 and $2.7 billion in value annually because the diversity in load profiles across the footprint reduces the amount capacity needed to reliably meet demand, while diversity in wind profiles results in an additional reduction in capacity need valued at $415-477 million annually.[145]

2. Xcel has also understated the capacity value of solar

As noted above, Xcel assumes that solar starts at a 50% capacity value through the year 2023, and declines by 2 percentage points per year after that, reaching 30% capacity value by 2033.[146] Xcel offers no analytical foundation for either the starting value of 50%, or the assumed rate of decline.

Xcel cites the 2 percentage point per year rate of decline in solar ELCC to MISO's MTEP.[147] While that assumption is used in MTEP, MTEP provides no documentation or analytical foundation for the assumption. The fact that the most important determinant of the rate of capacity value decline, solar penetration, varies considerably across MTEP scenarios, yet the same assumption for solar capacity value is used in all scenarios, indicates that this assumption is not grounded in an analytical foundation. The MTEP report mentions MISO's RIAA report as a source for the assumption, but RIAA's modeling did not produce that result. In fact, RIAA found an initial solar capacity value of around 60%.[148]

Other utility, grid operator, and national laboratory analyses indicate that solar should start at a capacity value higher than 50%. In 2009 analysis, Xcel's affiliate Public Service Company of Colorado found that average solar capacity value ranged from 59% to 63% for fixed-panel photovoltaic systems ("PV"), and from 69% to 75% for single-axis tracking PV systems.[149] NREL's analysis of solar capacity values across the Western U.S. shows a 52–86% capacity value for solar,

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144 IRP Suppl. at 107 of Attach A.

145 https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-value-proposition/

146 IRP Suppl. at 9.

147 IRP Suppl. at 105 of Attach A.

148 Bakke, *Renewable, supra* at 7.

149 J. Rogers and K. Porter, *Summary of Time Period-Based and Other Approximation Methods for Determining the Capacity Value of Wind and Solar in the United States*, National Renewable Energy Laboratory at 17 (Mar. 2012), https://www.nrel.gov/docs/fy12osti/54338.pdf

depending on location and the use of tracking.[150] PJM's renewable integration study found that even with 20-30% of electricity provided by wind and solar, solar provided around 62–66% capacity value.[151]

PJM's analysis found that solar capacity value was higher when the system wind penetration was higher, a finding confirmed by many other studies including Xcel's in Colorado.[152] The capacity value of solar increases with more wind on the power system, and vice versa, because their output patterns are negatively correlated on a daily and seasonal basis.[153] This is particularly true during peak demand periods. MISO's highest peak net loads tend to occur during heat dome events caused by high pressure systems, which cause clear hot days with high solar output, but low wind speeds. Given MISO's low solar penetration, and high wind penetration of 14.2%,[154]this suggests solar's initial capacity value is likely to be higher than 50%, or even the 60% figure calculated in MISO's RIAA. This is particularly true in the northwest MISO states of Minnesota, Iowa, South Dakota, and North Dakota, where for January-November 2020 wind accounted for 36.4% of total electricity generation, while solar accounted for only 1.3%.[155]

Analysis of Xcel load and solar output data provided in response to discovery confirms that solar's capacity value will be higher than 50% for the foreseeable future.[156] Grid Strategies' analysis uses the average capacity factor of Xcel's three largest solar plants during Xcel's 100 highest load hours over the last three years[157] to estimate solar's capacity value, a method that NREL has found to offer an

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150 Seyed Hossein Madaeni et al., *Comparison of Capacity Value Methods for Photovoltaics in the Western United States*, National Renewable energy Laboratory at 27 (July 2012), https://www.nrel.gov/docs/fy12osti/54704.pdf
151 *PJM Renewable Integration Study*, General Electric International Inc. at 29–30 (Mar. 31, 2014), https://www.pjm.com/-/media/committees-groups/subcommittees/irs/postings/pjm-pris-task-3a-part-f-capacity-valuation.ashx?la=en.
152 An Effective Load Carrying Capability Study of Existing and Incremental Wind Generation Resources on the Public Service Company of Colorado System filed by Xcel Energy Services, Inc. May 13, 2016, Hg. Ex. 103, Attachment JFH-2, CoPUC Proceeding No. 16A-0117E.
153 Nick Schlag et al., *Capacity and Reliability Planning in the Era of Decarbonization,* Energy and Environmental Economics (August 2020), https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf
154 https://docs.misoenergy.org/marketreports/historical_gen_fuel_mix_2020.xlsx
155 U.S. Energy Information Administration, *Electric Power Monthly,* U.S. Department of Energy (January 2021), https://www.eia.gov/electricity/monthly/current_month/january2021.pdf
156 Xcel Response to IR SC-192
157 Load and solar output data are taken from Xcel's response to SC-192, Attachment A. For Xcel's top 100 load hours over the last three years, we calculated the average capacity factor of the three existing solar plants during each hour of the afternoon (*e.g.*, in the first column, 12 indicates noon, 13 indicates 1 PM, etc). The average capacity factor of the three existing plants was then used to extrapolate the future output for a given amount of solar nameplate capacity (top row in bold) during that hour, which was then subtracted from the maximum peak load observed during that hour of the day (second column) over the three-year period to calculate the new peak net load with that amount of solar. The reduction in peak net load as a percent of solar installed capacity was then used to estimate the marginal and average capacity value of solar in the rows at the bottom of the table.

accurate estimate of solar's capacity value while being computationally simpler.[158] This analysis is presented in the following table.

Capacity Value of Solar on Xcel NSP's System

		Peak net load with amount of solar capacity indicated in top row								
Hour of day	Solar capacity MW: Peak load (MW)	**262**	**500**	**1000**	**1250**	**1368**	**1400**	**1500**	**2000**	**2500**
12	7618	7371	7147	6676	6441	6330	6300	6205	5735	5264
13	7852	7632	7432	7013	6803	6704	6677	6593	6173	5753
14	8060	7844	7648	7236	7030	6932	6906	6824	6411	5999
15	8196	7998	7818	7440	7251	7161	7137	7061	6683	6305
16	8413	8244	8090	7768	7606	7530	7510	7445	7122	6800
17	8540	**8388**	**8250**	**7960**	**7815**	**7746**	7727	7669	7379	7089
18	8330	8203	8088	7846	7725	7668	7652	7604	7362	7120
19	8199	8107	8023	7848	7760	7718	7707	7672	7496	7321
20	7975	7931	7891	7807	7766	7746	**7740**	**7724**	7640	7556
21	7734	7729	7725	7716	7711	7709	7708	7706	**7697**	**7688**
22	7504	7504	7504	7504	7504	7504	7504	7504	7503	7503
	Solar reduction in net load (MW)	152	290	580	725	794	800	816	843	852
	Average solar CV	**58%**	**58%**	**58%**	**58%**	**58%**	**57%**	**54%**	**42%**	**34%**
	Marginal solar CV	**58%**	**58%**	**58%**	**58%**	**58%**	**18%**	**17%**	**5%**	**2%**
	Solar capacity as share of peak load	3.1%	5.9%	12%	15%	16%	16%	18%	23%	29%

Source: analysis of data from Xcel Response to SC-192

The table shows how peak net load (load minus solar output) is reduced with the increasing amounts of solar nameplate capacity indicated in bold in the top row. For example, the current 262 MW of large utility-scale solar on Xcel's system reduces peak net load from 8,540 MW to 8,388 MW. This reduction of 152 MW indicates a solar capacity value of 58% (152 MW peak net load reduction/262 MW of solar nameplate capacity).

This analysis shows that solar's average and marginal capacity value remains at 58% until solar nameplate capacity penetrations reach 16% of Xcel's peak load, or 1,368 MW. At that point, the marginal capacity value declines because solar output has shifted peak net load later into the evening, though the average capacity value of the solar fleet remains high, and solar continues to offer significant capacity value even at higher penetrations. The bolded peak net load cells show that peak net load shifts from 5 PM to 8 PM, and then to 9 PM once 2,000 MW of solar capacity is online. The finding that solar's capacity value only begins to significantly decline once solar nameplate

[158] Seyed, *Comparison, Supra* at 18.

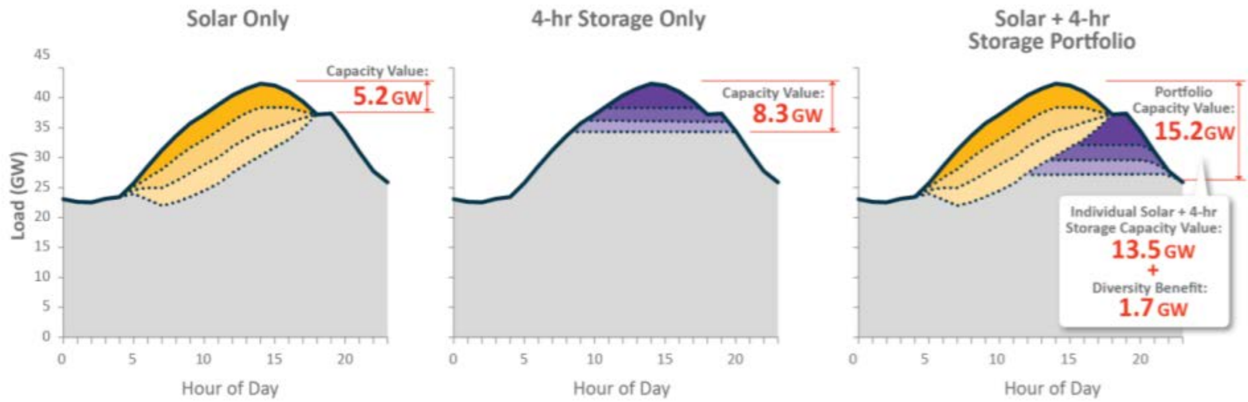
reaches 16% of peak demand implies that, across MISO North and Central, more than 14,000 MW of solar can be installed before they make up more than 16% of the region's peak demand of 87,700 MW.[159]

Battery storage also has a complementary relationship with wind and solar, so that increasing the penetration of any one of the three resources tends to increase the capacity value of the other two.[160] As a result, the combined capacity value of wind, solar, and storage is greater than the sum of its parts. Xcel's filing explains that the capacity value of wind or solar declines as the penetration increases, without noting that increasing the penetration of one increases the capacity value of the other.[161] This synergistic relationship among the capacity value of wind, solar, and battery storage is not accounted for in Xcel's assumption of static wind capacity value and declining solar capacity value.

Adding battery storage helps keep the capacity value of wind and solar high, as battery storage can absorb wind and solar output when it is less valuable and shift it later in time to peak demand periods. In particular, adding storage keeps solar capacity value high by making it possible to shift midday and early afternoon solar output to later in the afternoon and evening. Similarly, battery storage can shift overnight wind output later to help meet the morning load up ramp, particularly during winter periods when morning heating demand is high and solar output is low.

Less intuitively, solar also boosts the capacity value of storage. As noted above, at higher solar penetrations, solar output in the late afternoon and early evening shifts peak net load later into the evening.[162] This late afternoon solar output also shortens the duration of the peak net load period, allowing limited duration battery storage resources to fully meet the peak demand. As shown in the chart from industry consultant E3 below, the diversity benefit between solar and storage causes their combined Effective Load Carrying Capacity (ELCC) to be greater than the sum of their parts.

[159] Peak load data for 2020, from https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=/MarketReportType:Summary/MarketReportName:Historical%20Regional%20Forecast%20and%20Actual%20Load%20(xls)
[160] Schlag, Capacity, supra, at 6-7.
[161] IRP Suppl. at 105 Attach A.
[162] Bakke, *Renewable, supra* at 5.



Source: https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf, at 6-7

Xcel's assumption of declining capacity value for solar also does not account for the potential benefit of technological improvement. The use of single- and dual-axis tracking at solar plants is becoming more common over time, which significantly boosts solar output in early morning and late afternoon hours that tend to be peak demand periods in winter and summer, respectively.[163] Solar inverter-loading ratios, or the ratio of Direct Current solar module capacity to Alternating Current plant output capacity, have steadily increased as solar modules price declines have outpaced reductions in the cost of balance-of-plant equipment. Higher inverter-loading ratios also help provide a flatter solar output profile across the day, with less decline in solar output in early morning and late afternoon hours relative to noon output, similar to the impact of larger blades on wind turbine output.

Minnesota's far northern location also counterintuitively increases solar's capacity value because during summer peak demand periods, days are much longer than in more southern regions. Sunset in northern MISO can occur as late as 9:30-10 PM during the summer, while the sun sets at around 8 PM in southern MISO. In addition, Minnesota and the Dakotas are on the far western end of MISO and the Eastern Interconnect, which also causes the sun to be higher in the sky when areas to the east are reaching peak net load. MISO peak demand typically occurs in the mid- to late-afternoon during the summer, when the sun is still very high in the sky in Minnesota and the Dakotas.

As solar penetrations increase, Minnesota solar resources will continue to provide large capacity value for meeting peak net load due to their location. Even when MISO's solar penetration becomes high enough to shift summer peak net load into the evening, Minnesota and neighboring states will still have abundant solar output during these hours due to their location in the northern and western part of MISO, as confirmed by Grid Strategies' analysis above. By the time the sun sets in those areas, NSP and MISO load has typically dropped off dramatically.

[163] Bolinger, *Update*, *supra.*

In general, solar's capacity value typically remains relatively constant until the penetration threshold has been reached that solar output begins to shift peak net load later into the evening. It is likely to take Minnesota and MISO many years (if not decades), and dozens of GW of solar, to reach that threshold, given MISO's size and the low solar penetration in Minnesota, surrounding states, and MISO-wide now and in the near future. This is confirmed by the analysis above, showing that solar's capacity value is unlikely to significantly decline until over 14 GW of solar capacity are online in North and Central MISO. For comparison, there are currently only 10.3 GW of proposed solar and hybrid projects in the MISO West interconnection queue, and historically a large share of projects in the interconnection queue have not progressed to construction.[164] Xcel's filing includes a chart and discussion of how the capacity value of solar in California has dropped dramatically over the last several years as the state's solar penetration has increased.[165] However, this decline only became pronounced once solar was providing 13% of California's electric generation in 2018. As noted above, solar currently provides only 1.3% of electricity in Minnesota, Iowa, North Dakota, and South Dakota.[166]

Rather than the arbitrary 2%/year decline assumed by Xcel, a better approach would be to model solar's capacity value over time as a function of Xcel's and MISO's solar penetration and overall resource mix. ELCC tools can provide this analysis, and it is likely that the result would reveal a higher capacity value for solar, particularly in the near-term. However, because Xcel did not provide such an analysis, our modeling conservatively uses Xcel's assumption that solar's capacity value declines by 2%/year.

B. <u>Xcel's "reliability analysis" is flawed.</u>

Xcel's IRP Supplement, Attachment A, includes a section called "Reliability Analyses," which is also summarized on pages 56-59 of the IRP Supplement. In this section, Xcel explains that it tested its Preferred Plan and three other EnCompass modeling scenarios "with load and renewable shapes associated with a historical year's results that exhibited more volatility as compared to our base assumptions; in this case 2019."[167] Specifically, using EnCompass, Xcel "ran 8,760-hour simulations for each of the four portfolios…for the year 2034 and then assessed portfolio performance against four general categories of reliability metrics": "native capacity shortfalls, flexible ramp adequacy, market import risk as well as some standard reliability metrics included in the EnCompass results."[168] The purpose of these simulations was to "identify whether there were periods of high reliability risk; in other words where customers' needs may outstrip the resources we have available

164 MISO Interactive Queue, https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/gi-interactive-queue/, accessed February 9, 2021
165 IRP Suppl. at 111 of Attach A.
166 U.S. Energy Information Administration, *Electric, supra.*
167 IRP Supp at 56.
168 *Id.*

to serve them under that specific future scenario."[169] Xcel asserts that "[t]he findings of this analysis provided us with valuable insights about how reliably the four selected generation portfolios could meet system energy and capacity needs in 2034, if the plans faced the same pattern of hourly load and generation profiles seen in 2019."[170] From this analysis, Xcel concluded that "[these] findings indicate potential risks associated with portfolios that rely more heavily on variable renewables and use-limited resources."[171]

However, Xcel's reliability analysis is flawed as it does not account for the geographic diversity of future renewable additions, or Xcel's ability to rely on imports and exports with the rest of MISO and other neighboring power systems.

First, Xcel admits that the wind and solar output profiles used in its analyses were based on simply scaling up the output profiles of a small number of existing plants, without accurately accounting for the geographic diversity and improved technology of new wind and solar additions. Xcel explains that "[i]n order to account for geographic diversity, the wind speed profiles from geographically proximate wind farms were shifted either earlier or later in hourly increments to proxy the resources for which adequate historical generation data was not available."[172] However, this assumption overstates the correlation between the output of two wind plants, and thus understates the reduction in total wind fleet variability and increase in capacity value from adding new geographically diverse wind resources. NREL has even identified Xcel's method as one of the most common errors in renewable integration analysis. As NREL explains:

> A common error is to scale the output of an existing generator to represent the expected output of a larger fleet. This greatly overstates the variability of wind and likely overstates the variability of solar… It is similarly inappropriate to simulate a new wind plant simply by time delaying or advancing the output of an existing plant based on prevailing wind speed and direction. Wind does not remain coherent over inter-plant distances, so the resulting simulation will have too much correlation and too much variability.[173]

More significantly, most of Xcel's analysis constrains the model to prevent the use any imports from the rest of MISO.[174] The results of Xcel's "reliability analysis" are copied below.

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[169] *Id.* at 151 of Attach A.
[170] *Id.* at 152 of Attach A.
[171] *Id.*
[172] Xcel response to SC 130.
[173] Michael Milligan et al., *Cost-Causation and Integration Cost Analysis for Variable Generation*, National Renewable Energy Laboratory at 27-28 (June 2011), https://www.nrel.gov/docs/fy11osti/
51860.pdf
[174] IRP Suppl. at 158 of Attach A.

Table 14: Xcel table showing modeled capacity shortfalls in Xcel's Reliability Analyses

	Native Capacity Shortfall Metrics					Flexible Resource Adequacy Metric	Maximum Import Metric	Industry Metrics		
Expansion Plan (Test Dataset in Parentheses)	# of Native Capacity Shortfall Events	Average Duration of Shortfall Events (hours)	Average Intensity of Capacity Shortfall (MW)	Longest Shortfall Event (hours)	Peak Capacity Shortfall During 2034 (MW)	Maximum 3 – Hour Upward Ramp (MW)	# of Hours with High Imports	LOLH (Hours)	LOLE (Days)	EUE (MWH)
Baseline – Scenario 9 - Supplement Preferred Plan (Default)	0	0	0	0	0	4,760 (February)	9	0	0	0
Scenario 9 - Supplement Preferred Plan (2019)	4	1.75	363	2	615	5,506 (June)	158	0	0	0
Scenario 9 – High Distributed Solar Future (2019)	14	2.57	481	5	1,232	7,221 (June)	157	0	0	0
Scenario 9 – High Electrification Future (2019)	21	2.00	429	6	1,037	7,152 (March)	674	0	0	0
Scenario 9 – 50 percent ELCC (2019)	159	3.97	604	22	2,629	7,239 (January)	311	5 (2 separate events)	2	2,575

Source: Page 159 of IRP Supp, Attachment A.

These results are shown on the left side of the following table under the label "Native Capacity Shortfall Metrics." Once Xcel allows 2,300 MW of imports, all cases but one have an acceptable level of reliability, as shown by the zero loss of load hours ("LOLH") under the "Industry Metrics" columns on the right side of the chart. Said another way, Xcel's EnCompass modeling optimized the capacity expansion in these scenarios to meet reliability needs while correctly accounting for the ability to import power, so reliability concerns only appear if one assumes a fictional scenario in which Xcel has somehow decoupled from the rest of MISO. Using the correct Industry Metrics, only the 50 Percent ELCC future (which deploys large amounts of solar capacity and assumes solar holds a 50% capacity value throughout the modeling period) falls short of the industry standard of 2.4 hours per year of capacity shortfall, with a shortfall experienced in 5 hours per year. However, even if this shortfall continued to occur after the use of correct scaling methodology to account for the geographic diversity of renewable resource additions, it could easily be addressed by adding battery storage. Because these five hours were spread across two events, the typical four-hour duration of battery resources would be enough to address both of these shortfall events.

Xcel incorrectly claims that the 50% Percent ELCC case indicates that the capacity value of solar should be lower than 50%, and that the capacity value of batteries may be less than 100%, because "the longest shortfall duration in this test scenario far exceeds the capability of a four-hour battery to mitigate."[175] However, this is only true in Xcel's Native Capacity Shortfall Metrics analysis that assumes Xcel is not connected to MISO, and not in the Industry Metrics analysis that properly models 2,300 MW of import capacity.

Even the assumption of 2,300 MW of imports in the "Industry Metrics" analysis understates the availability of imports and exports with the rest of MISO. Xcel data indicates that **[PROTECTED DATA BEGINS…PROTECTED DATA ENDS]**.[176] This likely indicates that the physical limits on transmission capacity to import power are also greater than 2,300 MW, as the thermal limits on transfer capacity across a transmission line are typically identical in both directions, though stability limits on transfer capacity can somewhat vary by direction depending on system topology. Transmission expansion or the use of dynamic line ratings and other grid-enhancing technologies will only increase Xcel's import and export capacity, as would the deployment of storage in strategic locations to reduce congestion and address transmission system voltage and stability issues.

Long-distance Direct Current lines like the Soo Green line discussed earlier could also significantly reduce Xcel's capacity needs by increasing import capacity into western MISO. While these lines are primarily built to move wind power from western MISO eastward, they are fully bidirectional and can deliver power from other regions during periods of shortage in western MISO.[177] The Soo Green line has proposed to use Voltage Source Converters at either end, which allow the line to provide large amounts of black start service, voltage support, and other ancillary services.[178] If built, Soo Green or other Direct Current lines would further reduce the need for Xcel to obtain capacity and other reliability services from its own resources.

Moreover, the fact that **[PROTECTED DATA BEGINS…PROTECTED DATA ENDS]** confirms that Xcel's EnCompass modeling unduly constrained exports to 2,300 MW.[179] This likely impaired the economic viability of wind and solar generation in the EnCompass modeling. Constraining exports in EnCompass modeling causes wind and solar generation to appear to have low economic value or face curtailment during periods of abundance, even though in reality they would have been able to deliver that power at higher economic value.

Regardless, the Industry Metrics results that show acceptable reliability even with high penetrations of renewables should be the measure of reliability, as these are the metrics used by utilities, regional

175 IRP Suppl. at 58-59 of Attach A.
176 Xcel response to SC-191, Attachment A (Trade Secret)
177 Steve Frenkel, *PJM, supra.*
178 David Roberts, *Transmission Fortnight: Buying Power Lines Next to Rail & Roads to Make a National Transmission Grid,* Volts (February 1, 2021), https://www.volts.wtf/p/transmission-fortnight-burying-power
179 IRP Suppl. at 59 of Attach A.

reliability coordinators, and NERC.[180] In contrast, Xcel's Native Capacity Shortfall Metrics are not used by utilities and reliability entities.

Significant ability to transfer power within MISO is assumed in all of MISO's reliability modeling.[181] As noted above, MISO has calculated that the ability to transfer power within MISO provides between $2.6 and $3.2 billion in value annually because of the diversity in load and wind profiles across the MISO footprint, reducing the amount capacity needed to reliably meet demand.[182] Xcel's Native Capacity Shortfall Metrics ignore those benefits by assuming zero imports.

Xcel's reliability analysis section also includes two charts intended to illustrate the native capacity shortfall on certain modeled days resulting from the variability of wind and solar output.[183] These charts are misleading as they only show NSP's footprint and resources – that is, they only show Xcel's ability to meet its load with its own resources. What really matters to grid operators is MISO-wide variability, which is much smaller because most local fluctuations in wind or solar output are canceled out by geographic diversity in the renewable fleet, and many changes in renewable output net out against opposite fluctuations in electricity demand. These charts ignore Xcel's large imports and exports with the rest of MISO that offset most variability and are used for balancing, including large amounts of hydro imports from Manitoba. Dozens of renewable integration studies, including those conducted by NSP and Xcel's utility in Colorado, PSCO, demonstrate that large grid operating areas, like that offered by MISO, are the key to reliably and cost-effectively integrating large amounts of wind and solar energy.[184] MISO analysis confirms the ability for utilities to transfer power within its footprint saves around $300 million per year.[185] These studies are part of a large body of real-world operating experience[186] and forward-looking studies showing that power systems can operate reliably with penetrations of variable renewable resources many times higher than Xcel's and MISO's. For example, SPP obtained 32% of its electricity from wind in 2020 without experiencing

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180 For example, see https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf, at 20
181 *2019-2020 CIL/CEL Values and Study Timeline*, MISO at 4 (September 11, 2018) https://cdn.misoenergy.org/20180911%20LOLEWG%20Item%2003%202019-20%20PY%20CILCEL%20Values273688.pdf
182 https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-value-proposition/
183 IRP Suppl. at 155, 157 of Attach A, Figures XI-5 and XI-6.
184 An Effective Load Carrying Capability Study of Existing and Incremental Wind Generation Resources on the Public Service Company of Colorado System filed by Xcel Energy Services, Inc. May 13, 2016, Hg. Ex. 103, Attachment JFH-2, CoPUC Proceeding No. 16A-0117E.
185 https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-value-proposition/
186 *See, e.g.*, Michael Goggin, *Renewable Energy Builds a More Reliable and Resilient Electricity Mix*, American Wind Energy Association (May 2017), https://www.ourenergypolicy.org/wp-content/uploads/2017/05/AWEA-Renewable-Energy-Builds-a-More-Reliable-and-Resilient-Electricity-Mix.pdf.

reliability problems,[187] more than twice MISO's 14.2%, and models show much higher penetrations can be accommodated reliably.[188]

Even if Xcel found itself in a shortage event, its operators still have many tools at their disposal to prevent a loss of load event. Capacity shortages often do not result in a loss of load, as for that to occur, the shortfall must occur at the same time that transmission capacity and market purchases are unavailable. When faced with shortage conditions, operators have many solutions, including offering higher prices for market purchases, operating tie lines at emergency ratings, issuing consumer conservation notices, dipping into operating reserves, or reducing consumption through system voltage reductions.

Because of solutions like these, customer outages due to supply shortages occur much less frequently than predicted by power system planning criteria such as a 0.1 loss of load expectation.[189] Department of Energy ("DOE") data confirm that generation inadequacy causes less than 1/100th of 1% of all customer-hours of electricity outages, while transmission and distribution system outages account for over 99% of events.[190] Transmission and distribution systems are particularly vulnerable to the increasingly severe weather occurring as a result of climate change, as demonstrated by this past summer's blackouts in California due to catastrophic wildfires. As a result, spending scarce ratepayer dollars on additional generating capacity like the Sherco CC is unlikely to be the most cost-effective way to improve electric reliability.

Overall, Xcel's "reliability analysis" is flawed because the Native Capacity Shortfall Analysis is based on a fictitious assumption that Xcel must operate as an island from the rest of MISO. Once that is corrected in the "industry metrics" analysis, all high-renewable scenarios but one meet reliability criteria. Even that scenario would likely be reliable with proper modeling of renewable geographic diversity, additional storage additions, or increased imports.

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187 Kassia Micek, *SPP Tracker: Power Prices Rise on Colder Weather; Wind Leads Fuel Mix for 2020,* S &P Global (January 11, 2021), https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/011121-spp-tracker-power-prices-rise-on-colder-weather-wind-leads-fuel-mix-for-2020

188 C. Smith *et al.*, *Relevant Studies for NERC's Analysis of EPA's Clean Power Plan 111(d) Compliance* at v (June 2015), https://www.nrel.gov/docs/fy15osti/63979.pdf; Bethany Frew *et al.*, *Sunny with a Chance of Curtailment: Operating the US Grid with Very High Levels of Solar Photovoltaics*, iScience, Vol. 21 at 436–447 (Nov. 22 2019), https://reader.elsevier.com/reader/sd/pii/S2589004219303967?token=C728412B7E8EDC6128051FEBFD95D1954C1463B119DE788836D458B4B199CD0A0FC1946308C83817C6F2D8869C03D644.

189 Stephen Huntoon, *Have Mandatory Standards Improved Reliability?*, Fortnightly Magazine (Jan. 2015), http://www.energy-counsel.com/docs/Have-Mandatory-Reliability-Standards-Improved-Reliability-Fortnightly-January2015.pdf

190 Trevor Houser et al., *The Real Electricity Reliability Crisis*, Rhodium Group (Oct. 3, 2017), https://rhg.com/research/the-real-electricity-reliability-crisis-doe-nopr/

C. Xcel ignores the risk of the correlated failure of gas generators.

The electric sector's increasing dependence on gas generation has introduced new reliability risks. During several recent winter peak demand periods in regions across the country, gas generators have been forced offline by fuel supply limitations or interruptions. During these cold snap events, weather-related equipment failures have also forced multiple types of generators offline at the same time, including many gas generators.[191] Events in which many generators experience outages during the same time period due to a common cause, like extreme cold weather, are referred to as correlated outages or "common mode" failures. Accounting for these events would significantly reduce the capacity value of gas generators below what Xcel assumed, as Xcel's modeling assumes that conventional generators are not subject to correlated outages.

Following these events, grid operators and NERC are increasingly focused on the risks associated with fuel supplies. NERC has noted how correlated outages are a major risk, particularly for gas generators.[192] NERC's Winter Reliability Assessment and other NERC reports have continued to highlight this risk.[193] As noted earlier, the PJM and New England grid operators have conducted fuel security analyses, primarily motivated by reliability close calls during the 2014 Polar Vortex and other events.[194] The NERC and PJM fuel security efforts are ongoing.

Examples of recent pipeline supply interruption events include the 2011 Southwest outage, the Aliso Canyon outage in California, California desert pipeline outages, and the Enbridge/Westcoast Energy BC pipeline failures. Given the long distances traversed by interstate gas pipelines, events that reduce supply or increase demand anywhere along the pipeline can result in gas shortages for downstream customers, even if the event did not occur in their area. Most of the Upper Midwest is at the terminus of pipelines from other regions, with a large share of the region's supply coming from gas fields in the Southern U.S. As a result, the region is highly vulnerable to disruptions of supply shortfalls anywhere along that path.

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191 *See, e.g.*, PJM, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (May 2014), https://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx..

192 NERC, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System* (March 2020), https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf; NERC, *Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System* (November 2017), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf

193 NERC, *Winter Reliability Assessment* at 6 (Nov. 2019), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20WRA%202019_2020.pdf.

194 PJM, *Fuel Security Analysis: A PJM Resilience Initiative* (Dec. 17, 2018), https://www.pjm.com/-/media/library/reports-notices/fuel-security/2018-fuel-security-analysis.ashx?la=en; PJM, *Operational Fuel-Security Analysis Key Project* (Jan. 17, 2018), https://www.iso-ne.com/committees/key-projects/implemented/operational-fuel-security-analysis

Examples of widespread correlated failures of conventional generators including gas generation include the 2011 rolling blackouts in Texas, the 2014 Polar Vortex events that affected many regions of the country, and the 2018 Bomb Cyclone event that primarily affected the Northeast. During a cold snap in February 2011, ERCOT experienced rolling blackouts due to equipment failures at fossil generators and gas supply interruptions. In the 2014 Polar Vortex, PJM was forced to resort to voltage reductions to maintain reliability after extreme cold caused widespread conventional generator failures due to gas supply interruptions and equipment failures. Two other cold snaps that year, and a similar event in early 2015, also posed challenges for electric reliability in various regions of the country. In the January 2018 Bomb Cyclone event, New England faced reliability risks as gas supplies were interrupted and fuel oil supplies dwindled during a two-week cold spell. In January 2018, many conventional generators in Southern MISO experienced correlated outages due to equipment failures and gas supply interruptions.[195]

Notably, wind output was high during almost all of those events, demonstrating the resilience value renewables provide by diversifying the generation mix. After the 2011 ERCOT rolling blackouts, the Texas grid operator explicitly commended wind for helping to keeping the lights on.[196] During the 2014 Polar Vortex and other events that winter, wind output was consistently high.[197] Wind output across the Northeast was also high during the 2018 Bomb Cyclone event.[198] MISO and other parts of the country were also challenged by the 2019 Polar Vortex event, during which many types of generation experienced outages. As discussed above, the unusual loss of wind generation due to extreme cold temperatures is not a major cause for future concern, as there are a range of solutions to such events, including imports of wind generation from other regions.

In addition to the extreme winter weather and fuel supply interruptions discussed above, many other events can cause correlated outages. Water-cooled fossil and nuclear steam generators can be de-rated or even taken offline if drought or extreme heat affects their cooling water supplies.[199] Simultaneous generator outages can also result from equipment failures, lightning strikes, wind

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195 FERC, *2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018* (July 2019), https://www.ferc.gov/legal/staff-reports/2019/07-18-19-ferc-nerc-report.pdf

196 Kate Galbraith, *Trip Doggett: The TT Interview,* The Texas Tribune (February 4, 2011), https://www.texastribune.org/2011/02/04/an-interview-with-the-ceo-of-the-texas-grid/

197 Michael Goggin, *For the Third Time in a Month, Wind Energy Protects Consumers in a Cold Snap*, Into the Wind (Feb. 10, 2014), https://www.aweablog.org/for-the-third-time-in-a-month-wind-energy-protects-consumers-during-cold-snap/

198 Hannah Hunt, *How Did Wind Energy Perform during the Bomb Cyclone*, Into the Wind (Mar. 30, 2018), https://www.aweablog.org/wind-energy-perform-bomb-cyclone/

199 Melissa R. Allen-Dumas et al., *Extreme Weather and Climate Vulnerabilities of the Electric Grid: A Summary of Environmental Sensitivity Quantification Methods,* Oak Ridge National Laboratory, at 9–11 (Aug. 9, 2019), https://www.energy.gov/sites/prod/files/2019/09/f67/Oak%20Ridge%20National%20Laboratory%20EIS%20Response.pdf

storms, and other problems.[200] Six years ago in Minnesota, coal deliveries were interrupted due to rail congestion, forcing reduced output from multiple coal power plants.[201]

A recent paper co-authored by experts from NERC and Carnegie Mellon University documented that correlated generator outages are common and widespread. NERC data used in the Carnegie Mellon analysis demonstrates that conventional generators experience correlated outages many times more frequently than is predicted under the assumption that individual plant outages are uncorrelated independent events.[202] These correlated outages tend to be more common in regions with a high dependence on natural gas generation, like the Northeast and Southeast. While NERC's data show that MISO does not currently experience high rates of correlated outages, increasing Minnesota's dependence on gas generation could cause that problem to emerge. Other data in the Carnegie Mellon paper confirm that gas generators experiencing some of the highest correlated outage rates.[203]

Based on this data, the paper concluded:

> Our findings highlight an important limitation of current resource adequacy modeling (RAM) practice: distilling the availability history of a generating unit to a single value (e.g. EFORd, the equivalent forced outage rate during times of high demand) discards important information about when units in a power system fail in relation to one another. Only by incorporating the full availability history of each unit into RAM can we account for correlations among generator failures when determining the capacity needs of a power system. We strongly recommend that system planners incorporate correlated failure analysis into their RAM practice.[204]

Unfortunately, Xcel's planning and modeling do not follow that recommendation, which risks reliability and economic risks by overestimating the capacity value contributions of conventional power plants, and particularly gas generators. Xcel's modeling is based on the incorrect assumption that conventional generator outages are random, uncorrelated events. For example, if data indicates that each unit of a certain type of resource has a forced outage 10% of the time, then Xcel's method predicts that the odds of two units having an outage at the same time are only 1% (i.e., 10% times 10%). As noted above, recent experience during extreme events in MISO and other regions

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[200] *See* National Academies of Sciences, Engineering, and Medicine, *Enhancing the Resilience of the Nation's Electricity System* at 94–108 (2017), https://www.nap.edu/read/24836/chapter/5
[201] Jim Spencer & David Shaffer, *Feds Order BNSF Railway to Provide Emergency Coal Delivery Plans for Minnesota Power Plants,* Duluth News Tribune (January 6, 2015), https://www.duluthnewstribune.com/business/3649218-feds-order-bnsf-railway-provide-emergency-coal-delivery-plans
[202] *Id.* at S–22.
[203] *Id.* at 26–27.
[204] Sinnott Murphy et al., Resource Adequacy Risks to the Bulk Power System in North America at 29 (Feb. 15, 2018), https://www.andrew.cmu.edu/user/fs0v/papers/CEIC_17_02R1%20Resource%20adequacy%20risks%20to%20the%20bulk%20power%20system%20in%20North%20America.pdf.

demonstrates that the risk of multiple outages is much higher than that, as documented by the NERC data.

Xcel might argue that because peak demand occurs during the summer, the summer accounts for the loss of load risk on its system. However, that is circular reasoning. The assumption that loss of load risk is concentrated in the summer is driven by Xcel's assumption that conventional generator outages are random independent events. That assumption does not account for correlated failures that can take a large share of gas generation offline during winter peak demand periods. Even though electricity demand may be higher during the summer, winter events may pose a greater loss of load risk because supply can be lower because more gas generators are unable to operate during a winter peak demand period.

Failing to account for correlated outages of conventional generators overstates their capacity contributions relative to renewable and storage resources, as the correlated output patterns of wind and solar resources (i.e., the hourly output of one solar plant is positively correlated with the output of another solar plant) are accounted for in the Effective Load Carrying Capability method MISO uses to calculate their capacity value.

The capacity value of gas generators also declines at higher penetrations for the same reason that wind, solar, and storage resources' capacity values decline at higher penetrations: correlated output patterns. However, Xcel's analysis does not account for that. This can cause Xcel to miss opportunities to increase resilience by diversifying the generation mix by adding renewable generation that is not affected by fuel delivery and other constraints. The benefits of adding renewables that are not subject to fuel delivery constraints and other correlated risks have been demonstrated in the resilience analyses conducted by PJM and the New England grid operator.[205]

Accurately assessing the capacity value contributions of resources is also critical for ensuring that a planned resource portfolio is adequate to meet reliability needs. Overestimating the capacity value of new gas generation not only results in an economically suboptimal resource mix, but it can also cause electricity supply to fall short of demand. Accounting for the correlated outages experienced by some types of resources by reducing those resources' capacity value would address both problems.

Wind, solar, and battery storage resources are not vulnerable to both the fuel-supply and water-supply risks discussed above, and thus represent an opportunity to diversify Xcel's fossil-heavy portfolio. This will benefit customers by protecting them from the reliability and economic risks of a generation portfolio that is too dependent on any one fuel source.

[205] PJM, *Operational Fuel-Security Analysis Key Project* (Jan. 17, 2018), https://www.iso-ne.com/committees/key-projects/implemented/operational-fuel-security-analysis; *See* Michael Goggin, *PJM Study Quantifies Wind's Value for Building a Reliable, Resilient Power System*, Into the Wind (Apr. 4, 2017), https://www.aweablog.org/pjm-study-quantifies-winds-value-building-reliable-resilient-power-system/

D. Xcel overstates the reliability services provided by fossil generators, and understates the reliability services capability of renewable and storage resources.

Xcel's IRP Supplement also includes a section entitled "Resource Attributes."[206] Xcel explains that one objective inherent to the resource planning process is:

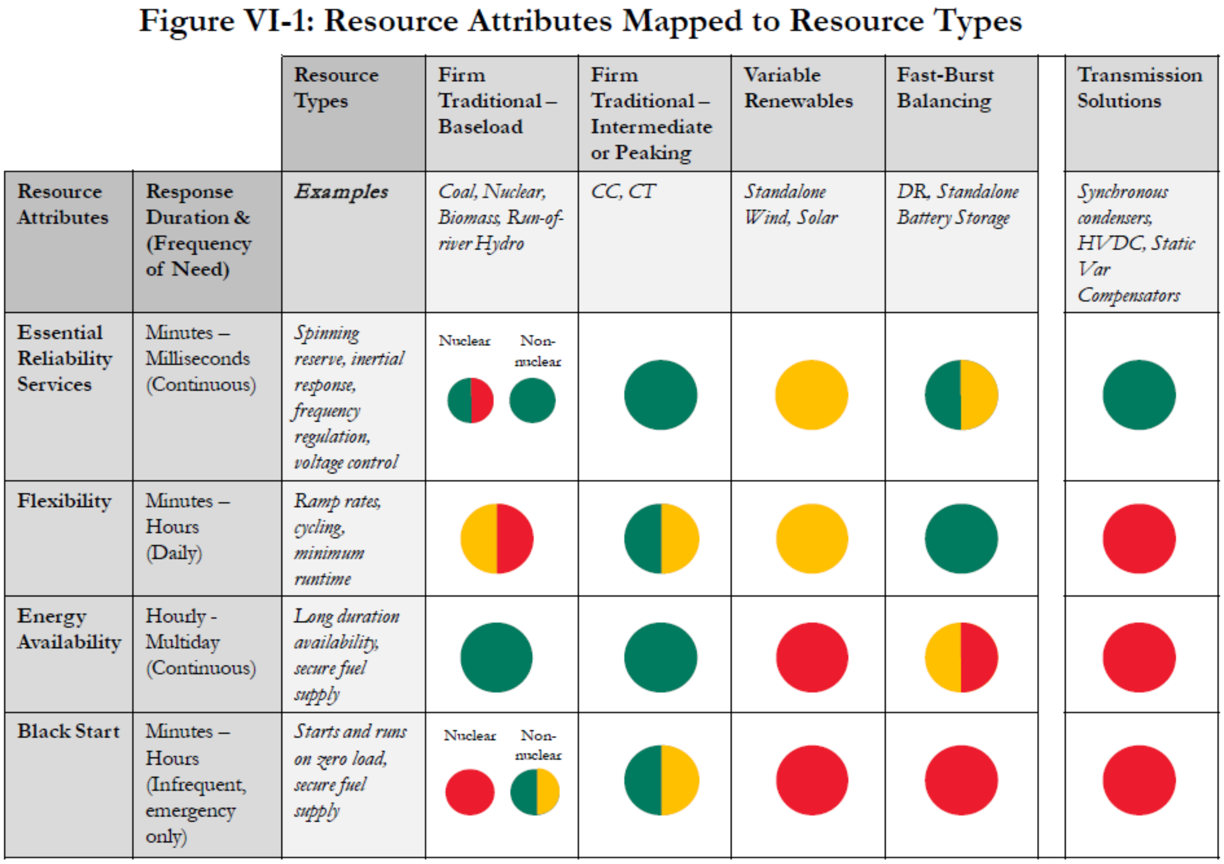
> "consideration of resource attributes and the importance of aligning the types of resources we need for the reliability of our system and broader grid. While we model our capacity expansion plans based on specific technology types' cost and operational characteristics, we also must look across resource types to ensure a balanced portfolio that provides appropriate capacity, energy and flexibility attributes in aggregate."[207]

However, just as Xcel has understated the capacity value of wind and solar, Xcel also makes a number of incorrect statements about the reliability contributions of battery and renewable resources relative to conventional generators.[208] These errors overstate the reliability contributions of conventional generators and understate those of renewable and storage resources. Xcel's modeling also does not fully account for the superior reliability services capabilities of renewable and storage resources.

On page 94 of Attachment A, Xcel provides a chart summarizing its view of the resource attributes of various resources, replicated below.

[206] IRP Suppl. 92 et seq. of Attach A, Section VI.
[207] IRP Suppl. at 92 of Attach A.
[208] *See*, e.g., IRP Suppl. at 94 of Attach A.

Figure 16: Xcel's Resource Attributes Chart



Source: Xcel IRP Supp, Attachment A at 94.

This chart does not accurately portray the reliability contributions of renewable and storage resources relative to conventional generators. In particular, the Essential Reliability Services capabilities of wind, solar, and storage resources exceed those of conventional generators in many ways. Wind, solar, and battery storage are digitally-controlled inverter-based resources, which allows them to respond to grid disturbances orders of magnitude more quickly than mechanically controlled conventional generators, with a full response in a few seconds or less.[209] This frequency response is fast enough that it can offset the need for inertial response from conventional generators, while also reducing the need for conventional generators' slower frequency response.[210] Wind and solar generators are also highly flexible, with an ability to have their output fully

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[209] Michael Goggin, *Renewables on the Grid: Market-Based Solutions Support Reliability,* Into the Wind the AWEA Blog (July 19, 2017), https://www.aweablog.org/renewables-grid-market-based-solutions-support-reliability/

[210] *Fast Frequency Response Concepts and Bulk Power System Reliability Needs,* North American Electric Reliability Corporation (March 2020), https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf

dispatched up or down in seconds, compared to many minutes for conventional generators. Thus, Xcel should not have rated wind and solar as less flexible than conventional generators. Moreover, inverter-based resources are increasingly technically able to provide black start services. These capabilities are discussed in more detail below.

The report conducted by Telos Energy in this proceeding on behalf of Sierra Club and CEOs, attached as Attachment C to these comments, also confirms the errors in Xcel's assessment of these capabilities. In Appendix C of Telos' Report, Telos provides a review of Xcel's Attachment A, Section VI: Resource Attributes. Telos finds that Xcel's table is "misleading, outdated or incorrect" in several ways. Telos provided a modified table correcting the errors in Xcel's table, Figure 17.

Figure 17 Resource Attributes Table As Modified by Telos Energy

Figure VI-1: Resource Attributes Mapped to Resource Types

		Resource Types	Firm Traditional – Baseload	Firm Traditional – Intermediate or Peaking	Variable Renewables	Fast-Burst Balancing	Transmission Solutions
Resource Attributes	Response Duration & (Frequency of Need)	*Examples*	*Coal, Nuclear, Biomass, Run-of-river Hydro*	*CC, CT*	*Standalone Wind, Solar*	*DR, Standalone Battery Storage*	*Synchronous condensers, HVDC, Static Var Compensators*
Essential Reliability Services	Minutes – Milliseconds (Continuous)	*Spinning reserve, inertial response, frequency regulation, voltage control*	Nuclear Non-nuclear				
Flexibility	Minutes – Hours (Daily)	*Ramp rates, cycling, minimum runtime*					
Energy Availability	Hourly - Multiday (Continuous)	*Long duration availability, secure fuel supply*					
Black Start	Minutes – Hours (Infrequent, emergency only)	*Starts and runs on zero load, secure fuel supply*	Nuclear Non-nuclear				

Source: Telos Report, Appx C.

As mentioned earlier in our comments, the modeling tools used by Xcel also lack the chronological and geographic resolution necessary to capture battery storage's ability to provide reliability services when and where needed. Batteries are highly modular and can be deployed in the sizes and locations on the grid where they are most needed. More importantly, batteries have the unique ability to absorb excess renewable output by charging, which gas and conventional generators cannot do. As a result, batteries can be located near renewable generators to absorb excess that output that would have been curtailed, and then release that output later when transmission capacity is available. In contrast, inflexible fossil generators tend to increase renewable curtailment, as these resources cannot change their level of output as quickly and often have high minimum output levels.

Batteries can respond much more quickly, flexibly, and precisely than gas-fired units can. Batteries can ramp from full charge to full discharge output in seconds or less in response to dispatch signals.[211] Batteries do not have a minimum partial output level or a minimum shut down period. In contrast, even quick start natural gas generators typically take nearly 10 minutes to start and ramp up to full load. A gas generator cannot provide negative generation like a battery can by charging, which is critical for reducing renewable curtailment. Batteries are faster and more accurate than gas generators in providing frequency regulation, which is used to accommodate second-to-second fluctuations in electricity supply and demand on the grid. Batteries also provide extremely fast primary frequency response, which is used to restore power system frequency in the seconds following a large disturbance on the grid, such as the loss of a large generator.

The extremely fast and accurate response and ramp rate capabilities of batteries were not fully valued in Xcel's modeling because the tools used by Xcel do not have sufficient chronological resolution to measure the benefits of extremely fast response. Xcel admits that it did not conduct sub-hourly modeling of the power system,[212] so Xcel's modeling did not fully account for the superior flexibility of batteries relative to gas generators.

Batteries provide far faster and more accurate response than gas generators to moment-to-moment fluctuations in supply and demand, but this valuable benefit was not captured because it is faster than the hourly modeling intervals evaluated by the EnCompass tool Xcel used. Similarly, as discussed below, the potential value of using the fast response of wind and solar resources to provide operating reserves was not fully captured by Xcel's analysis.

FERC and others have demonstrated that a small amount of fast and accurate operating reserve response from batteries can replace a significantly larger amount of operating reserves from slow and inaccurate fossil generators and offer comparable or better reliability.[213] As a result, portfolios with larger amounts of batteries, such as our Preferred Plan, can more easily meet reliability criteria by freeing up capacity from providing operating reserves for meeting capacity or flexibility needs. Thus, batteries' fast response provides an additional benefit for meeting peak demand, as typically more generating capacity must be held below its maximum output to provide upward operating reserves. Other studies have demonstrated that fast primary frequency response from batteries or from curtailed renewable resources provides greater value for stabilizing power system frequency

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211 *See* Thomas Bowen, *Grid-Scale Battery Storage: Frequently Asked Questions,* National Renewable Energy Laboratory at 2–3 (Sep. 2019), https://www.nrel.gov/docs/fy19osti/74426.pdf.
212 Xcel response to SC 140, page 104 of Attachment A.
213 Order No. 755, 137 FERC ¶ 61,064, Docket Nos. RM11-7-000 and AD10-11-000 at 2 (Oct. 20, 2011).

following a disturbance than the slow and inaccurate frequency response offered by conventional generators.[214]

Xcel also added "integration costs" to new wind and solar generation, though Xcel provides no information regarding what is included in those costs and why those costs and not covered by MISO's ancillary services markets.[215] MISO itself has noted that the impact of wind on the need for frequency regulation reserves, the fast-acting and more expensive ancillary services, is "little to none."[216] Increased wind and solar generation also tends to reduce the cost of ancillary services by causing conventional generators to be dispatched down, reducing their opportunity cost for providing ancillary services.[217] Regardless, wind and solar integration costs are generally picked up in MISO ancillary services markets, and thus should by spread across all MISO ratepayers with only a small portion accruing to Xcel ratepayers.

Xcel also did not account for the fact that fossil generators, and particularly coal generators, introduce far costlier net load variability by failing to accurately follow their output schedules, as demonstrated by MISO data. Specifically, coal output deviations average hundreds of MWs in most hours, and coal and gas generators are responsible for 62% and 36% of the total cost of output deviations, versus only 1% for wind.[218] Moreover, the cost of contingency reserves that are needed to offset the loss of large fossil and nuclear generators is far larger than the integration cost of wind.[219] NREL has also documented that large inflexible fossil and nuclear generators impose an integration cost on other generators by forcing them to operate more flexibly.[220]

Under FERC Order No. 827, inverter-based resources like solar, batteries, and wind are now also required to at least match the reactive power and voltage control provided by conventional generators.[221] Using their fast controls and inverter power electronics, batteries, wind, and solar plants are now capable of providing control of voltage and reactive power that is faster, more

[214] *See, e.g.*, NERC, *Reliability Guideline: Primary Frequency Control*, at 8 (May 2019), https://www.nerc.com/comm/OC/RS_GOP_Survey_DL/PFC_Reliability_Guideline_rev20190501_v2_final.pdf
[215] IRP Suppl. at 64, Integration Costs.
[216] Nivad Navid, *Multi-Faceted Solution for Managing Flexibility with High Penetration of Renewable Resources,* MISO (June 24, 2013), https://cms.ferc.gov/sites/default/files/2020-05/20140411130433-T1-A%2520-%2520Navid.pdf
[217] Marissa Hummon, *Fundamental Drivers of the Cost and Price of Operating Reserves,* National Renewable Energy Laboratory at 30 (July 2013), https://www.nrel.gov/docs/fy13osti/58491.pdf
[218] Potomac Economics, *2018 State of the Market Report for the Miso Electricity Market*, at 68–75 (July 2019), https://www.potomaceconomics.com/wp-content/uploads/2019/08/2018-SOM-Appendix_Final.pdf
[219] Michael Goggin, *Fact Check: Wind's Integration Costs Are Lower Than Those for Other Energy Sources,* Into the Wind the AWEA blog (July 25, 2014), https://www.aweablog.org/fact-check-winds-integration-costs-are-lower-than-those-for-other-energy-sources/
[220] Milligan, *Cost-Causation, supra* at 12-13.
[221] Order No. 827, 155 FERC ¶ 61,277, Docket No. RM16-1-000 (June 2016).

accurate, and more stable than that of gas generators.[222] Wind and solar can potentially even provide reactive power and voltage support when they are not producing power, such as solar plants pulling power from the grid at night to provide reactive power and voltage support to the grid using their inverters.[223] In contrast, conventional generators must be operating and producing power to provide reactive power control and voltage support. This limits the value of fossil generators, as they are often offline and therefore unavailable to provide reactive power and voltage control. These generators could be started up to provide voltage support, but starting and operating the plant would incur significant excess costs. In contrast, a battery can precisely tailor its output or charging to meet voltage and reactive power needs with no startup or fuel cost.

Thanks to technological advances, wind and solar resources are increasingly providing grid reliability services as well as or better than conventional generators.[224] For example, CAISO has shown that wind[225] and solar[226] resources that are curtailed offer dispatchable flexibility that is orders of magnitude faster than that offered by almost any conventional generator.[227] Xcel's Public Service Company of Colorado routinely uses its wind plants to provide frequency regulation by adjusting their output on a second-to-second basis, while wind plants in ERCOT provide primary frequency response that quickly and accurately stabilizes frequency following grid disturbances.[228]

Distributed solar and storage resources can also be used to provide these reliability services. The inverters used by distributed solar and storage resources are often the same or similar to those used by utility-scale resources, so they have the technical capability to provide these services. The 2018 revisions to the IEEE 1547 standard provide significant leeway for states and utilities to use inverter-based distributed resources to provide a range of reliability services.

Overall, Xcel has given inadequate weight to reliability capabilities of wind, solar, and storage, and has overvalued the contributions from fossil generation. This biases their analysis and proposed resource additions against renewable resources and towards fossil generators.

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[222] *Id.* at 4.
[223] *See, e.g.*, SMA, *Q at night*, https://www.sma-america.com/partners/knowledgebase/q-at-night.html (last accessed Apr. 2020).
[224] Michael Milligan, *Sources of Grid Reliability Services*, The Electricity Journal, Vol. 31, Issue 9 (Nov. 2018), https://www.sciencedirect.com/science/article/pii/S104061901830215X.
[225] California ISO, *ISO tests prove wind can play major role in renewable integration: Study results show wind farms' ability to supply essential grid services* (Mar. 11, 2020), http://www.caiso.com/Documents/ISOTestsProveWindCanPlayMajorRoleinRenewableIntegration.pdf
[226] Clyde Loutan et al., *Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant*, NREL (Mar. 2017), https://www.nrel.gov/docs/fy17osti/67799.pdf.
[227] E. Ela et al., *Active Power Controls from Wind Power: Bridging the Gaps*, NREL (Jan. 2014), https://www.nrel.gov/docs/fy14osti/60574.pdf.
[228] Michael Milligan *et al.*, *Alternatives No More*, IEEE Power & Energy Magazine (Nov./Dec. 2015), http://iiesi.org/assets/pdfs/ieee-power-energy-mag-2015.pdf

E. The Sherco CC, King, and Monticello plants are not needed for black start or other reliability services.

Xcel presents its Sherco Combined Cycle generator as being necessary to provide black start and other reliability services: "We also continue to include the planned Sherco CC in the Supplement Preferred Plan to support both the addition of renewable resources in the mid-2020s and our black start plan."[229]

As background, black start is a reliability service called upon to help restore the power system in the event of a widespread outage. This is typically done by starting up very small generators, like a small onsite diesel generator, and then using those generators to start slightly larger target generators, like a combustion turbine. This creates small islands of generation and load, which are then expanded until the grid is fully restored. Generators providing black start need to be small and highly flexible to balance supply and demand within those pockets of generation and load, so large and inflexible coal, nuclear, and combined cycle generators are not typically used.

For a number of reasons, a large combined cycle gas plant at the Sherco site is unlikely to be needed for black start. While Xcel declined to provide its system restoration plan that identifies the current plants that are used for black start,[230] it is very unlikely that the existing Sherco coal plant is a black start resource. Coal plants are typically not used for black start because they are too large and inflexible to be useful for bringing small pockets of load and generation online. Because system restoration relies on pre-defined cranking paths, this strongly indicates that there is not a need for black start at the Sherco site. Even if there is, alternative cranking paths can be created. Moreover, combined cycle generators like the proposed Sherco plant are typically too large and inflexible to be useful as black start resources. Even the frame combustion turbine component of a combined cycle generator is not typically used for black start, as smaller and more flexible stand-alone aeroderivative combustion turbines are better suited for the need.

As noted above, batteries offer superior technical capability for providing almost all needed reliability services, and this includes black start. Their small modular size and extremely fast response make them strong black start resources. Batteries can even provide the initial starting energy if they are outfitted with grid-forming converters that can set their own frequency and voltage signal.[231] Grid-forming converters are used for batteries and wind and solar resources installed in microgrids and other niche applications today, and will likely become increasingly common on the bulk power

[229] IRP Suppl. at 75; *see also* Attach A at 116 ("The Sherco site it currently a critical piece of our Minnesota black start plans.").
[230] Xcel response to SC 91.
[231] Himanshu Jain et al., *Blackstart of Power Grids with Inverter-Based Resources,* National Renewable Energy (August 2-6, 2020) https://www.nrel.gov/docs/fy20osti/75327.pdf

system as penetrations of renewables and storage increase.[232] Telos' Report (Attachment C) cites the Imperial Irrigation District's use of a battery for black start in California.

Xcel's supplemental IRP filing notes that they intend to file a plan in the future to address black start needs, indicating that there is no imminent need for new black start resources.[233] By the time Xcel's black start resources are retiring, technology will have likely advanced so that battery storage, potentially working with renewable resources also outfitted with grid-forming converters, will be able to meet at least some share of the need. Regardless, there are no black start needs that must be addressed in this proceeding.

As discussed earlier, inflexible coal, nuclear, and gas combined cycle generators impede the transition to a variable renewable power system, as they increase renewable curtailment relative to more flexible resources like batteries. Moreover, these generators do not provide any unique reliability services that cannot be provided by other resources.

F. <u>The proposed Sherco Combined Cycle Gas Plant Is Not Needed For Localized Reliability Purposes.</u>

One of Xcel's main justifications for needing its proposed Sherco combined cycle gas plant is reliability: "We also continue to include the planned Sherco CC in the Supplement Preferred Plan to support both the addition of renewable resources in the mid-2020s, or black start plan, and other critical operational reliability needs."[234] As discussed above, Xcel has not conducted a reasonable analysis showing that a large new gas CC is needed to integrate large amounts of new renewables, nor is it likely that Sherco is needed as part of Xcel's black start plan.

Xcel states that "Siting a CC at the existing Sherco site will cost-effectively address grid issues identified by the MISO Attachment Y-2 study of the Sherco Unit 1 and 2 retirements."[235] However, a study conducted by Telos Energy on behalf of Sierra Club and the CEOs, attached as Attachment C to these comments ("Telos Report"), makes it clear that the Sherco CC is also not needed for critical operational or reliability reasons. The purpose of Telos' analysis was to "assess reliability challenges related to the retirement of Xcel's remaining coal-fired generation in the greater Twin Cities region, and to examine whether Xcel's proposed Sherco combined cycle gas plant would cost-effectively mitigate any such reliability issues."[236] Telos conducted this analysis by reviewing and updating the three previous Y-2 studies relied upon by Xcel in its IRP: a 2015 Y-2 study of reliability

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232 Yashen Lin et al., *Research Roadmap on Grid-Forming Inverters,* National Renewable Energy Laboratory (November 2020), https://www.nrel.gov/docs/fy21osti/73476.pdf

233 IRP Suppl. at 13 of Attach A ("we anticipate that we will need to develop a plan for our black start resources before our next Resource Plan.").
234 IRP Suppl. at 5.
235 *Id.* at 64.
236 Telos Energy Report at 1 (hereafter Telos).

issues associated with the proposed retirement of the Sherco 1 & 2 coal units in 2024 ("Sherco 1&2 Only Y-2" or "2015 Y-2"), a 2016 study conducted by Siemens of replacing Sherco 1&2 with a 1,500 MW combined cycle gas plant ("Siemens Report"), and a 2018 Y-2 study of the reliability impact of retiring all three of the Sherco coal units as well as the A.S. King coal plant in 2030 ("Full Retirement Y-2" or "2018 Y-2").[237]

To conduct its analysis, Telos used the same modeling tool that was used to perform Xcel's prior Y-2s, the Siemens PTI's PSSE power system simulation software package.[238] Using MISO's Y-2 study methodology, Telos built upon Xcel's 2018 Y-2 by updating it in the following ways. First, Telos upgraded from MISO's MTEP17 powerflow database (used in the 2018 Y-2) to MISO's MTEP 2019 database.[239] This database contains updates to planned generation and transmission projects. Second, Telos included 2,500 MW of new solar photovoltaics by 2029, consistent with Xcel's Preferred Plan (and also consistent with Sierra Club's Clean Energy For All Plan, which would add 2,900 MW of solar by 2029).[240] The details of this 2,500 MW solar addition are provided in the Report at pages 5 and 8. Lastly, Telos used a study year of 2029, with data taken directly from the MTEP19 database.[241]

The results of Telos' analysis are striking:

> "Telos' Report finds that, in the case of the retirement of all of Xcel's remaining coal units, the addition of the Sherco CC plant did not materially decrease the number or severity of bulk system reliability violations. While Telos' analysis identified the need for several transmission reinforcements prior to 2029…Telos found that the addition of the Sherco CC did not solve or reduce any significant reliability issues or violations."[242]

While voltage and thermal violations resulted when all of the coal units are retired, the analysis found that "**none of the identified violations would be resolved by the addition of the Sherco CC plant…**."[243] The Report concludes that "there are no major obstacles or grid reliability concerns associated with retirement of Xcel's remaining coal units," although some minor transmission system mitigations and upgrades are likely required, and that "a new combined cycle power plant at the Sherco site would not mitigate or materially reduce any of the identified reliability issues"

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[237] *Id.*
[238] *Id.* at 7.
[239] *Id.* at 4.
[240] *Id.*
[241] *Id.* at 5. Xcel had used a 2030 model year in its 2018 Y-2. As the Telos report explains, Xcel's methodology was problematic in that Xcel took the MTEP17 2027 inputs and scaled up load to represent 2030, but did not commensurately scale up transmission and generation projects. As a result, Xcel increased load without reasonably increasing generation and transmission. In contrast, Telos directly used the MTEP19 database's data for 2029 load, generation and transmission without alteration. *Id.* at 5.
[242] *Id.* at 2.
[243] *Id.* at 2 (emphasis added).

associated with retirement of Xcel's remaining coal plants.[244] Instead, mitigation measures such as a "combination of operation adjustments to grid power flows, shunt compensation, and/or line reconductoring are better suited to addressing" the thermal or voltage violations identified when all of Xcel's coal units are retired.[245]

It is also worth noting that the MISO 2015 Y-2 study had identified voltage and thermal violations at the Monticello nuclear plant when Sherco 1 & 2 were retired.[246] Telos found that the violations were resolved when using the updated MTEP19 database and a 2019 revision to the Monticello Nuclear Power Interface Requirements, which expanded the voltage tolerance at the plant.[247] The addition of the proposed Sherco CC was not relevant to addressing in violations associated with the nuclear plant.

The Telos Report makes it clear: there is no reliability justification for the Sherco CC.

G. Portfolios high in renewables and battery storage can be reliable and deliver significantly greater returns to Minnesota's economy through job creation and local community investment.

As discussed above, renewable energy and battery storage are capable of providing many of the reliability attributes required to support a reliable grid. Contrary to Xcel's assertions in its "reliability analysis," independent studies have recently found that high renewable penetration portfolios can deliver energy at significantly lower cost without compromising reliability, particularly by ensuring appropriate consideration of the value of distributed resources.

A recent study by Vibrant Clean Energy, LLC, "Why Local Solar For All Costs Less: A New Roadmap for the Lowest Cost Grid: Technical Report," illustrates how traditional capacity expansion planning models fail to capture the reliability benefits of distributed generation. [248] In the study, VCE used the Weather-Informed energy Systems: for design, operations and markets planning (WIS:dom®- P) optimization software tool that is a combined capacity expansion and production cost model.[249] Traditional modeling tools do not integrate and optimize the benefits of locally-sited solar and storage. One of the key differences between WIS:dom and other modeling tools is its ability to optimize the addition of distributed solar and storage as resources, rather than assuming pre-determined buildout rates (as, for example, Xcel has done in its IRP modeling).[250]

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244 *Id.* at 3.
245 *Id.* at 14.
246 *Id.* at 12.
247 *Id.* at 5-6, 12.
248 *Why Local Solar for All Costs Less: A New Roadmap for the Lowest Cost Grid,* (December 2020) Vibrant Clean Energy, LLC on behalf of Local Solar for All, Vote Solar, and Coalition for Community Solar Access, https://www.vibrantcleanenergy.com/wp-content/uploads/2020/12/WhyDERs_TR_Final.pdf
249 Id. at 1
250 Id at 1-2

WIS:dom also "zooms in" compared to traditional planning models by using granular location planning and optimizing down to 5 minute increments.[251] Finally, WIS:dom incorporates distribution, transmission and generation planning into one tool, while other modeling tools do not integrate transmission and distribution costs and benefits.[252]

In its study, VCE evaluated whether distributed energy resources (distributed solar PV, energy efficiency, demand-side management, demand response, and distributed storage, or "DER") can lower costs across the US electricity system compared to alternatives, while maintaining resource adequacy, reliability and resilience. The study found that customers could save a cumulative $473 billion by employing a clean energy standard that reduces emission by 95% from 1990 levels by 2050, while also creating over 2 million more jobs.[253] This cleanest, lowest cost grid requires 223 GW more local solar nationwide.[254] The report found that traditional utility planning based on construction of utility scale generation fails to take into account the many benefits of a more distributed resource system, leading to an over-reliance on overbuilding peaking plants and large scale transmission projects. Adding the correct amount of distributed resources (by considering these benefits) allows the transmission system to be better utilized, and reduce the amount of peaking resources required. VCE's optimization shows that dramatically more distributed generation is beneficial than traditional models and utility planning account for.

Another study by GridLab recently demonstrated the technical and economic feasibility of achieving a reliable, 90% carbon-free grid by 2035, with wholesale electricity costs lower in 2035 than they are today.[255]

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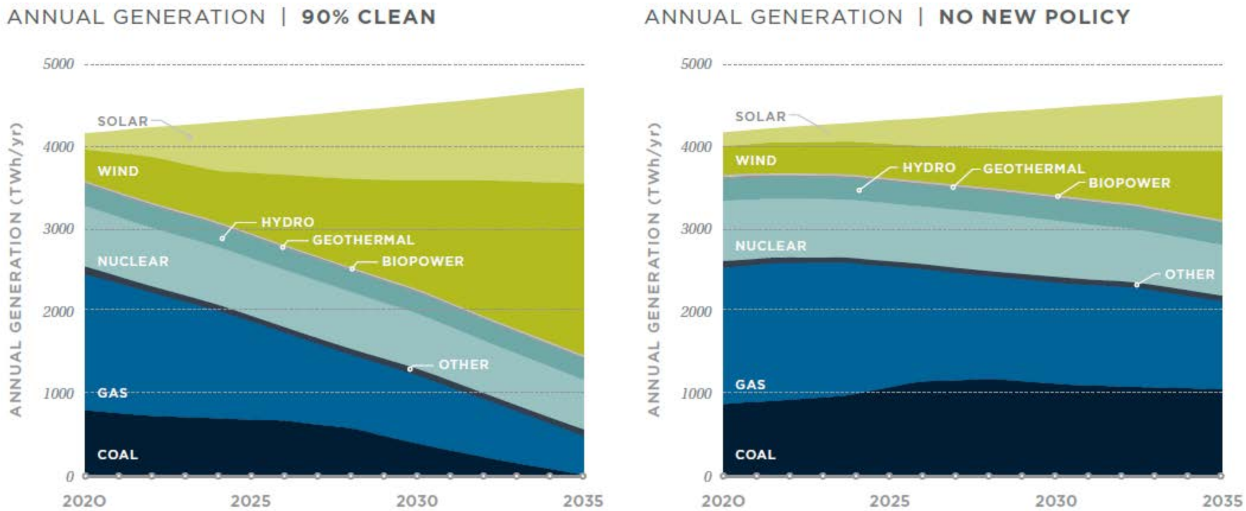
[251] VCE LLC, *Why Local Solar for All Costs Less: A New Roadmap for the Lowest Cost Grid: Results Summary*, at 13 (December 2020), https://www.vibrantcleanenergy.com/wp-content/uploads/2020/12/LocalSolarRoadmap_FINAL.pdf.
[252] *Id.* at 14.
[253] VCE LLC, *Why Local, supra.*
[254] *Id.*
[255] *Plummeting Solar, Wind, and Battery Costs Can Accelerate Our Clean Electricity Future*, Goldman School of Public Policy, UC Berkeley, GridLab, and PaulosAnalysis at 1, 21, (June 2020), http://www.2035report.com/wp-content/uploads/2020/06/2035-Report.pdf?hsCtaTracking=8a85e9ea-4ed3-4ec0-b4c6-906934306ddb%7Cc68c2ac2-1db0-4d1c-82a1-65ef4daaf6c1



Source: Id. at 4.

This study used NREL's Regional Energy Deployment System capacity-expansion model and Energy Exemplar's PLEXOS electricity production cost model, as well as NREL's ATB 2019 for renewable energy and battery costs (the same source Xcel used).[256] They describe their reliability analysis as follows:

> "To assess system dependability, defined as the ability to meet power demand in every hour of the year, we simulated hourly operation of the U.S. power system over 60,000 hours (each hour in 7 weather years). For each of these hours, we confirmed that electricity demand is met in each of the 134 regional zones (subparts of the U.S. power system represented in the model) while abiding by several technical constraints (such as ramp rates and minimum generation) for more than 15,000 individual generators and 310 transmission lines."[257]

In this scenario, all existing coal plants are retired by 2035 and no new fossil fuel plants, including gas, are built.[258] Their 90% by 2035 scenario is not only lower in cost, but avoids $1.2 trillion in health and environmental damages nationally, including 85,000 premature deaths, while also delivering reliable energy.[259] Achieving this scenario requires building about 70 GW of new wind and solar per year, contributing to creation of approximately 8.5 million net job-years "as increased employment from expanding renewable energy and battery storage more than replaces lost employment related to declining fossil fuel generation."[260]

[256] *Id.* at 12-13.
[257] *Id.* at 13.
[258] *Id.* at 4.
[259] *Id.* at 5.
[260] *Id.* at 6-7.

H. Xcel's claimed need for 2,600 MW of firm capacity resources in 2030-2034 can be better met with battery storage, demand response, and transmission expansion to access more diverse renewable resources.

As explained in the preceding sections, Xcel's analysis consistently understates the reliability contributions of renewable and storage resources, and overstates those of gas generators. Moreover, Xcel can use transmission expansion to increase import and export capacity with the rest of MISO and beyond, increasing the capacity value of wind and solar by accessing more geographically diverse resources while providing significant other economic and reliability benefits. Therefore, it is likely that a portfolio of renewables, storage, demand response, and transmission expansion can meet Xcel's 2030-2034 capacity needs with greater economic and reliability benefits than building new gas capacity. Continued technology improvements for renewable, storage, demand response, and grid-enhancing technologies like dynamic line ratings are likely to further increase their economic and reliability benefits relative to adding gas capacity. In addition, electrification of transportation, building heating, and water heating will enable new forms of demand response, as all of those loads are controllable and can typically be shifted many hours in time to alleviate short-term capacity shortfalls.

For all of those reasons, we agree with Xcel's reasoning that "[b]ecause these additions do not occur for more than ten years, we are intentionally leaving them technology neutral, recognizing that they could be non-emitting resources like storage or DR,"[261] but we would add transmission expansion to that list of potential solutions. It is particularly important for Xcel to take near-term action to develop transmission and push transmission expansion at MISO, given that it takes multiple years to permit and build transmission. A number of studies have found that transmission expansion provides large economic and reliability benefits by aggregating diverse loads and resources over larger geographic areas, and concluded that transmission expansion is essential for cost-effectively integrating large amounts of wind and solar generation. For example, MISO has found that its MVP transmission additions are yielding benefits that are 2.2 to 3.4 times greater than their cost,[262] while SPP has found similar net benefits for its recent transmission additions.[263]

For the same reason, we would caution Xcel against looking only at its own loads and resources and using the ratio of its firm dispatchable resources to its peak load as the metric of reliability. Xcel proposes this ratio as a key metric of reliability, arguing that it "[e]valuates the share of peak load that we are able to serve without relying on NSP system use-limited and variable resources, or off-system market energy and capacity purchases. This measure helps us identify market exposure in the

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261 IRP Suppl. at 75, FN 36.
262 MISO, *MTEP17 MVP Triennial Review (September 2017),* https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf
263 Southwest Power Pool, *The Value of Transmission,* (January 26, 2016), https://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf

event variable and use-limited resources are unavailable for a period of time."[264] While Xcel acknowledges that "current MISO Resource Adequacy rules do not include any requirements for these traditional firm resources," Xcel argues that such a metric ensures "that we are hedged during periods of extreme MISO market demand and/or locational marginal price (LMP) spikes."[265]

Contrary to Xcel's claims, off-system sales and purchases are an essential part of efficiently meeting reliability needs that will only become more important with higher penetrations of wind and solar. NREL and others have documented that the lowest-cost solution for power system flexibility includes expanding the footprint of grid operating areas, which reduces the variability in electricity supply and demand through aggregation and provides greater access to sources of flexibility.[266] Another recent publication found that transmission drives a 46% reduction in total power system cost with the use of 100% renewable energy, with significant benefits from both regional and inter-regional transmission.[267]

As another example, analysis published in the journal *Nature Climate Change* developed a transmission plan to cost-effectively expand wind and solar use to 38 percent and 17 percent of America's electricity use, respectively.[268] Even with a 14 percent increase in electricity consumption from current levels, the study found that demand can still be reliably met in all hours with the removal of all coal-fired generating capacity and a significant reduction in gas-fired generating capacity from what we have today. That article found that a major benefit of transmission is capturing the geographic diversity in wind and solar output due to the fact that "the average variability of weather decreases as size increases; if wind or solar power are not available in a small area, they are more likely to be available somewhere in a larger area." The study notes that "paradoxically, the variability of the weather can provide the answer to its perceived problems."

Similar results were observed in recent modeling of the eastern U.S. power system by VCE.[269] That study demonstrated transmission expansion made it possible to cost-effectively reduce electric sector

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264 IRP Suppl. at 41, Table 2-5.
265 *Id.* at 50.
266 Michael Milligan et al., *Advancing System Flexibility for High Penetration Renewable Integration,* National Renewable Energy Laboratory at 7, citing Cochran et al., 2014 (October 2015), https://www.nrel.gov/docs/fy16osti/64864.pdf
267 Patrick Brown & Audun Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System,* Joule (December 11, 2020), https://www.cell.com/joule/pdf/S2542-4351(20)30557-2.pdf
268 http://www.nature.com/nclimate/journal/vaop/ncurrent/full/nclimate2921.html; Robert Walton, *Study: Deep Decarbonization of U.S. Grid Possible Without Energy Storage,* Utility Drive (January 26, 2016), https://www.utilitydive.com/news/study-deep-decarbonization-of-us-grid-possible-without-energy-storage/412721/
269Christopher T.M. Clack et al., *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.,* Americans for a Clean energy Grid (October 2020), https://cleanenergygrid.org/wp-content/uploads/2020/10/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S.pdf

CO_2 emissions by 65% by 2035, and by more than 95% by 2050, by producing more than 80% of electricity from wind and solar by 2050. This decreased the average electric bill rate by more than one-third, from more than 9 cents/kWh today to approximately 6 cents/kWh by 2050, saving a typical household more than $300 per year. The cost of transmission accounted for only 3.6% of total electricity costs on average in the strong carbon-reduction cases, and transmission yielded savings many times greater than that by providing access to low-cost renewable resources and increasing the overall efficiency of the power system. VCE also found this would create more than 6 million net new jobs, increasing electric sector employment more than 5-fold from approximately 1.3 million to more than 7.5 million jobs by 2050, with transmission investment alone driving more than 1.5 million new jobs. Storage and transmission worked together to make it possible to meet electricity demand in every 5-minute period of the year with wind and solar providing 82% of electricity in 2050, despite 32% load growth in electricity demand and a reduction in fossil and nuclear generating capacity of over 85%.

Consulting firm E3 examined a host of potential solutions to solar curtailment under a 50% Renewable Portfolio Standard (RPS) in California, and found that some of the most effective solutions were regional coordination and access to a diverse mix of resources, both of which are enabled by transmission.[270] Another recent study found that a package of flexibility solutions, including expanded imports and exports, would greatly reduce curtailment as California increases its use of renewable energy. In a high solar case, curtailment fell from 9.5% to less than 0.5% with the package of flexibility solutions in place, while in the case with less solar and more wind generation, curtailment fell from over 4% to 0.2%.[271]

Solely looking at on-system firm capacity resources misses another crucial benefit of transmission. As discussed above, power system planning typically assumes conventional generator outages are random independent events, even though data shows many outages are correlated. As a result, these models not only understate the risk of localized generator outages, but also understate the benefits of using transmission to build larger connected footprints. Transmission is particularly valuable for alleviating the impact of localized correlated generator outages during extreme weather events. In the 2019 Polar Vortex, parts of MISO experiencing high rates of generator outages were able to maintain reliability because transmission allowed them to import power from other regions that were not as severely affected by the cold snap. By focusing solely on on-system firm capacity resources and not transmission ties, Xcel misses that benefit, in large part because it fails to account for the risk of conventional generator correlated outages.

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[270] Energy and Environmental Economic, *Investigating a Higher Renewables Portfolio Standard in California,* (January 2014), https://www.ethree.com/wp-content/uploads/2017/01/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf

[271] Gregory Brinkman et al., *Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California,* National Renewable Energy Laboratory at v-vii (January 2016), https://www.nrel.gov/docs/fy16osti/64884.pdf

Xcel's proposal to look inward at firm capacity resources to meet its capacity needs is moving in the wrong direction. To cost-effectively enable the transition to a reliable high-renewable future, Xcel should be looking outward at increased transmission ties and market transactions. Unlike gas capacity resources, transmission is highly flexible and is not subject to fuel delivery interruptions or fuel price risk. Expanded transmission ties reduce the risk of price spikes and lessen the impact of severe weather events that affect limited geographic areas. As noted above, MISO and others use sophisticated planning tools to calculate the diversity benefits among utilities, and these studies indicate that large amounts of imports that can be relied upon for meeting peak demand.[272] Both MISO[273] and SPP[274] have found that transmission expansion reduces economic and reliability risk. As a result, a combination of renewables, storage, demand response and transmission expansion should be the primary focus for meeting any need for capacity in the 2030s, and not gas capacity.

<u>Conclusion</u>
Xcel's claims that it needs the Sherco CC and other gas resources for reliability purposes does not withstand scrutiny. The Commission should instruct Xcel to account for the full reliability benefits of renewable energy, battery storage, distributed generation, and the regional transmission system in conducting its reliability analyses in IRPs. There is no evidence that Xcel cannot meet its customers' electricity needs reliably under a portfolio such as Sierra Club's Clean Energy For All Plan, and in fact various studies indicate that Sierra Club's Plan can meet Xcel's needs reliably and at lower cost.

VII. ENVIRONMENTAL AND SOCIOECONOMIC BENEFITS: APPROVING SIERRA CLUB'S CLEAN ENERGY FOR ALL PLAN WOULD RESULT IN GREATER ENVIRONMENTAL AND SOCIOECONOMIC BENEFITS TO MINNESOTANS.

To evaluate whether a resource plan is in the public interest, the Commission is also required to assess plans based on their ability to minimize adverse socioeconomic effects and adverse effects upon the environment.[275] This includes whether the resource plan helps the utility achieve Minnesota's statutory greenhouse gas reduction goals.[276] The regulations define "socioeconomic effects" as "changes in the social and economic environments, including, for example, job creation, effects on local economies, geographical concentration of persons and structures, concentrations of

[272] *2019-2020 CIL/CEL Values and Study Timeline*, MISO at 4 (September 11, 2018) https://cdn.misoenergy.org/20180911%20LOLEWG%20Item%2003%202019-20%20PY%20CILCEL%20Values273688.pdf
[273] MISO, *MTEP17, supra.*
[274] Southwest Power Pool, *The Value, supra.*
[275] Minn. R. 7843.0500, subp. 3.
[276] Minn. Stat. § 216B.2422, subd. 2c.

investment capital, and the ability of low-income and rental households to receive conservation services."[277]

While Xcel's proposed early coal retirements and significant additions of renewable energy, efficiency, and demand response help move the Company in the right direction, the Company's proposal to build a large new fossil gas plant and pipeline is a significant barrier to achieving decarbonization of the utility's electricity and runs counter to Minnesota's statutory carbon reduction goals. Moreover, Xcel's failure to take full advantage of renewable energy (including hybrids and battery storage) and its minimization of distributed generation and community solar as part of its plan misses significant opportunities to create jobs and invest in local economies. Sierra Club's Clean Energy For All Plan, which dramatically expands both utility scale and distributed generation, will put the Company on a better track to achieve its carbon reduction goals and will better serve Minnesotans by creating more jobs and providing more opportunities for customers to share in the wealth of the clean energy economy.

A. <u>Our Clean Energy For All Plan Is A "No Regrets" Plan that Avoids New Investments in Gas and Sets Xcel on Track to Achieve the State's Carbon Reduction Goals.</u>

Minnesota's legislature has made it clear that reducing the impacts of climate change is in the interest of Minnesotans. Minn. Stat. § 216H.02 set Minnesota's greenhouse gas emission reduction goals in statute: "It is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050." In 2018, Xcel became the first utility in the nation to announce a goal of achieving 100% carbon-free electricity by 2050, and an 80 percent reduction from 2005 levels by 2030.[278]

Governor Walz recently announced a policy goal of 100% carbon-free electricity by 2040, a decade earlier than Xcel has proposed.[279] His announcement followed the release of a report from the Minnesota Pollution Control Agency, issued in January 2021, that found that the state has fallen far behind on meeting its statutory goals of reducing economy-wide greenhouse gas emissions 30% below 2005 levels by 2025, and 80% by 2050. It reported that overall, Minnesota's greenhouse gas emissions have only declined 8% since 2005. Emissions from electricity generation have fallen 29% since 2005, making it the only sector on track to meet Minnesota's statutory goals. As Governor Walz said in a statement: "The time to fight climate change is now. Not only is clean energy the right and responsible choice for future generations, clean energy maximizes job creation and grows our economy, which is especially important as we work to recover from the COVID-19 pandemic."

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[277] Minn. R. 7843.0100 subp. 10.
[278] IRP Suppl. at 3.
[279] Kisti Marohn, *Walz Calls for 100 Percent Carbon-Free Electricity by 2040,* MPRnews (January 25, 2021) https://www.mprnews.org/story/2021/01/24/walz-calls-for-100-percent-carbonfree-electricity-by-2040

Meanwhile, the Biden Administration has set a goal of 100% carbon free electricity by 2035.[280] John Kerry, President Biden's Climate Envoy, spoke just a few weeks ago at the virtual Davos conference about the perils of new gas infrastructure: "The problem with gas is, if we build out a huge infrastructure for gas now to continue to use it as the bridge fuel—when we haven't really exhausted the other possibilities—we're going to be stuck with stranded assets in ten, twenty, thirty years," he said. "Gas is primarily methane, and we have a huge methane problem, folks."[281] President Biden's administration can be expected to enact policies consistent with achieving this 100% by 2035 goal, further raising questions about the prudence of new gas expenditures.

As noted above, Xcel's Preferred Plan, which includes the Sherco CC as well as 2,600 MW of "firm peaking" resources after 2030 (modeled as generic gas CTs), would achieve an almost 80% reduction in Xcel's carbon emissions by 2030. See Figure 11, above. After 2030, however, its carbon emissions essentially flatten. The Company's plan to install the Sherco CC and other gas resources make it impossible to meet the 2050 carbon-free goal without leaving significant stranded costs. According to the EnCompass modeling outputs associated with Xcel's Preferred Plan, the Sherco CC is expected to emit over **[PROTECTED DATA BEGINS…PROTECTED DATA ENDS]** tons of carbon dioxide in 2030. The Company cannot keep gas units on-line past 2050 while also meeting its goal of 100% carbon-free electricity by that year. Xcel's assumed book life for new gas units in the IRP, including the Sherco CC, is 40 years.[282] This means that the Sherco CC would be in ratebase until 2067—17 years past the zero-carbon goal. The plant could retire prior to 2050 to meet the emissions goal, but in that event there would be significant stranded costs because the plant would not be fully depreciated. If the plant were to retire in 2050, stranded costs could amount to **[TRADE SECRET DATA BEGINS…TRADE SECRET DATA ENDS]**. If the plant were to retire in 2040, consistent with the goal Governor Walz has said is required to avert the worst impacts of climate change in Minnesota, customers could still owe **[TRADE SECRET DATA BEGINS…TRADE SECRET DATA ENDS]** on the gas plant. And, if the plant were required to retire by 2035, consistent with President Biden's goal, customers could remain on the hook for **[TRADE SECRET DATA BEGINS…TRADE SECRET DATA ENDS]**.[283] Indeed, for this reason, industry analysts have recently noted the stranding risk associated with building new gas plants.[284]

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[280] John Muyskens & Juliet Eilperin, *Biden Calls for 100 Percent Clean Electricity by 2035,* The Washington Post (July 30, 2020), https://www.washingtonpost.com/climate-environment/2020/07/30/biden-calls-100-percent-clean-electricity-by-2035-heres-how-far-we-have-go/?arc404=true

[281] Bill McKibben, *The Biden Administration's Landmark Day in the Fight for Climate*, The New Yorker (January 28, 2021), https://www.newyorker.com/news/daily-comment/the-biden-administrations-landmark-day-in-the-fight-for-the-climate

[282] *Id.* at 69.

[283] Xcel Supplemental response to SC-90-Trade Secret

[284] *See*, e.g., Bryndis Woods et al., *Risks Outweigh Rewards for Investors Considering PJM Natural Gas Projects,* Applied Economics Clinic and Institute for Energy Economics and Financial Analysis (October 2020),

Sierra Club asked the Company in discovery whether Xcel would intend to retire the proposed new Sherco CC by 2050, consistent with its "ultimate vision of 100 percent carbon-free energy by 2050[.]"[285] Xcel responded that it:

> "has not determined how or whether the Sherco CC may be used beyond 2050. As noted in the response to Sierra Club IR 8, we plan to bring forward a filing detailing our Sherco CC project plan in the 2020-2021 timeframe under Minn. H.F. 113 (2017). The Company was explicit, in announcing our aspiration of 100 percent carbon-free electricity for our customers by 2050, that achieving this aspiration will require research, development and deployment of new carbon-free dispatchable technologies that are not yet commercially available at the cost and scale needed."[286]

It is unreasonable to bet hundreds of millions of ratepayer dollars on technologies that do not yet exist when known and established carbon free technologies – wind, solar, and battery storage – are available today at lower cost. Options for converting gas generation resources to emit low or zero emissions are at best theoretical at this point—and no such costs are modeled by the Company in this IRP. Numerous technical and economic hurdles would have to be overcome, and the Company has offered no analysis of how it would do so. The only pilot project anywhere in the world for adding carbon capture technology to a gas combined cycle project was canceled, and the two coal plant carbon capture projects in the U.S. have collapsed under ballooning budgets.[287] The energy required to capture carbon dioxide significantly increases the fuel consumption of carbon capture power plants, reducing their competitiveness in regional power markets, and it is impractical to capture all emissions at these power plants.

There is conceptual interest in running gas generators on hydrogen produced using renewable electricity. However, hydrogen cannot be blended into existing natural gas pipelines beyond a relatively low threshold, due to issues related to cracking and weakening pipeline steel, leaks, and

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https://static1.squarespace.com/static/5936d98f6a4963bcd1ed94d3/t/5f7b536c01913d3bb4ffd05d/1601917808676/Risks+Outweigh+Rewards+for+PJM+Natural+Gas+Project+Investors_October+2020.pdf; Charles Teplin et al., *The Growing Market for Clean Energy Portfolios*, Rocky Mountain Institute (2019), https://rmi.org/insight/clean-energy-portfolios-pipelines-and-plants

285 Xcel Response to SC 9 Supp (a).

286 *Id.*

287 Carlos Anchondo & Edward Klump, *Petra Nova is Closed: What it Means for Carbon Capture,* E&E News (September 22, 2020), https://www.eenews.net/stories/1063714297; Henry Fountain, *In Blow to 'Clean Coal', Flawed Plant Will Burn Gas Instead,* The New York Times (June 28, 2017), https://www.nytimes.com/2017/06/28/climate/kemper-coal-mississippi-clean-coal-project.html; Damian Carrington, *UK Cancels Pioneering 1 Billion Carbon Capture and Storage Competition,* The Guardian (November 25, 2015), https://www.theguardian.com/environment/2015/nov/25/uk-cancels-pioneering-1bn-carbon-capture-and-storage-competition

impacts on consumer appliances.[288] Without overcoming those technical challenges or building dedicated hydrogen fuel delivery and storage infrastructure, it would likely be necessary to produce and store hydrogen at or near the site of the gas generator. Similarly, many biofuels cannot be transported in existing oil pipelines because of problems that could result from their hydrophilic properties. Therefore, converting gas generators to these alternative fuels would require dedicated fuel delivery infrastructure, which would significantly increase costs if it is even feasible.

As discussed elsewhere in these comments, adding a gas combined generator that is far less flexible than other resources, like battery storage, and constrains the Company's ability to achieve the high penetrations of wind and solar generation needed to reduce emissions by 80 to 100%. During periods of renewable abundance, like midday and overnight hours, inflexible resources like gas combined cycle resources that cannot ramp quickly or turn their output down to low levels will force the regular curtailment of wind and solar generation. This is harmful to ratepayers, causing gas generators with high fuel costs to run instead of zero fuel cost renewable resources, while also constraining the Company's ability to reduce emissions.

In contrast, Sierra Club's Clean Energy For All Plan presents a "no regrets" option that uses existing technologies to achieve a 90% reduction in carbon emissions by 2030. Sierra Club's plan does not bet on some future hypothetical new technology, instead relying completely on existing carbon free technologies – utility scale solar and wind, hybrids, battery storage, as well as distributed and community solar – whose costs every industry analyst agrees are dramatically declining. Sierra Club's plan also avoids significant stranded cost risks. If, in several years – closer to Xcel's stated need for the Sherco CC – the Commission finds that battery storage and renewables costs have not declined as industry analysts all predict, there will still be plenty of time to consider whether it would be reasonable and prudent for Xcel to build a combustion turbine that would meet the need at lower cost and emissions, and with less curtailment of renewable energy, than a massive combined cycle plant.

B. Sierra Club's Clean Energy For All Plan Would Also Deliver Greater, More Equitable Socioeconomic Benefits That Will Help Minnesota Communities Recover from the COVID Crisis.

Xcel's IRP Supplement devotes a section, Attachment C, to its plans to deliver "greater inclusion, diversity and equity in our company and community."[289] Xcel states that "[t]he recent nationwide unrest and ongoing protests demanding change to address systemic racism have only strengthened our resolve to find ways we can do more to help our employees and communities heal, recover and

[288] M. W. Melaina, et al., *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues*, National Renewable Energy Laboratory (March 2013), https://www.energy.gov/sites/prod/files/2014/03/f11/blending_h2_nat_gas_pipeline.pdf
[289] IRP Suppl. at 1 of Attach C.

grow."[290] Xcel focuses the section on topics brought forward in discussions with Fresh Energy and Sierra Club, including cultivating a diverse and inclusive workforce, ensuring a just and equitable workforce transition in host communities, and expanding access to energy efficiency, solar, and transportation electrification.

Sierra Club appreciates Xcel's direct response to our request through its acknowledgement of the impact of their IRP planning process on energy equity and access for all Minnesotans. We believe that all Minnesota utilities should make it a standard practice to include a similar discussion in their IRP filings. Now, more than ever, it is essential that utilities craft their IRPs through a lens of equity and access to the benefits of clean energy. As we and many others recently noted in the COVID economic stimulus docket, 20-492, Black, Indigenous, and People of Color (BIPOC) Minnesotans have disproportionately been harmed as a result of the three "syndemics": the COVID pandemic and economic fallout, the climate crisis, and centuries of systemic racism in Minnesota. A failure to acknowledge and address this disproportionate harm will result in maintaining the status quo and exacerbate existing inequalities.

While Xcel has taken the critical first step of discussing equity considerations in its IRP, certain key elements of Xcel's proposed plan create a barrier to achieving the outcome the utility has expressed it desires. First, Xcel's proposal to construct a massive new gas plant and associated pipeline is inconsistent with this commitment because the impacts of climate change will be borne disproportionately by BIPOC communities in Minnesota.[291] The gas plant would also cost customers an estimated $200 million more than clean alternatives and could saddle customers with hundreds of millions of dollars in stranded costs, an economic burden that would most harm our most vulnerable communities.

Moreover, Xcel's plan unreasonably minimizes the role that community solar and distributed generation can and should play in its portfolio. *See* Section V.D-F. A plan that includes both robust investment in utility scale renewables as well as strong deployment of distributed and community solar will deliver far more in terms of job creation and community investment, both key to Minnesota's sound economic future. As discussed in our reliability section above, Section VI, a recent study by Vibrant Clean Energy found that portfolios high in distributed energy generation can deliver significant energy cost savings while creating 2 million more jobs nationally. (On a population basis, this translates into 33,800 additional jobs in Minnesota.) These conclusions are

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[290] *Id.*
[291] See, e.g., *Minnesota Climate Change Vulnerability Assessment*, Minnesota Department of Health https://www.health.state.mn.us/communities/environment/climate/docs/mnclimvulnsummary.pdf; *Talking the Relation Between Climate Change, COVID-19 and Public Health with U of M,* University of Minnesota News and Events (July 17, 2020), https://twin-cities.umn.edu/news-events/talking-relation-between-climate-change-covid-19-and-public-health-u-m

supported by data from Minnesota regarding its own community solar program.[292] So far, Minnesota's community solar gardens have provided a way for 12,000 households and 2,000 businesses, non-profits, and public sector customers to own solar projects.[293] Community solar employed over 4,000 workers in Minnesota in 2018, and community solar projects currently pay about $5 million a year to landowners for leases and royalty payments, totaling $182 million over the next 25 years.[294] Community solar projects will pay over $1 million in 2019 to counties and towns through the state Solar Production Tax Credit, plus increased property tax revenues likely to exceed $2 million per year.

Sierra Club's Clean Energy For All Plan forecasts more than twice the level of community solar investment as Xcel's, and nine times more distributed solar generation. This element alone is critical to maximizing socioeconomic benefits for Minnesotans.

Additional programs are needed, however, to ensure that the customers who most need the benefits of clean energy – BIPOC and low-income Minnesotans, as well as renters – have access to community solar, distributed generation, and energy efficiency. For example, 80% of Xcel's low-income CIP funds for natural gas efficiency went to owner-occupied homes instead of renters; in Minneapolis, 80% of Black households rent, compared to only 43% of white households. The areas with highest concentrations of residents of color and low-income residents, North Minneapolis and central South Minneapolis, experience a higher energy burden relative to the rest of the city.[295]

Xcel must improve access to clean energy and efficiency programs

Xcel states that it is "eager to work with stakeholders to identify economic solutions that bring solar energy to disadvantaged communities," noting that it worked with stakeholders to develop a low income Solar*Rewards program and brought forward a new Low-Income rooftop solar pilot as part of its filing in docket 20-492.[296] Xcel also proposed to double its spending on low-income energy efficiency, as well as expanding programs for low-income customers and multifamily homes. We appreciate Xcel's interest in working with stakeholders and its initial proposals, and we encourage Xcel to work with stakeholders to expand opportunities for low-income customers to access solar and energy efficiency and develop dedicated marketing plans for these programs. It is critical that the development of programs and marketing plans is done in partnership and consultation with low-income customers and community stakeholders. In order to enable individuals and organizations to

[292] John Farrel, *Minnesota's Solar Gardens: The Status and Benefits of Community Solar*, Institute for Local Self-Reliance (May 2019), https://ilsr.org/minnesotas-solar-gardens-the-status-and-benefits-of-community-solar/
[293] *Id.* at 3.
[294] *Id.* at 3.
[295] Greenlink Analytics, *Minneapolis' Utility Burden,* Tableau Public (December 5, 2019), https://public.tableau.com/profile/greenlinkanalytics#!/vizhome/MinneapolisTableau/Dashboard1
[296] IRP Suppl. at 10 of Attach C.

participate in this process, Xcel should provide financial support for that participation. This will allow the company to better meet the needs of the community. For example, while there may be some community interest in the proposed low-income solar program where Xcel owns solar panels and provides a $30 bill rebate, we have heard from a number of community advocates that they would prefer a program that provides a path to project ownership. We encourage Xcel to continue to engage with community advocates to develop programs that meet customers' needs, including lowering bills, providing access to clean energy, reducing pollution and generating wealth through ownership opportunities. We would also like to see Xcel explore financing options that would decrease barriers to access, including models such as the Minneapolis inclusive financing pilot with CenterPoint. In addition, we were disappointed to see the Railroad Island low-income solar community garden fail to move forward. We would like to see more low-income community solar pilots started in partnership with the communities in which they are sited, especially communities experiencing disproportionate energy burden or pollution. Finally, we would like to see Xcel withdraw its opposition to Minnesota's statutorily created community solar gardens program, which has been a phenomenal success and has made Minnesota a national leader in community solar.

In terms of transportation electrification, Sierra Club has been deeply engaged on the development of transportation electrification policy at the Commission. Sierra Club was an active participant in the Commission's Inquiry into Electric Vehicle Charging and Infrastructure (Docket No. E-999/CI-17-879), and strongly support the Commission's findings and its final Order directing utilities to develop Transportation Electrification Plans and to work together with stakeholders to develop TE program proposals. Critically, in the same Order, the Commission directed utilities to address "environmental justice, with a focus on communities disproportionately disadvantaged by traditional fossil fuel use" and "low-income access and equitable access to vehicles and charging infrastructure, which can include all-electric public transit and EV ride-sharing options" in any program proposals filed with the Commission.

The Company identifies its Fleet EV Service and Public Charging Pilot as the program "with the greatest equity benefits." Sierra Club supported approval of that program, and generally agrees that it will improve access to clean transportation options for all customers and help to reduce transportation pollution in higher-emissions and environmental justice communities through its support for transit bus electrification and electric car-sharing. The Company's multi-unit dwelling charging program, pending now before the Commission, would help to ensure more customers can access to EV charging at the home, the location where they need it most, regardless of the type of housing they live in. With modifications to improve load management and higher rebate levels to support affordable-housing participants, Sierra Club strongly supports approval of the MDU pilot. But there is much more that needs to be done to reduce harmful emissions and improve customer access to clean vehicles. Sierra Club looks forward to continued work with the Company, the Commission, and all stakeholders to accelerate transportation electrification in a manner that centers and promotes equity.

Xcel should help improve access to clean energy jobs

Xcel currently prioritizes union contracting and local jobs. The high levels of renewable energy investment envisioned in Sierra Club's Clean Energy For All Plan would support significant job growth in Minnesota. However, as Xcel acknowledges, more must be done to ensure these good-paying, family-supporting jobs are accessible to BIPOC Minnesotans. In its comments, Xcel provides useful information regarding its commitment to increasing its workforce's diversity. We would like to see Xcel make firm quantitative commitments, including benchmarks with dates. We note that Xcel has included contractor diversity criteria in its recent RFP for the Sherco solar project, which is a good step. We would like Xcel to work with community stakeholders to develop additional actions to improve workforce diversity, including supporting workforce training centers located and developed in partnership with BIPOC communities.

Local workforce training in Minnesota's BIPOC communities must be a part of Xcel's efforts. In the COVID economic stimulus docket, 20-492, we requested that Xcel commit to a stakeholder process to develop programs that will work for communities. We repeat this request here.

Support for Host Communities
We thank Xcel for its plan for no layoffs as part of the retirement of the Sherco and King coal plants, as well as creating a fund for worker retraining.

Xcel notes that "we have helped to draw new investment to the Becker area, including Northern Metals Recycling, the Company's planned combined cycle unit at the Sherco plant, and a potential Google data center."[297] We appreciate Xcel's effort to support the community, but we would like to see non-polluting industry that will support sustainable long-term economic development. Google has made an industry-leading commitment to 100% carbon free energy 24/7, and can be expected to bring high-paying jobs to Becker. We note, however, that Northern Metals has had a problematic environmental record, and shut down in North Minneapolis after falsifying its air pollution data.[298] The proposed gas plant, as discussed elsewhere in these comments, is incompatible with Minnesota's climate goals.

We would like to see Xcel prioritize clean energy development in Becker and Sherburne County. The proposed 460 MW solar facility appears likely to be a step in this direction (although we have not yet seen the project details). Xcel NSP may want to look at its sister company, Xcel Colorado, for a strong example of community transition. Xcel Colorado, in coordination with the state and

[297] IRP Suppl. at 7 of Attach C.
[298] Walker Orenstein, *Northern Metals Minneapolis Facility Shut Down After Company Admits to Altering Pollution Records,* Minnpost (September 24, 2019), https://www.minnpost.com/environment/2019/09/northern-metals-minneapolis-facility-shut-down-after-company-admits-to-altering-pollution-records/

stakeholders, developed a transition plan for Pueblo County – the county that hosted a retiring coal plant – that included new commitments to solar and battery storage, including leading to the nation's first solar-powered steel mill.[299] In addition to utility scale solar, we encourage Xcel to work with community members on programs to increase access to rooftop solar and energy efficiency in Sherburne County, including programs targeted to low-income customers. This would help residential and commercial customers lower bills and be part of clean energy development in their community.

<u>Xcel should commit to not renewing its contract with the HERC incinerator</u>
Lastly, we ask Xcel to commit to ending its contract with the HERC incinerator when it expires in 2024, and to continue to explore ways to exit that contract as soon as possible. The HERC incinerator is a major source of PM 2.5, lead, and mercury air pollution, and directly impacts Minneapolis environmental justice communities.[300] The facility is emblematic of our nation's history of siting heavily polluting industry in communities of color, and its continued role in Xcel's electricity portfolio runs counter to Xcel's goal of helping Minnesota communities heal from systemic racism. The long-term health impacts to environmental justice communities in Minneapolis from this facility should further motivate Xcel to commit to additional investments in clean energy access and jobs in these communities.

VIII. RISK: UNLIKE SIERRA CLUB'S CLEAN ENERGY FOR ALL PLAN, XCEL'S PREFERRED PLAN WOULD LIMIT ITS FLEXIBILITY AND EXPOSE CUSTOMERS TO SIGNIFICANT RISK.

The last element of the Commission's public interest test for IRPs is whether a proposed plan will "limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control."[301] Xcel defines this as maintaining portfolio diversity, retaining optionality, and managing market exposure.[302] Xcel further defines "portfolio diversity" as "assess[ing] the share of total portfolio generation in 2034 from wind and from natural gas," claiming that this metric "reduces the risk that a disruption to any one resource will result in customer exposure to market or reliability risks."[303]

This narrow definition of diversity is highly problematic and should be rejected by this Commission. Defining portfolio diversity in terms of a ratio of wind and gas is overly simplistic and pre-determines the outcome towards one that (obviously) includes large amounts of gas. As discussed at

[299] Judith Kohler, *Xcel Energy Partners Announce Deal for Large Solar Facility at Pueblo Steel Mill,* The Denver Post (September 28, 2019), https://www.denverpost.com/2019/09/28/xcel-energy-solar-pueblo-steel-mill-evraz/
[300] The Tishman Environment and Design Center, *The Cost of Burning Trash,* GAIA (November 2020), https://static1.squarespace.com/static/5d14dab43967cc000179f3d2/t/5fc653c09ee0f32b872bd1c4/1606833089063/Minnesota.pdf
[301] Minn. R. 7843.0500, subp. 3(E).
[302] IRP Suppl. at 13, Fig 2-1.
[303] IRP Suppl. at 41, Table 2-5.

length in prior sections of these comments, Xcel has understated the reliability attributes that can be provided by a diverse portfolio of wind, solar, battery storage, and distributed energy resources. Multiple studies suggest that portfolios with high levels of both utility scale and distributed renewables, efficiency, and demand response can deliver reliable energy at lower cost. Our Clean Energy For All Plan – by including significant amounts of new solar, battery storage, and distributed generation – offers significant diversification benefits that Xcel's Plan lacks.

Xcel also claims that a "key aspect" of their plan is its "ability to maintain optionality and defer significant capacity additions within the Five Year Action Plan window."[304] This statement completely ignores that Xcel plans to move forward with the $837 million[305] addition of the Sherco CC (and pipeline) during this period. This element alone exposes customers to a significant risk; as discussed in the prior section, Xcel's plan would lock it into paying for a massive new carbon-polluting plant through 2067, 27 years past when Governor Walz has stated our electricity must be 100% carbon free. As discussed in greater detail in Section VII.A, if retired in 2040, the stranded costs would amount to **[PROTECTED DATA BEGINS…PROTECTED DATA ENDS]**. But this is not the only stranded cost risk associated with Xcel's 5-year plan.

A. <u>Xcel's Proposed Addition of the Sherco CC Includes Significant Risk Associated With a Required Pipeline.</u>

Aside from the risk of stranded costs associated with the gas plant itself, another major risk associated with Xcel's preferred plan is its reliance on a proposed new gas pipeline of undetermined size and cost, which inserts significant uncertainty into its proposal. In its EnCompass expansion plan modeling, Xcel has preliminary assumed "that natural gas delivery costs for the Sherco combined cycle plant would involve a combination of monthly demand charges paid to the pipeline owner and capital investment."[306] However, Xcel made clear that it has not yet determined whether it would "procure[] natural gas delivery service from a third party owner or via direct capital investment."[307] Xcel also does not yet know the size or cost of the needed pipeline. When asked for a reasonable cost range given the uncertainties associated with the required pipeline infrastructure, Xcel responded:

> Appendix F2 of the Resource Plan contained a cost for gas transportation of $15 million per year for demand charges and a $192 million CIAC charge in 2018 dollars. When the demand charge is converted into a capital cost equivalent, we estimate it would be approximately equal to an additional **[PROTECTED DATA BEGINS…PROTECTED DATA ENDS]** of capital cost. When adding these costs to the CIAC estimate and inflating to 2026 dollars, the capital cost factored into our Resource Plan analysis totals approximately would

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[304] IRP Suppl. at 77.
[305] IRP Suppl. at 69, Table IV-14.
[306] Xcel Response to CEOs IR 20.
[307] *Id.*

> total about **[PROTECTED DATA BEGINS…PROTECTED DATA ENDS]**. We recently received an engineering estimate from a pipeline engineering consultant estimating the capital cost to construct the pipeline to be in a range of **[PROTECTED DATA BEGINS…PROTECTED DATA ENDS].** We note that the cost assumption used in the estimate included in the Resource Plan is within the updated third party engineering estimate range we recently received.[308]

It also remains undetermined what approvals would be required in order to build the pipeline. Under Minnesota Statutes 216B.243 and 216B.2421, a new pipeline would require a Certificate of Need from this Commission if it is "greater than six inches in diameter and having more than 50 miles of its length in Minnesota." *Id.* at 216B.2421, Sub.2(4). In discovery, Xcel provided the following information about the pipeline:

> [T]he preliminary design scenarios involved between **[PROTECTED DATA BEGINS…PROTECTED DATA ENDS]** miles of gas infrastructure facilities, various pipe sizes between **[PROTECTED DATA BEGINS…PROTECTED DATA ENDS]** inches outside diameter, and supply points at or near **[PROTECTED DATA BEGINS…PROTECTED DATA ENDS]**. We are considering the broadest array of gas infrastructure transportation options to ensure we obtain the best transportation services for our customers."[309]

From this information, it appears likely that a Certificate of Need would be required. The pipeline would also require a routing permit from the Commission, a Department of Commerce Environmental Impact Statement, a 404 Permit from the US Army Corps, and 401 permit from the MPCA.

Using Xcel's preliminary data about the possible pipeline diameter and length, it is also possible to calculate how much a generic pipeline of similar size might be expected to cost. The Interstate Natural Gas Association of America (INGAA) provides estimates of infrastructure costs. According to its 2015 "North American Midstream Infrastructure Through 2035: Leaning into the Headwinds" Report, new pipeline costs are currently $155,000 per inch-mile (2015 dollars).[310]Inch-miles are equal to the diameter of the pipeline multiplied by the mileage of the pipeline. Using Xcel's preliminary data from its response to CEO IR-121-Trade Secret, this means the pipeline could cost up to **[PROTECTED DATA BEGINS…PROTECTED DATA ENDS]** Xcel's estimate. The pipeline thus presents a huge risk factor to Xcel's preferred plan.

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[308] Xcel Response to CEOs 72-Trade Secret.
[309] Xcel Response to CEOs 121-Trade Secret.
[310] Kevin Petak et al., *North American Midstream Infrastructure Through 2035: Leaning Into Headwinds,* ICF International (April 12, 2016) at 22, https://www.ingaa.org/File.aspx?id=27961&v=db4fb0ca

IX. Xcel has failed to demonstrate a need for the Sherco CC as part of a least-cost portfolio or for reliability purposes, and the Commission should reject its inclusion in any preferred plan.

While Xcel does not explicitly state so anywhere in its IRP, it is clear from the manner in which Xcel discusses the Sherco CC that Xcel does not believe it needs to obtain Commission approval of its inclusion of the CC in its preferred resource plan in this docket. Xcel has stated that it is not requesting any "specific approvals for actions related to the planned Sherco combined cycle (CC) in this docket,"[311] and that it "plan[s] to bring forward a filing detailing our Sherco CC project plan in the 2020-2021 timeframe under Minn. H.F. 113 (2017)."[312] Xcel included the Sherco CC in its plan as an "existing and approved resource."[313] In discovery, the utility stated that the planned Sherco CC is "included in our baseline modeling" because "that the unit is provided for via Minnesota statute."[314] Sierra Club asked in discovery how the Company determined that adding a CC in 2027 was reasonable, and how it determined the size of 727 MW (UCAP) was reasonable.[315] Xcel did not respond to that portion of the request.

It appears that Xcel would prefer this Commission conclude that it does not have the authority to review whether the Sherco CC is needed as part of this IRP proceeding. Xcel is wrong. As explained in this Section, while Xcel obtained a statutory exemption from Minnesota's Certificate of Need and siting requirements, it did not obtain an exemption from demonstrating a need for the plant under Minnesota's IRP statute. A finding of need under the IRP statute is of significant value to the utility, because it may rely on such a determination to justify subsequent actions with respect to the plant – such as relying on it to support the need for any new gas pipeline that would be required, or to support recovery of costs for the gas plant in its next rate case. While Xcel may protest, this Commission has an obligation to assess whether the addition of the Sherco CC is in fact needed as part of a least cost, reliable plan that is in the public interest.

A. The Commission has statutory authority to review the need for the Sherco CC in this IRP.

Despite any assertions Xcel may make to the contrary, the Commission continues to have legal authority – and in fact, the legal duty – to determine whether there is a need for the Sherco CC as part of any resource plan it approves in this docket.

In 2017, Xcel was successful obtaining passage of legislation that applies only to its proposal to construct the Sherco CC. H.R. 113 (2017). That legislation states that:

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311 Xcel response to CEOs IR 27.
312 Xcel response to SC-8(a) Supplemental.
313See, e.g., IRP Supp at Table 2-2, page 25
314 Xcel Supplemental Response to SC-8(a).
315 *Id.*

> "Notwithstanding Minnesota Statutes, section 216B.243 and Minnesota Statutes, chapter 216E, a public utility may, at its sole discretion, construct, own, and operate a natural gas combined cycle electric generation plant as the utility proposed to the Public Utilities Commission in docket number E-002/RP-15-21, or as revised by the utility and approved by the Public Utilities Commission in the latest resource plan filed after the effective date of this section…."

The statute thus allows Xcel to bypass a Certificate of Need determination under Minnesota Statutes Section 216B.243, and a site permit under Minn. Stat. Ch. 216E. The statute does not, however, exempt Xcel from demonstrating a need for the new plant under Minnesota's resource planning statute, 216B.2422. Under that statute, Xcel must show that the gas plant is part of a plan that is in the public interest, under the criteria provided in Minn. R. 7843.0500.[316] Subdivision 4 of that statute also continues to apply: " The commission shall not approve a new or refurbished nonrenewable energy facility [such as a gas plant] in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest." Minn. Stat. 216B.2422 Subd. 4. In making that public interest determination, the commission must consider:

> "(1) whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, subdivision 2f;
> (2) impacts on local and regional grid reliability;
> (3) utility and ratepayer impacts resulting from the intermittent nature of renewable energy facilities, including but not limited to the costs of purchasing wholesale electricity in the market and the costs of providing ancillary services; and
> (4) utility and ratepayer impacts resulting from reduced exposure to fuel price volatility, changes in transmission costs, portfolio diversification, and environmental compliance costs."

A finding by this Commission that the Sherco CC is not needed or in the public interest in this IRP proceeding would then be relevant in other proceedings. For example, as discussed above, the gas pipeline needed to supply firm gas supply to the Sherco CC may require a Certificate of Need from this Commission. A finding that the Sherco CC itself is not needed would have clear implications for the need for an associated gas pipeline.

Moreover, the second part of H.R. 113 makes clear that a finding in the IRP that the gas plant is not needed could put at risk the utility's ability to recover the costs of the facility, and to secure a rate of return, in a subsequent rate case. H.R. 113 Section 1(b) states that "Reasonable and prudently incurred costs and investments by a public utility under this section may be recovered pursuant to

[316] Minn. Stat. 216B.2422 Subd. 2.

the provisions of Minnesota Statutes, section 216B.16." Xcel is therefore still required to demonstrate the reasonableness and prudence of allowing the utility to recover and earn a rate of return on the estimated $837 million[317] capital cost of a gas plant that this Commission has found is not needed. Minn. Stat. 216B.16 places the burden on proof "to show that the rate change is just and reasonable" on the utility.[318] The Commission reviews rates to determine whether they are "unjust or unreasonable or discriminatory."[319] In making this determination, the Commission "shall give due consideration to the public need for adequate, efficient, and reasonable service…."[320]

H.R. 113 also preserves the Commission's authority to approve a gas plant of a different size in this proceeding. It exempts from the Certificate of Need and Siting process a gas plant "as the utility proposed" in its last IRP "or as revised by the utility and approved by the Public Utilities Commission in the latest resource plan filed after the effective date of this section," i.e., the current docket. Consistent with that provision, the Commission ordered the utility to explore smaller sizes to the proposed gas plant in its IRP Supplement; as discussed in Section V.B.10 above, Xcel's "sensitivity analysis" is not sufficient to demonstrate the reasonableness of its chosen size of gas plant.

Because the Commission continues to have legal jurisdiction to review the need for the Sherco gas plant as part of the IRP process, Xcel was required to demonstrate that it evaluated renewable energy alternatives to the new fossil plant and found that a renewable alternative was not in the public interest. Minn. Stat. § 216B.2422, subd. 4. As discussed herein, Xcel has not even attempted to make such a demonstration, and so the Commission cannot approve the gas plant's inclusion in Xcel's preferred plan.

The Commission made clear in Xcel's last IRP proceeding that Xcel should continue to explore alternatives to a new gas plant. In that docket, while the Commission found there was likely a need for capacity "coinciding with the retirement of Sherco 1 in 2026," it concluded that it was "premature…to determine with specificity the fuel type and location to address the identified 750 MW capacity need."[321] It therefore required Xcel to "evaluate and pursue other resource options between 2023 and 2030," emphasizing that "[i]n light of rapidly changing costs among potential energy and capacity sources, Xcel must maintain flexibility and consider a broad range of resource options…[including] supply-side, demand-side, and transmission alternatives to address its 750 MW

[317] IRP Suppl. at 69, Table IV-14.
[318] *Id.* Subd. 4.
[319] *Id.* Subd. 5.
[320] *Id.* Subd. 6.
[321] Order Approving Plan with Modifications and Establishing Requirements for Future Resource Plan Filings, In the Matter of Xcel Energy's 2016–2030 Integrated Resource Plan, , Docket No. E-002/RP-15-21, 9 (Jan. 11, 2017).

need identified above…."[322] Xcel has not complied with either the Commission's prior Order nor with Minnesota's IRP statute.

B. Xcel has failed to demonstrate that the Sherco CC is part of a least cost resource plan, nor has it shown the plant is required for reliability purposes, to minimize environmental and socioeconomic impacts, or to preserve flexibility and limit risk.

As discussed in Section V.B.1 above, Xcel did not test in its capacity expansion plan modeling whether Sherco CC was an optimal resource addition; all of its optimization runs included the plant as a fixed "baseline" resource. Xcel therefore does not include any justification in its IRP that the addition of the Sherco CC is a component of a least cost, optimized plan.

Our own modeling shows that even under Xcel's own set of assumptions, only updating from the NREL 2019 to NREL 2020 database, the model chooses not include the Sherco CC. When a more reasonable set of assumptions that corrects for errors in Xcel's modeling methodology (particularly with respect to renewable costs) is used, adding the Sherco CC is $200 million more expensive than excluding it.

Moreover, as explained in Section VI.F, our expert conducted a power flow analysis using the same methodology as Xcel's Y-2 studies and found there is no critical local reliability need for the Sherco CC. Nor has Xcel offered an evidentiarily sound basis for rejecting portfolios higher in renewable penetration as unreliable. Section VI. The addition of the Sherco CC risks stranding hundreds of millions of ratepayer dollars, as outlined in Section VII.A, and would also create a significant barrier to achieving Minnesota's carbon reduction goals. It would also significantly reduce Xcel's optionality by locking in a massive new capital expenditure through 2067, and would expose customers to risk associated with the need for an expensive new gas pipeline. Sections VII.A and VIII. Finally, a plan that instead commits to substantial investment in both utility scale renewables and battery storage as well as distributed generation will better serve Minnesota's economy and people. Section VII.B. For all of these reasons, we ask that the Commission find the Sherco CC is not in customers' interests.

X. THE COMMISSION SHOULD DISAPPROVE THE MONTICELLO NUCLEAR LICENSE EXTENSION AS PART OF THE PREFERRED PLAN.

A. Synapse's modeling shows extending the Monticello nuclear license is not in customers' interests.

As presented in Section V.D., above, Synapse's modeling shows that when errors with Xcel's modeling assumptions are corrected, the Monticello nuclear license extension is not part of a least cost plan. As shown in Table 12, above, Sierra Club's Preferred Plan is $1.9 billion cheaper than

[322] *Id.* at 10.

Xcel's even if the Monticello nuclear license is extended, but it becomes $2.2 billion cheaper if the license is not extended. Building additional wind, solar, battery storage, and distributed generation saves customers an additional $300 million compared to the license extension.

B. Environmental impacts.

In addition to cost, nuclear power is dirty and dangerous. Further extending the operating license at the Monticello Nuclear Generating Plant - which has already been extended once past its original end date of 2010 - would exacerbate the risks of burdening current and future generations with toxic pollution, which impact communities already disproportionately affected by environmental problems.

Nuclear power plants result in radioactive contamination throughout its life cycle, especially for low income and Indigenous communities living near uranium mines, mills, plants, and storage. In addition, significant safety weaknesses are inherent in reactors' operation. While the chance of an adverse incident is low, the plant's location on the banks of the Mississippi means that an accident would not only impact local communities but also millions of people downstream. The horrific disaster at the Fukushima Daiichi plant – which had a very similar design to Monticello, a boiling water reactor (BWR) nuclear steam supply system (NSSS) - reminded us that fundamental problems with nuclear power have not been addressed.

At Monticello, a portion of the plant's spent fuel is stored in dry casks in an onsite location that was intended to be temporary. However, with no viable federal repository currently under consideration, we cannot expect a long-term waste storage solution in the foreseeable future.

Finally, while some would portray nuclear power as an indisputable solution to climate change, it has a large carbon footprint when the lifecycle of fuel extraction, milling, processing, conversion, enrichment and transportation is considered.

XI. RECOMMENDATIONS

For all of the reasons outlined herein, Xcel has not demonstrated that its Preferred Plan – particularly the Sherco CC addition – is in the public interest. Sierra Club's Clean Energy For All Plan would better position Xcel and Minnesota to achieve carbon reduction goals while maintaining a reliable system, and would also save customers an estimated $2.2 billion. Sierra Club's Clean Energy For All Plan thus better satisfies the public interest criteria set forth in Minnesota law.

As a result, Sierra Club recommends that the Commission:

1. Approve Xcel's proposed retirement dates for Sherco Unit 3 by no later than 2030 and A.S. King by no later than 2028, with instructions that Xcel should evaluate whether

those units should be retired earlier in its next IRP; and approve moving Sherco 2 to seasonal dispatch and King to seasonal dispatch until 2023 and economic commitment thereafter;

2. Disappove the need for the Sherco CC in 2027 (or at minimum find that Xcel has not demonstrated that a CC as large as its proposed CC is needed);

3. Approve the need for 1,350 MW of utility scale solar and 4,320 MW of new wind beginning in years 2027 and 2026, as well as an additional 4,070 MW of utility scale solar paired with 1,080 MW of battery storage starting in 2031, and 1,020 MW of standalone battery storage beginning in 2027;

4. Approve Xcel's proposal to achieve 780 GWh/year savings from energy efficiency programs through 2034 and 400 MW of new demand response by 2023;

5. Approve the need for 2,050 MW of community solar and 1,851 MW of distributed generation solar, and order Xcel to bring forward a proposal by January 2022 for programs that could incentivize the growth of solar distributed generation within its territory at levels consistent with Sierra Club's Clean Energy For All Plan, and in a manner that would advance the goals of equity and access;

6. Disapprove the need for the Monticello license extension through 2040; and

7. Order Xcel in its next IRP to include a discussion of potential options for exiting its contract with the HERC incinerator, as well as the costs and benefits of declining to renew its contract with the incinerator.

Dated: February 11, 2021

Respectfully submitted,

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ATTACHMENT A

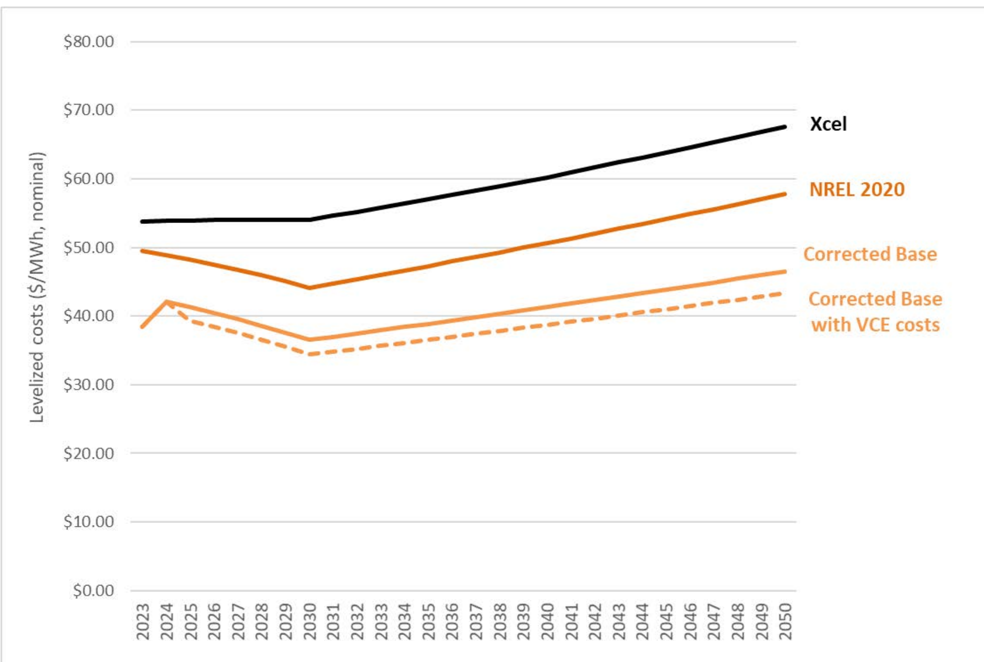
Technical Appendix – SC Modeling Assumptions and Methodology

The costs of solar PV, wind, and battery storage included in our modeling are shown below. These costs include interconnection, with most of them including Xcel's interconnection cost assumption. Those labeled "VCE interconnection costs" are where we substituted the VCE model costs for Xcel's, starting in 2025.

We modeled three possible cost trajectories for solar PV and wind resources (NREL 2020, Corrected RE Base, and Corrected RE Base with VCE interconnection costs), and two trajectories for battery storage (NREL 2020 and Corrected RE Base). These figures show the differences between Xcel's base assumptions, our NREL 2020 and Corrected RE Base costs, as well as the impact of using the VCE interconnection costs paired with our Corrected RE Base costs for wind and solar PV. (Xcel did not model interconnection costs for battery storage separately.)

Sierra Club EnCompass Modeling Inputs

Figure 18: Comparison of Solar PV Levelized Costs (nominal $/MWh)[323]



[323] Xcel's costs: 19-0368 Sierra Club-097_Attachment A NREL ATB Renewable – Base. Sierra Club's costs are shown for the 150 MW project size.

Figure 19: Comparison of Wind Levelized Costs (nominal $/MWh)[324]

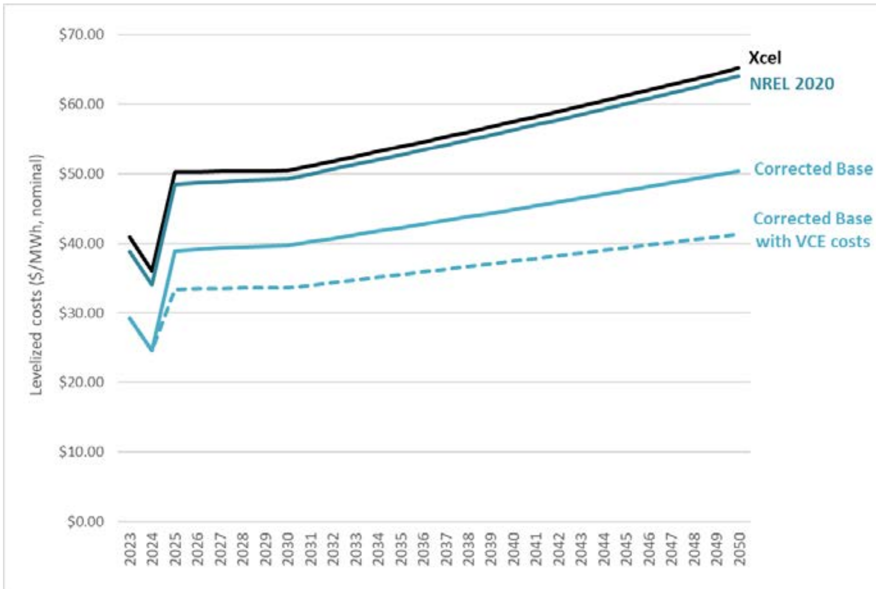
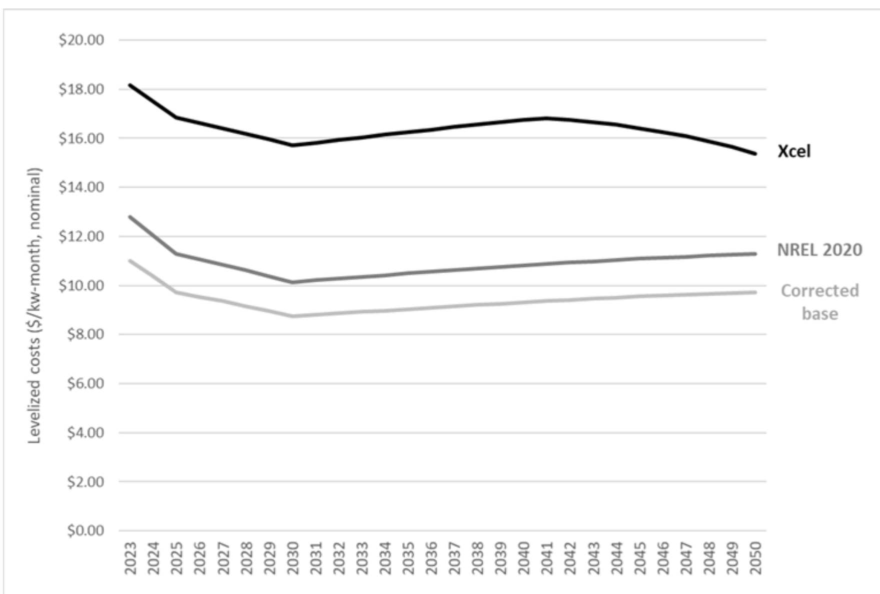


Figure 20: Comparison of Standalone Battery Levelized Costs (nominal $/kW-month)[325]



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324 Xcel's costs: 19-0368 Sierra Club-097_Attachment A NREL ATB Renewable – Base
325 Xcel's costs: 19-0368 Sierra Club-097_Attachment D NREL ATB Battery

Table 15: Solar PV Levelized Costs ($/MWh, nominal)

	Xcel	NREL 2020 (20 MW)	NREL 2020 (150 MW)	Corrected Base RE (20 MW)	Corrected Base RE (150 MW)	Corrected Base RE (20 MW) with lower interconnection	Corrected Base RE (150 MW) with VCE interconnection
2023	$53.81	$54.50	$49.53	$42.68	$38.49	$42.68	$38.49
2024	$53.87	$53.75	$48.90	$46.97	$42.12	$46.97	$42.12
2025	$53.93	$52.95	$48.23	$46.04	$41.31	$44.11	$39.39
2026	$53.97	$52.10	$47.51	$45.05	$40.46	$43.09	$38.50
2027	$53.99	$51.20	$46.75	$44.00	$39.55	$42.00	$37.55
2028	$54.01	$50.24	$45.93	$42.89	$38.59	$40.86	$36.55
2029	$54.00	$49.21	$45.07	$41.73	$37.58	$39.65	$35.50
2030	$53.98	$48.13	$44.15	$40.49	$36.51	$38.37	$34.39
2031	$54.60	$48.79	$44.76	$41.00	$36.97	$38.84	$34.81
2032	$55.21	$49.46	$45.39	$41.51	$37.44	$39.31	$35.23
2033	$55.83	$50.13	$46.02	$42.03	$37.91	$39.78	$35.66
2034	$56.45	$50.81	$46.65	$42.55	$38.39	$40.25	$36.09
2035	$57.07	$51.50	$47.30	$43.07	$38.86	$40.73	$36.52
2036	$57.70	$52.20	$47.95	$43.60	$39.35	$41.21	$36.96
2037	$58.32	$52.90	$48.61	$44.13	$39.83	$41.69	$37.40
2038	$58.96	$53.61	$49.27	$44.66	$40.32	$42.18	$37.84
2039	$59.59	$54.33	$49.95	$45.20	$40.82	$42.67	$38.28
2040	$60.23	$55.05	$50.63	$45.74	$41.32	$43.16	$38.73
2041	$60.94	$55.78	$51.31	$46.29	$41.82	$43.65	$39.18
2042	$61.66	$56.52	$52.01	$46.84	$42.32	$44.15	$39.63
2043	$62.38	$57.27	$52.71	$47.39	$42.83	$44.65	$40.09
2044	$63.10	$58.02	$53.42	$47.95	$43.34	$45.15	$40.54
2045	$63.83	$58.78	$54.14	$48.50	$43.86	$45.65	$41.00
2046	$64.57	$59.55	$54.86	$49.07	$44.37	$46.16	$41.46
2047	$65.31	$60.33	$55.59	$49.63	$44.90	$46.66	$41.93
2048	$66.05	$61.11	$56.33	$50.20	$45.42	$47.17	$42.39
2049	$66.80	$61.90	$57.08	$50.77	$45.95	$47.68	$42.86
2050	$67.55	$62.70	$57.83	$51.35	$46.48	$48.20	$43.33

Table 16: Wind Levelized Costs ($/MWh, nominal)

	Xcel	NREL 2020	Corrected Base RE	Corrected Base with VCE interconnection
2023	$40.91	$38.79	$29.25	$29.25
2024	$36.03	$34.09	$24.55	$24.55
2025	$50.24	$48.47	$38.94	$33.41
2026	$50.28	$48.66	$39.12	$33.49
2027	$50.32	$48.84	$39.30	$33.55
2028	$50.36	$49.01	$39.45	$33.59
2029	$50.41	$49.16	$39.59	$33.61
2030	$50.46	$49.30	$39.71	$33.61
2031	$51.13	$49.97	$40.21	$33.99
2032	$51.81	$50.65	$40.72	$34.37
2033	$52.50	$51.33	$41.23	$34.75
2034	$53.19	$52.02	$41.74	$35.13
2035	$53.89	$52.72	$42.25	$35.52
2036	$54.60	$53.42	$42.77	$35.90
2037	$55.31	$54.13	$43.30	$36.29
2038	$56.03	$54.85	$43.82	$36.67
2039	$56.76	$55.58	$44.35	$37.06
2040	$57.49	$56.31	$44.88	$37.44
2041	$58.23	$57.05	$45.42	$37.83
2042	$58.98	$57.80	$45.96	$38.22
2043	$59.73	$58.55	$46.50	$38.60
2044	$60.49	$59.31	$47.04	$38.99
2045	$61.26	$60.08	$47.59	$39.37
2046	$62.03	$60.85	$48.14	$39.76
2047	$62.81	$61.64	$48.69	$40.14
2048	$63.60	$62.43	$49.24	$40.52
2049	$64.39	$63.22	$49.80	$40.91
2050	$65.19	$64.02	$50.35	$41.29

Table 17: Battery Storage Levelized Costs ($/kW-month, nominal)

	Xcel	NREL 2020	NREL 2020 (solar hybrid w/ ITC)	Corrected Base RE	Corrected Base RE (solar hybrid w/ ITC)
2023	$18.18	$12.79	$11.78	$11.02	$9.19
2024	$17.52	$12.05	$11.10	$10.38	$9.60
2025	$16.84	$11.28	$10.39	$9.72	$8.99
2026	$16.63	$11.08	$10.21	$9.54	$8.83
2027	$16.41	$10.86	$10.01	$9.36	$8.65
2028	$16.19	$10.64	$9.80	$9.16	$8.47
2029	$15.95	$10.39	$9.58	$8.95	$8.28
2030	$15.71	$10.14	$9.34	$8.73	$8.08
2031	$15.83	$10.21	$9.41	$8.80	$8.13
2032	$15.94	$10.28	$9.47	$8.86	$8.19
2033	$16.04	$10.36	$9.54	$8.92	$8.25
2034	$16.15	$10.43	$9.60	$8.98	$8.30
2035	$16.26	$10.49	$9.67	$9.04	$8.36
2036	$16.36	$10.56	$9.73	$9.10	$8.41
2037	$16.46	$10.63	$9.79	$9.15	$8.47
2038	$16.56	$10.69	$9.85	$9.21	$8.52
2039	$16.65	$10.75	$9.91	$9.26	$8.57
2040	$16.74	$10.81	$9.96	$9.32	$8.61
2041	$16.83	$10.87	$10.02	$9.37	$8.66
2042	$16.76	$10.93	$10.07	$9.41	$8.71
2043	$16.66	$10.98	$10.12	$9.46	$8.75
2044	$16.55	$11.04	$10.17	$9.51	$8.79
2045	$16.42	$11.09	$10.21	$9.55	$8.83
2046	$16.26	$11.13	$10.26	$9.59	$8.87
2047	$16.08	$11.18	$10.30	$9.63	$8.91
2048	$15.88	$11.22	$10.34	$9.67	$8.94
2049	$15.65	$11.26	$10.38	$9.70	$8.97
2050	$15.39	$11.30	$10.41	$9.73	$9.00

Table 18. Sierra Club Cumulative Distributed Generation Resource Options, by Price (MW AC)

Year	$0/MWh	$10/MWh	$20/MWh	$30/MWh	$35/MWh	$40/MWh
2021	33	14	17	21	12	14
2022	60	26	33	40	23	26
2023	65	33	41	51	29	33
2024	74	40	51	63	37	41
2025	89	49	62	77	45	50
2026	109	60	75	94	55	61
2027	136	72	90	112	66	73
2028	169	86	108	134	78	86
2029	211	102	127	158	92	101
2030	262	120	149	184	107	118
2031	322	140	174	214	124	137
2032	393	163	201	247	143	157
2033	476	188	231	283	163	179
2034	572	215	265	322	185	203

Table 19. VS/ILSR/EJ/CEF Cumulative Community Solar Resource Options

Year	MW AC
2020	126
2021	210
2022	276
2023	362
2024	490
2025	629
2026	768
2027	906
2028	1,044
2029	1,182
2030	1,187
2031	1,187
2032	1,187
2033	1,187
2034	1,187

<u>EnCompass Modeling Results</u>

Incremental resource additions in the Sierra Club Preferred Plan are shown in **Error! Not a valid bookmark self-reference.**, below.

Table 20. Incremental resource additions in Sierra Club's Preferred Plan

Plan Namplate (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Battery	-	-	-	-	-	-	-	40	60	280	640	-	-	-	-
Paired Battery	-	-	-	-	-	-	-	-	-	-	-	440	200	280	160
Paired Solar	-	-	-	-	-	-	-	-	-	-	-	1,650	770	1,050	600
Wind	-	-	-	-	-	-	480	480	80	400	1,200	240	-	640	800
Solar	-	-	-	-	-	-	-	450	-	-	900	-	-	-	-
Hybrid	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Firm Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DR	67	269	136	(173)	47	42	12	14	15	17	19	20	21	22	24
EE	321	363	339	(325)	174	173	205	211	213	191	186	182	169	164	161
Distributed Solar	180	352	208	174	179	362	236	246	252	268	152	167	169	189	211
Total	**569**	**985**	**683**	**(325)**	**400**	**576**	**933**	**1,441**	**621**	**1,156**	**3,097**	**2,699**	**1,329**	**2,345**	**1,956**

Table 21. Incremental CSG and DG additions in Sierra Club's Preferred Plan vs Xcel's

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Xcel CSG	658	714	787	841	852	853	854	855	857	858	859	860	861	862	863
Xcel DG	80	95	109	123	138	152	166	180	194	208	222	236	249	263	276
SC CSG	1	211	277	363	491	630	769	907	1,045	1,183	1,188	1,188	1,188	1,188	1,188
SC DG	6	70	125	145	171	378	460	553	652	767	899	1,051	1,205	1,379	1,575
Total	**745**	**1,090**	**1,299**	**1,472**	**1,651**	**2,013**	**2,249**	**2,495**	**2,747**	**3,016**	**3,167**	**3,334**	**3,503**	**3,692**	**3,903**

Re-running Xcel's Preferred Plan in EnCompass Version 5.0 leads to the following resource additions:

Table 22. Incremental resource additions in Xcel's Preferred Plan in EnCompass Version 5.0

Plan Namplate (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	321
Paired Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Paired Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	750	750	750
Solar	-	-	-	-	-	500	500	-	-	1,000	500	-	-	500	500
Hybrid	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Firm Peaking	-	-	-	-	-	-	-	-	-	374	374	748	374	374	-
CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco CC	-	-	-	-	-	-	-	835	-	-	-	-	-	-	-
DR	67	269	136	(173)	47	42	12	14	15	17	19	20	21	22	24
EE	321	363	339	(325)	174	173	205	211	213	191	186	182	169	164	161
Distributed Solar	173	71	87	68	25	16	15	15	15	15	15	15	15	15	15
Total	**562**	**704**	**562**	**(431)**	**246**	**730**	**732**	**1,075**	**244**	**1,597**	**1,094**	**965**	**1,329**	**1,825**	**1,771**

Table 23. Carbon Dioxide Emissions from Sherco CC under Xcel's Preferred Plan, EnCompass Version 5.0 – TRADE SECRET

Year	Released (tons)
	[PROTECTED DATA BEGINS…
2027	
2028	
2029	
2030	
2031	
2032	
2033	

2034	
2035	
2036	
2037	
2038	
2039	
2040	
2041	
2042	
2043	
2044	
2045	
	…**PROTECTED DATA ENDS]**

Attachment 2: Expert Resumes

Michael Goggin

Education:

Harvard University class of 2004, B.A.

- Graduated *cum laude* in Social Studies
- Wrote thesis “Is it Time for a Change? Science, Policy, and Climate Change”

Experience:

Grid Strategies Vice President February 2018-present

- Serve as an expert consultant on electricity transmission, grid integration, reliability, market, and public policy issues for environmental and clean energy industry clients

AWEA Senior Director of Research, other titles February 2008-February 2018

- Led team responsible for all AWEA policy analysis and data collection
- Served as primary technical and economic expert for market design, transmission, grid integration, carbon policy, and other topics
- Authored regulatory filings at state (IRP and transmission siting cases), regional (ISO transmission and market design), and federal (FERC transmission, interconnection standard, grid integration, and market design cases; EPA carbon policy) levels
- Directed economic and power sector modeling to inform AWEA’s policy strategy and support advocacy positions
- Communicated with the press and policy makers about wind energy
- Authored reports to promote AWEA’s policy agenda, rebut misconceptions about wind energy, and explain complex energy topics to lay audiences
- Other titles included Electric Industry Analyst, Senior Analyst, Manager of Transmission Policy, Director of Research

Sentech, Inc. Research Analyst October 2005-February 2008

- Conducted economic analyses of solar, wind, geothermal, and energy storage technologies for Department of Energy officials
- Provided analytical support for DOE’s renewable energy R&D funding decisions

Union of Concerned Scientists Clean Energy Intern May 2005-October 2005

- Worked with the legislative and field staff to promote the inclusion of pro-renewable energy measures in the Energy Policy Act of 2005

State Public Interest Research Groups Policy Analyst August 2004-May 2005

- Analysis and writing of renewable energy policies at the state and federal level

Selected Publications:

- M. Milligan, et al., “Impact of Electric Industry Structure on High Wind Penetration Potential,” NREL Technical Report TP-550-46273
- R. Gramlich and M. Goggin, “What’s Next for Wind Power,” March 2013, Electricity Journal
- Michael Goggin, “Wind Energy’s Emissions Reductions: A Statistical Analysis,” presented at 2013 IEEE PES annual conference
- R. Gramlich and M. Goggin, “The Ability of Current U.S. Electric Industry Structure and Transmission Rules to Accommodate High Wind Energy Penetration,” 7th International Workshop on Large Scale Integration of Wind Power

Tyler Comings, Senior Researcher
1012 Massachusetts Avenue, Arlington MA 02476 ○ tyler.comings@aeclinic.org ○ 617-863-0139

PROFESSIONAL EXPERIENCE

Applied Economics Clinic, Arlington, MA. Senior Researcher, June 2017 – Present.

Provides technical expertise on electric utility regulation, energy markets, and energy policy. Clients are primarily public service organizations working on topics related to the environment, consumer rights, the energy sector, and community equity.

Synapse Energy Economics Inc., Cambridge, MA. Senior Associate, July 2014 – June 2017, Associate, July 2011 – July 2014.

Provided expert testimony and reports on energy system planning, coal plant economics and economic impacts. Performed benefit-cost analyses and research on energy and environmental issues.

Ideas42, Boston, MA. Senior Associate, 2010 – 2011.

Organized studies analyzing behavior of consumers regarding finances, working with top researchers in behavioral economics. Managed studies of mortgage default mitigation and case studies of financial innovations in developing countries.

Economic Development Research Group Inc., Boston, MA. Research Analyst, Economic Consultant, 2005 – 2010.

Performed economic impact modeling and benefit-cost analyses using IMPLAN and REMI for transportation and renewable energy projects, including support for Federal stimulus applications. Developed a unique web-tool for the National Academy of Sciences on linkages between economic development and transportation.

Harmon Law Offices, LLC., Newton, MA. Billing Coordinator, Accounting Liaison, 2002 – 2005.

Allocated IOLTA and Escrow funds, performed bank reconciliation and accounts receivable. Projected legal fees and costs.

Massachusetts Department of Public Health, Boston, MA. Data Analyst (contract), 2002.

Designed statistical programs using SAS based on data from health-related surveys. Extrapolated trends in health awareness and developed benchmarks for performance of clinics for a statewide assessment.

EDUCATION

Tufts University, Medford, MA

Master of Arts in Economics, 2007

Boston University, Boston, MA

Bachelor of Arts in Mathematics and Economics, Cum Laude, Dean's Scholar, 2002.

AFFILIATIONS

Society of Utility and Regulatory Financial Analysts (SURFA)

Member

Global Development and Environment Institute, Tufts University, Medford, MA.
Visiting Scholar, 2017 – 2020

CERTIFICATIONS

Certified Rate of Return Analyst (CRRA), professional designation by Society of Utility and Regulatory Financial Analysts (SURFA)

PAPERS AND REPORTS

Woods, B., E. A. Stanton, T. Comings, and E. Tavares. 2019. *Emission Reduction Synergies for Massachusetts Community Choice Energy Programs, Heat Pumps and Electric Vehicles*. Applied Economics Clinic. Prepared for Green Energy Consumers Alliance. [Online]

Lopez, R., T. Comings, E.A. Stanton, and E. Tavares. 2019. *Home Heat Pumps in Massachusetts*. Applied Economics Clinic. Prepared for Green Energy Consumers Alliance. [Online]

Comings, T., B. Woods, and M. Majumder. 2019. *Updated Costs of Community Choice Energy Aggregation in Boston*. Applied Economics Clinic. Prepared for Barr Foundation. [Online]

Comings, T., R. Lopez, and B. Woods. 2018. *A Critique of an Industry Analysis on Claimed Economic Benefits of Offshore Drilling in the Atlantic*. Applied Economics Clinic. Prepared for the Southern Environmental Law Center. [Online]

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Comings, T. and B. Woods. 2017. *The Future of the Martin Drake Power Plant*. Applied Economics Clinic. Prepared for Green Cities Coalition and Southeastern Colorado Renewable Energy Society. [Online]

Wilson, R., T. Comings, and E.A. Stanton. 2017. *Ratepayer Impacts of ConEd's 20-Year Shipping Agreement on the Mountain Valley Pipeline.* Applied Economics Clinic. Prepared for the Environmental Defense Fund. [Online]

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Economic Development Research Group. 2007. *The Economic Impact of Philadelphia Convention Center*. Prepared for Pew Charitable Trusts. [Online]

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TESTIMONY AND EXPERT COMMENTS

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Comings, T. 2020. *Comments on Evergy's 2020 Integrated Resource Plan*. Comments to the Public Service Commission of the State of Missouri, File No. EO-2020-0280 EO-2020-0281. [Online]

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Comings, T. 2017. *Testimony on the economics of the proposed acquisition of the Pleasants plant*. Testimony to the West Virginia Public Service Commission, Case No. 17-0296-E-PC. [Online]

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Comings, T. 2014. *Testimony evaluating the assumptions and analysis used by FirstEnergy Ohio in support of its application for approval of an electric security plan and related Retail Rate Stability Rider*. Testimony to the Ohio Public Utilities Commission, Case No. 14-1297-EL-SSO. [Online]

Comings, T. 2014. *Testimony evaluating the assumptions in the analysis supporting Oklahoma Gas & Electric's request for authorization and cost recovery of a Clean Air Act compliance plan and Mustang modernization*. Testimony to the Oklahoma Corporation Commission, Cause No. PUD 201400229. [Online]

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Comings, T. 2014. *Testimony on the economic impact analysis filed by Exelon Corporation and Pepco Holdings, Inc. in their joint petition for the merger of the two entities*. Testimony to the State of New Jersey Board of Public Utilities, Docket No. EM14060581. [Online]

Comings, T. 2014. *Testimony on the economic impact analysis filed by Exelon Corporation and Pepco Holdings, Inc. in their joint petition for the merger of the two entities*. Testimony to the District of Columbia Public Service Commission, Formal Case No. 1119. [Online]

Daniel, J., T. Comings, and J. Fisher. 2014. *Comments on Preliminary Assumptions for Cleco's 2014/2015 Integrated Resource Plan*. Synapse Energy Economics. Prepared for Sierra Club. [Online]

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Comings, T. 2013. *Testimony regarding East Kentucky Power Cooperative's Application for Cooper Station Retrofit and Environmental Surcharge Cost Recovery*. Testimony to the Kentucky Public Service Commission, Case No. 2013-00259. November 27, 2013 and December 27, 2013. [Online]

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Hornby, R. and T. Comings. 2012. *Comments on Draft 2012 Integrated Resource Plan for Connecticut.* Synapse Energy Economics. Prepared for AARP. [Online]

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Principal Associate*, April 2019 – present*, Senior Associate*, 2013 – 2019, *Associate*, 2010 – 2013, *Research Associate*, 2008 – 2010.

Provides consulting services and expert analysis on a wide range of issues relating to the electricity and natural gas sectors including: integrated resource planning; federal and state clean air policies; emissions from electricity generation; electric system dispatch; and environmental compliance technologies, strategies, and costs. Uses optimization and electricity dispatch models, including Strategist, PLEXOS, EnCompass, PROMOD, and PROSYM/Market Analytics to conduct analyses of utility service territories and regional energy markets.

Analysis Group, Inc., Boston, MA.

Associate, 2007 – 2008, *Senior Analyst Intern*, 2006 – 2007.

Provided litigation support and performed data analysis on various topics in the electric sector, including tradeable emissions permitting, coal production and contractual royalties, and utility financing and rate structures. Contributed to policy research, reports, and presentations relating to domestic and international cap-and-trade systems and linkage of international tradeable permit systems. Managed analysts' work processes and evaluated work products.

Yale Center for Environmental Law and Policy, New Haven, CT. *Research Assistant*, 2005 – 2007.

Gathered and managed data for the Environmental Performance Index, presented at the 2006 World Economic Forum. Interpreted statistical output, wrote critical analyses of results, and edited report drafts. Member of the team that produced *Green to Gold*, an award-winning book on corporate environmental management and strategy. Managed data, conducted research, and implemented marketing strategy.

Marsh Risk and Insurance Services, Inc., Los Angeles, CA. *Risk Analyst*, Casualty Department, 2003 – 2005.

Evaluated Fortune 500 clients' risk management programs/requirements and formulated strategic plans and recommendations for customized risk solutions. Supported the placement of $2 million in insurance premiums in the first year and $3 million in the second year. Utilized quantitative models to create loss forecasts, cash flow analyses and benchmarking reports. Completed a year-long Graduate Training Program in risk management; ranked #1 in the western region of the US and shared #1 national ranking in a class of 200 young professionals.

EDUCATION

Yale School of Forestry & Environmental Studies, New Haven, CT
Master of Environmental Management, concentration in Law, Economics, and Policy with a focus on energy issues and markets, 2007

Claremont McKenna College, Claremont, California
Bachelor of Arts in Environment, Economics, Politics (EEP), 2003. *Cum laude* and EEP departmental honors.

School for International Training, Quito, Ecuador
Semester abroad studying Comparative Ecology. Microfinance Intern – Viviendas del Hogar de Cristo in Guayaquil, Ecuador, Spring 2002.

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- Competent in oral and written Spanish.
- Hold the Associate in Risk Management (ARM) professional designation.

PUBLICATIONS

Wilson, R., E. Camp, N. Garner, T. Vitolo. 2020. *Obsolete Atlantic Coast Pipeline Has Nothing to Deliver: An examination of the dramatic shifts in the energy, policy, and economic landscape in Virginia and North Carolina since 2017 shows there is little need for new gas generation.* Synapse Energy Economics for Southern Environmental Law Center.

Eash-Gates, P., D. Glick, S. Kwok. R. Wilson. 2020. *Orlando's Renewable Energy Future: The Path to 100 Percent Renewable Energy by 2020.* Synapse Energy Economics for the First 50 Coalition.

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Wilson, R., N. Peluso, A. Allison. 2019. *North Carolina's Clean Energy Future: An Alternative to Duke's Integrated Resource Plan.* Synapse Energy Economics for the North Carolina Sustainable Energy Association.

Wilson, R., N. Peluso, A. Allison. 2019. *Modeling Clean Energy for South Carolina: An Alternative to Duke's Integrated Resource Plan.* Synapse Energy Economics for the South Carolina Solar Business Alliance.

Camp, E., B. Fagan, J. Frost, D. Glick, A. Hopkins, A. Napoleon, N. Peluso, K. Takahashi, D. White, R. Wilson, T. Woolf. 2018. *Phase 1 Findings on Muskrat Falls Project Rate Mitigation.* Synapse Energy Economics for Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Allison, A., R. Wilson, D. Glick, J. Frost. 2018. *Comments on South Africa 2018 Integrated Resource Plan.* Synapse Energy Economics for Centre for Environmental Rights.

Hall, J., R. Wilson, J. Kallay. 2018. *Effects of the Draft CAFE Standard Rule on Vehicle Safety*. Synapse Energy Economics on behalf of Consumers Union.

Whited, M., A. Allison, R. Wilson. 2018. *Driving Transportation Electrification Forward in New York: Considerations for Effective Transportation Electrification Rate Design*. Synapse Energy Economics on behalf of the Natural Resources Defense Council.

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Wilson, R., T. Comings, E. A. Stanton. 2015. *Analysis of the Tongue River Railroad Draft Environmental Impact Statement.* Synapse Energy Economics for Sierra Club and Earthjustice.

Wilson, R., M. Whited, S. Jackson, B. Biewald, E. A. Stanton. 2015. *Best Practices in Planning for Clean Power Plan Compliance.* Synapse Energy Economics for the National Association of State Utility Consumer Advocates.

Luckow, P., E. A. Stanton, S. Fields, B. Biewald, S. Jackson, J. Fisher, R. Wilson. 2015. *2015 Carbon Dioxide Price Forecast.* Synapse Energy Economics.

Stanton, E. A., P. Knight, J. Daniel, B. Fagan, D. Hurley, J. Kallay, E. Karaca, G. Keith, E. Malone, W. Ong, P. Peterson, L. Silvestrini, K. Takahashi, R. Wilson. 2015. *Massachusetts Low Gas Demand Analysis: Final Report.* Synapse Energy Economics for the Massachusetts Department of Energy Resources.

Fagan, B., R. Wilson, D. White, T. Woolf. 2014. *Filing to the Nova Scotia Utility and Review Board on Nova Scotia Power's October 15, 2014 Integrated Resource Plan: Key Planning Observations and Action Plan Elements.* Synapse Energy Economics for the Nova Scotia Utility and Review Board.

Wilson, R., B. Biewald, D. White. 2014. *Review of BC Hydro's Alternatives Assessment Methodology*. Synapse Energy Economics for BC Hydro.

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Fagan, R., M. Chang, P. Knight, M. Schultz, T. Comings, E. Hausman, R. Wilson. 2012. *The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region*. Synapse Energy Economics for Energy Future Coalition.

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Wilson, R. 2011. *Comments Regarding MidAmerican Energy Company Filing on Coal-Fired Generation in Iowa*. Synapse Energy Economics for the Iowa Office of the Consumer Advocate.

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Fisher, J., C. James, L. Johnston, D. Schlissel, R. Wilson. 2009. *Energy Future: A Green Alternative for Michigan*. Synapse Energy Economics for Natural Resources Defense Council (NRDC) and Energy Foundation.

Schlissel, D., R. Wilson, L. Johnston, D. White. 2009. *An Assessment of Santee Cooper's 2008 Resource Planning*. Synapse Energy Economics for Rockefeller Family Fund.

Schlissel, D., A. Smith, R. Wilson. 2008. *Coal-Fired Power Plant Construction Costs*. Synapse Energy Economics.

TESTIMONY

Virginia State Corporation Commission (Case No. PUR-2020-00035): Direct testimony of Rachel Wilson evaluating Dominion's 2020 Integrated Resource Plan and providing independent capacity optimization modeling. On behalf of the Sierra Club. September 15, 2020.

Virginia State Corporation Commission (Case No. PUR-2020-00015): Direct testimony of Rachel Wilson examining the economics of the coal units owned by Appalachian Power Company as part of the rate case. On behalf of the Sierra Club. July 30, 2020.

North Carolina Utilities Commission (Docket No. E-2, SUB 1219): Direct testimony of Rachel Wilson examining the economics of the coal units owned by Duke Energy Progress as part of the rate case. On behalf of the Sierra Club. April 13, 2020.

North Carolina Utilities Commission (Docket No. E-2, SUB 1219): Direct testimony of Rachel Wilson examining the economics of the coal units owned by Duke Energy Carolinas as part of the rate case. On behalf of the Sierra Club. February 25, 2020.

Alabama Public Service Commission (Docket No. 32953): Direct testimony of Rachel Wilson regarding Alabama Power Company's petition for a Certificate of Convenience and Necessity. On behalf of the Sierra Club. December 4, 2019.

Georgia Public Service Commission (Docket No. 42516): Direct testimony of Rachel Wilson regarding coal ash spending in Georgia Power's 2019 Rate Case. On behalf of the Sierra Club. October 17, 2019.

Mississippi Public Service Commission (Docket No. 2019-UA-116): Direct testimony of Rachel Wilson regarding Mississippi Power Company's petition to the Mississippi Public Service Commission for a Certification of Public Convenience and Necessity for ratepayer-funded investments required to meet Coal Combustion Residuals regulations at the Victor J. Daniel Electric Generating Facility. On behalf of the Sierra Club. October 16, 2019.

Georgia Public Service Commission (Docket No. 42310 & 42311): Direct testimony of Rachel Wilson regarding various components of Georgia Power's 2019 Integrated Resource Plan. On behalf of the Sierra Club. April 25, 2019.

Washington Utilities and Transportation Commission (Dockets UE-170485 & UG-170486): Response testimony regarding Avista Corporation's production cost modeling. On behalf of Public Counsel Unit of the Washington Attorney General's Office. October 27, 2017.

Texas Public Utilities Commission (SOAH Docket No. 473-17-1764, PUC Docket No. 46449): Cross-rebuttal testimony evaluating Southwestern Electric Power Company's application for authority to change rates to recover the costs of investments in pollution control equipment. On behalf of Sierra Club and Dr. Lawrence Brough. May 19, 2017.

Texas Public Utilities Commission (SOAH Docket No. 473-17-1764, PUC Docket No. 46449): Direct testimony evaluating Southwestern Electric Power Company's application for authority to change rates to recover the costs of investments in pollution control equipment. On behalf of Sierra Club and Dr. Lawrence Brough. April 25, 2017.

Virginia State Corporation Commission (Case No. PUE-2015-00075): Direct testimony evaluating the petition for a Certificate of Public Convenience and Necessity filed by Virginia Electric and Power Company to construct and operate the Greensville County Power Station and to increase electric rates to recover the cost of the project. On behalf of Environmental Respondents. November 5, 2015.

Missouri Public Service Commission (Case No. ER-2014-0370): Direct and surrebuttal testimony evaluating the prudence of environmental retrofits at Kansas City Power & Light Company's La Cygne Generating Station. On behalf of Sierra Club. April 2, 2015 and June 5, 2015.

Oklahoma Corporation Commission (Cause No. PUD 201400229): Direct testimony evaluating the modeling of Oklahoma Gas & Electric supporting its request for approval and cost recovery of a Clean Air Act compliance plan and Mustang modernization, and presenting results of independent Gentrader modeling analysis. On behalf of Sierra Club. December 16, 2014.

Michigan Public Service Commission (Case No. U-17087): Direct testimony before the Commission discussing Strategist modeling relating to the application of Consumers Energy Company for the authority to increase its rates for the generation and distribution of electricity. On behalf of the Michigan Environmental Council and Natural Resources Defense Council. February 21, 2013.

Indiana Utility Regulatory Commission (Cause No. 44217): Direct testimony before the Commission discussing PROSYM/Market Analytics modeling relating to the application of Duke Energy Indiana for Certificates of Public Convenience and Necessity. On behalf of Citizens Action Coalition, Sierra Club, Save the Valley, and Valley Watch. November 29, 2012.

Kentucky Public Service Commission (Case No. 2012-00063): Direct testimony before the Commission discussing upcoming environmental regulations and electric system modeling relating to the application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity and for approval of its 2012 environmental compliance plan. On behalf of Sierra Club. July 23, 2012.

Kentucky Public Service Commission (Case No. 2011-00401): Direct testimony before the Commission discussing STRATEGIST modeling relating to the application of Kentucky Power Company for a Certificate of Public Convenience and Necessity, and for approval of its 2011 environmental compliance plan and amended environmental cost recovery surcharge. On behalf of Sierra Club. March 12, 2012.

Kentucky Public Service Commission (Case No. 2011-00161 and Case No. 2011-00162): Direct testimony before the Commission discussing STRATEGIST modeling relating to the applications of Kentucky Utilities Company, and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity, and approval of its 2011 compliance plan for recovery by environmental surcharge. On behalf of Sierra Club and Natural Resources Defense Council (NRDC). September 16, 2011.

Minnesota Public Utilities Commission (OAH Docket No. 8-2500-22094-2 and MPUC Docket No. E-017/M-10-1082): Rebuttal testimony before the Commission describing STRATEGIST modeling performed in the docket considering Otter Tail Power's application for an Advanced Determination of Prudence for BART retrofits at its Big Stone plant**.** On behalf of Izaak Walton League of America, Fresh Energy, Sierra Club, and Minnesota Center for Environmental Advocacy. September 7, 2011.

Resume updated October 2020

CERTIFICATE OF SERVICE

I, S. Laurie Williams, hereby certify that I have this day, served or caused to be served copies of the following document on the attached list of persons by electronic filing or e-mail.

Sierra Club Initial Comments – Public Version
PUC Docket No. E002/RP-19-368

Dated this 11th day of February 2021

/s/ S. Laurie Williams

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