SIERRA CLUB

October 15, 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 Surreply Comments – Public Version

Dear Mr. Seuffert:

Sierra Club respectfully submits its Surreply 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 (415) 977-5716 or kristin.henry@sierraclub.org if you have any questions regarding this filing.

Sincerely,

<u>/s/Kristin A. Henry</u>
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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 SURREPLY COMMENTS

Drafted with the assistance of

Applied Economics Clinic

Grid Strategies LLC

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OCTOBER 15, 2021

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

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I. Summary and Overview

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. Now is the time for a "no regrets" energy strategy that retires expensive, carbon-intensive coal plants, avoids investments in new gas-fired generation, and rapidly builds out low-cost clean technologies – wind, solar, and battery storage – with proven ability to provide needed grid reliability services. This will save customers money while also reliably diversifying our energy supply through a commitment to both utility scale and distributed generation.

In its Reply Comments, Xcel has developed an "Alternate Plan" that excludes the Sherco plant, an ill-advised proposal to build a new 800 MW combined-cycle methane gas plant in 2027 ("Sherco CC"). The Company's decision to drop its plan to build the Sherco CC is both a climate and rate-payer victory for Minnesota, which Sierra Club adamantly supports. However, Xcel undercuts that progress with its proposal to build two new methane-gas combustion turbine plants (CTs) in 2027 and 2029. Sierra Club's experts' analysis, using the same modeling platform as Xcel, shows that building the newly proposed greenfield CTs are not the least-cost option and would fail to address reliability concerns.

As with its Supplement Plan (Xcel's preferred Plan that was presented in its June 2020 Supplement), 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 under the Alternate Plan. (Section II.) The flaws in Xcel's modeling of its Alternate Plan include: hard-wiring the two newly proposed greenfield CTs into all modeling runs, without regard to whether they were optimal resource additions; inflating the costs of solar PV and battery storage despite the use of a reasonable primary source (the NREL ATB); largely ignoring battery storage, despite it being an increasingly attractive resource option from a cost and reliability perspective; and failing to adequately assess hybrids, as required by Commission order. When Sierra Club's experts corrected many of these issues and conducted modeling using more reasonable assumptions (the No Forced GR CT Scenario), they found that the model did not build any new greenfield CTs and that it was $395 million cheaper compared to Xcel's Alternative Plan.

Xcel asserts that its Alternate Plan is needed as scenarios high in renewable energy are less reliable than those with gas. Our expert Grid Strategies reviewed Xcel's reliability arguments and found that 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 (especially during events like storm Uri), 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, voltage support, and blackstart, Xcel again understates the capabilities of renewable and storage resources and overstates the need for conventional generators like the two newly proposed greenfield CTs.

Moreover, there is no need for the Commission to rush and decide now whether to let Xcel build two new greenfield CTs as these plants are not slated to go online until 2027 and 2029. This gives the Commission ample time to weigh the reliability, life-cycle climate change, and stranded asset implications of the request, and determine if other solutions can meet the need for reliability services at lower cost.

Finally, while Xcel has taken the critical first step of discussing equity considerations in its IRP, certain key elements of its proposed Alternate Plan continue to create a barrier to achieving the outcome the utility has expressed it desires. First, Xcel's proposal to construct two new gas plants is inconsistent with this commitment because the impacts of climate change will be borne disproportionately by Black, Indigenous, and People of Color (BIPOC) communities in Minnesota. The two proposed CTs, combined with the additional greenfield CTs added over the analysis period, would also cost customers an estimated $395 million more than clean energy alternatives and could saddle customers with stranded costs, an economic burden that would most harm our most vulnerable communities. Second, Xcel's Alternate Plan continues to unreasonably minimize the role that community solar and distributed generation can and should play in its portfolio. Finally, additional programs are needed, 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 programs.

Because Sierra Club's Clean Energy For All Plan,[1] which was discussed in-depth in our Initial Comments, will deliver clean, reliable energy at significantly lower cost than either the Alternate Plan or Supplement Plan, 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. Disapprove the need for the Sherco CC in 2027;

3. Disapprove the need for the two newly proposed greenfield CTs in 2027 and 2029 or, alternatively, defer a decision on the CTs to another docket so that the Commission can fully consider all the implications, including cost, reliability, and life-cycle climate change impacts

[1] The purpose of the No Forced GR CT Scenario that was modeled for these Surreply Comments was to test the cost-effectiveness of the Alternate Plan. The No Forced GR CT Scenario was $395 million cheaper than Xcel's Alternate Plan on a PVSC basis. Sierra Club is not offering the No Forced GR CT Scenario as its preferred plan. Sierra Club spent over a year developing the Clean Energy For All Plan, which robustly considered all relevant factors and would deliver clean, reliable energy at significantly lower cost than either the Alternate or Supplement Plan. Like the No Forced GR CT Scenario, the capacity optimization that resulted in the Clean Energy For All Plan also does not add any new gas-fired generating units to the long-term resource portfolio. It is this plan that Sierra Club respectfully requests that the Commission adopt.

associated with this request, and determine if other solutions can meet the need for reliability services at lower cost;

4. Approve the need for 1,350 MW of utility scale solar and 4,320 MW of new wind beginning in years 2027 and 2026, respectively, as well as an additional 4,070 MW of utility scale solar paired with 1,080 MW of battery storage starting in 2031, and 1,200 MW of standalone battery storage beginning in 2027;

5. 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;

6. 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 in 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;

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

8. 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. COST[2]: The Commission should not approve the two new greenfield CTs that are part of the Alternate Plan as they are not the least-cost option or, alternatively, the Commission should defer any decision on the CTs until another docket.

The focus of our Initial and Reply Comments was on the Company's selection of the Sherco CC plant as part of its preferred plan. Sierra Club and other parties issued strong rebukes to this resource selection including that Xcel forced in the selection of the Sherco CC rather than as an economically optimal selection, and showed that alternative plans—such as Sierra Club's Clean Energy For All Plan—provided substantial savings from not building the Sherco CC.

In its Reply Comments, the Company has developed an "Alternate Plan" that excludes the Sherco CC. We are pleased that the Company has now conducted modeling that did not include the Sherco

[2] 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 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. As with our Initial Comments, Sierra Club will organize its Surreply Comments around these consideration factors.

CC as opposed to all of the IRP modeling previously conducted by the Company which forced in the plant's selection.

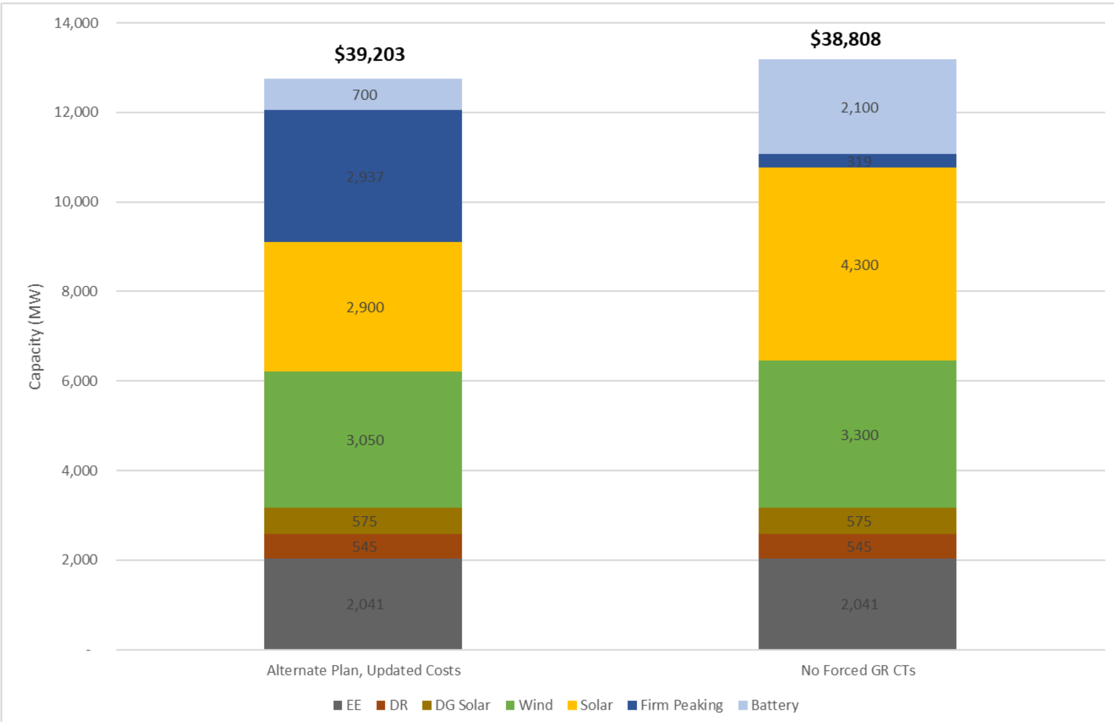
The Company's modeling of the Alternate Plan in these Reply Comments show savings of $606 million PVSC and $46 million PVRR with the exclusion of the Sherco CC.[3] This is a strong result showing—as with initial and reply comments from other parties—that the Sherco CC is not in the public interest. All of the relevant modeling in the record demonstrates that the Commission should disapprove the need for the Sherco CC in 2027.

However, we are concerned that the Company's Alternate Plan, while preferable to its previous plans, carries some of the same methodological flaws that it employed in selecting the Sherco CC. Namely that the Company is now pursuing 1,100 MW of gas CTs[4] which were not economically optimized and modeled using out-of-date cost assumptions for other resource types (such as solar, wind, and battery storage).

As with our Initial Comments, we remain focused on producing a reliable, low-cost, low-risk plan for Xcel's Minnesota ratepayers. We have once again reviewed the modeling that the Company has conducted using the Encompass software, made changes to the resource cost assumptions underlying that modeling and allowed for optimized selection of resources as part of a new No Forced GR CTs scenario. This new scenario produced a plan that is in the public interest, including savings of $395 million PVSC compared to the Company's Alternate Plan (using the same updated costs as our plan). The cumulative capacity expansion through 2034 for both plans, along with the net present value of revenue requirements from 2020-2050 is shown in Figure 1.

[3] Xcel Reply Comments, p. 2.
[4] Xcel Reply Comments, p. 9.

Figure 1. Capacity Expansion, Through 2034, Alternate Plan w/ Updated Costs versus No Forced GR CTs



Our plan allowed for the Encompass model to select the lowest-cost resource under a more reasonable—albeit conservative—resource cost future. Other than those changes, we maintained Xcel's capacity expansion and production cost modeling methodology. The Company's hard-coded aeroderivative turbines (2025), reciprocating engines (2026), and the brownfield CT (2026) were left unchanged in our updated modeling,[5] and appear in Figure 1 in the Selectable CTs scenario. Our model chose additional battery storage, wind, and solar PV and did not select the two newly proposed greenfield CTs, nor did it select any additional greenfield CTs for the duration of the analysis period. Further in Sections III, IV, and V, we discuss the Company's reliability arguments, discuss Xcel's biases against renewables and storage, and explain that solutions other than the greenfield CTs can likely meet the need for reliability services at lower cost.

A. Summary of Xcel's Latest Encompass Modeling.

The Company used the Encompass modeling software to conduct both capacity expansion and production cost modeling of its Supplement Plan and Alternate Plan. The Company presents the costs of these two plans against one another, showing substantial savings with the Alternate Plan. Both the Supplement and Alternate plans include the retirement of all coal units by 2030 (including seasonal dispatch of Sherco Unit 2 and King) and the extension of the Monticello nuclear plant license until 2040.[6] However, unlike the Supplement Plan, the Alternate Plan excludes the Sherco

[5] The fact that our modeling did not change an assumption does not indicate that we thought the assumption was reasonable. Rather our modeling only changed the more egregious assumptions because of time constraints.
[6] Xcel Reply Comments, p. 4.

CC and assumes that transmission interconnection at retiring coal units at Sherco and King will facilitate solar PV, wind, and new gas CT's.[7] Below, we discuss the Company's resource selection under its Alternate Plan, including the flaws in the methodology and assumptions underlying the selection of new gas CT's in that Alternate Plan.

1. Xcel's Updated Modeling Adds Further Evidence that the Sherco CC is uneconomic.

We are pleased that Xcel has put forth a plan, the Alternate Plan, that did not include the Sherco CC and as a result provided substantial savings. A main focus of our Initial and Reply comments was that the Company had failed to economically justify the Sherco CC. Our modeling, and that of other parties, showed that Sherco CC was an uneconomic resource. The Company's Reply Comments modeling of its Alternate Plan further reinforces Sierra Club findings regarding the Sherco CC by showing savings of $606 million PVSC by not building the plant.

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

As with the initial IRP modeling, we show that the Company continues to prejudice the results against renewable and battery resources in favor of gas resources. The Company's modeling fails to correct errors that previously led the Company to select the uneconomic Sherco CC in its initial IRP. Specifically, the Company has once again hard-wired resources in its modeling (as it did with Sherco CC previously) and that its solar, wind and battery costs assumptions remain out-of-date and inflated. Thus, the Alternate Plan is unfairly biased in favor of new gas CT resources by not letting these resources compete with other reasonable options on an even playing field. Further in these comments, we show that more reasonable modeling that allows for economic selection of new resources fails to choose any new greenfield CT's and as a result provide $395 million in PVSC savings compared to the Alternate Plan.

i. Xcel hardwired the newly proposed greenfield CT plants into its modeling runs, preventing the model from determining whether they are a reasonable, least-cost resource addition.

The Company's Alternate Plan includes the construction of two 374 MW greenfield natural gas CTs for operation in 2027 and 2029. The Company's modeling does not justify the CT plants. Xcel hard-wired the CT additions 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 for its Alternate Plan that include the CT resource additions 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

[7] *Id.*

in its Reply Comments and Alternate Plan that the newly proposed greenfield CTs are optimal resource additions because Xcel baked them into all of its model runs. As explained below, solutions other than the CTs can likely meet the claimed need for reliability services at lower cost. The hard-wiring of the CT's into the model prevents decision-makers from seeing a truly optimal solution. The capacity expansion component of Encompass is designed to economically select resources dispassionately and should do so under reasonable and unbiased assumptions. Xcel's pre-selection of CT resources subverts that optimization process in its Alternate Plan and, while the Company has shown that this Alternate Plan is clearly superior to its previous Supplemental Plan, it has not proven that it is in the public interest.

Much like the previous Sherco CC selection, the selection of these CT's is premature. Xcel does not propose to build these gas-fired CTs until 2027 and 2029. Therefore, there is no reason that the Commission should approve these resources at this point in time, especially given declining renewable and battery storage cost expectations and the increasing ability of those resources to provide reliability services. The Company and the Commission has ample time to fully consider the full breadth of options available and to evaluate what is the least-cost resource for ratepayers. Approving these resources now will simply preclude the Company and its ratepayers from pursuing better and cheaper alternatives.

ii. Xcel's EnCompass modeling remains biased against renewable and battery storage.

In our Initial Comments, we addressed many flaws in the Company's treatment of renewable and battery storage which unfairly prevented the Company's model from selecting these resources or limiting the amount that was selected.[8] The Company has addressed several of those concerns in its Reply Comments but unfortunately major flaws remain that disfavor renewable and storage in the Company's Alternate Plan. First, the primary source of Xcel's renewable and battery storage costs is NREL ATB 2019 which is even more stale and unrealistically high in late 2021. NREL has done two annual updates to this data (NREL ATB 2020 and 2021[9]) but the Company has failed to update its modeling accordingly. Second, the Company assumes a 10-year useful life for batteries, which unreasonably inflates their cost, and miscalculates the levelized costs of batteries. Both the Company's Supplement and Alternate Plans used outdated cost data and an unreasonable useful life for batteries. Sierra Club's modeling throughout this case has corrected these flaws, as does our newest modeling.

[8] *See* SC Initial Comments, p.11-12, 32.
[9] *See*: *Electricity Annual Technology Baseline (ATB) Data Download,* NREL, https://atb.nrel.gov/electricity/2021/data

iii. Xcel's costs of solar PV, wind, and battery storage are outdated and inflated.

We are pleased that the Company has addressed some of our previous concerns about its modeling of new solar, wind, and battery resources—including by modeling smaller-sized resources that would allow the model to make more modular capacity additions.[10] The Company has also applied up-to-date extensions of the Production Tax Credit (PTC) and Investment Tax Credit (ITC), which are new since its initial filing.[11] But the Company's baseline costs of solar, wind, and battery resources remain outdated and inflated. The Company continues to rely on NREL ATB 2019 as a basis for solar, wind and battery capital and operating costs despite two annual updates of this data available.[12] In our Initial Comments, we updated these costs to reflect the latest data available at that time (NREL ATB 2020) and in these Surreply Comments we have updated once again to use the NREL ATB 2021 which was released in July of 2021. Synapse modeled both Xcel's Alternate Plan and our No Forced GR CT Scenario under these cost assumptions.

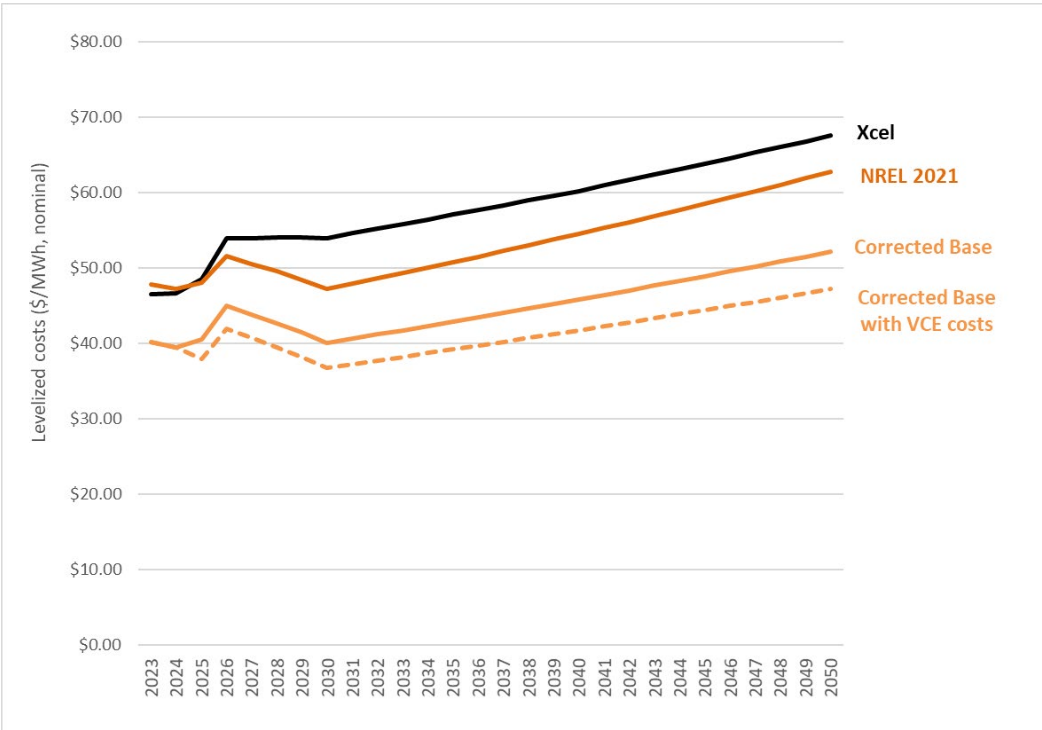
Below Figures 2-4 show the comparison of Xcel's levelized costs of solar, wind, and battery compared to our updated costs using the NREL ATB 2021. The battery costs shown below for "NREL 2021" also include a 15-year useful life instead of Xcel's 10-year life. We maintain that this is a reasonable yet conservative assumption. In fact, Xcel is assuming a 15-year life for battery storage that is part of its current resource planning process in Colorado.[13] We also updated the Company's solar and wind costs for resources that would not require additional interconnection costs because they would make use of the interconnection at the retiring King and Sherco coal plants—referred to as "Gen-tie" resources.[14] This is a new resource type that the Company has included in its Alternate Plan alongside resources that would require new interconnection costs. Unsurprisingly, both Xcel's and our NREL 2021 costs for the "gen-tie" resources are lower without any interconnection costs; these costs along with the data for the figures below (where interconnection costs are included) are provided in the appendix.

Notably, we only used the "NREL 2021" costs in our modeling, which already produced a lower PVSC than Xcel's Alternate Plan. As shown below, we developed further alternative forecasts which decreased the costs below our NREL 2021 forecasts. As we did in our Initial Comments, these forecasts focused on the treatment of interconnection costs and the underlying assumption for those costs ("Corrected Base" and "Corrected Base VCE" for solar and wind); and the "Corrected Base" for battery storage assumes a 20-year useful life.[15] Applying these lower and more reasonable cost

[10] Xcel Reply Comments, Appendix A, p.1. The Company is now modeling 50 MW sizes for solar, wind, and battery instead of 500 MW, 750 MW, and 321 MW sizes, respectively.
[11] *Id.*
[12] Xcel Reply Comments, p.95.
[13] Colorado PUC, Proceeding No. 21A-0141E, Public Service Company of Colorado, 2021 Electric Resource Plan and Clean Energy Plan, Hearing Exhibit 101, CORRECTED Attachment AKJ-2_Technical Appendix_CLEAN, p.309.
[14] Xcel Reply Comments, p. 25.
[15] *See*: SC Initial Comments, p.37. With the exception of the safe harbor, we made the same adjustments to the interconnection costs in "Corrected Base" and "Corrected Base VCE" as

forecasts would only increase our savings estimate. Thus, the Commission should consider our modeling results using the NREL 2021 as conservative, i.e. favorable to the Company, but in all likelihood the benefits would be even greater than forecasted.

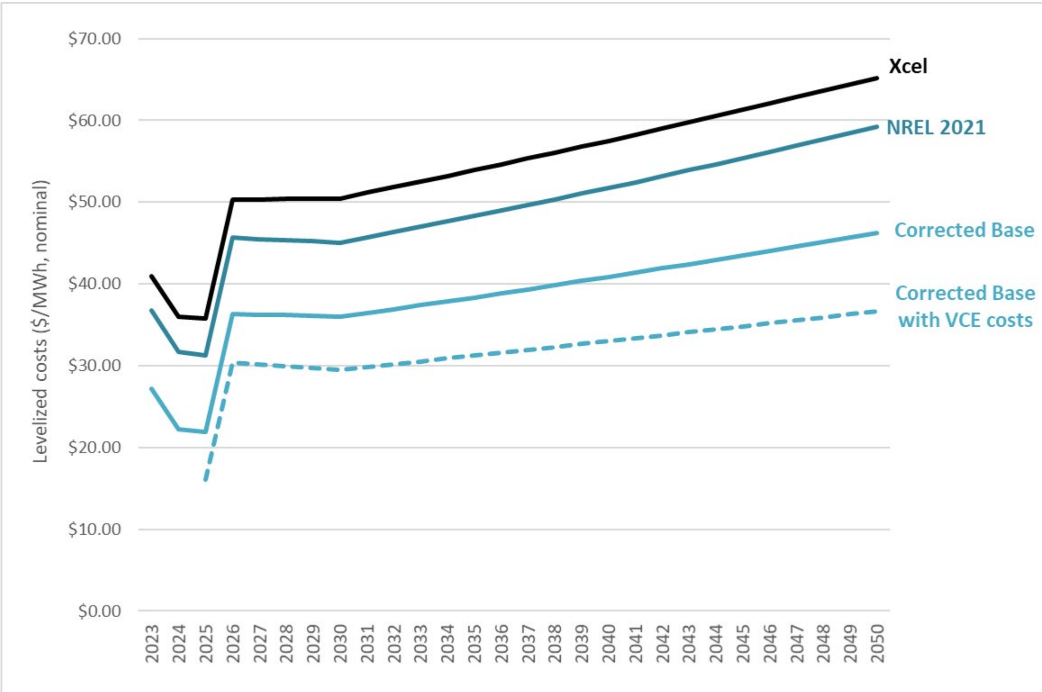
Figure 2: Solar PV Levelized Costs ($/MWh, nominal) with Interconnection[16]



described in our initial comments. However, in these surreply comments, we conservatively only modeled the "NREL 2021" costs.

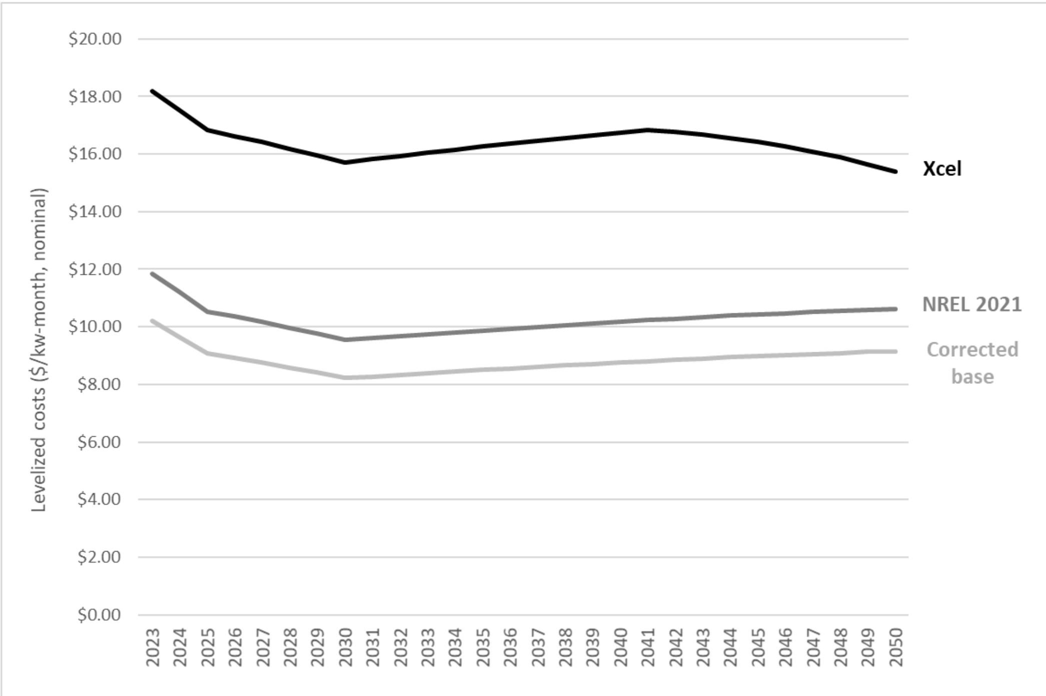
[16] 19-0368 XLI-180_Att C NREL ATB Renewable – Base; NREL ATB 2021 (https://atb.nrel.gov/electricity/2021/data).

Figure 3: Wind Levelized Costs ($/MWh, nominal) with Interconnection[17]



[17] *Id.*

Figure 4: Battery Levelized Costs ($/MWh, nominal)[18]



In our Initial Comments and in these Surreply Comments, we corrected the levelized costs of batteries, as shown above.[19] The Company continues to incorrectly calculate the real levelized costs of battery by using a nominal discount rate rather than a real discount rate.[20] The real levelized costs are later translated into nominal by including inflation—those nominal costs are shown above. But the use of a higher discount rate in calculating real levelized costs inflates those costs at the start. This error does not apply to solar and wind because the Company takes the real levelized costs as calculated by NREL, correctly using the real discount rate.[21] For batteries, however, the Company should correct this error and discontinue this incorrect practice in the future.

iv. The Company did not model solar-battery hybrid resources.

Sierra Club's Initial Comments in this docket critiqued Xcel's modeling of hybrid solar-battery resources, as the Company only included hybrid resources in limited sensitivity cases, evaluating whether a hybrid option was an economic alternative to standalone renewables. In Sierra Club's Clean Energy for All plan, EnCompass economically added hybrid solar-battery resources beginning

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[18] 19-0368 XLI-180_Att B - NREL ATB Battery; NREL ATB 2021 (https://atb.nrel.gov/electricity/2021/data).
[19] SC Initial Comments, p. 16.
[20] 19-0368 XLI-180_Att B - NREL ATB Battery, "NREL Costs_real" tab.
[21] 19-0368 XLI-180_Att C NREL ATB Renewable – Base, "NREL Solar - Utility PV" and "NREL Land-Based Wind" tabs.

in 2031 and included over 4,000 MW of solar paired with 1,080 MW of battery storage over the analysis period.

Sierra Club's approach was consistent with Commission order. In an 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." 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." However, the Company's modeling done in support of its Alternate Plan did not explore hybrids. 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.

We did not model hybrid resources for the purposes of these Surreply Comments as we kept many of our input assumptions similar to Xcel's. However, we will once again note that paired renewable-battery resources are eligible for the ITC, while standalone batteries are not currently eligible resources. Our modeling results in these Comments can thus be considered conservative from that perspective, and inclusion of hybrid resources would result in additional cost savings.

B. When problems with Xcel's modeling assumptions were corrected, Synapse's modeling shows that Sierra Club's No Forced GR CT Scenario is a lower-cost alternative to Xcel's Alternate Plan.

Synapse's modeling, for the purposes of these Surreply Comments, corrected only a limited number of Xcel's input assumptions.[22] First, we updated the Company's source data by using the more recent NREL 2021 ATB instead of the 2019 ATB used by Xcel. Second, we decreased the battery size to 20 MW and increased the operating life to 15 years. Finally, we removed the hard-coded dates for the greenfield CTs and made them all selectable resources. We did, however, leave the hard-coded dates for the aeroderivative turbines (2025), reciprocating engines (2026), and the brownfield CT (2026).

Synapse modeled two scenarios using the latest version of the EnCompass capacity expansion and dispatch software, Version 5.1.3. In our first scenario, Synapse re-ran Xcel's Alternate Plan with updated NREL 2021 ATB costs for wind, solar, and battery storage resources, fixing the Company's proposed combustion turbine resource build to match Xcel's. We allowed for optimization of wind, battery, and storage resources to reflect the changes to the relative economics of those resources in NREL's 2021 ATB. We also adjusted the operating life of the batteries to 15 years and lowered the size to 20 MW. In the second scenario, we updated the costs for wind, solar, and battery storage to match the NREL 2021 ATB, made the greenfield CTs selectable (as opposed to hard coded), made the operating life of the batteries 15 years, and made the battery size 20 MWs.

[22] As noted above, the purpose of the No Forced GR CT Scenario that was modeled for these Surreply was to test the cost-effectiveness of the Alternate Plan. Sierra Club is not offering the No Forced GR CT Scenario as its preferred plan. Sierra Club is still putting forth its robustly developed Clean Energy For All Plan for approval by the Commission.

C. Synapse modeling results for the No Forced GR CT Scenario.

Synapse's modeling results show that Xcel's Alternate Plan is not the least-cost option for its customers. In our No Forced GR CT Scenario, the EnCompass model did not select any new greenfield CTs, preferring instead to add solar, wind, and storage resources. The No Forced GR CT scenario also results in cost savings of $395 million on a net present value basis over the 2020-2050 analysis period.

A summary of the resulting PVSC and PVRR values for the two Sierra Club scenarios is shown in Table 1. Using updated NREL 2021 ATB costs, the No Forced GR CT portfolio, which does not add new greenfield CTs, is the lower-cost portfolio when compared to Xcel's Alternate Plan.

Table 1. Summary PVSC and PVRR Results for Sierra Club Scenarios

Scenario	PVSC ($million, 2020-2050)	PVRR ($million, 2020-2050)
Xcel's Alternate Plan w/ Updated Costs	$39,203	$36,193
No Forced GR CTs Scenario	$38,808	$35,950
Delta	($395)	($243)

As mentioned above, when given the choice, the EnCompass model did not select any new greenfield CTs, instead adding additional wind, solar, and battery storage resources. A comparison of the cumulative (through 2034) new-build resources selected by the EnCompass model in the Alternate Plan w/ Updated Costs and the No Forced GR CTs scenarios is shown in Figure 4. The annual incremental resource additions in the No Forced GR CTs scenario are shown in Figure 5.

Figure 5. Comparison of Expansion Resources (MW), Alternate Plan w/ Updated Costs versus No Forced GR CTs Scenario

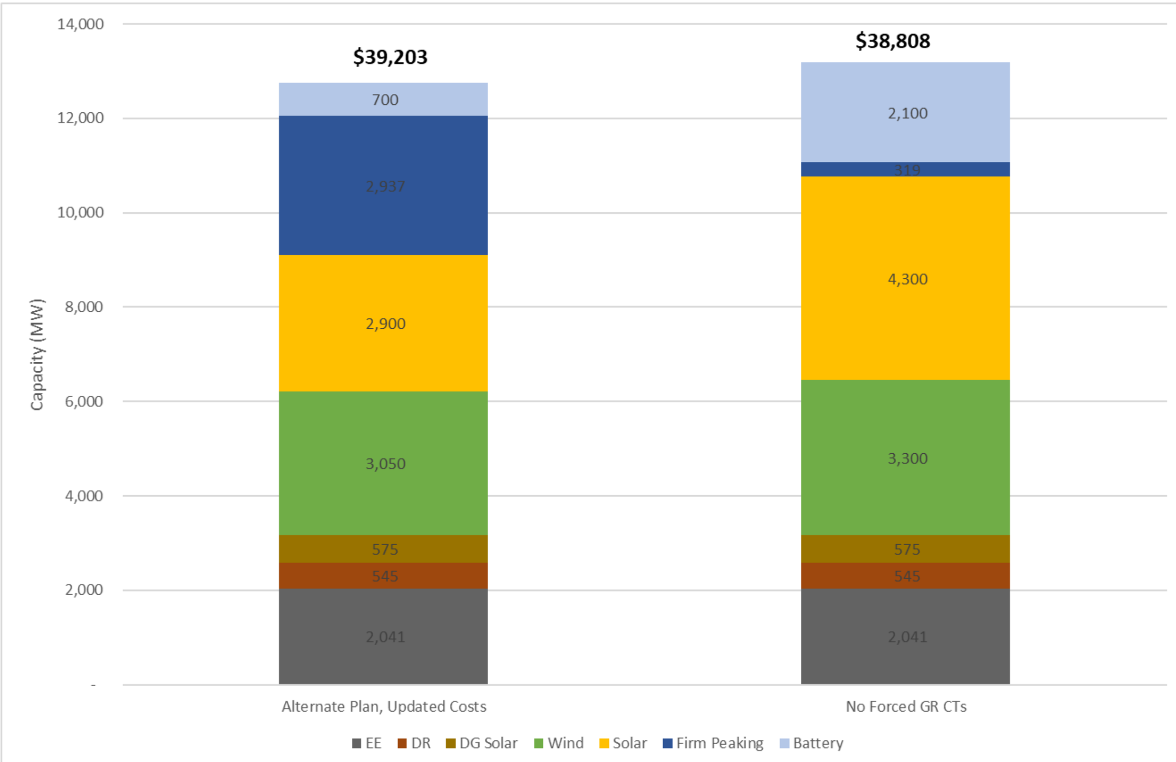
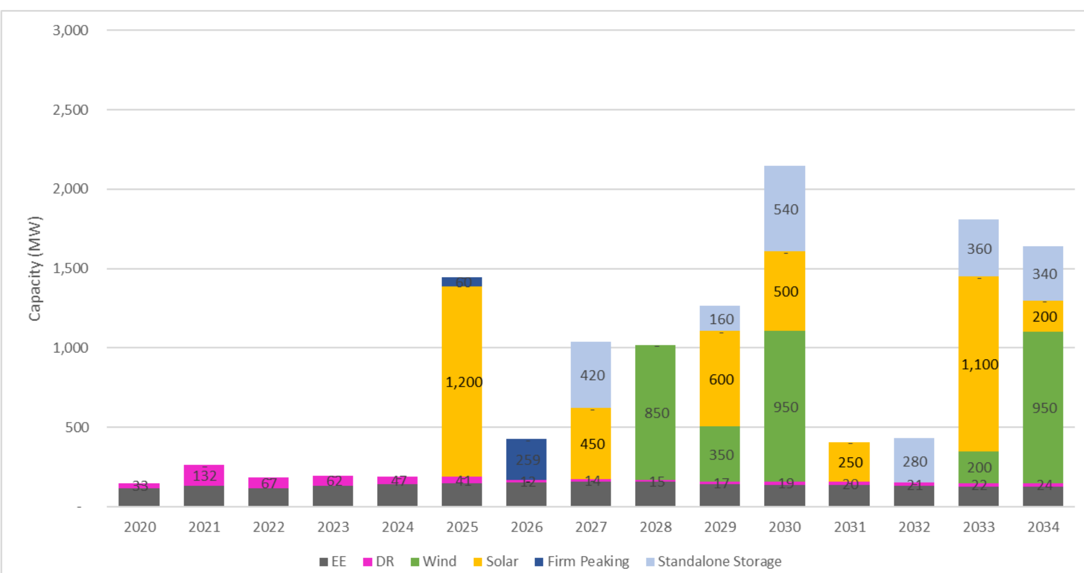


Figure 6. Annual Incremental Resource Additions, No Forced GR CTs scenario



Xcel's Alternate Plan adds 2,937 MW of new gas-fired resources by 2034. The No Forced GR CTs scenario, in contrast, selected no new greenfield combustion turbines as part of the least-cost optimization. The Firm Peaking resources shown in Figure 6 (60 MW of aeroderivative turbines in 2025 and 259 total MW of reciprocating engines and a brownfield CT in 2026) were hardcoded in Xcel's modeling and we maintained those resources in the No Forced GR CTs scenario.

III. RELIABILITY: Xcel Overstates the Reliability Benefits of Its Preferred Plan, and Understates the Ability of Renewable and Storage Resources to Provide Reliability Services; In Actuality Renewables, storage, and imports can meet peak capacity needs without the need for new gas generators.

A. Xcel's reliability modeling is riddled with problems.

At pages 124-138 of its Reply Comments, Xcel compares its plans against those put forward by the CEOs and Sierra Club on various metrics that Xcel claims measure reliability. When read closely, these results confirm that Sierra Club's plan is reliable, as it meets the metrics that actually reflect real-world reliability risk.

First, Xcel compares these plans using a simplistic metric, the ratio of what Xcel considers to be "firm dispatchable" generation to peak load.[23] The largest problem with this metric is that it gives zero credit for the large contributions of battery storage, demand response, renewable resources, and imports towards meeting electricity demand. It also incorrectly assumes conventional generators are fully available and not subject to correlated outages and derates that limit their ability to meet peak demand. Effective Load Carrying Capability (ELCC) analysis, the gold standard for accounting for the actual reliability contributions of these different resources that is endorsed by NERC and grid operators, consistently confirms renewables, storage, demand response, and imports provide significant capacity value, while correlated outages reduce the capacity value of conventional generators.[24] Moreover, as the Department of Commerce (DOC) noted in its Initial Comments, increased use of imports is an economic risk and not a reliability risk, as imports do meet demand.[25] Like the "Reliability Requirement" that Xcel attempted to justify in its initial 2019 filing, the Commission should disregard this metric as it does not reflect resources' actual reliability contributions and disregard Xcel's argument that "the Sierra Club and CEOs' proposed plans lack sufficient firm dispatchable capacity to adequately mitigate customer risk and reliability concerns."[26]

Next, Xcel presents net load duration curves for the various plans,[27] ranking hours in the year from highest- to lowest-net load. This metric is inferior to sequential hourly modeling in representing the real-world dispatch of resources, as Xcel notes itself in footnote 45. That said, Xcel's net load

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[23] Xcel Reply Comments, p. 126.
[24] *Methods to model and calculate capacity contributions of variable generation for resource adequacy planning,* North American Electric Reliability Corporation (March 2011), https://www.nerc.com/files/ivgtf1-2.pdf
[25] DOC Initial Comments, p. 34-36.
[26] Xcel Reply Comments, p. 87.
[27] *Id.* at p. 128.

analysis does confirm that renewables provide significant capacity value, as indicated by the fact that peak net load is more than 5,000 MW lower than peak load in both the CEO and Sierra Club plans. This reflects that renewable resources are available during peak demand periods, reducing the amount of net load that must be met by nearly half. Xcel's presentation also misleadingly shows many hours of negative net load under the CEO and Sierra Club plans, ignoring that energy storage will be charging during these hours, which when considered in conjunction with market sales will keep net load positive.

Third, Xcel presents sequential hourly modeling that confirms Sierra Club's portfolio is reliable for the entirety of the planning period of 2020-2034. As noted above, sequential hourly modeling is the best approach for representing actual reliability needs. However, Xcel misleadingly focuses on modeled generation shortfalls that occur in 2037-2045, well outside of the planning period.[28] Sierra Club's modeling was focused on meeting reliability needs during the 2020-2034 planning period, and did not attempt to meet reliability needs in the 2037-2045 timeframe. Had we wanted to meet reliability needs in 2037-2045 our modeling could have optimized around that, and likely could have easily met those needs by extending existing resources like hydropower; adding more new resources like battery storage, demand response, and renewables; or increasing transmission capacity to other parts of MISO. At most, if those solutions fail to materialize and there is a need for additional capacity in the late 2030s, Xcel can assess the optimal mix of resources for meeting that need at that time instead of making an irreversible investment in CTs now. Given that there is more than 15 years to meet those needs should they arise, and that any additional cost of doing so would be discounted to minimal value in a net present value calculation, this is not a real reliability or economic concern with Sierra Club's plan.

Xcel then attempts to use the 2037-2045 shortfalls to claim that the cost of those shortfalls justifies an additional investment in CTs. Setting aside the important point made above that our modeling could have met reliability needs in 2037-2045 if that were part of the planning period, Xcel's analysis is misleading because it assumes a $10,000/MWh cost for the unserved energy in the 2037-2045 timeframe.[29] In reality, MISO caps generation offers at $2,000/MWh, and has a hard price cap of $3,500/MWh, as that is MISO's assumed value of lost load.[30] If Xcel conducted its analysis using MISO's actual operating practices, the amount of CT capacity Xcel claims would be justified to add to Sierra Club's Clean Energy For All Plan 15-25 years from now would be reduced from 869 MW to around 300 MW. However, the more important point is that Xcel's modeling confirms that both

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[28] Xcel confirms these shortfalls are outside of the planning period on page 131, of its Reply Comments noting that "Although it appears that these unserved energy periods happen in the years beyond our current 2020-2034 planning period, we believe it remains relevant because the PVSC and PVRR analyses in the Resource Plan consider the full 2020-2045 modeling period."

[29] Xcel Reply Comments, p. 133, FN 54.

[30]Market Subcommittee, *Emergency & Scarcity Pricing Evaluation,* MISO (March 5, 2020), https://cdn.misoenergy.org/20200305%20MSC%20Item%2009a%20Improve%20Scarcity%20and%20Emergency%20Pricing%20(IR071,%20IR077)433010.pdf, at 16.

the CEO and Sierra Club plans are fully reliable through the 2020-2034 planning period, and even beyond.

Finally, Xcel presents a worst-case analysis of what it claims represents reliability risk under a repeat of 2019 polar vortex conditions, with high load and unavailability of many resources.[31] This analysis again shows that Sierra Club's Clean Energy For All Plan is reliable under the conditions it was optimized to meet, with no loss of load under typical conditions or even under many of the scenarios Xcel used to represent 2019 polar vortex conditions.[32] Only under extreme scenarios, like a repeat of 2019 conditions using a worst-case wind output profile, combined with the assumption that the vast majority of gas plants would be unavailable, did Xcel's plan encounter reliability challenges.[33] This finding reveals more about the risk of increasing Xcel's gas dependence, as discussed below, than it does about the reliability of Sierra Club's Clean Energy For All Plan. **[TRADE SECRET DATA BEGINS . . . TRADE SECRET DATA ENDS]** [34] if Xcel were to extend contracts for some or all of its current 1,001 MW of hydropower capacity,[35] these shortages likely could have been avoided. As explained above, Sierra Club's modeling could have optimized around this reliability constraint and met load under any condition by extending existing hydropower resources, adding new clean resources, and/or building transmission.

More importantly, Xcel's reliability modeling is fundamentally flawed because it repeats a major error that we pointed out in our Initial Comments – failing to account for how wind and solar capacity additions increase the fleet's geographic diversity. If this error were corrected, Xcel's claimed reliability concerns with Sierra Club's Preferred Plan would likely be eliminated. Geographic diversity reduces renewable output variability and fills in periods when the existing fleet experienced low output due to local weather phenomenon, including low-temperature cut-outs or icing events at wind plants during extreme winter weather.[36] Adding the amount of wind and solar capacity Xcel is proposing inherently reduces the variability of the fleet's output profile, given the area over which large wind and solar plants are inherently spread. National laboratory analysis has shown that even short distances between two wind plants or two solar plants is enough to greatly reduce the

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[31] Xcel Reply Comments, p. 133-138.
[32] Xcel presents a range of reliability metrics that do not account for Xcel's ability to import power from the rest of MISO; only the Loss of Load Hours and Expected Unserved Energy metrics account for those imports, and those metrics show no loss of load under typical meteorological year conditions.
[33] **[TRADE SECRET DATA BEGINS . . . TRADE SECRET DATA ENDS]**
[34] *Ibid., Attachments H and K.*
[35] Xcel Reply Comments, Appendix B p. 2.
[36] Sierra Club Initial Comments, p. 69.

correlation in their variability.[37] Another study found that 50 miles (approximately 80 kilometers) is sufficient to reduce two wind plants' hourly output variation correlation to less than 0.2.[38]

Xcel's Reply Comments note this concern from our Initial Comments; however, Xcel's solution does not address our concern at all, as it still uses the output of a single wind plant to represent all future wind capacity additions.[39] In response to SC Information Request 226, Xcel confirms that the results of its reliability analysis, shown in Table 4-14 on page 135 of its Reply Comments, are based on extrapolating the output of all future wind plants from the output of single existing wind plant: "Yes, modeling of generic units uses the same shape for all units. In response to feedback in the Initial Comments, we added another scenario ("Revised 2019 Actuals") that included the use of a wind shape with a higher net capacity factor (NCF). In this case, we picked the wind farm with the highest NCF shape in 2019 and applied that shape to the generic wind units for our 2019 scenario for study of all Plans shown in Table 4-14 of the Company's Reply Comments."

Similarly, Xcel's solution of conducting 50 modeling runs, each of which extrapolates future wind plant from a single wind shape,[40] totally misses the point of our concern. In our Initial Comments at page 69, we quoted an NREL report that discusses common flaws in renewable integration analysis and notes, "a common error is to scale the output of an existing generator to represent the expected output of a larger fleet."[41]

Even though Xcel's 50 modeling run approach is fundamentally flawed, results Xcel provides in response to SC Information Request 233 still indicate that Sierra Club's Clean Energy For All Plan is reliable. Xcel reveals that the average loss of load hours for Sierra Club's plan across those 50 runs was 0.7 loss of load hours per year, which more than meets the reliability criteria of 2.4 loss of load hours per year that NERC and others use to represent the 1-day-in-10-year outage reliability standard.[42] SC Information Request 233 also reveals that the range of results Xcel presented in Table 4-14 on page 135 of its Reply Comments is misleading, as the average results are at the very low end of the range. Specifically, Table 4-14 in Xcel's Reply Comments shows a range of 0 to 17 loss of load hours per year, when the average result is 0.7 hours per year. Similarly, Table 4-14 shows between 0 and 5,767 MWh of expected unserved energy per year, while the average result was 236 MWh.

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[37] Andrew Mills and Ryan Wiser, *Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power,* Berkeley Lab (Sept. 2010),
https://eta-publications.lbl.gov/sites/default/files/report-lbnl-3884e.pdf.

[38] IEA Wind Task 25, *Design and operation of power systems with large amounts of wind power*, VTT (2009), https://iea-wind.org/wp-content/uploads/2021/08/T2493.pdf, at p. 25.

[39] Appendix A to Xcel's Reply Comments, p. 33.

[40] *Id.* at p. 33.

[41] 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

[42] *2020 Long-term reliability assessment,* North American Electric Reliability Corporation (Dec. 2020), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf, p. at 18.

In summary, Xcel's reliability modeling is fundamentally flawed because it continues to assume that new wind plants will have output profiles that are identical to those of existing wind plants, ignoring the major geographic diversity benefit inherent in adding large amounts of new wind and solar resources. If this error were corrected, Xcel's claimed reliability concerns with Sierra Club's Clean Energy For All Plan would likely be eliminated. If there are any remaining concerns, those only exist when Xcel moves the goal posts and forces the plan to operate under conditions that it was not optimized to meet. If we had wanted to design a plan that meets demand in 2037-2045 or under a repeat of the 2019 polar vortex conditions with limited gas availability, we could have designed a plan that optimizes around those conditions. Those needs almost certainly could have been met by extending existing resources like hydropower; adding more new resources like battery storage, demand response, and renewables; or increasing transmission capacity to other parts of MISO.

B. Xcel's discussion of generator performance during cold snap events is misleading.

At pages 41-50 of its Reply Comments, Xcel discusses recent cold snap events, including February's winter storm Uri. This discussion understates the contributions of renewable resources and overstates the reliability of gas generators.

First, on pages 43-44, Xcel claims that during February's event wind speeds in its service territory were "70-85 percent below normal levels." However, Xcel's map on page 44 shows that wind speeds were only 15-30% below normal. When pressed on this error in SC Information Request 213, Xcel acknowledged that "[t]he statement on page 43 should read: "Figure 2-4 below shows that the average wind speeds during this timeframe were about 70 to 85 percent of normal levels."

Moreover, the chart on page 44 shows that at Xcel's 150 MW Border Winds Project, wind speeds were actually 105-115% of normal during Uri. This confirms a primary point made in our Initial Comments and reinforced below – accessing geographically diverse renewable resources across the footprint of Xcel, neighboring MISO utilities, and even neighboring RTOs will become increasingly valuable at higher renewable penetrations. This is particularly true because extreme weather events that reduce wind output, such as by exceeding their minimum operating temperature as occurred for some wind plants during the 2019 polar vortex event or causing icing of blades as occurred during the 2021 event, tend to have a limited geographic scope. Wind speeds are usually quite high as cold air moves in during events related to a breakdown of the polar vortex, and cold air has higher density which boosts wind turbine output, so wind output is likely to be high somewhere in the region. For example, during the 2019 event wind output in western PJM was high, allowing large exports to MISO when its wind output was reduced.[43]

Xcel's analysis of Uri is also misleading as it arbitrarily focuses on wind speeds for the period of February 6-17, 2021; within and outside that time period, wind output was high when MISO and

[43] Michael Goggin, *Transmission makes the power system resilient to extreme weather,* Grad Strategies LLC (July 2021), https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf

Xcel electricity demand was high. For MISO as a whole, the most challenging period was February 14-19, and MISO wind output averaged over 4,800 MW during those days. MISO Zone 1, which includes Xcel's footprint, experienced its highest load on the evening of February 11, when wind output was even higher at 7,390 MW. In response to SC Information Request 214, Xcel acknowledges that "[a]ny analysis of demand levels was not incorporated into this section as the focus was on extreme weather conditions that power system planners must be aware of due to their potential impacts on different types of generation."

Throughout its narrative, Xcel attempts to portray renewables as a primary factor in reliability concerns observed during the February 2021 event in ERCOT and MISO, ignoring that gas generator failures had a many times larger impact. For example, at page 32 Xcel claims that "As discussed in more detail below, the recent electricity blackout events in Texas underscore the need to carefully plan the system to be resilient to extreme weather events. We and other utilities are significantly increasing the amount of renewable generation on our systems, and as a result, increasing the risks associated with lack of continuity of energy supply. To mitigate those risks, our renewable additions must be measured and supported by sufficient firm, dispatchable resources." At page 123 of its Reply Comments, Xcel similarly claims that "Firm dispatchable generation serves an important role for reliability, including both system stability and blackstart, and its ability to support capacity and energy needs when variable renewables are not available. This is particularly true when such resources are not available at their normally expected output (such as the polar vortex of 2019 or the cold weather event our region experienced earlier this year)."

When pressed in response to SC Information Request 212, Xcel acknowledges that "natural gas, which contributes the highest amount of capacity in ERCOT, also experienced the highest net generator outages of any fuel type during the week of February 14-19. In the report, ERCOT indicated that the main causes of the natural gas generator outages were weather-related equipment issues (i.e. frozen or flooded lines or valves), non-weather-related equipment issues (i.e. trips and derates related to control system failures, excessive turbine vibrations, etc.), fuel limitations, and existing ongoing or planned outages." The generation failures in MISO during the February 2021 event, which led to the shedding of firm customer load in MISO South, were also mostly gas generators taken offline by equipment failures or fuel supply disruptions.[44] This is confirmed by the preliminary results of the FERC-NERC investigation into the event, which found that gas generators accounted for 55% of the total capacity of outages across ERCOT, SPP, and MISO, while wind accounted for 22% and solar 1%.[45] Contributing to the failures of gas generators in that

[44] *The February Arctic Event,* MISO (Feb. 2021), https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf
[45] *February 2021 cold weather grid operations: Preliminary findings and recommendations,* North American Electric Reliability Corporation (Feb. 2021), https://www.ferc.gov/february-2021-cold-weather-grid-operations-preliminary-findings-and-recommendations p. 5.

region, as well as supply disruptions on gas pipelines serving other regions, Texas, Louisiana, and Oklahoma saw their natural gas production drop by more than half throughout most of that week.[46]

February's event also highlights the risk to Minnesota ratepayers from their heavy dependence on gas supplies that are delivered from Texas and Oklahoma. During February's cold snap, the operator of the pipeline that delivers gas from Texas to Minnesota declared a force majeure event, though in response to SC 193 Xcel denies that its generators were affected by that event. In response to SC 194, Xcel notes that "Northern Natural Gas declared six force majeure events since July 2019 including the one referenced in SC IR No.193(b). All of these events occurred in the southern half of Northern's system (the Field Area), which does not serve Xcel Energy's MISO power plants." This response is at best misleading, as outages of the pipelines and supply fields that are the source of the gas delivered to Minnesota can obviously curtail deliveries to the state. In response to SC Information Request 211, Xcel unconvincingly argues this risk is acceptable because such events are "generally rare."[47]

Xcel seems to confirm that natural gas supplies to its generators were not economic or available during at least some of February's event, as these generators instead resorted to burning expensive diesel—per page 49 of Xcel's Reply Comments: "Indeed, during Winter Storm Uri, all of our units that had dual fuel capability utilized diesel fuel during the storm." While dual fuel capability provides some resilience, if oil deliveries are disrupted or depleted by extended winter weather events like the New England Bomb Cyclone in 2018, onsite fuel supplies can also run low.[48]

Xcel also touts the capability of its proposed CTs to potentially run on a blend of hydrogen and natural gas. However, there are substantial uncertainties and unproven technologies in each of the steps of producing, transporting, storing, and using renewable hydrogen. Less than 0.1% of global hydrogen production today is via electrolysis.[49] As a result, electrolyzers are an immature technology, particularly the large-scale electrolyzers that would be required for renewable electrolysis for electricity generation. Most current electrolyzer designs also rely on significant usage of precious metals for efficiency and longevity, which may also prevent cost-effective global adoption of electrolysis.

Because most hydrogen is produced on demand today by reforming natural gas, large-scale hydrogen storage technology is also immature. Long-term high-capacity hydrogen storage will likely be required for Xcel to ensure hydrogen is available for the time periods in which Xcel intends to use it. Hydrogen's low density requires storage tanks that are very large or operate at very high

[46] *Ibid.*, at p. 4.
[47] "While constraints on gas availability can occur, supply disruptions or equipment failures are generally rare and do not significantly impact reliability and resource adequacy."
[48] Andrew Coffman Smith, *ISO New England warns that recent cold snap foreshadows future winter troubles,* S&P Global (April 30, 2018), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/iso-new-england-warns-that-recent-cold-snap-foreshadows-future-winter-troubles-44388316.
[49] *The future of hydrogen,* IEA (June 2019), https://www.iea.org/reports/the-future-of-hydrogen.

pressure. In addition, storage challenges are complicated by hydrogen embrittlement of metals and permeation of polymers that could be used for the tanks.[50] Hydrogen compression is very energy intensive due to hydrogen's low density. In addition, due to its small molecular size, there are large hydrogen losses throughout the production, transportation, and storage steps, which poses both cost and potentially safety risks that must be addressed due to hydrogen's flammability. Hydrogen can be liquified and stored, though this adds further costs for equipment, energy inputs, and losses due to boil-off. Under any production, transport, storage, and generation pathway, and even with substantial technology improvement, the round-trip efficiency of hydrogen generation will be very low, further increasing costs. For example, electrolyzers are only 70-90% efficient, compression or liquefaction consumes 5-35% of the energy in hydrogen, and combustion turbines are at maximum only 35% efficient, so those three steps alone typically result in an efficiency well below 20%, without even factoring in significant leakage of hydrogen during all process steps.

The capacity factor for equipment used in renewable hydrogen production, transport, and storage would also be low because hydrogen would primarily be produced when there is excess renewable output, which is likely to be a relatively small percentage of the time. Said another way, the vast majority of the time, expensive hydrogen production and transport equipment will sit idle because renewable output is being used to meet load and not produce hydrogen. This further increases the cost of each of these capital-intensive process steps. Due to chemical properties like metal embrittlement, hydrogen cannot be used in existing natural gas infrastructure and thus will need dedicated storage and transport infrastructure.[51] As a result, dedicated equipment will be required for hydrogen transport and storage, further limiting the utilization factor of this equipment, increasing its cost, and posing the risk of stranded assets if renewable hydrogen proves not to be economically viable.

Returning to the topic of recent cold weather events, despite the widespread failures of gas generators during those events and the fact that all thermal generators face significant output derates at high ambient temperatures,[52] Xcel insists that gas CTs are available "during the hottest and coldest days of the year, even when renewable generation is limited or non-existent."[53] At page 44, Xcel similarly argues that "Nuclear plants are built to withstand extreme weather, as proven during hurricanes and freezing temperatures,"[54] despite the fact that ERCOT nuclear plants experienced outages during both the February cold snap event and another shortage event during extreme heat this summer, and the fact that NRC rules require nuclear plants to shut down during hurricanes.

[50] Ahmed Elberry et al., *Large-scale compressed hydrogen storage as part of renewable electricty storage systems* (April 26, 2021), https://www.sciencedirect.com/science/article/pii/S0360319921005838.
[51] M. W. Melaina, O. Antonia, & M. Penev, *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.
[52] Sinnott Murphy, Fallaw Sowell & Jay Apt, *A time-dependent model of generator failures and recoveries captures correlated events and quantifies temperature dependence,* Applied Energy (Nov. 1, 2019), https://www.sciencedirect.com/science/article/pii/S0306261919311870
[53] Xcel Initial Comments, p. 72, 91-93.
[54] *Id.,* at p. 44.

A more reasonable interpretation of the lesson of recent events is that all resources are subject to outages during extreme weather events. As noted above, extreme weather events tend to be at their most severe across only limited geographic areas, making large regional power systems with large ties to neighboring RTOs, like MISO, an essential part of the solution. Just as large geographic areas cancel out the effect of extreme weather, they also balance out location fluctuations in wind or solar output, ensuring a higher capacity value for those resources. As discussed extensively in our Initial Comments,[55] this makes it even more critical for Xcel to look regionally, rather than solely within its power system, when assessing resource adequacy needs and solutions. Xcel focusing solely on its own resources, as it does in the chart showing the performance of its wind and solar fleet during the 2019 polar vortex on page 41 and in most of the reliability metrics it presents on pages 124-138, greatly overstates the need for capacity. This is especially true for cold weather events – which Xcel notes have accounted for five of MISO's last six challenging events[56] – because transmission lines have significantly higher capacity during winter peak than summer peak due to lower ambient temperatures,[57] allowing Xcel to import far more energy than it can during summer peak. In response to SC Information Request 235, Xcel admits that its assumed "2,300 MW technical [import] limit is modeled as an annual rating with no variation by season." Xcel should also plan for regional and inter-regional transmission expansion as a key solution to cost-effectively transitioning to renewable resources and also mitigating the effect of extreme weather.[58] Looking regionally not only reduces Xcel's need for capacity, but also keeps the capacity value of Xcel's wind, solar, and storage resources high.

C. The capacity value of wind, solar, and storage is high and will likely increase in MISO.

In its Reply Comments, Xcel expresses concern that battery resources will experience a decline in capacity value at higher penetrations.[59] Similarly, Xcel assumes that solar resources experience a linear decline in capacity value from 50% in 2023 to 30% in 2033. As explained in our Initial Comments at pages 64-67, the complementarity among wind, solar, and storage resources, and particularly between solar and storage, should ensure the capacity value of each of those resources remains high at higher penetrations.

The recent development of MISO's planned move to seasonal resource adequacy should increase the winter accreditation for wind and summer accreditation for solar, with MISO estimating a 20%

[55] Sierra Club Reply Comments, p. 42.
[56] Xcel Reply Comments, p. 32.
[57] Dillion Kolkmann, *Managing transmission line ratings,* FERC (Aug. 2019), https://www.ferc.gov/sites/default/files/2020-05/tran-line-ratings.pdf
[58] Michael Goggin, *Transmission makes the power system resilient to extreme weather,* Grad Strategies LLC (July 2021), https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf
[59] Xcel's Reply Comments, p. 96, FN 12; Xcel's Response to SC Information Request 222.

winter capacity credit for wind.[60] MISO's current plan, to conduct seasonal ELCC analysis for wind, and accredit solar based on its capacity factor "during hours 15, 16 and 17 EST for the relevant spring, summer, and fall months. Winter accreditation will be based on hours 8, 9, 19 and 20 EST for the winter months,"[61] should guarantee a high capacity value for both resources.

MISO's move to a seasonal resource adequacy construct also undermines Xcel's argument that it needs surplus capacity on its own system to protect against seasonal shortfalls under MISO's current annual resource adequacy approach. At page 85, Xcel argues that "[i]n the absence of a seasonal resource adequacy construct, being able to meet the majority of the Company's winter load with dispatchable resources on our system is a critically important risk and reliability consideration." At page 129 Xcel explains, "Further, we prioritize plans that maintain sufficient baseload, intermediate, and firm peaking capacity equal to a reasonably large share of winter customer load, in part because MISO has not yet introduced a seasonal RA construct that accounts for different resources' RA capabilities in winter."

Finally, Xcel continues to overlook the value of batteries for meeting peak demand and mitigating price risk associated with market sales and purchases. At page 46 of its Reply Comments, Xcel touts how firm dispatchable resources, which in its view do not include battery storage, "provide the Company with a measure of insurance to address peak load and operate reliably in rapidly-fluctuating power market conditions. If a spike in prices suddenly occurs, we can quickly ramp-up the firm dispatchable resources to minimize costs for our customers." However, batteries are better suited for providing this service than gas-combustion turbines, as batteries can both discharge when market prices are high and charge when market prices are low, while gas CTs can only do the former. Xcel also claims CTs offer "near-instant availability, making them the ideal suppliers of peak power and the best backups for intermittent wind and solar generation. They can also be turned on and used for short periods of time to meet temporary increases in demand." Only when pressed in SC Information Request 217 does Xcel acknowledge, "[b]atteries are faster in response to grid support needs than combustion turbines."

At pages 46-47 of its Reply Comments, Xcel argues that battery storage lacks sufficient duration for some peak demand periods, pointing to January 30-31, 2019, during the polar vortex event. However, a closer examination of the chart on page 47 shows that battery storage would offer a high capacity value, while also raising questions about Xcel's need for additional gas combustion turbines. While Xcel claims its existing CTs were needed for 45 consecutive hours, in response to SC Information Request 219 Xcel admits that the CTs only operated above a 20% capacity factor for 25 consecutive hours. Moreover, within that 25-hour time period, Xcel's chart shows two single hour

[60] MISO, *RAN Reliability Requirements and Sub-annual Construct*, RASC meeting Feb. 3, 2021, (Updated Feb. 25, 2021), https://cdn.misoenergy.org/20210203%20RASC%20Item%2004a%20Subannual%20Construct%20Presentation%20(RASC010,%20011,%20012)517859.pdf, at 22

[61] *Resource adequacy reforms, conceptual design,* MISO (Aug. 16, 2021), https://cdn.misoenergy.org/20210901%20RASC%20Item%2003%20Seasonal%20RA%20Conceptual%20Design585538.pdf, at p. 16-17.

events in which CTs were dispatched above 35% capacity factor; battery storage resources clearly have sufficient duration to displace the need for CT capacity to meet those spikes. Moreover, Xcel's chart on page 41 shows that Xcel solar output was high on January 30, 2019, while both wind and solar output were relatively high on January 31, 2019. This indicates that higher penetrations of wind and solar could complement limited duration resources like battery storage and demand response, as well as imports, in meeting load during such a period. More fundamentally, the fact that Xcel's gas combustion turbines peaked at a 42% capacity factor during the event, **[TRADE SECRET DATA BEGINS . . .TRADE SECRET DATA ENDS]** raises questions about Xcel's need for additional CT capacity. Given that those resources were operating at around half of their installed capacity during what Xcel describes as "a critical time period,"[62] it appears Xcel has sufficient capacity resources even with planned retirements.

Xcel makes other questionable claims about the limits of battery resources, claiming that their performance is not well understood in cold climates before acknowledging that HVAC and thermal management systems can address those concerns.[63] This also overlooks the fact that charging and discharging batteries, as would occur leading into and during a peak demand period, generates significant heat that allows batteries to operate efficiently. At page 49, Xcel claims that "in a catastrophic scenario where we were unable to secure sufficient capacity in the Planning Reserve Auction for a given year, our customers, and potentially other MISO regions, could face reliability and price spikes similar to that Texas experienced this past year – as it would be unlikely we could build new generation within a single-year period." However, real-world battery installations have been completed within a few months of being awarded a contract,[64] despite Xcel's claim of a longer lead-time for battery deployment in response to SC Information Request 221.

IV. Reliability: Xcel did not evaluate whether renewable, storage, and existing resources can meet the need for other reliability services better than new gas generators.

Xcel attempts to justify new gas plant investments based on the need to provide reactive power and voltage support, short circuit contribution, stability, **[TRADE SECRET DATA BEGINS . . . TRADE SECRET DATA ENDS]** However, Xcel did not provide sufficient details of the need or evaluation of alternatives to demonstrate that new gas capacity is needed to provide these services. Batteries in particular are able to provide these services while providing other benefits that gas plants cannot, like charging to reduce renewable curtailment and increase the utilization factor of transmission lines. Despite these known benefits, Xcel admits that it did not evaluate the use of batteries to provide these services.[65] First and foremost, the Commission should address these highly

[62] Xcel's Reply Comments, p. 46.
[63] *Id.* at p. 48.
[64] David Roberts, *Elon Musk bet that Tesla could build the world's biggest battery in 100 days. He won.,* Vox (Dec. 20, 2017), https://www.vox.com/energy-and-environment/2017/11/28/16709036/elon-musk-biggest-battery-100-days
[65] See Xcel's Response to SC Information Request 202.

technical issues, and the range of potential solutions using new and existing resources, in another docket. Since the proposed new CTs are not scheduled to come online until 2027 and 2029, the Commission has plenty of time to consider these issues in a separate docket. Without such an analysis, it is premature for Xcel to justify the inclusion of almost 800 MW of new gas CTs, **[TRADE SECRET DATA BEGINS . . . TRADE SECRET DATA ENDS]** in the IRP for the stated reason of providing those services.

[TRADE SECRET DATA BEGINS . . . TRADE SECRET DATA ENDS] Xcel's own projections show that there is not a significant capacity need until 2027 (the projected 1 MW shortfall in 2026 should not be considered significant), or 2030 if existing hydropower contracts are extended.[66] Both are outside of the 5-year action plan window. If one accounts for Xcel's history of overestimating load growth, as explained by the DOC,[67] the capacity need could be even further in the future.

[TRADE SECRET DATA BEGINS . . . TRADE SECRET DATA ENDS][68] As a result, there is plenty of time to assess the need and determine optimal solutions for providing these services.

A. Battery and renewable resources can provide blackstart and other reliability services.

Despite Xcel's claims to the contrary, commercially available batteries have a proven ability to provide blackstart, in addition to voltage support, stability, short-circuit current contribution to counteract weak grid issues, and other reliability services. At page 61 of its Reply Comments, Xcel states that using battery energy storage for blackstart "is not practicable today," and pushes back against an example we provided in our earlier comments of a battery providing blackstart by claiming that was only done once as part of a test. However, we have since become aware of numerous other examples of batteries providing this and other reliability services on a regular basis.

The Dalrymple Substation Battery project in South Australia started commercial operation in December 2018 and has demonstrated that grid-forming batteries can provide short-circuit current contribution, fast frequency response, blackstart, and islanded operation.[69] Another battery in South Australia, the 150 MW Hornsdale Power reserve, has provided fast frequency response to stabilize the grid within seconds of major real-world grid disturbances.[70] Batteries have been used to provide

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[66] Xcel Reply Comments, p. 91.
[67] *See* DOC's Initial Comments, p. 5.
[68] Xcel Reply Comments, p. 66.
[69] *A 30MW Grid Forming BESS Boosting Reliability in South Australia and Providing Market Services on the National Electricity Market*, in Proc. 18th Int'l Wind Integration Workshop (Oct. 2019), https://www.electranet.com.au/wp-content/uploads/2021/01/Wind-Interation-Workshop-30MW-BESS-October-2019.pdf.
[70] Giles Parkinson, *"Virtual machine": Hornsdale battery steps in to protect grid after Callide explosion,* Renew Economy (May 27, 2021), https://reneweconomy-com-au.cdn.ampproject.org/c/s/reneweconomy.com.au/virtual-machine-hornsdale-battery-steps-in-to-protect-grid-after-callide-explosion/amp/.

blackstart service in multiple islanded microgrids around the world.[71] Here in the U.S., a recently announced 185 MW battery project in Hawaii will fully replace the grid services currently provided by a nearby coal plant by providing blackstart, fast frequency response, and grid-forming services.[72] Renewable plants can also be designed to provide blackstart and other services. In Great Britain, controls of an existing 69 MW wind farm were modified to grid-forming, and the wind farm then successfully provided fast frequency response, blackstart, and islanded operation capability.[73]

Xcel's primary argument against the use of batteries for blackstart is that, due to their limited energy duration, the battery capacity must be dedicated to providing blackstart and cannot provide other grid services.[74] However, in response to Sierra Club's Information Request 220, Xcel admits that "[d]uring normal operation of lithium ion batteries, the battery charge state would be between 30-70 percent of the battery capacity." Thus, under normal operations the battery would always have at least 30 percent of its capacity available, and likely much more, to provide blackstart if the grid unexpectedly collapsed. Moreover, as the system is restored, batteries providing blackstart service can be recharged as they help balance generation from nearby resources, including wind and solar plants. For example, the Dalrymple Substation Battery project discussed above is rated at 30 MW but only 8 MWh, meaning that it only has about 15 minutes of energy storage duration when discharging at full output, 1/16th the duration provided by typical 4-hour batteries. However, this battery is still adequate to provide blackstart and islanded operation because it operates in a generation and load pocket with a large wind project and a large amount of distributed solar.[75]

Xcel also argues that long energy duration is needed because "if the system becomes unstable and goes back down after the initial start, the battery must be prepared to again blackstart and support other generating units repeatedly until the system stabilizes."[76] Xcel correctly explains that during restoration "We must balance the load and generation carefully because, without sufficient load, damage to our or customer equipment can occur from an overload of reactive power; if we energize lines and restore load too quickly, we can trip relays and will have to begin the process again."[77] However, this ignores that restoration with batteries is less likely to fail, given that batteries are superior to conventional generators in their ability to quickly balance fluctuations in electricity

[71] Oliver Schömann, *Experiences with large grid-forming inverters on various island and Microgrid projects,* SMA (May 2019), https://hybridpowersystems.org/wp-content/uploads/sites/13/2019/06/3A_3_HYB19_017_presentation_Schoemann_Oliver_web.pdf
[72] Julian Spector, *Hawaii building huge new battery, bidding farewell to coal,* Canary Media (Aug. 18, 2021), https://www.canarymedia.com/articles/hawaii-building-huge-new-battery-bidding-farewell-to-coal/.
[73] A. Roscoe, et. al., *Practical experience of providing enhanced grid forming services from an onshore wind park*, in Proc. 19th Wind Integr. Workshop, Nov. 2020, https://knowledge.rtds.com/hc/en-us/article_attachments/1500001877941/Practical_Experience_of_Operating_a_Grid_Forming_Wind_Park_and_its_Response_to_System_Events.pdf.
[74] See Xcel Reply Comments, p. 47, 61.
[75] S, Cherevatskiy et al., *Gird forming energy storage addresses challenges of grids with high penetration of renewables (a case study),* Cigre (2020), https://www.electranet.com.au/wp-content/uploads/2021/02/CIGRE48-Grid-Forming-BESS-Case-Study-August-2020.pdf
[76] Xcel Reply Comments, p. 47.
[77] *Id.* at p. 62.

supply and demand, and are immune to the mechanical stresses that can cause conventional generators to trip offline while attempting to balance these fluctuations. Batteries can ramp up their output many times faster and more accurately than conventional generators, and once other generation is online batteries also have the unique ability to charge if supply exceeds demand. **[TRADE SECRET DATA BEGINS . . . TRADE SECRET DATA ENDS]**

Xcel also points to "technical concerns with regard to how batteries can absorb reactive power,"[78] and states that wind and solar have a "general inability to provide or absorb reactive power."[79] However, FERC now requires new wind, solar, and battery resources to match the reactive power capabilities of conventional generators,[80] and batteries' fast and flexible power electronics allow them to provide or absorb reactive power as needed.[81]

B. Blackstart

The Commission should thoroughly evaluate whether the claimed benefits of Xcel's proposed zonal restoration approach merit its significant cost. **[TRADE SECRET DATA BEGINS . . . TRADE SECRET DATA ENDS]** it is clear that building redundant initial and target units in each restoration zone will require a significant investment.

The benefits Xcel claims from a zonal approach are dubious at best. Xcel discusses the potential for somewhat faster restoration of customer power under the zonal approach.[82] However, it is important to keep the value of this benefit in perspective, given that it is unlikely blackstart restoration will be required during our lifetime. As Xcel notes in response to SC 224, "blackstart restoration has not been required within Minnesota." Even in past large-scale blackouts, like the 2003 and 1965 outages that affected multiple states in the Northeast, power was mostly restored not from blackstart units but by connecting load and generation to other parts of the Eastern Interconnect that were unaffected. This is not to minimize the importance of blackstart units, but rather to explain that because of the extremely low chance of them being needed, the speed of restoration should be given much lower weight than the absolute certainty of the high cost of building and maintaining redundant blackstart resources in each of many zones.

[TRADE SECRET DATA BEGINS . . . TRADE SECRET DATA ENDS]

There are also serious questions regarding the need for specific investments Xcel proposes for new blackstart resources. At page 65, Xcel discloses that **[TRADE SECRET DATA BEGINS . . . TRADE SECRET DATA ENDS]** As Xcel notes when discussing ERCOT's experience during the February 2021 cold snap at page 54 of its Reply Comments, "[t]he blackstart resources… were

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[78] Xcel Reply Comments, p. 61.
[79] *Id.* at p. 59.
[80] Reactive Power Requirements for Non-Synchronous Generation, Docket No. RM16-1-000, https://www.ferc.gov/sites/default/files/2020-06/RM16-1-000.pdf.
[81] Gabriel Haines, *Power factor control with a battery energy storage system (BESS), (*April 13, 2018), https://www.adelaide.edu.au/energy-storage/docs/aeskb-case-study-2-power-factor-control-with-a-bess.PDF.
[82] Xcel Reply Comments, p. 71-72.

not working properly. When the storm hit, nine of the thirteen primary generators designed to get a downed system going again were, at times, out of commission, according to grid operators. And six of fifteen secondary generators—what the article describes as "the fail-safe for the fail-safe"— had periodic trouble as well, including freeze damage and problems getting fuel." **[TRADE SECRET DATA BEGINS . . . TRADE SECRET DATA ENDS]**

C. Storage and renewables can provide the reliability services Xcel proposes to provide from the 374 MW Lyon County CT.

As discussed above, Xcel attempts to justify gas capacity additions based on the claim that they are needed to provide reliability services, even though wind, solar, and battery storage can provide those same services. This includes claiming that 374 MW of CT capacity is needed in Lyon County at the end of the proposed Sherco gen-tie to provide reactive power support. In response to SC Information Request 201, Xcel argues that "[w]ithout the additional reactive support located at Lyon County the amount of generation that can be delivered on that line is reduced."

This argument is highly misleading. Xcel's response to Information Request XLI-159, which provides the stability assessment Xcel conducted for the Sherco gen-tie, reveals that **[TRADE SECRET DATA BEGINS . . . TRADE SECRET DATA ENDS]** The 2,000 MW limit is the binding relevant factor, as Xcel explained at page 19 in its Reply Comments: "The 2,000 MW interconnection rights do set a ceiling on the amount of instantaneous energy injection; meaning that if the model chose 2,000 MW of wind and 1,500 MW of solar for the Sherco gen-tie tranche, those resources combined could only inject 2,000 MW of energy into the grid at any given time and any excess production would need to be curtailed."

Even if one assumes that Southern Minnesota Municipal Power Agency also intends to re-use its 400 MW of interconnection rights at the Sherco site,[83] and can negotiate arrangements with Xcel for the use of capacity on the proposed gen-tie, there does not appear to be significant value in adding the Lyon County CT to increase the transfer capacity on the gen-tie. Those 400 MW of interconnection rights combined with Xcel's 2,000 MW of interconnection rights would equal a 2,400 MW injection limit at the Sherco site. **[TRADE SECRET DATA BEGINS . . . TRADE SECRET DATA ENDS]**

If needed, a number of low-cost solutions could be implemented to further increase the stable power transfer limit on the Sherco gen-tie. If weak grid stability issues are the limiting factor, the controls of wind and solar plants can be tuned to ensure stable operation of the line at a higher transfer limit.[84] Similarly, the reactive power capabilities of one or more wind or solar plants can be enhanced with a number of potential solutions, including using larger generator step-up transformers to allow additional reactive power injection from the renewable plant, using a lower

[83] Xcel Reply Comments, at p. 52.

[84] *Integrating inverter-based resources into low short circuit strength systems,* North American Electric Reliability Corporation (Dec. 2017), https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Item_4a._Integrating%20_Inverter-Based_Resources_into_Low_Short_Circuit_Strength_Systems_-_2017-11-08-FINAL.pdf, at 19-21.

impedance tie-line between the generator step-up transformer and the point-of-interconnection to improve reactive power delivery, or the installation of additional reactive power devices near the plant's point of interconnection to the Sherco line.

With some deployment of battery storage, grid-forming converters at renewable or storage plants, additional reactive power capability or better control tuning at one or more renewable plants interconnecting to the line, **[TRADE SECRET DATA BEGINS . . . TRADE SECRET DATA ENDS]**

In response to SC Information Request 206, Xcel admits that it did not evaluate the potential use of battery storage to absorb curtailed renewable energy or provide reactive power service on the Sherco gen-tie: "While we are open to it, the Company has not yet evaluated the potential for adding battery energy storage resources on the gen-ties specifically. As we noted in our Reply Comments, the coal interconnection reutilization plan we presented here is in early stages and we expect that we will evaluate opportunities for storage to be added to the gen-ties or elsewhere on our system, as we continue to transition to a cleaner resource mix." In response to SC Information Request 202, Xcel further confirms that "the Company did not conduct a quantitative evaluation of whether batteries could perform the same technical capabilities as the CT proposed for the Sherco gen-tie." Because batteries can absorb renewable energy that would have been curtailed due to the 2,000 MW interconnection rights limit, unlike the proposed Lyon County CT they would be effective at increasing the amount of wind and solar energy that can be interconnected and delivered via the Sherco gen-tie. Recent analysis has shown that locating storage along transmission lines used to deliver renewable energy to load is highly beneficial, as it reduces renewable curtailment and increases the utilization factor of the line.[85]

At page 109 of its Reply Comments, Xcel indicates that it did not even allow its economic optimization to build storage on either the Sherco or King gen-ties, limiting the King line to solar and the Sherco line to solar, wind, and 374 MW of CTs. It is not surprising that the model selected a 374 MW CT when Xcel did not provide it with the option of selecting competing technologies. Xcel should evaluate the benefits of deploying batteries on the new gen-ties and elsewhere on its system, including existing transmission lines that are experiencing congestion and renewable curtailment.

[85] Christopher Clack et al., *Consumer, employment, and environmental benefits of electricity transmission expansion in the eastern U.S.,* Americans for a Clean Energy Grid (Oct. 2020), https://cleanenergygrid.org/wp-content/uploads/2020/11/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S.pdf, at p. 23-24.

As noted above, FERC now requires new wind, solar, and battery resources to match the reactive power capabilities of conventional generators.[86] Batteries,[87] wind,[88] and solar[89] plants are all operated with fast and flexible power electronics allow them to provide or absorb reactive power as needed. These power electronics can even use grid power to provide voltage and reactive power support when the plant is not producing power, such as solar plants providing reactive power at night.[90]

The amount of battery capacity that can be added to the Sherco gen-tie using existing interconnection rights is very large. At page 151 of its Reply Comments, Xcel itself notes that "it may be possible to add more capacity interconnecting at the site in the future beyond what was modeled here – potentially in the form of storage – particularly if that capacity further supports renewable integration. We include an example calculation below, based on the resources added in the Alternate Plan by 2034." Xcel finds up to 575 MW of additional accredited capacity can be added to Sherco gen-tie before reaching the 2,000 MW interconnection rights limit; however, that analysis is unduly conservative as it includes the 374 MW CT that was hardwired into the modeling. Without the CT, Xcel could add nearly 1,000 MW of battery capacity to the line, or a combination of additional wind, solar, and storage to take advantage of storage's ability to absorb renewable energy that would have been curtailed.

At page 51 of its Reply Comments, Xcel notes that it evaluated series compensation, synchronous condensers, STATCOMs, and switched capacitor banks as potential voltage solutions for the Sherco gen-tie. Batteries are notably missing from that list, even though Xcel's economic optimization called for the addition of 250 MW of storage around the time it proposes energizing the Sherco gen-tie. Xcel did not evaluate where that battery resource should be located; if it had, Xcel may have found the battery could displace the need for the Lyon County CT. In addition, by failing to account for the benefits of strategically locating battery storage where it can reduce renewable curtailment or provide other reliability services, Xcel's economic modeling underestimated both the economically optimal amount of storage and also the amount of renewable capacity that can be interconnected.

Batteries can provide other grid reliability services, like fast frequency response that can improve the stability of the Sherco gen-tie and the overall grid. If Xcel determines that additional system strength in the form of short circuit current contribution is needed on the Sherco gen-tie, it could deploy a

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[86] Reactive Power Requirements for Non-Synchronous Generation, Docket No. RM16-1-000; Order No. 827, https://www.ferc.gov/sites/default/files/2020-06/RM16-1-000.pdf.

[87] *See* Gabriel Haines, *Power factor control with a battery energy storage system (BESS), (*April 13, 2018), https://www.adelaide.edu.au/energy-storage/docs/aeskb-case-study-2-power-factor-control-with-a-bess.PDF.

[88] *See* Eduard Muljadi, Yongcheol Kang & Jinho Kim, *Advanced voltage controls for a wind power plant,* IEE (July 2016) https://www.nrel.gov/docs/fy16osti/66795.pdf at 17.

[89] *See* Clyde Loutan et al., *Demonstration of essential reliability services by a 300-MW solar photovoltaic power plant,* National Renewable Energy Laboratory (March 2017), https://www.nrel.gov/docs/fy17osti/67799.pdf at p. 41-42.

[90] Alice Grundy, *Lightsource BP delivers night time reactive power using solar in 'UK first',* Solar Power Portal (Nov. 25, 2019), https://www.solarpowerportal.co.uk/news/lightsource_bp_delivers_night_time_reactive_power_using_solar_in_uk_first.

battery or renewable resources with grid-forming converters that can provide that service as well. As documented above, batteries are increasingly being deployed on power systems around the world to provide voltage and reactive power control, frequency regulation, spinning reserves, and fast frequency response; if needed, grid-forming batteries can additionally provide blackstart and short circuit current contribution.

V. RELIABILITY: Xcel should explore other transmission solutions, in addition to the proposed lines interconnecting at Sherco and King.

While Xcel deserves credit for its creative re-use of interconnection rights at Sherco and King, and the proposed lines interconnecting at those sites should move forward as a critical tool for cost-effectively integrating new renewable resources, Xcel should also explore other creative solutions for interconnecting more renewable resources. As discussed in Sierra Club's Initial Comments, in addition to moving forward with new transmission on its own or through MISO's regional transmission planning process, Xcel can take a number of near-term steps to increase renewable interconnection using existing transmission rights-of-way. We explained that Xcel should aggressively pursue double-circuiting of single-circuit lines, adding HVDC circuits on existing right-of-way, using grid-enhancing technologies like dynamic line ratings (DLR), and making substation upgrades and other investments that increase transfer capacity without requiring new right-of-way.[91] Xcel recently announced the use of DLR at several locations in Minnesota.[92] This effort should be expanded, particularly once it is confirmed that those early installations provide significant benefits. DLR and similar grid-enhancing technologies offer larger benefits when they are deployed across the system rather than on a small number of lines or segments, as the capacity along a transmission path is limited by the most constraining line or segment on that path.

The Commission and Xcel should also explore how making the Sherco gen-tie into a network transmission line would increase the ability to interconnect renewable resources by removing the 2,000 MW interconnection right limit and addressing voltage and stability concerns. The Sherco gen-tie route appears to cross the 345-kV Brookings line, and its proposed terminus in Lyon County is near other high-voltage transmission lines. Connecting to those lines would help address any voltage and stability concerns on the Sherco line and the other lines, while also increasing the amount of renewable energy that could flow over all of those lines by integrating more diverse resources. More importantly, making the line a network element should remove the 2,000 MW cap on power injections at the Sherco site, which appears to be the real binding cap on the amount of renewable capacity that can be interconnected on the line. The Commission should also ensure that Xcel is not pursuing a gen-tie approach because that requires Xcel to own the first 2,000 MW of capacity,[93]

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[91] Sierra Club Initial Comments, p. 20-21.

[92] Colin Mahoney, *Xcel energy installs LineVision's V3 transmission line monitoring system in Colorado, Minnesota and Wisconsin to increase grid capacity and safety,* Linevision (Feb. 25, 2021), https://www.linevisioninc.com/https-www-prnewswire-com-news-releases-linevisions-v3-transmission-line-monitoring-system-installed-in-colorado-minnesota-and-wisconsin-to-increase-grid-capacity-and-safety-301235609-html/

[93] Xcel Reply Comments, p. 19.

while making the line a network element would open all of the line's capacity to competition under FERC Open Access rules.[94]

Xcel should also evaluate potential wind additions to the King gen-tie[95] as a means of increasing the geographic diversity of Xcel's wind fleet and increasing the line's utilization factor, given that wind's output profile is negatively correlated with solar's profile. At minimum, Xcel should evaluate the benefits of deploying batteries on the new gen-ties and elsewhere on its system, including existing transmission lines that are experiencing congestion and renewable curtailment.

Sierra Club would like to note that Xcel's ability to interconnect over 4,000 MW of new renewable resources at low cost confirms the point made in our Initial Comments that Xcel's assumed interconnection costs for wind and solar are too high. As Xcel itself notes at page 12 of its Reply Comments, "[w]hile the proposed transmission gen-tie lines require significant investment, the total cost is lower, on a per kW basis, than our estimate of the average observed cost to interconnect new renewables through the interconnection queue. In total, the average cost per kW for resources on the Sherco gen-tie line is under $140/kW and on the King line it is approximately $55/kW, as compared to the estimated average MISO queue costs, based on observed queue results, of $500/kW for wind and $200/kW for solar." Notably, the $140/kW cost on the Sherco line is almost perfectly consistent with the $147/kW cost Sierra Club suggested in our initial comments and used in some of our modeling runs.

Despite that fact, in its reply comments Xcel continues to argue against the $147/kW cost assumption Sierra Club used in some of our modeling runs. At page 145 Xcel claims that the Lawrence Berkeley National Laboratory report we cite as secondary support for our cost assumption is out of date. However, that report was published less than two years ago in October 2019,[96] which makes it less out of date than many of the assumptions used in Xcel's IRP. At page 147 Xcel presents more recent cost results from the MISO interconnection queue. Xcel's data show an average interconnection cost of $113/kW for wind and solar projects that made it through the queue in MISO's West zone, lending further support for our $147/kW cost assumption. Xcel points out that some of those projects only requested Energy Resource Interconnection Service and therefore may require further upgrades if they want to receive capacity credit, though because most of those are wind projects with a low capacity accreditation the foregone capacity credit is relatively small.

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[94] Preventing Undue Discrimination and Preference in Transmission Service, Docket Nos. RM05-17-000 and RM05-25-000; Order No. 890, https://www.ferc.gov/sites/default/files/2020-04/E-1_14.pdf.

[95] In response to SC 205, Xcel notes that "we are still open to the possibility of adding wind resources on the line if it makes sense in the future. Our focus at this stage was to evaluate the reuse of all of the interconnection rights we own at King – and ~600 MW of proposed solar accomplishes that goal."

[96] *New national lab study quantifies the cost of transmission for renewable energy,* Berkeley Lab (Oct. 24, 2019), https://emp.lbl.gov/news/new-national-lab-study-quantifies-cost.

Other study results confirm that the $147/kW cost assumption Sierra Club used in some of our modeling runs is reasonable. The Phase 2 results from the April 2018 DPP for the West zone show $746 million in MISO upgrade costs plus $57.5 million in SPP affected system costs.[97] The $804 million of upgrade costs across the 4447 MW of interconnecting projects yields a cost of interconnection of under $180/kW. The 2019 DPP Phase 1 results for MISO West show costs of $695 million for 8,126 MW, for an interconnection cost of only $85/kW.[98] In addition, the 2014 Minnesota Renewable Energy Integration and Transmission Study study found transmission expansion of $2.567 billion would allow the interconnection of 17,245 MW of new wind capacity, which equates to $149 per kW of wind.[99]

At page 8 of its Reply Comments, Xcel echoes the Department of Commerce's February 2021 supplemental comments arguing for an extension of the Monticello nuclear unit due to uncertainty about the cost and feasibility of interconnecting new renewable resources. However, that argument is made obsolete by Xcel's proposal to interconnect over 4,000 MW of renewable resources at low cost using the Sherco and King gen-ties, and the potential for further renewable additions using the strategies we have outlined above, most notably the deployment of storage in locations where it can facilitate renewable interconnection, such as on the gen-ties.

The retirement of the Monticello nuclear plant would likely open up additional interconnection rights that could be re-used for renewable resources. A gen-tie like the Sherco line could be run from the Monticello site to the wind resource area in southwest Minnesota. The retirement of Monticello could also potentially reduce the need for voltage and reactive power support on those gen-ties, as Xcel notes that a constraint in its modeling was to "[e]nsure that voltage is maintained within Nuclear Regulatory Commission requirements at our Monticello Nuclear Plant and develop a plan to address any thermal or voltage violations."[100]

While Xcel should evaluate the transmission options we have highlighted above, the most important action for the Commission to take at this point is to ensure that Xcel does not rush into deploying the 374 MW Lyon County CT that was forced into the Company's modeling and is not needed for nearly a decade. Without more thorough analysis of the claimed need for and alternative sources of

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[97] Yaming Zhu et al., *MISO DPP 2018 April West Area phase 2 study,* MISO (Feb. 16, 2021), https://cdn.misoenergy.org/GI-DPP-2018-APR-West-Phase2_System_Impact_Report _Public523356.pdf;
MISO affected system impact studies, MISO DPP-2018-APR, Southwest Power Pool, Inc. (Feb. 16, 2021),
https://cdn.misoenergy.org/DPP_2018_APR_West-Central_SPP_Phase2_Final_Report_ Public523268.pdf.
[98] Yaming Zhu et al., *MISO DPP 2019 West Area phase 1 study,* MISO (March 2, 2021), https://cdn.misoenergy.org/GI-DPP-2019-West-Phase1_System_Impact_Report_ PUBLIC528746.pdf
[99] *Minnesota Renewable Energy Integration and Transmission Study*, GE Energy Consulting (Oct. 31, 2014), https://mn.gov/commerce-stat/pdfs/mrits-report-2014.pdf, at p. 4-21.
[100] Xcel Reply Comments, p. 37.

reliability services, this CT could become a stranded asset for ratepayers. Relative to battery storage, the CT could also inhibit the Company's transition to a cleaner generation mix, as battery storage can provide comparable reliability services as a CT while also absorbing curtailed renewable generation, something a CT cannot do. At page 52 of its Reply Comments, Xcel itself notes that the proposed "stability investments are intended to be indicative of cost only. Should the Commission approve the Alternate Plan, we would commence further regulatory proceedings related to the line, including specific proposed stability investments." Given that the Lyon County CT is by far the largest of those stability investments, it is premature for that plant to be included in the IRP. As part of the stability investment proceeding and the blackstart docket that Xcel has called for, the Company and the Commission should comprehensively evaluate all reliability services that are needed and evaluate all potential solutions to determine the optimal mix of resources to meet those needs, rather than Xcel's approach of limiting the solution to the single option of building a 374 MW CT.

VI. ENVIRONMENTAL AND SOCIOECONOMIC BENEFITS: Equity Remains a Critical Consideration in this IRP.

As we discussed in our Initial and Reply comments, we believe it is essential that utilities craft their IRPs through a lens of equity and access to the benefits of clean energy. While Xcel has taken the critical first step of discussing equity considerations in its IRP and publicly stating its commitment to racial equity, certain key elements of its proposed Alternate Plan continue to create a barrier to achieving the outcome the utility has expressed it desires. Xcel should live up to its rhetoric by taking four important steps.

First, Xcel's proposal to construct two new gas plants is inconsistent with this commitment because the impacts of climate change will be borne disproportionately by Black, Indigenous, and People of Color (BIPOC) communities in Minnesota.[101] The gas plants would also cost customers an estimated $395 million more than clean energy alternatives and could saddle customers with stranded costs, an economic burden that would most harm our most vulnerable communities.

Second, Xcel's Alternate Plan continues to unreasonably minimize the role that community solar and distributed generation can and should play in its portfolio. 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 keys to Minnesota's sound economic future.

Third, we ask the Commission to order Xcel to commit to ending its contract with the HERC incinerator when it expires in 2024, and to explore ways to exit that contract as soon as possible. The HERC incinerator is a major source of particulate matter 2.5, lead, and mercury air pollution,

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[101] *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.

and directly impacts Minneapolis environmental justice communities. 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.

Finally, additional programs are needed, 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 programs. The Commission should 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 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.

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

Xcel is asking for the Commission to approve now two newly proposed greenfield CTs totaling 748 MWs. This element alone exposes customers to a significant risk; Xcel's plan would lock it into paying for two new carbon-polluting plants through 2067 and 2069, 27 and 29 years past when Governor Walz has stated our electricity must be 100% carbon free. If retired in 2040, these newly proposed CTs would leave stranded costs for costumers.

VIII. Conclusion

For all of the reasons outlined above, Xcel has not demonstrated that its Preferred, Supplement, or Alternate Plan – particularly the Sherco CC or new greenfield CT additions – are 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. Disapprove the need for the Sherco CC in 2027;

3. Disapprove the need for the two newly proposed greenfield CTs in 2027 and 2029 or, alternatively, defer a decision on the CTs to another docket so that it can fully consider all the implications, including cost, reliability, and life-cycle climate change impacts associated with this request, and determine if other solutions can meet the need for reliability services at lower cost;

4. Approve the need for 1,350 MW of utility scale solar and 4,320 MW of new wind beginning in years 2027 and 2026, respectively, as well as an additional 4,070 MW of utility scale solar paired with 1,080 MW of battery storage starting in 2031, and 1,200 MW of standalone battery storage beginning in 2027;

5. 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;

6. 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 in 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;

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

8. 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.

Respectfully submitted,

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IX. Appendix – Renewable and Battery Costs

Table 2: Solar PV Levelized Costs with Interconnection ($/MWh, nominal)

	Xcel	NREL 2021 Solar	Corrected Base Solar	Corrected Base Solar with VCE Tx	Xcel Gentie (no Tx)	NREL 2021 Solar Gentie (no Tx)
2023	$46.52	$47.84	$40.24	$40.24	$33.71	$35.04
2024	$46.62	$47.22	$39.46	$39.46	$33.56	$34.16
2025	$48.51	$48.04	$40.49	$37.95	$35.19	$34.72
2026	$53.97	$51.57	$44.98	$41.90	$40.38	$37.99
2027	$53.99	$50.58	$43.86	$40.72	$40.14	$36.72
2028	$54.01	$49.53	$42.67	$39.47	$39.87	$35.40
2029	$54.00	$48.42	$41.42	$38.16	$39.58	$34.00
2030	$53.98	$47.25	$40.11	$36.78	$39.28	$32.54
2031	$54.60	$47.94	$40.65	$37.26	$39.59	$32.93
2032	$55.21	$48.63	$41.20	$37.74	$39.91	$33.33
2033	$55.83	$49.34	$41.76	$38.23	$40.22	$33.73
2034	$56.45	$50.05	$42.33	$38.72	$40.53	$34.13
2035	$57.07	$50.78	$42.89	$39.22	$40.83	$34.54
2036	$57.70	$51.51	$43.47	$39.72	$41.13	$34.95
2037	$58.32	$52.25	$44.05	$40.22	$41.43	$35.36
2038	$58.96	$53.00	$44.64	$40.73	$41.73	$35.77
2039	$59.59	$53.76	$45.23	$41.25	$42.01	$36.19
2040	$60.23	$54.53	$45.83	$41.77	$42.30	$36.61
2041	$60.94	$55.31	$46.44	$42.29	$42.65	$37.03
2042	$61.66	$56.10	$47.05	$42.82	$43.00	$37.45
2043	$62.38	$56.90	$47.67	$43.36	$43.35	$37.88
2044	$63.10	$57.71	$48.29	$43.89	$43.70	$38.30
2045	$63.83	$58.53	$48.92	$44.44	$44.04	$38.73
2046	$64.57	$59.36	$49.56	$44.98	$44.38	$39.17
2047	$65.31	$60.19	$50.20	$45.53	$44.71	$39.60
2048	$66.05	$61.04	$50.85	$46.09	$45.05	$40.04
2049	$66.80	$61.90	$51.50	$46.65	$45.37	$40.47
2050	$67.55	$62.77	$52.16	$47.21	$45.70	$40.91

Table 3: Wind Levelized Costs with Interconnection ($/MWh, nominal)

	Xcel	NREL 2021 Wind	Corrected Base Wind	Corrected Base Wind with VCE Tx	Xcel Gentie (no Tx)	NREL 2021 Wind Gentie (no Tx)	Corrected Base Wind Gentie (No Tx)
2023	$40.91	$36.72	$27.18		$25.27	$21.07	$19.39
2024	$36.03	$31.70	$22.25		$20.07	$15.74	$14.30
2025	$35.78	$31.29	$21.92	$16.09	$19.50	$15.01	$13.82
2026	$50.28	$45.63	$36.33	$30.38	$33.67	$29.02	$28.06
2027	$50.32	$45.50	$36.26	$30.19	$33.38	$28.56	$27.83
2028	$50.36	$45.36	$36.18	$29.98	$33.09	$28.08	$27.57
2029	$50.41	$45.21	$36.07	$29.75	$32.79	$27.58	$27.29
2030	$50.46	$45.05	$35.95	$29.50	$32.49	$27.08	$26.99
2031	$51.13	$45.68	$36.42	$29.84	$32.80	$27.35	$27.29
2032	$51.81	$46.32	$36.89	$30.19	$33.11	$27.62	$27.58
2033	$52.50	$46.97	$37.37	$30.53	$33.43	$27.90	$27.87
2034	$53.19	$47.63	$37.86	$30.88	$33.74	$28.17	$28.17
2035	$53.89	$48.29	$38.35	$31.23	$34.05	$28.45	$28.47
2036	$54.60	$48.96	$38.84	$31.58	$34.36	$28.72	$28.76
2037	$55.31	$49.64	$39.34	$31.94	$34.67	$29.00	$29.06
2038	$56.03	$50.33	$39.85	$32.29	$34.97	$29.27	$29.36
2039	$56.76	$51.03	$40.35	$32.65	$35.28	$29.54	$29.65
2040	$57.49	$51.73	$40.86	$33.01	$35.58	$29.82	$29.95
2041	$58.23	$52.44	$41.38	$33.36	$35.88	$30.09	$30.25
2042	$58.98	$53.16	$41.90	$33.72	$36.18	$30.37	$30.55
2043	$59.73	$53.89	$42.42	$34.09	$36.48	$30.64	$30.84
2044	$60.49	$54.63	$42.95	$34.45	$36.78	$30.91	$31.14
2045	$61.26	$55.38	$43.49	$34.81	$37.07	$31.18	$31.44
2046	$62.03	$56.13	$44.02	$35.17	$37.36	$31.45	$31.73
2047	$62.81	$56.89	$44.57	$35.54	$37.64	$31.72	$32.03
2048	$63.60	$57.66	$45.11	$35.90	$37.92	$31.99	$32.32
2049	$64.39	$58.44	$45.66	$36.27	$38.20	$32.26	$32.62
2050	$65.19	$59.23	$46.21	$36.63	$38.47	$32.52	$32.91

Table 4: Battery Storage Levelized Costs ($/kW-month, nominal)

	Xcel	NREL 2021	NREL 2021 (solar hybrid w/ ITC)	Corrected Base RE	Corrected Base RE (solar hybrid w/ ITC)
2023	$18.18	$11.85	$9.42	$10.21	$8.21
2024	$17.52	$11.20	$8.91	$9.65	$7.76
2025	$16.84	$10.53	$8.71	$9.07	$7.57
2026	$16.63	$10.35	$9.54	$8.92	$8.25
2027	$16.41	$10.17	$9.37	$8.76	$8.10
2028	$16.19	$9.97	$9.19	$8.59	$7.94
2029	$15.95	$9.76	$8.99	$8.41	$7.77
2030	$15.71	$9.54	$8.79	$8.21	$7.60
2031	$15.83	$9.61	$8.85	$8.27	$7.65
2032	$15.94	$9.67	$8.91	$8.33	$7.71
2033	$16.04	$9.74	$8.97	$8.39	$7.76
2034	$16.15	$9.81	$9.03	$8.45	$7.81
2035	$16.26	$9.87	$9.09	$8.50	$7.86
2036	$16.36	$9.93	$9.15	$8.56	$7.91
2037	$16.46	$10.00	$9.21	$8.61	$7.96
2038	$16.56	$10.06	$9.26	$8.66	$8.01
2039	$16.65	$10.11	$9.32	$8.71	$8.06
2040	$16.74	$10.17	$9.37	$8.76	$8.10
2041	$16.83	$10.23	$9.42	$8.81	$8.15
2042	$16.76	$10.28	$9.47	$8.86	$8.19
2043	$16.66	$10.33	$9.52	$8.90	$8.23
2044	$16.55	$10.38	$9.56	$8.94	$8.27
2045	$16.42	$10.43	$9.61	$8.98	$8.31
2046	$16.26	$10.47	$9.65	$9.02	$8.34
2047	$16.08	$10.52	$9.69	$9.06	$8.38
2048	$15.88	$10.56	$9.73	$9.09	$8.41
2049	$15.65	$10.59	$9.76	$9.13	$8.44
2050	$15.39	$10.63	$9.79	$9.16	$8.47

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