STATE OF MINNESOTA
PUBLIC UTILITIES COMMISSION

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In the Matter of Xcel Energy's 2024-2040 Integrated Resource Plan

PUC Docket No. E002/RP-24-67

INITIAL COMMENTS OF CLEAN ENERGY ORGANIZATIONS

August 9, 2024

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INTRODUCTION

The Clean Energy Organizations ("CEOs") appreciate the opportunity to comment on Xcel Energy's 2024-2040 Upper Midwest Integrated Resource Plan ("2024 IRP"). The CEOs' comments are submitted by the nonprofit organizations Fresh Energy, Clean Grid Alliance, Sierra Club, and the Minnesota Center for Environmental Advocacy. Our comments draw upon expert technical analysis performed by Chelsea Hotaling, David Hill, and Anna Sommer of Energy Futures Group ("EFG"); Tyler Comings of Applied Economics Clinic ("AEC"); and Matthew Richwine, Kelsey Ciemny, Andrew Siler, and Isabela Anselmo of Telos Energy. The findings of our experts are summarized throughout this Initial Comment, and our experts' full reports are included as the following attachments: *Clean Energy Alternatives to Xcel's 2024 Integrated Resource Plan* ("EFG-AEC Report"), Attachment A; *Review of Grid Stability Concerns in the 2024 Xcel IRP* ("Telos Report"), Attachment B; and *Evaluation of Energy Efficiency, Demand Response and Other Demand Side Resources in the 2024 Xcel IRP*, Attachment C.

SUMMARY OF THE ARGUMENT

CEOs have taken a slightly different approach in these comments than in previous IRPs. Instead of offering the Commission a full alternative modeling scenario to that proposed by Xcel, the CEOs present the Commission with four fully developed modeling scenarios to illustrate the trade-offs that come with Xcel's new modeling approach taken in this IRP. Specifically, in this IRP Xcel has chosen to restrict the EnCompass model so it has no access to the energy market when the model is creating an optimized resource plan—and then has also required the model to solve for each hour of the planning period. Put another way, Xcel has directed the model to develop a resource portfolio assuming the Company is an islanded utility that can never access power beyond what it alone can generate. This is a new approach for Xcel that fails to reflect how its system actually functions, and it is not how they operated the EnCompass model in their last IRP ("2019 IRP"). This is also a highly conservative approach to modeling. It results in a capacity expansion plan that maximizes one benefit (resource adequacy, reduced dependence on the regional energy market), but does not adequately balance these against corresponding costs (overbuilding capacity, stranded asset risk, increased emissions, a high cost-premium to ratepayers, and misalignment with state and federal policy).

Of particular note, Xcel's new modeling approach caused the EnCompass model to recommend Xcel build a *significant* amount of new fossil fuel generation, namely more than ***2 GW*** of new gas peaker plants by the end of 2030. A plan that builds thousands of MWs of new gas plants in this timeframe simply does not work for Minnesota. It is incompatible with state and federal climate policy, Xcel's own corporate goal to be carbon-free by 2050, and the changes we need to make to avoid worsening the impacts of climate change. It also creates a serious stranded asset risk and has long-term pollution consequences that harm human health. Additionally, Xcel's modeling approach produces a resource plan that comes at a cost premium of as high as $3.5 billion more dollars by 2050 per CEOs' calculations.

CEOs believe there is a better approach. As such, we have put forth four scenarios that change the level of market access so the Commission can see the trade-offs that arise when this input is changed in the model. In these comments, CEOs show the optimal resource builds created when the model has access to 0%, 25%, 50% and 100% of Xcel's market access assumption[1] and recommend a five-year action plan that strikes a reasonable balance between minimizing market exposure and enhancing reliability for customers, avoiding stranded assets, maintaining affordability and planning in alignment with decarbonization requirements. Specifically, CEOs believe the best plan forward that balances these competing factors includes:

- 3,800-4,800 MW of wind by 2030;
- 400 MW of solar by 2030;
- 800-1,200 MW of energy storage resources by 2030;
- 970 MW of generic dispatchable capacity by 2030, which could be met by extending contracts at existing gas plants or procuring other dispatchable technologies; and
- At least 780 GWh per year of energy conservation.

CEOs recommend the Commission adopt the CEOs' Five-Year Action Plan or at the very least, remove most new gas capacity from Xcel's Preferred Plan, for the reasons discussed in the following comment.

I. The Accelerating Climate Crisis Means Xcel Should Avoid New Long-Term Investments in Carbon-Emitting Technologies as Much as Possible

A. The Scale of Xcel's Proposed Gas Peaker Construction Is Incompatible with the Urgency of the Climate Crisis, Which Has Reached a New Level

Xcel's IRP must be judged against the growing urgency of the climate crisis. CEOs appreciate that Xcel is closing its coal plants by 2030, not planning any gas-fired combined cycle plants, and aiming for significant carbon dioxide ("CO_2") emissions reductions. However, Xcel proposes building several new gas peaker plants, including 2,244 megawatts ("MW") before the end of 2030, which is the equivalent of six or more units, depending on size.[2] Its plan then includes another 1,350 MW of gas peaker plants before 2040, or the equivalent of four or more additional units.[3] This is a dramatic increase over the "approximately, but not more than, 800 MW of generic firm dispatchable resources between 2027 and 2029" that the Commission found a likely need for when approving Xcel's last IRP only two years ago.[4] Such a massive investment in new fossil fuel plants is incompatible with the urgent need to reduce greenhouse gases ("GHGs") as quickly and deeply as feasible.

Climate change is accelerating at a pace never seen before, and we are already feeling and seeing some of the consequences. Average global temperatures in 2023 shattered global records,

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[1] In the 2019 IRP, and in the production cost modeling step in this IRP, Xcel used a 2,300 MW market access limit. CEOs have used that limit throughout our modeling, so the 25%, 50% and 100% market access scenarios refer to 25% of 2,300 MW, etc.

[2] Xcel IRP, chapter 4, p.2. These resources are labelled as "firm peaking" units in Xcel's IRP, however they are modeled as natural-gas fired peaker plants, with the model allowed to select between two unit types, one of 374 MW size and the other of 225 MW. Xcel IRP, Appendix F, p. 36, Table F-23.

[3] Xcel IRP, chapter 4, p. 2.

[4] Minn. Pub. Utils. Comm'n., Order Approving Plan with Modifications and Establishing Requirements for Future Filings, *In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy,* Docket No. E-002/RP-19-368 (Apr. 15, 2022), at 32.

exceeding the previously warmest years by a margin that astonished scientists.[5] It was a year of record-breaking heat waves, droughts and wildfires, as well as extreme storms and flooding, with Antarctic sea ice hitting a record low.[6] And so far, *2024 has been even warmer*, with month after month exceeding previous records and with extreme heat waves affecting more than 60% of the world's population in June.[7] Once again this summer, extensive wildfires are raging in the western states and Canada, forcing thousands to flee and spreading smoke to Minnesota and beyond.[8] The hottest day ever since recordkeeping began (as a global average) took place on July 21, 2024, and that record was then exceeded the next day.[9]

"What is truly staggering is how large the difference is between the temperature of the last 13 months and the previous temperature records. We are now in truly uncharted territory…," warned the head of the European agency that tracks global temperatures.[10] This unprecedented leap in planetary temperatures clearly threatens humanity's ability to achieve the globally agreed upon goal of limiting warming to 1.5ºC set in the Paris Agreement on climate change. In fact, as of June 2024, the Earth had already seen 12 consecutive months of global warming at or above 1.5º Celsius.[11] While the Paris 1.5ºC goal refers to sustained warming levels and not merely one year's warmth, having already crossed this threshold over a 12-month period is a clear warning sign of how close we are to more permanently breaching the threshold.[12] It is also a signal that

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[5] "'We're frankly astonished.' Why 2023's record-breaking heat surprised scientists." *PBS News* (Jan. 19, 2024), https://www.pbs.org/newshour/science/were-frankly-astonished-why-2023s-record-breaking-heat-surprised-scientists; Raymond Zhong and Keith Collins, "See How 2023 Shattered Records to Become the Hottest Year," *New York Times* (Jan. 9, 2024), https://www.nytimes.com/2024/01/09/climate/2023-warmest-year-record.html.

[6] National Oceanic and Atmospheric Administration, "2023 was the world's warmest year on record, by far," (Jan. 12, 2024), https://www.noaa.gov/news/2023-was-worlds-warmest-year-on-record-by-far#:~:text=It's%20official%3A%202023%20was%20the,a%20record%20low%20in%202023;
Australian National University, "Record heat in 2023 worsened global droughts, floods and wildfires," *ScienceDaily* (Jan. 11, 2024), https://www.sciencedaily.com/releases/2024/01/240111113103.htm#:~:text=%22Extremely%20hot%20and%20dry%20conditions,severe%20drought%20in%20late%202023.%22.

[7] National Oceanic and Atmospheric Administration, "Global climate summary for June 2024," (July 16, 2024), https://www.climate.gov/news-features/understanding-climate/global-climate-summary-june-2024; Climate Central, "Analysis: Global extreme heat in June 2024 strongly linked to climate change," (June 28, 2024), https://www.climatecentral.org/report/global-heat-review-june-2024.

[8] Nia Williams, "Thousands flee western Canadian town as wildfires spread," *Reuters* (July 23, 2024), https://www.reuters.com/business/environment/wildfires-prompt-evacuation-orders-jasper-alberta-2024-07-23/; Paul Huttner, "Extensive wildfire smoke plumes building west of Minnesota," *MPRNews* (July 23, 2024), https://www.mprnews.org/story/2024/07/23/extensive-wildfire-smoke-plumes-building-west-of-minnesota.

[9] Copernicus Climate Change Service, "New record daily global average temperature reached in July 2024," (July 23, 2024), https://climate.copernicus.eu/new-record-daily-global-average-temperature-reached-july-2024.

[10] *Id.*

[11] Copernicus Climate Change Service, "June 2024 marks 12th month of global temperatures at 1.5ºC above preindustrial levels," (July 10, 2024), https://climate.copernicus.eu/june-2024-marks-12th-month-global-temperatures-15degc-above-pre-industrial-levels.

[12] World Meteorological Organization, "Global temperature is likely to exceed 1.5ºC above pre-industrial level temporarily in next five years," press release (June 5, 2024), https://wmo.int/news/media-centre/global-temperature-likely-exceed-15degc-above-pre-industrial-level-temporarily-next-5-years.

we are not cutting emissions fast enough, and that a utility's long-term plans must be designed with extreme caution around adding new fossil fuel resources.

B. Extending Safe Operations of Xcel's Three Nuclear Units Is Consistent with Climate Science and Energy Systems Modeling[13]

The Monticello and Prairie Island nuclear plants provide a significant amount of carbon-free electricity and play an important role in supporting Xcel's energy transition and development of a diverse carbon-free portfolio. These facilities comprise 1,650 MW of existing carbon-free generation capacity, at a time when Xcel's load is growing and demonstrating a need for carbon-free capacity. Extending the asset life of existing nuclear facilities where doing so can be done cost-effectively and safely is consistent with a robust body of research on how to achieve a highly decarbonized electric system. Deep decarbonization studies from public, academic, and private research institutions consistently find that keeping existing and safely operating nuclear units online in the U.S. is important in the near-term for reducing emissions from the electric system as we accelerate the ramp-up of renewable energy, energy efficiency, and storage to replace existing coal plants; reduce natural gas generation; and work towards a net-zero carbon economy by 2050.[14]

In addition to ensuring plants continue to be cost-effective while meeting high safety standards, CEOs believe it is important that nuclear license extension decisions are informed by deep engagement with the host communities and are responsive to host community concerns. The Prairie Island Indian Community and Xcel Energy reached an agreement in 2023 that will increase compensation to the Tribal Nation for continued nuclear waste storage at the plant in recognition of the burdens of being host and neighbor to the facility, and the value the facility provides to the Xcel system especially as Xcel moves toward a carbon-free system.[15] CEOs also support Prairie Island Indian Community's continued efforts to require the Federal government to fulfill its legal obligation under the Nuclear Waste Policy Act to remove spent nuclear fuel from the site.

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[13] Sierra Club does not join this subsection.

[14] See *e.g., 2035: The Report: Plummeting Solar, Wind and Battery Costs Can Accelerate our Clean Energy Future,* Goldman School of Public Policy (June 2020), https://www.2035report.com/ (analyzing achieving a 90% carbon-free electric system by 2035 and includes existing nuclear units that are not already planned for retirement); Eric Larson, et al., *Net Zero America: Potential Pathways, Infrastructure, and Impacts, Interim Report*, Princeton University (2020), https://acee.princeton.edu/rapidswitch/projects/net-zero-america-project/ (five net-zero carbon pathways are analyzed, 4 assume 50% of the U.S. nuclear fleet is extended to 80 operating years); James H. Williams, et al., "Carbon-Neutral Pathways for the United States," *AGU Advances* 2 (1): e2020AV000284 (2021) https:// agupubs.onlinelibrary.wiley.com/doi/10.1029/2020 AV000284 (finding that maintaining current nuclear capacity is a high confidence required action); John Larsen et al., *Pathways to Build Back Better: Investing in 100% Clean Electricity,* Rhodium Group at 7 (Mar. 23, 2021) https://rhg.com/research/build-back-better-clean-electricity/ (provides four key actions needed to fully decarbonize the electric system. One of these four is to retain existing clean capacity: "Getting to zero will be easier and happen faster if existing clean generators such as hydro and nuclear plants stay on the grid longer.").

[15] Walker Orenstein, "Xcel Energy agrees to pay Prairie Island $7.5 million more a year to tore spent nuclear waste," *MinnPost* (Mar. 29, 2023), https://www.minnpost.com/greater-minnesota/2023/03/xcel-energy-agrees-to-pay-prairie-island-7-5-million-more-a-year-to-store-spent-nuclear-waste/.

C. Building Thousands of MW of New Gas Plants Is Incompatible with State and Federal GHG-Reduction Goals for 2050 and with Xcel's Own Corporate Goal

Both the state of Minnesota and the U.S. government have committed to achieving net zero carbon emissions by 2050.[16] And Xcel has its own corporate goal of providing entirely carbon-free power by 2050.[17] However, as modeled, the thousands of MWs of gas plants Xcel proposes to build have a forty year book life, and even those built this decade would still be operating in 2050.[18] Indeed, Xcel's modeling shows its gas combustion turbines emitting nearly **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]** of CO_2 in 2050 alone.[19] Xcel suggests that the gas plants built this decade could be converted to run on hydrogen, but as we discuss in Section III.D.3, it is unclear if Xcel could or even should do that, and those costs are certainly not included in Xcel's Preferred Plan (nor are the costs of adding carbon capture and storage, or "CCS").

In short, Xcel's gas turbine construction plans are not compatible with existing state or federal climate goals for 2050, nor with its own corporate goal. A large new fleet of gas turbines is therefore not "consistent with the public interest," which is the statutory standard the Commission must use in assessing the plan.[20] In making that public interest determination, the Commission must consider whether the plan "helps the utility achieve the state's greenhouse gas reduction goals under section 216H.02."[21] And under the state's longstanding renewable energy preference, the Commission may not approve new non-renewable energy facilities proposed in a plan unless the utility has demonstrated that a renewable energy alternative is not in the public interest.[22]

Finally, any long-term plan must contemplate the possibility that the existing governmental 2050 net-zero goal will need to be moved up from 2050. For example, Minnesota's 2050 net-zero goal, and its interim emission reduction goals, are subject to annual review by the Minnesota Pollution Control Agency, which must take account of the most recent science and forward any recommended changes to the legislature.[23] It would be imprudent for any utility contemplating the construction of long-lived carbon-emitting resources to count on today's climate protection laws remaining unchanged as the climate crisis unfolds.

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[16] Minn. Stat. § 216H.02, subd. 1(a); "The United States of America Nationally Determined Contribution: Reducing Greenhouse Gases in the United States: A 2030 Emissions Target" (Apr. 21, 2021) https://unfccc.int/sites/default/files/NDC/2022-06/United%20States%20NDC%20April%2021%202021%20Final.pdf (submitted by the U.S. government under Article 4 of the Paris Agreement).
[17] Xcel IRP, chapter 3, p. 22.
[18] Xcel IRP, Appendix F, p. 36, Table F-23.
[19] Xcel response to CEOs IR No. 1, Modeling Output Files, EO-2024 IRP – Base Scenarios – 2024-01-31, Emissions tab [TRADE SECRET].
[20] Minn. Stat. § 216B.2422, subd. 2(a).
[21] Minn. Stat. § 216B.2422, subd. 4.
[22] *Id.*
[23] Minn. Stat. § 216H.02, subd. 1(c).

II. The Commission Should Adopt CEOs' Plan, or at the Very Least, Remove Most New Gas Capacity From Xcel's Plan

A. Xcel's Preferred Plan Advances a Carbon-Free System, But Is Overly Reliant on New Gas-Fired Peaker Plants

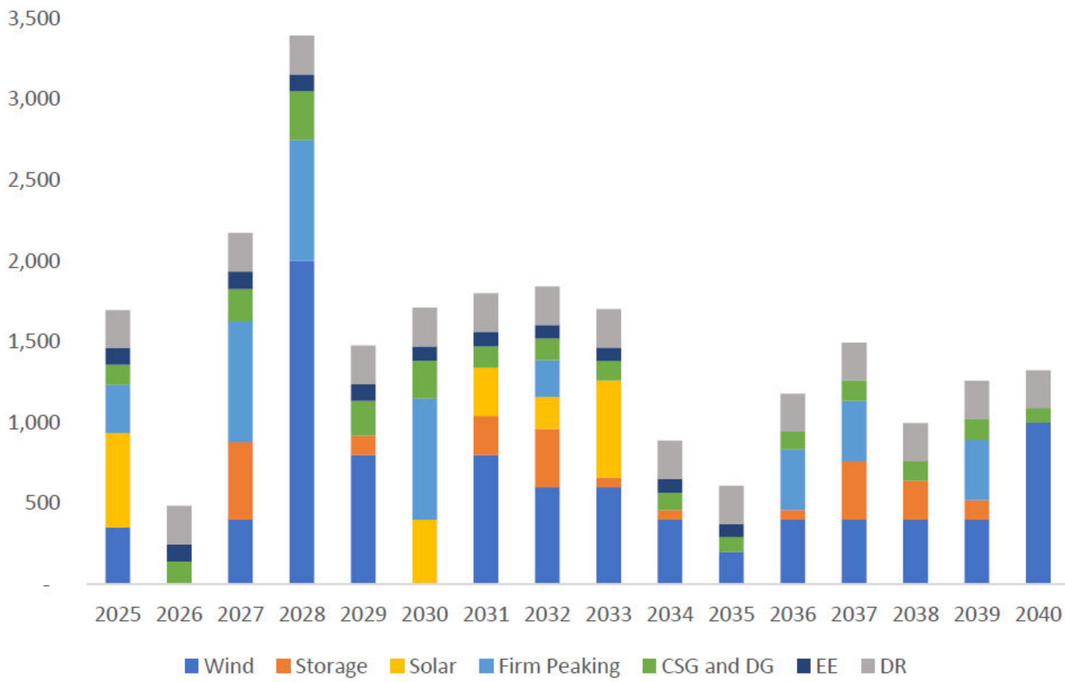
The CEOs appreciate that Xcel's Preferred Plan in its 2024 IRP makes strides toward a cleaner, more flexible system. In the 2019 IRP, the Company's plan included retirement of all of its coal units by 2030. We are pleased to see that the 2024 IRP Preferred Plan does not delay these coal retirements. The 2024 plan also includes major new investments in renewable resources, energy storage, demand-side management ("DSM"), and extensions of the Company's two large nuclear facilities. Between 2026 and 2030, Xcel's Preferred Plan includes: 3,200 MW of new wind resources, 600 MW of battery storage, 400 MW of utility-scale solar, almost 1,100 MW of small-scale solar, and 1,700 MW of DSM (including energy efficiency and demand response).[24] This is an objectively ambitious plan, and we applaud Xcel for its efforts.

However, the plan also includes over 2,200 MW of "firm peaking" resources (modeled as natural gas combustion turbines). We are concerned that the Company has developed its plan based on the most *conservative* approach and, as a result, it is planning on overbuilding new gas resources to the detriment of both the climate and customers' bottom line.

The chart below is Xcel's Figure 1-6, illustrating its Preferred Plan additions through 2040.

[24] Xcel IRP, chapter 1, p. 13, Figure 1-6.

Figure 1-6: 2024-2040 Preferred Plan Resource Additions (MW)



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Wind	350	0	400	2,000	800	0	800	600	600	400	200	400	400	400	400	1,000
Storage	0	0	480	0	120	0	240	360	60	60	0	60	360	240	120	0
Solar	585	0	0	0	0	400	300	200	600	0	0	0	0	0	0	0
Firm Peaking	298	0	748	748	0	748	0	225	0	0	0	374	374	0	374	0
CSG and DG	124	140	198	301	215	237	131	134	123	106	94	110	125	121	130	90
EE	103	108	108	105	103	87	91	85	82	86	80	0	0	0	0	0
DR	234	237	238	239	239	239	238	237	237	236	236	235	235	235	234	234

The Company's Preferred Plan specifically includes the installation of 2,244 MW of firm peaking resources – modeled as six new gas combustion turbines ("CT") in a five-year period from 2026 through 2030. In that same period where the 2,244 MW of firm peaking is being added, 1,700 MW of coal will retire (i.e., the new gas replacement capacity is 500 MW greater than the amount of coal retiring); and simultaneously 5,300 MW of new clean resources are being added.

The proposed "firm peaking" resources would add to Xcel's already significant gas fleet. In summarizing its existing gas resources, Xcel states it has "five owned or contracted intermediate-type generating assets that provide over 2,000 MWs of capacity. We have peaking-type resources located at seven sites, providing nearly another 2,000 MWs of capacity."[25] Xcel's load and resources tables show a total of 4,687 MW (ICAP) of existing gas and oil resources in 2024, dropping to 3,538 in 2030 due to expirations of existing contracts.[26]

[25] Xcel IRP, chapter 3, p. 15.
[26] Xcel IRP, chapter 4, p. 21.

This volume of new firm peaking capacity was chosen by the Company's EnCompass model in large part because Xcel cut off access to the MISO wholesale energy market when it conducted its modeling, and because the Company understated the costs of new CTs which led the model to be more likely to choose them. The Company notes that "firm peaking" or "firm dispatchable" units could be a number of technologies including energy efficiency, demand response, and energy storage,[27] but implies that flexibility does not apply to near-term resources, saying "we have left open our firm and dispatchable capacity needs in our ***long-term plan,*** recognizing that the technology landscape is rapidly changing, and new options may be more economically favorable than natural gas at that time."[28] CEOs are therefore concerned that the Company intends to use this plan to justify massive gas investments in the next few years, when more reasonable alternatives exist. As we discuss in detail further in these comments, the assumptions Xcel used led the model to overbuild new gas, resulting in substantially more costs to customers (as well as a new fleet of carbon-emitting resources that if operated as modeled would prevent the level of decarbonization we need).

We are generally concerned that Xcel is over-building carbon-emitting resources due to modeling itself as an islanded utility that has to stand on its own. This is not how Xcel has modeled itself in previous IRPs and is a highly conservative approach that leads to the addition of more gas generation, higher carbon emissions, and higher costs—where customers are paying billions more for the Preferred Plan as opposed to a plan developed with market access.

The Company's capacity expansion modeling settings in EnCompass ignored the MISO wholesale market. The only exception was one sensitivity ("market access optimization expansion plan") where the Company allowed the model to have access to 2,300 MW of market access at each hour, which was the default market assumption used in Xcel's 2019 IRP.[29] In all other capacity expansion runs, the market was not accessible at all, i.e. the Company ran its system as an island.[30] The production cost runs, which dispatch a fixed resource portfolio to predict costs and emissions, then were able to access the market for purchases and sales of energy. But all but one of Xcel's resource portfolios were constructed with the assumption that Xcel's territory was an island. This is to the detriment of customers because the cost of the one run with market access is $4.7 billion in Present Value of Societal Cost ("PVSC") lower than that of its Preferred Plan by 2050.[31]

The Company claims that it is disregarding the market so that its Preferred Plan can "meet customer needs with very limited reliance on neighboring systems and the broader MISO market."[32] But this directly contradicts how the Company's system actually operates and will continue to operate. In reality, Xcel's territory is not an island. It is highly interconnected and a part of the MISO grid at-large. The idea that Xcel *could* operate as an island is false. The Company's customers get all of their energy needs from the MISO grid, not directly from Xcel's generators, and the energy from Xcel's generators is delivered to the MISO grid and cannot be corralled into just serving Xcel's territory. Additionally, there are significant trade-offs that come with planning as if one were an island. Doing so foregoes opportunities for sharing operating

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[27] *See e.g.,* Xcel IRP, chapter 4, page 15; chapter 5, page 33.
[28] Xcel IRP, chapter 4, p. 15 (emphasis added).
[29] Xcel IRP, chapter 5, p. 9-10.
[30] Xcel IRP, chapter 5, p. 9.
[31] Xcel response to CEOs IR No. 1, Modeling Output Files, EO - 2024 IRP - Scenario 3 Sens R 2300 MW Mkt Access - 2024-01-31 [TRADE SECRET]. Xcel has given CEOs permission to treat this number nonprotected data.
[32] Xcel IRP, chapter 5, p. 9.

reserves with neighboring entities and ignores the advantages of resource diversity across geographies—highly valuable capabilities that helped drive the creation of regional power pools and regional independent system operators in the United States.

MISO is responsible for reliably operating the bulk system in its region, including Xcel's territory. Xcel's main obligation to MISO and the regional power system is to provide an adequate level of capacity for its local resource zone. But energy is being imported and exported at all hours, and MISO has an excellent track record of maintaining bulk system reliability through extreme weather and other system disturbances.[33] It is not reasonable to develop a multi-billion-dollar resource portfolio *exclusively* based on modeling that entirely ignores the MISO market.

While the Company did perform one modeling run where market access was allowed, it rejected the run, even though it was very similar to the Company's methodology in the 2019 IRP. The rejection of the market access plan—which is $4.7 billion PVSC cheaper than the Preferred Plan—rests largely on the argument that it produces too much market exposure given the amount of renewable additions in that plan.[34] But the market access run was so much cheaper that Xcel had plenty of headroom to alter the market access plan. If over-exposure to the market was the main concern, the Company could have placed constraints on each new build type (e.g. wind projects) and/or conducted modeling with *mitigated* market access, rather than eliminating the market entirely.

B. Xcel's Modeling Shows that Extending Its Nuclear Facilities' Operating Lives is Cost-Effective and Improves Environmental Outcomes

Xcel currently operates three nuclear generation units, two at Prairie Island and one at Monticello, totaling 1,650 MW of net generating capacity. Xcel is proposing to "extend operation of the two Prairie Island Nuclear Generating Plant units for 20 years past the current license expirations, to 2053/2054, and to extend operation of the Monticello Nuclear Generating Plant by 10 years to 2050, which aligns with our Subsequent License Renewal application for Monticello pending review by the Nuclear Regulatory Commission."[35] Xcel evaluated the impacts of three potential nuclear plant scenarios in its IRP: a Reference Case (Scenario 1) with no extensions beyond the current license expiration dates, Scenario 2 which includes a 20-year extension of the Prairie Island units, and Scenario 3 (Xcel's Preferred Plan) which includes a 20-year extension of the Prairie Island units and a 10-year extension of Monticello.

Xcel's capacity expansion modeling results find that Scenarios 1 and 2 contain significantly higher levels of new resources than Scenario 3. This is an expected result given the scale of capacity that would retire by 2034 and/or 2040 in those Scenarios. In particular, CEOs note that both Scenarios 1 and 2 contain 25% more new "firm peaking" capacity by 2040 compared to Xcel's Preferred Plan (Scenario 3) – 4,488 MW compared to 3,592 MW.[36] Below is Xcel's Figure 5-9 illustrating the cumulative builds by scenario between 2024-2040.

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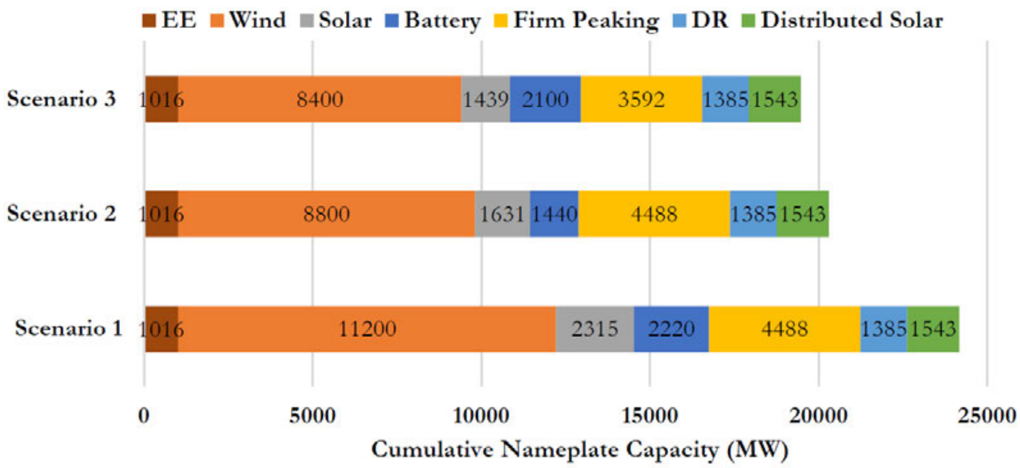
[33] *See, e.g.*, MISO Reliability Subcommittee, Overview of Winter Storm Elliott December 23, Maximum Generation Event (Jan. 17, 2023), https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf (comparing winter storms Uri and Elliott).
[34] Xcel IRP, chapter 5, p.11.
[35] Xcel IRP, chapter 4, p. 7.
[36] Xcel IRP, chapter 5, p. 23.

Figure 5-9: Expansion Plans by Scenario (MW, Cumulative Nameplate Capacity Resource Additions by Resource Type, 2024-2040)



Xcel's production cost modeling results find that Scenario 3 provides significant savings compared to the other options evaluated. On a PVSC basis, Xcel expects Scenario 3 (in which both plants are extended) to save $1.025 billion by 2050 and $785 million by 2040 compared to the Reference Case (no extensions). Xcel expects Scenario 3 to save $513 million by 2050 and $372 million by 2040 compared to Scenario 2, in which only Prairie Island is extended.[37]

The Company's sensitivity analysis also indicates that Scenario 3 provides important emission reductions and is more compatible with Xcel's corporate goal of providing carbon-free electricity by 2050. Xcel evaluated the three nuclear scenarios using six different cost of carbon assumptions. The results demonstrated that extending both facilities has consistently lower externality costs.[38] The Company's sensitivity evaluating these nuclear scenarios under the constraint of achieving a 100% carbon-free generation fleet by 2050 finds that Scenario 3 is significantly more cost-effective than other options for achieving this carbon goal, saving approximately $2 billion by 2050 on a Present Value of Revenue Requirement ("PVRR") or PVSC basis, compared to the Reference Case. This finding is consistent with the large body of research on how to achieve a highly decarbonized electricity system, as discussed earlier in Section I.B.

Given these findings, and the Company's agreement with the Prairie Island Indian Community in 2023, CEOs are supportive of including the operating extensions for both nuclear facilities proposed in Xcel's Preferred Plan, and these extensions are unchanged in CEOs' modeling.[39] The Company's analysis shows the extensions to be cost effective under a range of future scenarios and to support the transition to a carbon-free system. Additionally, both nuclear plants are existing facilities already connected to the MISO system, and therefore license extensions have the benefit of avoiding long interconnection processes and construction uncertainty.

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[37] Xcel IRP, chapter 5, p. 24.
[38] Xcel IRP, chapter 5, p. 27.
[39] Sierra Club abstains from this statement as it does not support nuclear license extensions.

However, it is important that Xcel not underestimate the costs or potential costs of continuing to operate existing nuclear plants, especially compared to other low-carbon alternatives that are projected to become less expensive over time. Given the cost uncertainty, we recommend that the Commission continue to review updated cost forecasts from Xcel and other industry benchmarks as the Monticello and Prairie Island license extensions move through additional regulatory processes.

CEOs also assert that existing reactors should only receive additional license extensions if they can continue to meet high safety standards through implementing strong aging management programs and address outstanding safety issues, including through potential voluntary measures to provide added protection of public health and the environment over the period of extended operation. These conditions can vary by reactor depending on the reactor type, location, and other conditions; accordingly, the NRC's review will be a key procedural element for ultimately deciding whether to extend the operating life of the plants.

C. CEOs' EnCompass Modeling Made Reasonable Adjustments and Minor Corrections to the Model

The focus of CEOs' modeling was on reducing long-term investments in carbon-emitting resources relative to Xcel's Preferred Plan, while maintaining reliability and affordability. To that end, the CEOs' plan fixed in the resources on the Sherco and King tie-lines from Xcel's Preferred Plan, while allowing it to select additional resources if economical. We recognize the benefits of locating resources at these interconnection points, especially given the MISO interconnection queue wait times and the potential costs of new interconnections. However, our modeling experts at EFG and AEC did make changes in the EnCompass model which creates differences between our modeling and Xcel's Preferred Plan, as explained below:

First, we assumed that the power purchase agreements ("PPA") for some existing gas units could be extended by 10 years due to the young age of these resources. This change made 968 MW (winter ICAP) of existing gas resources available into the late 2030's, through the following PPA extensions:

- LSP Cottage Grove CC (262 MW) extended until 2037
- Cannon Falls CT units 1 and 2 (356 MW) extended until 2038 and 2039, respectively
- Mankato Energy Center (350 MW) extended until 2038

Notably, the owners of the Cannon Falls CT and Mankato Energy Center have offered PPA extensions into the Company's currently ongoing firm dispatchable procurement (docket E002/CN-23-212).[40] That procurement process required that offers have a term of 10 years or longer,[41] so we know that these resources are available for at least that duration.

The second change EFG made was to increase the costs of solar and wind resources to properly include inflation. The EnCompass model was set up to use inflation-included values for

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[40] Onward Energy Holdings, Base Proposal (May 24, 2024), and Invenergy Cannon Falls, Refiled Proposal (July 27, 2024), *In the Matter of Xcel's Competitive Resource Acquisition Process for up to 800 Megawatts of Firm Dispatchable Generation,* Docket No. E002/CN-23-212.
[41] Xcel, Compliance - Notice Petition, Attachment A, Attributes 6 and 7, *In the Matter of Xcel's Competitive Resource Acquisition Process for up to 800 Megawatts of Firm Dispatchable Generation,* Docket No. E002/CN-23-212 (November 13, 2023).

every project year—i.e., nominal dollars—for wind and solar projects. These resources were effectively modeled as PPAs, where the costs are recovered on a per MWh—or "levelized"—basis for the projects' lives. The Company calculated what it called a "nominal levelized cost" where it took the real levelized cost values and inflated them, but it only did this up until the installation year. This approach is not sufficient because it does not account for inflation for the rest of the project's life, which is needed to provide nominal dollars to EnCompass. The Company should have either: 1) calculated a true nominal levelized cost, which would have been flat for the project's life in nominal terms (but higher than what the Company estimated); or 2) incorporated an escalation rate to its real levelized cost over every year of the project's life. In our modeling, we incorporated an annual inflation rate on the levelized cost. Thus, our levelized costs are higher for both solar and wind when compared to Xcel's.

The third change EFG made was to address the costs of new dispatchable resources (modeled as gas CTs) in the model. Xcel developed costs for two types of CTs that were offered into the model: F-class and H-class turbines. Xcel assumed a new H-class turbine costs $749 per kW (in 2023 dollars) while an F-class turbine costs $954 per kW—27% higher than the H-class.[42] Unsurprisingly, the model chose the cheaper H-class unit in almost all cases. But this is problematic because the Company's lower H-class costs lacked justification. While the Company could provide recent documentation for the F-class costs, the H-class costs were based on an estimate from a portion of the Sherco CC project.[43] That project was proposed in Xcel's initial 2019 IRP but withdrawn in 2021, meaning the unit was never pursued or built.[44] Additionally, the Sherco CC was a combined cycle plant, not a peaking facility, and costs from 2019 are unlikely to be accurate in 2024 due to the large economic disruptions of the last four years, even after adjusting for inflation. The Company could not provide another source to justify the H-class costs. As a result, the model was unfairly biased toward selecting the H-class turbines with this unsupported cost assumption and, by extension, underestimated the costs of future new gas builds in Xcel's plans. Due to the lack of sufficient evidence for Xcel's H-class costs, EFG changed the costs in the model for all new CTs to the Company's F-class turbine capital costs as that is a more reasonable proxy for new gas builds.

Finally, the CEOs took a more measured and balanced approach to market access than Xcel. Xcel's portfolios, including its Preferred Plan, presupposed a world where the Company's territory would have to be self-sufficient, or operate as an electrical island. This scenario is a modeling hypothetical only and is not an accurate picture of how Xcel's system works. This approach produces a skewed picture of resource needs that leads to over-building dispatchable resources and billions of additional costs to Minnesota customers. The Company could have addressed its reliability and market exposure concerns while still allowing market access, such as by limiting the amount of new wind resources available in each year or modeling an intermediate level of market interaction, but it did not do so. Instead, we were left with an "all or none" approach when it came to the MISO market.

The CEOs generally favor capacity expansion modeling that allows for a reasonable and realistic level of market access because that is how the Company's system actually operates and regional power exchange is crucial for achieving an affordable, reliable, decarbonized electricity

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[42] Xcel IRP, Appendix F, p. 36, Table F-23.

[43]Xcel supplemental response to CEOs IR No. 19.

[44] Minn. Pub. Utils. Comm'n, "Order Approving Plan with Modifications and Establishing Requirements for Future Filings, *In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy*, Docket No. E-002/RP-19-368 (Apr. 15, 2022).

system. While modeling with zero market interaction may provide an interesting bookend, it is not reasonable to use these results alone to develop a resource portfolio. CEOs therefore developed four scenarios to evaluate the impact of varying levels of market access. Thus, we present a range of portfolios that result from gradations of market access ranging from 2,300 MW import/export capability—the limit used in Xcel's market optimization run and 2019 IRP—to 0 MW market access—the limit used in Xcel's Preferred Plan. The table below summarizes the import/export limit and annual sales limits used in each of these modeling runs.

CEOs Table 1. Summary of Market Access Assumptions by Expansion Plan

	Import/Export limit
Xcel 2024 Preferred Plan	0 MW
Xcel 2019 Preferred Plan	2,300 MW
Xcel 2024 Market Optimization Plan	2,300 MW
CEO Market Access 100%	2,300 MW
CEO Market Access 50%	1,150 MW
CEO Market Access 25%	575 MW
CEO Market Access 0%	0 MW

Our approach shows the Commission the benefits of market access: costs to customers are decreased as market access increases. Moreover, as we discuss below, assuming no market access leads to a resource portfolio with higher carbon emissions. The Company will argue that relying on the market compromises reliability and increases exposure to high market prices. However, ignoring market access ensures over-building dispatchable resources and exposing customers to higher costs. CEOs believe it is much more reasonable to consider the results of a range of market access scenarios—and the subsequent portfolios selected, their costs, their emissions, and market exposure—to develop a plan that balances each of these important factors.

In summary, the changes that EFG and AEC made to Xcel's modeling assumptions are:

1. Fixing in resources selected in Xcel's Preferred Plan on the generation tie-lines
2. Modeling 10-year PPA extensions at three existing facilities
3. Increasing Xcel's solar and wind resource costs to accurately reflect inflation
4. Revising the capital cost assumptions for one of the two CT types that Xcel modeled
5. Modeling a range of market access scenarios from 0 MW to 2,300 MW

D. A Plan that Utilizes Existing Capacity and Battery Storage Instead of New Gas Plants is Cost-Effective, Reliable, Aligned with Climate Science, and Better Meets Minnesota Policy Needs

To evaluate Xcel's Preferred Plan and develop a clean energy alternative, CEOs' modeling experts at EFG and AEC undertook a multi-step process. First, they analyzed Xcel's EnCompass assumptions and modeling approach and adjusted the model to correct errors, use better-supported assumptions, and reduce unnecessary complexity. Then, using these updated assumptions, EFG optimized expansion plans in EnCompass under four different MISO market interaction scenarios. EFG also re-ran Xcel's Preferred Plan using the same changes to modeling assumptions to ensure we were comparing plans on an apples-to-apples basis.

Next, EFG ran each of these five plans through the production cost step within EnCompass to derive annual and cumulative costs on a PVRR and PVSC basis. As a final step, EFG ran the plans through Xcel's Energy Adequacy Study, which applies the load shape and renewable generation profiles observed in seven historical weather years (2016-2022) to a future year (2030) under each of the potential future generation portfolios.

Each of the four optimized resource plans EFG modeled meets the same energy and capacity (resource adequacy) requirements Xcel modeled, including MISO's seasonal capacity construct and changing accreditation assumptions. The plans were dispatched against the same 8,760 hourly, chronological profile that the Company used, and in the Energy Adequacy step, were dispatched against the same historical load and renewable generation profiles.

As noted above, EFG optimized a capacity expansion plan under four different market access scenarios: 100% access, 50% access, 25% access, and 0% access. The 100% access run limits hourly market imports and exports to 2,300 MW. These are the same market access assumptions used to develop Xcel's last IRP and the market access assumptions Xcel uses in its "Market Access Optimization" run.[45] Xcel states that the 2,300 MW "limit was established in our 2019 Plan based on PROMOD modeling and historical transfer data."[46] EFG's optimization of the expansion plan under 100%, 50%, 25%, and 0% of Xcel's market access optimization run assumptions identifies the trade-offs in resource selection, cost, and emissions that come with conducting resource planning that utilizes or ignores the MISO market.

1. Capacity Expansion Plan Results

EFG's modeling shows that there are at least three main trade-offs that arise when turning off market access in resource planning: resource selection, emissions, and cost. Runs with less access to the market substitute battery storage resources for wind resources. This change in resource selection, along with the change in market access, leads to increased emissions compared to plans with more market access (which have more wind generation). Additionally, the lower the market access, the higher the cost of the plan.

As the table below shows, after making our adjustments to the model, optimizing Xcel's resource mix when assuming zero market interaction leads to the addition of 4,894 MW (ICAP) of new resources through 2030, including 1,320 MW of battery storage and 2,800 MW of wind. In contrast, using the same modeling assumptions but allowing up to 2,300 MW of market interaction leads to the addition of 5,814 MW through 2030, including 4,800 MW of wind and just 240 MW of battery storage.

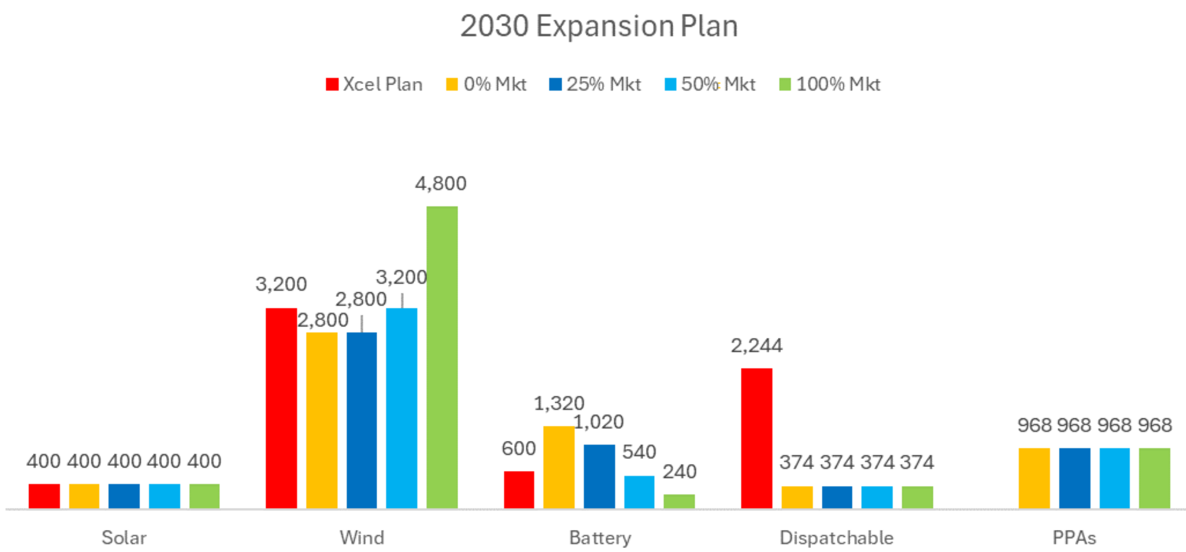
Notably, the level of generic dispatchable capacity (modeled as a CT) optimized by the model is consistent across all four of CEOs' market scenarios for 2030, and consistent in all but the 0% run for 2035. The solar build is consistent across all four scenarios for both 2030 and 2035.

[45] Xcel IRP, chapter 5, p. 4, 9.
[46] Xcel IRP, chapter 5, p. 4.

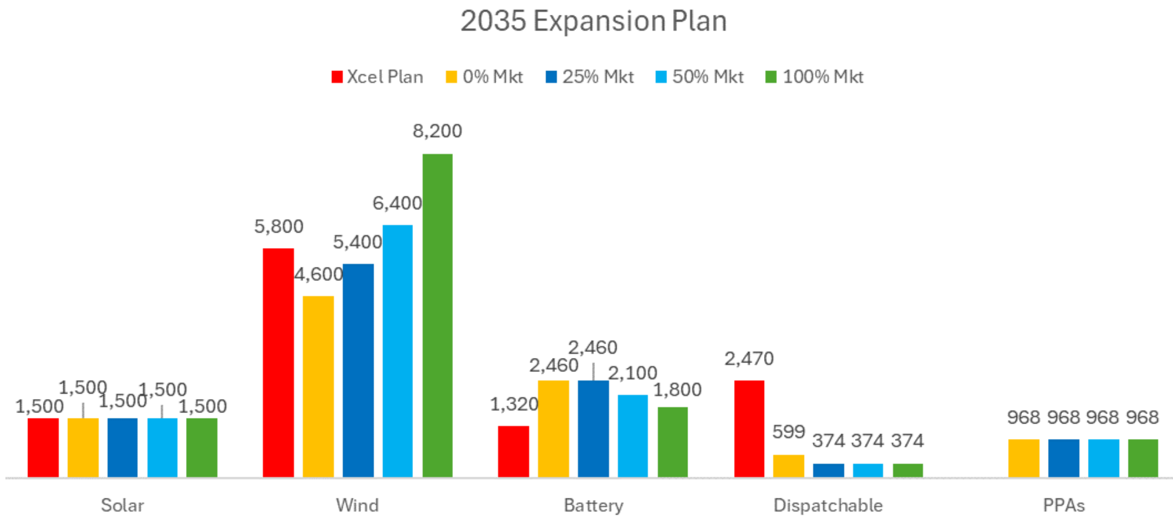
CEOs Table 2. Expansion Plan Summary: Cumulative Builds by 2030 and 2035, MW ICAP

	Xcel Preferred Plan	CEO 0% Mkt	CEO 25% Mkt	CEO 50% Mkt	CEO 100% Mkt
2030					
Solar	400	400	400	400	400
Wind	3,200	2,800	2,800	3,200	4,800
Battery	600	1,320	1,020	540	240
Dispatchable	2,244	374	374	374	374
PPA	0	968	968	968	968
2035					
Solar	1,500	1,500	1,500	1,500	1,500
Wind	5,800	4,600	5,400	6,400	8,200
Battery	1,320	2,460	2,460	2,100	1,800
Dispatchable	2,470	599	374	374	374
PPA	0	968	968	968	968

CEOs Figure 1. Comparison of Five Scenarios: Capacity Added by 2030, MW ICAP



CEOs Figure 2. Comparison of Five Scenarios: Capacity Added by 2035, MW ICAP



The primary difference between the four CEOs scenarios and Xcel's Preferred Plan is the use of 10-year contract extensions with existing gas plants (CEOs' proposal) versus building 2,244 MW of new gas capacity (Xcel's proposal). EFG also fixed in 374 MW of dispatchable capacity (modeled as a CT on Xcel's Sherco tie-line), as the tie-line approach was approved in the 2019 IRP and a procurement decision will be made through the Firm Dispatchable contested case roughly concurrent with the IRP proceeding. After considering the already-approved 374 MW of firm dispatchable capacity and extending 968 MW of existing PPAs, **EnCompass does not add any new gas CT capacity before 2030 in any of the four scenarios CEOs evaluated.** In the 0% market access scenario, EnCompass adds one 225 MW dispatchable resource (modeled as a CT) in 2035. However, by that year it is highly likely that additional carbon-free firm dispatchable generation technologies will be available.

Similarly, Xcel's own modeling shows EnCompass selecting far less CT capacity in the sensitivity that allows the model to assume 2,300 MW of market access. Rather than the 2,244 MW under Xcel's Preferred Plan through 2030, Xcel's market access sensitivity selects only 748 MW of CT capacity through that year – only one-third as much.[47] This shows that unrealistically assuming zero market access leads to a plan with far more CT capacity than when a more realistic assumption is used.

2. Plans that Replace Xcel's Proposed New Gas Plants with PPA Extensions, Renewables, and Storage Are Equal- or Lower-Cost

EFG ran the above five scenarios (CEOs' four market access scenarios and corrected Xcel scenario) through the production cost function in EnCompass, which makes hourly dispatch decisions on a fixed portfolio, and calculates the costs and emissions that result. These runs include the mid-range regulatory cost of carbon as a dispatch adder, which suppresses the dispatch of carbon-emitting units compared to the counterfactual. EnCompass calculates a PVRR which reflects the financial costs of a portfolio after including the impact of the regulatory cost of carbon. It also calculates a PVSC which includes the PVRR and externality costs assigned to

[47] Xcel IRP, chapter 5, p. 10, Figure 5-1.

carbon and criteria pollutants. (As we discuss in Section V.D, while Xcel includes carbon regulatory costs as a dispatch adder in its PVSC runs, thus affecting the dispatch of carbon-emitting sources, it does *not* include carbon regulatory costs in its PVRR run or its reporting of the Preferred Plan's PVRR, contrary to the Commission's regulatory cost of carbon order.)[48]

EFG found a consistent pattern of higher PVRR and PVSC costs in scenarios without access to the MISO market. Between 2024 and 2050, the Revised Xcel Preferred Plan costs $1.009 billion more on a PVRR basis, and costs $3.46 billion more on a PVSC basis compared to the CEOs' 100% market access scenario. Looking at a shorter period until just 2040, Xcel's Preferred Plan still costs $1.461 billion (PVRR) or $3.179 billion (PVSC) more compared to the CEOs' 100% market access scenario.

The cost difference between the Revised Xcel Preferred Plan and the CEOs' 0% market access scenario is negligible: 0.1% (PVRR)/0.6% (PVSC) higher cost for the CEOs' plan before 2040, or 0.5% (PVRR)/0.7% (PVSC) higher cost by 2050. The other CEOs plans show *savings* ranging from 0.6%-6.3% (on a PVSC basis) compared to Xcel's plan before 2040 and 0.3%-5.0% (on a PVSC basis) compared to Xcel's plan by 2050.

CEOs Table 3. PVRR/PVSC Results ($Millions) for 2024-2040

Modeling Run	PVRR	PVSC	PVRR Savings/(Cost) CEO vs. Xcel Plan	PVSC Savings/(Cost) CEO vs. Xcel Plan
Rerun Xcel Preferred Plan	$34,833	$50,607	-	-
CEO Market Access 0%	$34,869	$50,922	($36)	($315)
CEO Market Access 25%	$34,170	$50,294	$663	$313
CEO Market Access 50%	$33,729	$49,217	$1,104	$1,390
CEO Market Access 100%	$33,372	$47,428	$1,461	$3,179

CEOs Table 4. PVRR/PVSC Results ($Millions) for 2024-2050

Modeling Run	PVRR	PVSC	PVRR Savings/(Cost) CEO vs. Xcel Plan	PVSC Savings/(Cost) CEO vs. Xcel Plan
Rerun Xcel Preferred Plan	$50,369	$68,687	-	-
CEO Market Access 0%	$50,635	$69,149	($266)	($462)
CEO Market Access 25%	$49,974	$68,471	$395	$216
CEO Market Access 50%	$49,570	$67,174	$799	$1,513
CEO Market Access 100%	$49,360	$65,227	$1,009	$3,460

These results demonstrate that there are significant costs to performing resource planning as if Xcel is an island – in the range of $1.5 billion in ratepayer dollars over the next fifteen years, or $3.5 billion when including environmental externality costs.[49] These results also show that extending contracts with existing gas plants instead of building new plants and adding a higher

[48] Xcel response to CEOs IR No. 40.
[49] Comparing CEO 100% market access to CEO 0% market access in 2040.

level of wind power and battery storage creates a resource portfolio with commensurate or lower cost compared to Xcel's Preferred Plan.

3. Environmental Performance

EFG's production cost modeling finds that the plan developed while allowing 100% market access has significantly lower carbon emissions. As shown in the figure below, and in Figure 1 of the attached EFG-AEC Report, the CEO 100% market access scenario consistently has the lowest emissions of the five plans while the other scenarios have similar emissions to Xcel's Preferred Plan.

CEOs Figure 3. Annual Carbon Emissions by Scenario, tons (2024-2040)

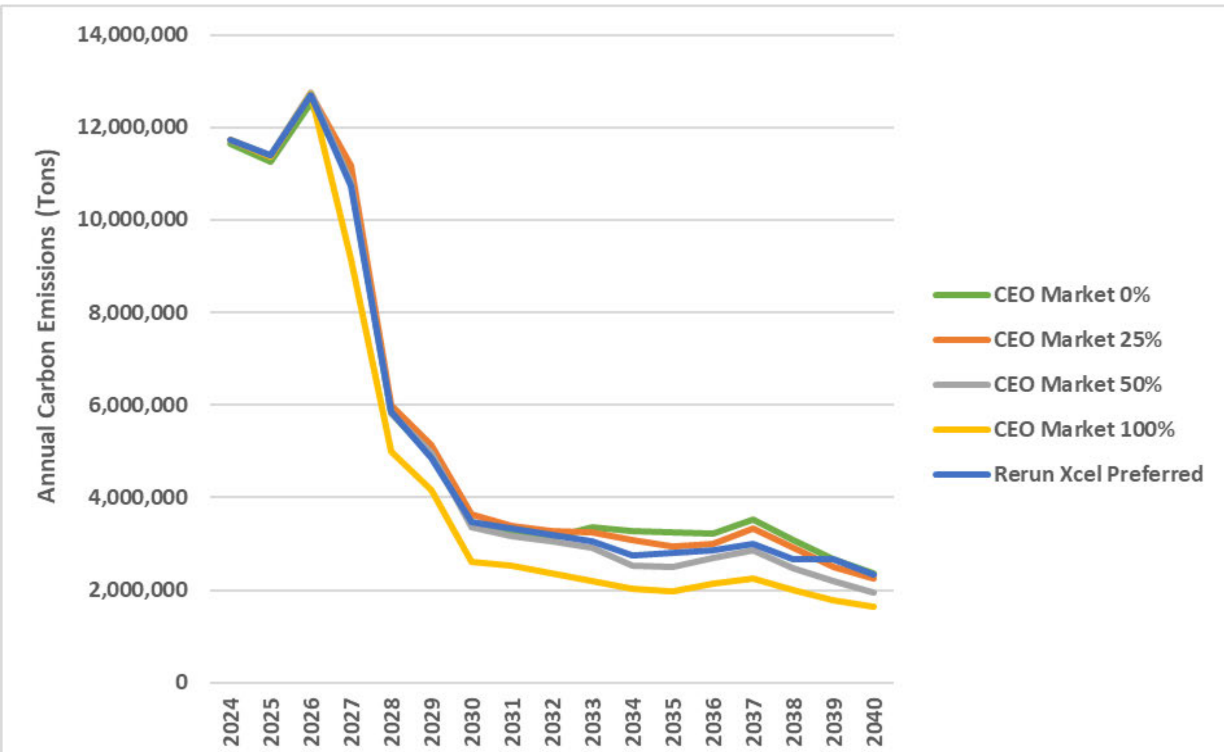


Figure 3 shows a steep decline in CO_2 in the years ahead for all five runs, which is welcome and necessary given the urgency of the climate crisis and our climate protection goals. However, Figure 3 does not show the full climate and financial risk posed by the multiple new gas plants in Xcel's Preferred Plan or the relative advantage of extending existing gas contracts instead, for the following reasons:

- First, each of the CEO market access scenarios above includes emissions from the gas plants we model extended contracts with—Mankato Energy Center 1, Cannon Falls 1 and 2, and Cottage Grove. These facilities would emit more than 5 million tons of carbon dioxide during the ten years of extended contracts that we modeled.[50] If Xcel does not extend PPAs with these facilities, it appears more likely than not that these facilities will

[50] Dispatch results indicate the three plants emit 6,246,642 tons of CO_2 between 2027-2038 in the CEO 50% market access scenario, and 4,938,960 tons of CO_2 in the CEO 100% market access scenario.

find another off-taker or become merchant generators in the MISO market. Thus, while the 5+ million tons of carbon are not reflected in the emissions modeled for Xcel's Preferred Plan above, there is a significant chance these emissions will still occur under that scenario. Letting the contracts lapse would then result in no reduction in statewide greenhouse gas emissions from those facilities.[51] We discuss this issue further in Section II.F.

- Second, the capacity factors and thus the carbon emissions of the new gas plants Xcel proposes could be far higher than is reflected in the CEOs' rerun of Xcel's Preferred Plan in Figure 3. While Xcel has stated that its proposed CTs are designed to run at a 5-10% capacity factor, Xcel is seeking to permit its proposed Lyon County CT to run up to a 35% capacity factor, which would cause the emissions from this single 420 MW CT to exceed one million tons per year (as we discuss further in Section III.D.5).[52] Moreover, Figure 3 assumes new carbon regulatory costs beginning in 2028, and if these future costs are delayed or the policies implementing them not adopted at all, capacity factors and emissions from the remaining carbon-emitting facilities would be substantially higher (as we discuss further in Section V.D). By avoiding the addition of multiple long-lived gas plants, CEOs reduce the risk of carbon emissions being significantly higher than those shown above.
- Third, if the gas plants Xcel proposes to build are taken offline early, they will pose less of a threat to the climate, but then the Company and its customers will not recover their financial investment, as we discuss in Section III.D.2. Continuing to rely on existing gas plants instead of building long-lived new ones allows Xcel to avoid stranded-asset risks while investing more in carbon-free alternatives in the next five years. Looking further ahead, CEOs' approach preserves the opportunity for Xcel to build a meaningful amount of carbon-free dispatchable technology by the late 2030s, positioning the Company to continue to lower emissions into the 2040s. Building a new fleet of gas plants in the years ahead would likely have the opposite effect.

The difference in emissions between market access scenarios shown above appears to be due in large part to the scale of wind additions under the different plans. Compared to Xcel's Preferred Plan, the CEOs' 100% market access scenario builds significantly more wind, the 50% access scenario adds somewhat more wind, and the 0% and 25% market access scenarios build slightly less wind than Xcel's Preferred Plan. Therefore, our modeling shows that a plan that extends contracts with existing plants while adding additional wind capacity will have lower emissions than one that relies heavily on building new gas capacity, even if those new plants are peakers with low capacity factors.

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[51] Minn. Stat. § 216H.01, subd. 2.

[52] Xcel IRP, chapter 1, p.12; Xcel Energy, "Application to the Minnesota Public Utilities Commission for Approval of a Competitive Resource Acquisition Proposal: Lyon County Generating Station Proposal," *In the Matter of Xcel's Competitive Resource Acquisition Process for up to 800 Megawatts of Firm Dispatchable Generation,* Docket No. E002/CN-23-212 (Jan. 2024), chapter 4, p. 33.

E. Xcel Can Meet MISO Resource Accreditation Requirements Without 2 GW of New Gas Capacity

As noted above, each of the alternative CEO plans optimized in EnCompass use Xcel's load and peak load forecasts and capacity accreditation assumptions and meet the same MISO Resource Adequacy ("RA") requirements. Xcel's modeling (and ours) assigns resources accredited capacity "based on their [seasonal accredited capacity] SAC values from MISO PY 2023/2024 with a long-term trend to ELCC values for wind and solar resources, to ensure we maintain adequate capacity on our system over the planning period."[53] ELCC, short for effective load carrying capability, is a measurement of a resource's ability to produce energy when the grid is most likely to experience electricity shortfalls. Xcel, and EFG, also used the seasonal planning reserve margins established by MISO for PY 2023/2024, as shown below in Xcel's table 5-1.

Table 5-1: Seasonal Planning Reserve Margin

	Summer	Fall	Winter	Spring
MISO Planning Reserve Margin (PRM) PY24/25	9.00%	14.20%	27.40%	26.70%
Average Coincidence Factor	92.24%	92.67%	97.09%	95.61%

Using these assumptions, the four scenarios EFG modeled each meet Xcel's RA obligations in each year. The tables below summarize summer and winter accredited capacity under each CEOs market access scenario and in our rerun of Xcel's preferred plan in 2030 and 2035. The Attached EFG-AEC Report contains complete load and resources tables for summer and winter in each year 2024-2035 under each scenario.

CEOs Table 5. Accredited Capacity in 2030 and 2035 across all Scenarios, Summer and Winter (UCAP)

Year	Rerun Xcel Preferred Plan	CEO 0% Market Access	CEO 25% Market Access	CEO 50% Market Access	CEO 100% Market Access
Summer 2030	11,835	11,848	11,363	11,035	11,071
Summer 2035	12,556	12,834	12,557	12,408	12,450
Winter 2030	12,142	12,288	11,779	11,521	11,871
Winter 2035	12,495	12,770	12,623	12,632	12,955

CEOs Table 6. Accredited Capacity Surplus/(Deficit) in 2030 and 2035 across all Scenarios, Summer and Winter (UCAP)

Year	Rerun Xcel Preferred Plan	CEO 0% Market Access	CEO 25% Market Access	CEO 50% Market Access	CEO 100% Market Access
Summer 2030	1,000	1,013	528	199	236
Summer 2035	344	623	345	196	238

[53] Xcel IRP, chapter 3, p. 12.

Winter 2030	4,394	4,539	4,030	3,772	4,122
Winter 2035	3,596	3,872	3,725	3,734	4,057

Each of the five scenarios above meet the resource adequacy obligations and planning reserve margin requirements modeled by Xcel in EnCompass and use Xcel's capacity accreditation assumptions. These data show that resource portfolios developed when ignoring the MISO market have greater surplus capacity, particularly when looking at the summer season. The CEOs' 0% market access scenario shows the highest firm capacity out of these five scenarios and the four seasons examined, with surplus amounts slightly larger than Xcel's plan. The CEOs' 25% market access scenario shows a 528 MW surplus in summer 2030, about half of Xcel's (and the CEOs' 0% plan's) surplus, but has a very similar size surplus to Xcel in summer 2035, winter 2030 and winter 2035. The 50% market access and 100% market access plans show smaller summer surpluses, approximately 200-240 MW in 2030 and 2035. It is important to note that a larger surplus is not necessarily better – this is capacity ratepayers will pay for, and as discussed in Section II.D.2, the plans with higher surplus capacity come at a higher cost.

F. Extending Contracts with Certain Existing Gas Plants is Preferable to Building New Gas for Cost and Climate Reasons

CEOs' modeling includes extending contracts with three existing gas plants rather than building several new gas plants, as Xcel proposes. This is preferable for both cost and climate reasons.

The three contracts we modeled are for plants located in Minnesota – the Cottage Grove CC plant, the Mankato Energy CC plant, and the Cannon Falls CT plant. (We modeled ten-year extensions of these contracts, though five-year extensions with an option to extend another five years would be preferable, to maximize flexibility to respond to changing needs and options as the grid is decarbonizing.) Minnesota's statutory emission reduction targets apply to "statewide greenhouse gas emissions," which include all emissions generated within the state (as well as emissions from imported electricity).[54] If these existing contracts lapse, the plants will likely continue operating given their relatively recent vintage, and they will sell their output to other customers. If these plants do keep operating, and of course Xcel cannot retire them since they are owned by others, there would be no direct decrease in statewide greenhouse gas emissions achieved by allowing these contracts to lapse. Continuing to rely on these existing plants, therefore, does not increase Minnesota's statewide greenhouse gas emissions under the law, whereas building new gas plants with new CO_2 emissions clearly would.

In addition, extending the existing gas capacity contracts for ten years (or preferably five years with an option for 5 more) avoids locking in a new stream of carbon emissions from new plants that would last far longer and directly interfere with achieving the 2050 net-zero goals (as discussed in Section I.C). Avoiding new CT construction also reduces the risk of the new gas plants becoming stranded assets (as discussed in Section III.D.2), while preserving the opportunity for Xcel to build a meaningful amount of carbon-free dispatchable technology by the late 2030s.

[54] Minn. Stat. § 216H.01, subd. 2, and § 216H.02, subd. 1.

G. CEOs Recommend a Five-Year Action Plan that Considers and Balances the Benefits and Trade-Offs of the Five Evaluated Scenarios

CEOs' analysis of the five scenarios described above reveals several tradeoffs that must be weighed when approving resources to be acquired for the next five-year action plan period. These include: (1) the higher costs of planning as an island; (2) the risks of over-building long-term fossil fuel assets; (3) different levels of market exposure; and (4) the higher emissions of planning as an island.

Weighing these factors as well as considering the broader issue of what Minnesota and the U.S. must do to achieve our GHG emission reduction goals, CEOs recommend a Five-Year Action Plan for Xcel that balances the needs to achieve a fully reliable system, an affordable system, and one that best positions Xcel customers for the future. We recommend the Commission approve a plan that includes the following new resources by 2030:

1. **Xcel should be directed to acquire between 3,800-4,800 MW of wind resources by 2030.** CEOs recommend that Xcel be directed to acquire wind resources within this range to provide flexibility for Xcel and to account for the benefits of larger wind additions for long-term cost and emissions, as discussed earlier in this section. The average of wind additions in CEOs' plans is 3,800 MW by 2030 and 6,400 by 2035. CEOs' 100% market access run selects 4,800 MW of wind by 2030 as the most economic option for Xcel and its ratepayers and it has the lowest cost and emissions of the five scenarios examined.

   Additionally, Xcel's Preferred Plan and all CEOs' plans show large wind additions between 2031-2035; Xcel's plan includes 4,600 MW by 2032 and 5,800 MW by 2035. Given the timing of IRA tax credits, it may be beneficial to have flexibility for accelerating economic wind procurements from the 2030s into this decade.

   Moreover, prioritizing wind investments aligns with the broader need to decarbonize our economy. Multiple studies charting out pathways through which the U.S. can achieve its decarbonization goals show that the nation's wind capacity needs to expand dramatically, roughly *tripling* between the beginning of this decade and 2030, and continuing to expand beyond that.[55] This broader need and Xcel's location amongst some of the best wind resources in the world indicates that there are large societal advantages to prioritizing a

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[55] *See e.g.*, Steve Clemmer, et al., *Accelerating Clean Energy Ambition: How the United States Can Meet Its Climate Goals While Delivering Public Health and Economic Benefits,* Union of Concerned Scientists (Nov. 2023), at 15, https://www.ucsusa.org/resources/accelerating-clean-energy-ambition (under the net zero pathway, wind and solar capacity triples from 2021 to 2030 and increases three to five times again between 2030 and 2050); Eric Larson, et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts,* Princeton University (Oct. 2021), p. 99, *https://netzeroamerica.princeton.edu/?explorer=pathway&state=national&table=ref&limit=200* (under net zero pathways wind capacity increases ~2.5-3 times between 2021 and 2030 except in scenario that artificially caps wind deployment); *Accelerating Decarbonization of the U.S. Energy System*, National Academies of Sciences, Engineering, and Medicine, The National Academies Press (2021), p. 75, https://nap.nationalacademies.org/catalog/25932/accelerating-decarbonization-of-the-us-energy-system (net zero pathways deploy 2-3 times existing wind capacity by 2030, deploying at US record rates through 2025 and doubling that deployment rate in 2026-2030); James H. Williams, et al., 2021. "Carbon-Neutral Pathways for the United States." *AGU Advances* 2 (1): e2020AV000284 (2021) p. 1, https://agupubs.onlinelibrary.wiley.com/doi/10.1029/2020AV000284 (multiple pathways analyzed and all required expanding renewable capacity 3.5 fold by 2030).

large wind build by 2030. The Commission's planning rule requires it to consider, when evaluating a resource plan, whether it enhances a utility's ability to respond to changes in the financial, social, and technological factors affecting its operations, and whether it limits the adverse effects of such changes on the utility and its customers.[56] Increasing its wind build to 3,800-4,800 MW by the end of 2030 maximizes Xcel's ability to benefit from decarbonization and limits its exposure to the risks of future carbon regulatory costs. It also minimizes Xcel's impact on the environment, which is a third factor the Commission must consider under its rules.[57]

2. **Xcel should be directed to acquire 400 MW of solar resources by 2030.** Xcel should also be directed to continue evaluating opportunities for additional economic solar capacity, especially after MISO's resource accreditation process has stabilized. The 400 MW minimum is an amount of solar that appears in every run, regardless of what assumptions are made about market access and, as such, is a no-regrets floor for solar procurement.

3. **Xcel should be directed to acquire 800-1,200 MW of energy storage resources by 2030, with procurements considering both short- and long-duration technologies.** The need for large quantities of additional storage capacity in a decarbonized electricity system is well established. Greatly expanded energy storage, like greatly expanded renewable energy, is a critical part of many analyses charting out the nation's most feasible pathways for achieving the nation's GHG reduction targets, which are the same as Minnesota's GHG reduction targets.[58]

   The four market access scenarios CEOs examined contain an average of 780 MW of storage by 2030 and 2,205 MW by 2035, while Xcel's Preferred Plan includes 600 MW by 2030 and 1,320 MW by 2035. CEOs' 0% market access plan includes the most battery storage, at 1,320 MW by 2030, and 2,460 MW by 2035. CEOs believe that instructing Xcel to pursue battery resources within the range of 800 to 1,200 strikes a reasonable balance that gives Xcel flexibility to respond to changing storage costs and performance, limits market exposure, and reflects the fact that Xcel and the entire U.S. grid will need far more energy storage capacity as decarbonization continues. Currently, storage is the primary alternative to gas plants when it comes to providing new dispatchable capacity. Increasing Xcel's storage acquisition by 2030 addresses the need for dispatchable power without making a new long-term investment in carbon-emitting capacity. While all of the batteries modeled were four-hour duration, Xcel should consider both short and long-duration storage options in these procurements to ensure it can select resources with the most benefit for customers and the system.

4. **Xcel should be directed to achieve annual energy conservation of at least 780 GWh, as ordered in the 2019 Xcel IRP.** This is the level the Company plans to continue to achieve

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[56] Minn. R. 7843.0500, subp. 3, items (D) and (E).
[57] Minn. R. 7843.0500, subp. 3, item (C).
[58] *See e.g.,* Clemmer et al., 2023, *supra* n. 55, p. 15 (under net zero pathway capacity for energy storage increases six-fold by 2030 and 20-fold by 2050); Dan Esposito, 2021, *Studies Converge on Benefits of a Rapid Clean Energy Transition,* Energy Innovation (July 2021), p. 2 (meta analysis of pathways to achieve 80-90% clean electricity by 2030-2035 find they require 9 to 13 GW per year of new battery storage).

through its plan,[59] which reflects energy efficiency bundles developed to reflect its then-proposed (now approved) 2024-2026 ECO Plan.[60] As discussed in the attached EFG Report on demand side resources, CEOs have identified several areas for potential expansion and deeper energy savings, which is why we characterize the above recommendation as a floor. These findings are discussed further in Section V.C.

5. **The Commission should direct Xcel to acquire approximately 970 MW of generic dispatchable capacity by 2030 through a technology-neutral procurement process that limits new commitments to carbon-emitting resources to no longer than 10 years.** We have modeled approximately 968 MW (winter ICAP) of generic dispatchable capacity in each of CEOs' runs. (This is in addition to 374 MW of firm dispatchable power on the gen-tie line approved by the Commission in the last IRP and being considered in the current firm dispatchable docket.) Our modeling portrays this additional 968 MW as the extension of three of Xcel's existing PPAs, two of which have put bids into the firm dispatchable docket, but we recognize that the Commission cannot order Xcel to extend specific PPAs with specific parties.

   We therefore recommend the Commission direct Xcel to acquire approximately 970 MW of generic dispatchable capacity through a technology-neutral procurement process. For carbon-emitting resources bidding into this procurement, Xcel should limit contract terms or depreciable life to no longer than 10 years. For new dispatchable resources that may be acquired outside the firm dispatchable docket (where bids have already been submitted), Xcel should seek to limit its commitment to carbon-emitting resources to five years with an option to extend it another five years, in order to maximize the Company's ability to flexibly respond to the rapidly changing environment.

There is obviously much we do not know about the future of the grid between now and 2040, but there are several general features about which we can be quite certain: (1) we must continue to replace carbon-emitting generation with carbon-free generation, aiming toward full decarbonization by no later than 2050; (2) we will need far more renewable energy; (3) we will need far more energy storage; (4) we will need far more energy efficiency and demand management, and (5) Xcel will continue to function within a regional market.

Accelerating Xcel's investments in wind and storage and continuing to seek effective ways to expand energy conservation and demand reduction is entirely consistent with – indeed, demanded by – this decarbonizing future. That makes these investments important and low risk. By contrast, building a fleet of several new carbon-emitting gas plants is incompatible with this future, making that investment high-risk. The new gas plants would either need to retire well before the end of their operating lives, be retrofitted to burn 100% low-GHG hydrogen, or be retrofitted with 100% CCS. None of the financial costs of these three alternatives is reflected in Xcel's modeling. Moreover, the power sector may not be the best use of low-GHG hydrogen, and we don't know if retrofitting gas peakers with 100% CCS is even feasible. CEOs therefore believe the above portfolio – accelerating resources we know we need while limiting those we know we cannot rely upon – strikes the right balance for Xcel and its customers going forward.

[59] Xcel IRP, chapter 1, p. 3.
[60] Xcel IRP, Appendix F, pp. 6-7.

III. Xcel's Modeling Approach Is Overly Conservative and Results in Over-Building New Gas Capacity

Xcel made several assumptions and methodological choices in developing its resource plan that led to an overly conservative plan relying heavily on dispatchable generation (modeled as gas CTs). Each of these methodology choices are new approaches Xcel has not used to develop its plan in previous IRPs.

1. Xcel turned off MISO imports and exports in EnCompass when developing its capacity expansion plan.

2. Xcel required EnCompass to match Xcel's NSP load and NSP generation for each hour of each year of the 30-year planning period.

3. Xcel modeled its Preferred Plan in 2030 and 2040 against historical load and renewable generation profiles from the seven years 2016-2022 to assess whether the plan can meet load in each hour of each historical profile, without accessing the MISO market.

The implications of these methodological choices are discussed further below.

A. Xcel Assumes It Has No Access to the MISO Market, Contrary to Reality and Best Practice

First, Xcel chose to turn off the MISO market in all expansion plans except the "Market Access Optimization" scenario.[61] Xcel states, "In past resource plans, our modeling analysis allowed a portion of our resource needs to be fulfilled by the MISO market. When we performed the same analysis for the 2024 Plan, however, the models produced an expansion plan that would be unable to serve our load during a significant number of hours each year."[62] This statement reflects the Company's modeling assumption that Xcel is an island with no access to the MISO market. In reality, a shortfall would come about only if Xcel was unable to access its robust transmission connections to neighboring load serving entities and the MISO region, or if the MISO region was short on capacity at the same time as Xcel. MISO has robust market products, transmission planning, and resource adequacy requirements in place to prevent these scenarios.

1. It is Unnecessary to Constrain the Model on the Front End, Especially When Performing a Robust Energy Adequacy Analysis on Each Scenario

Second, Xcel used a new and more complex modeling methodology in this IRP, which involved two capacity expansion runs for each scenario. In the first step, Xcel uses typical settings for capacity expansion planning, optimizing for 24 representative days per year (an on- and off-peak day for each month) for each year of the 30-year planning period.

In Step 2, Xcel asked EnCompass to solve for *all calendar days* of the planning period. Because this requires many more calculations, Xcel had to change the optimization period (the period EnCompass looks at to solve for the best fit resource plan) from the whole planning period, as used in Step 1, to four-year periods. By using a short four-year optimization window, Xcel is

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[61] Xcel IRP, chapter 5, p. 4.
[62] Xcel IRP, chapter 1, p. 8.

asking EnCompass to develop a long-term resource plan while EnCompass can only see four years at a time. CEOs are concerned that this will necessarily lead to sub-optimal results.

Further, the risk Xcel is aiming to avoid with this modeling decision – "market reliance"[63] – is directly evaluated in its Energy Adequacy studies which apply historical weather years, including some with extreme weather events, to a future peak load and resource mix to gauge performance of the portfolio in real-world conditions. CEOs explain why the energy adequacy modeling is also highly conservative in Section IV. But, if the results of a conservative energy adequacy analysis demonstrate a reliable system with an acceptable level of imports, there is no need to *also* use highly conservative constraints on the front-end.

The conventional modeling process using on-and off-peak time sampling reflects a focus on achieving a reasonable result by ensuring the optimized resource plan can meet load on representative peak days and ensuring that resource adequacy is met, while not overbuilding for outlier hours. It is important to recognize that there is a cost at which adding more capacity to avoid loss of load is not an efficient economic decision, which is why the industry has historically planned for a 1 day in 10 years loss of load probability. CEOs agree with other entities who have argued that this metric is not granular or specific enough; but that does not mean the standard should be absolutely 0. While reliability is absolutely critical, the industry has long recognized that "gold-plating" is not an economically optimal response.

2. Xcel Has Robust Transmission Connections to Its Neighbors, and Its MISO Zone Is in a Reasonable Capacity Position

For a resource plan, it is simply not necessary to model each hour of each day in order to achieve a reliable system. Xcel has robust transmission connections to its neighbors in Zone 1 and the broader MISO region. While additional transmission is critically important for reducing congestion, serving growing load, facilitating more renewable energy integration, and enhancing reliability, Zone 1 has the capability to move thousands of MW of electricity across its boundaries.[64] MISO is undertaking a historic level of transmission expansion through its Long Range Transmission Planning ("LRTP") initiative, with Tranche 1 lines expected to be in service by the end of 2030, Tranche 2.1 lines to be approved by the end of the year and in service as soon as 2032,[65] and a likely Tranche 2.2 addressing the Midwest MISO subregion's needs coming shortly thereafter.[66]

For each of the past ten years, Zone 1 has had sufficient or surplus capacity[67] and is in good shape to continue to have sufficient capacity in all seasons. The most recent zone-level

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[63] Xcel IRP, chapter 5, p. 11-12.
[64] Xcel IRP, chapter 3, p. 10, Table 3-3.
[65] MISO LRTP Tranche 2.1 Reliability & Economic Deep Dive (Central and East Region focus) LRTP Workshop July 17, 2024, slide 61, https://cdn.misoenergy.org/20240717%20LRTP%20Workshop%20Item %2002%20Reliability%20%20Economic%20Deep%20Dive638965.pdf.
[66] MISO Reliability Imperative: Long Range & Interregional Transmission Planning, Presentation to the System Planning Committee of the Board of Directors, June 25, 2024, slides 10 and 17, https://cdn.misoenergy.org/20240625%20System%20Planning%20Committee%20of%20the%20BOD%20 Item%2007%20Reliability%20Imperative_LRITP634901.pdf.
[67] Zone 1 has had very low planning reserve auction (PRA) clearing prices for each of the past 10 years, indicating the Zone has sufficient generating capacity to meet demand, as shown in MISO, Planning Resource Auction Results for *Planning* Year 2024-25, Slide 25 (Apr. 25, 2024), https://cdn.misoenergy.org /2024%20PRA%20Results%20Posting%2020240425632665.pdf.

information publicly available comes from MISO's 2023 Regional Resource Assessment, which was developed using data and announced projects as of January 2023.[68] At that time, MISO projected Zone 1 would have a 1 GW surplus in summer 2027 and may have a 1GW shortfall by summer 2032—*but this is before* accounting for generators planned or announced after January 2023. One GW is approximately 5.5% of the zone's current summer PRMR; 20.75 GW of capacity in Zone 1 was offered into the summer PRA for the 2024/25 planning year.[69]

Forecasted energy and peak demand growth should not cause us to over-build dispatchable generation as if we are an island, but instead cause us to focus on bringing proposed capacity online faster. In the past six months alone (January-June 2024), 14.6 GW (ICAP) of projects located in Zone 1 have entered the MISO generator interconnection queue, including over 4 GW of battery storage or hybrid projects.[70]

CEOs Table 7. MISO Generator Interconnection Queue: Applications Submitted January-June 2024 in MN, SD, ND, and WI (ICAP)

Fuel Type	Number of Projects	Summer MW	Winter MW
Battery Storage	20	3,245	3,245
Diesel	1	0	40
Gas	5	1,240	900
Hybrid	4	852	852
Solar	27	5,139	5,139
Wind	20	4,129	4,129
Total	**77**	**14,605**	**14,305**

To take just Xcel as an example, the timing of MISO's 2023 RRA report means that none of Xcel's planned investments from this IRP are included in the 2023 RRA, just the projects approved in Xcel's last IRP. In Xcel's last IRP, the Commission approved up to 800 MW of firm dispatchable capacity to be added in the 2027-29 timeframe. In its 2024 IRP, Xcel has proposed 1,500 MW of firm dispatchable capacity in that same timeframe, another 750 MW in 2030, and another 225 MW in 2032 – meaning that Xcel's incremental new firm dispatchable plans (an additional 1,675 MW, or 1,340 accredited capacity) would more than fill the capacity gap MISO's 2023 RRA Study projected for the entire zone by 2032. This also is before we consider the capacity added by the incremental 1,000 MW of storage and 1,900 MW of wind included in Xcel's 2024 proposed plan.

[68] MISO, 2023 Regional Resource Assessment*: A Reliability Imperative Report* (Nov. 2023), https://cdn.misoenergy.org/2023%20Regional%20Resource%20Assessment%20Report630736.pdf.
[69] MISO, Planning Resource Auction Results for Year 2024-25, Slide 16 (Apr. 25, 2024), available here: https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%2020240425632665.pdf.
[70] MISO, Interactive Interconnection Queue database available at: https://www.misoenergy.org/planning/resource-utilization/GI_Queue/gi-interactive-queue/.

B. MISO is Making Changes to Its Resource Adequacy Construct Intended to Address the Same Concerns Xcel Points to Regarding Capacity, Risk Hours, and Energy Adequacy

As the Commission is intimately aware, MISO is in the process of making numerous changes to key market constructs and requirements with the explicit purpose of improving reliability and ensuring adequate capacity and energy as the region shifts to utilizing more weather-dependent generation resources. These efforts include major reforms to MISO's resource adequacy construct and planning reserve margin requirements ("PRMR"), its capacity accreditation methodology, the planning reserve auction and capacity pricing, increasing the value of lost load, and myriad efforts under the umbrella of "system attributes."

The new seasonal resource adequacy construct and related Direct Loss of Load ("DLOL") capacity accreditation methodology make several changes that address the exact concerns Xcel is over-correcting for by modeling its system without the ability to import or export from neighbors. These changes include:

- Establishing PRMRs specific to each season and tying these margins to the riskiest hours in each season.
- Using the DLOL capacity accreditation method to develop PRMR and local reliability requirements that reflect both modeled and actual generator performance during the riskiest hours, not the peakiest hours.
- Calculating resource-class level capacity accreditation based on that class of generator's performance only during the riskiest hours MISO forecasts on its system: hours that MISO's loss of load expectation model identifies as loss of load events or very low margin hours, and giving extra weight in this calculation to loss of load hours.
- An individual generators' performance during *actual* recent risk hours is layered onto the class-level resource accreditation to calculate the capacity accreditation that specific generator will receive.

These changes to resource accreditation and resource adequacy are a significant paradigm shift. MISO has moved very quickly away from planning for system peaks, or even seasonal peaks, and toward planning for net peak (the peak of demand after accounting for renewable generation) and the riskiest hours. To achieve this, MISO has radically shifted capacity accreditation to resources that have, or are forecast to (based on MISO's LOLE modeling), perform better during a narrow range of risk hours. These changes will not fully go into effect until the 2028/29 planning year (starting June 2028).

In the interim, MISO has provided market participants with indicative planning reserve margin requirements and seasonal capacity accreditation values. While CEOs have not seen Xcel's indicative results, MISO has indicated that after DLOL goes into effect, many winter season PRMs will be negative (on a UCAP basis). While capacity accreditation values will drop, particularly for renewables and storage in certain seasons, PRMs will also drop, mitigating the severity of the change. MISO is also updating its model for forecasting loss of load events, which may lead to some changes to resource accreditation under DLOL compared to what we know today.

We do not yet know exactly how all of these changes will balance out, but we do know that it is not necessary for utilities to go far above and beyond their resource adequacy obligations and plan for *the* most risk-averse portfolio—self-supplying in each hour. Doing so risks over-building, foregoing opportunities for sharing reserves, and eroding the value ratepayers should get from participation in a large regional market.

C. Gas Plants Are Not Necessary to Address "Critical Reliability Needs"

In the 2024 Integrated Resource Plan, Xcel's Appendix D1: Inertial Floor Study Report concluded that the nearing retirement of four coal-fired generation units, Sherco 1, Sherco 2, Sherco 3, and King, could introduce risks to system stability, which if unaddressed could result in system collapse. To mitigate this risk, Xcel advocates for new synchronous resources to meet the "Critical Reliability Needs" required to maintain transmission system stability. CEOs agree that system strength and reliability are fundamental needs that must be maintained by Xcel across all future resource mixes and appreciate that Xcel is proactively studying their system to identify and mitigate threats to system stability that could be introduced as the grid moves away from synchronous thermal generation to renewable inverter-based resources.

CEOs asked expert transmission modeling firm Telos Energy to review Xcel's report and determine whether adequate evidence of an inertia deficiency was shown, and whether adequate consideration was given to new (and commercially available) grid technology as an alternative to new thermal generation. This analysis is presented as Attachment B, *Review of Grid Stability Concerns in the 2024 Xcel IRP*. Telos Energy's review found that despite nearing coal plant retirements, Xcel did not demonstrate that their system is approaching an unacceptably low level of inertia. The report also did not identify a "floor" or minimum level of inertia required to maintain system stability. As a result, the study provides no evidence of a need for new thermal generation, or any inertia assets.

Furthermore, while Xcel's report did explain how new thermal generation can increase system inertia and therefore improve system stability, it did not include a rigorous or broad review of other technologies that can provide similar system benefits, often at lower costs and emissions. While CEOs agree that thermal generators can provide additional services to the transmission system beyond capacity and energy, these services can also be provided today with battery energy storage systems ("BESS") equipped with Grid Forming ("GFM") Inverter controls which are commercially available and have been deployed across the globe. These technologies, as well as other Flexible AC Transmission System ("FACTS") devices including synchronous condensers, can be used to ensure Xcel's system can continue to meet or exceed its current level of reliability. Xcel does not adequately evaluate these technologies or compare them to thermal generation assets.

Telos' findings indicate that there is no evidence that new gas units are needed to maintain critical reliability services in the wake of coal retirements. As a result, CEOs recommend that for any thermal generation proposed or premised based on its ability to provide critical reliability services including inertia or system stability, Xcel must properly evaluate and compare new carbon-free technologies including BESS with GFM inverters and FACTS as alternatives to ensure just and reasonable investment.

Xcel and the Commission should ensure that procurement processes enable this evaluation to take place, namely by ensuring that IBR with GFM are allowed to compete with thermal resources in procurements where grid stability is at issue. This may require heightened intentionality when developing procurement processes. For example, Xcel is currently in the process of acquiring renewable resources that will connect to the Minnesota Energy Connection ("MNEC")—the generation tie-line from southwestern Minnesota to the Sherco site—through a development-transfer procurement process (docket no. 23-342) separate from the firm dispatchable contested case (docket no. 23-212), which will select dispatchable resources that could be located on MNEC or could be located elsewhere. If concerns are raised about grid stability on MNEC during the firm dispatchable case (e.g., as a reason to select a thermal resource on the tie-line), those concerns may not be able to be addressed by adjusting the requirements of the already-underway development transfer procurement process to require or prioritize projects using GFM. This is unfortunate, because concerns about voltage stability on MNEC could be most effectively addressed by requiring that renewable energy and storage projects connecting to the line use GFM technology.

As this example shows, dividing resource acquisitions by technology type can prevent—or at minimum complicate—efforts to directly compare the relative strengths of GFM-equipped renewable energy or storage with thermal resources. For future procurements where grid support or critical reliability services may be at issue, it is imperative that procurements are designed with this in mind to enable evaluation of different resource types and enable the procurement to identify the best solution. Therefore, CEOs recommend that the Commission direct Xcel to identify in future procurements whether the procurement is intended to address any location-specific or grid stability related concerns, explain what those concerns are, and detail how the procurement process will enable comparison of different resource types that may have the capability to resolve the concerns.

D. There Are Substantial Costs and Risks to Over-Building Gas Capacity

1. EnCompass Modeling Demonstrates the Costs of Planning as if Xcel Is an Island Approach $4-5 Billion by 2050

As discussed earlier, there will be significant costs and tradeoffs for customers if Xcel develops a resource plan as if it is an island. Doing so creates a plan that includes significantly more near-term dispatchable capacity with a commensurately higher cost. And, if fossil fuels are used for the dispatchable capacity, such a plan will also come with high future fuel price exposure and regulatory and stranded asset risks.

Xcel's modeling and EFG's modeling both demonstrate that there is a cost to planning a resource portfolio as if one is an island. Xcel's Preferred Plan costs $4.7 billion more than its market access optimization scenario by 2050.[71] EFG's analysis shows a similar result. By 2040, the cost difference between the CEOs' 100% market access scenario and CEOs' 0% market access scenario is $1.3 billion on a PVRR basis and $3.9 billion on a PVSC basis, as shown in the table below. Thus, planning as if the market can never deliver comes with a significant cost premium that would need to be scrutinized carefully for prudence and reasonableness.

[71] Xcel response to CEOs IR No. 1, Modeling Output Files, EO-2024 IRP – Scenario 3 Sens R 2300 MW Mkt Access – 2024-01-31 [TRADE SECRET]. Xcel has given CEOs permission to treat this value as nonprotected data.

CEOs Table 8. PVRR/PVSC Value of Market Access, ($Millions), 2024-2050

Modeling Run	PVRR	PVSC	PVRR Savings/(Cost) vs. 0% Mkt	PVSC Savings/(Cost) vs. 0% Mkt
CEO Market Access 0%	$50,635	$69,149	-	-
CEO Market Access 25%	$49,974	$68,471	$661	$678
CEO Market Access 50%	$49,570	$67,174	$1,065	$1,975
CEO Market Access 100%	$49,360	$65,227	$1,275	$3,922

2. The Risk of New Gas Plants Becoming Stranded Assets is High

Xcel's Preferred Plan would build 2,244 MW of new CTs by the end of 2030 and models the addition of another 1,347 MW of CTs by the end of 2040.[72] (While beyond the scope of this IRP, the modeling underlying Xcel's Preferred Plan then **[PROTECTED DATA BEGINS…**

…PROTECTED DATA ENDS].[73]) None of the CTs in Xcel's Preferred Plan are modeled with carbon capture and they all burn natural gas, not hydrogen. They are assumed by Xcel to have a depreciable life of 40 years.[74] Obviously, even the CTs built in the 2020s cannot operate as modeled for their full depreciable life if we are to achieve the science-backed state and federal goals of reaching net-zero by 2050,[75] or if Xcel is to reach its own corporate goal of providing its customers entirely carbon-free power by 2050.[76] It is by no means certain that the CTs Xcel proposes to build would or should ever be fully converted to hydrogen (see Section III.D.3 below), or that it would be financially or technologically feasible to capture 100% of their carbon emissions. Thus, even building the CTs Xcel proposes to build through 2030 sets the utility and its ratepayers up for an inordinate and unnecessary risk of stranded assets in the future.

Xcel's Preferred Plan does not achieve its corporate goal of being carbon-free by 2050. As noted above, Xcel's plan would have CO_2 emissions of nearly **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]** in 2050 from its gas combustion turbines.[77] These emissions would be even higher but for the assumed carbon regulatory costs the Commission has projected for 2028 and beyond, which suppress dispatch of the gas plants.

The risk that newly-built gas plants will have to be retired well before the end of their depreciable lives is also evident in the literature considering how the U.S. can meet its GHG reduction goals. Since 2021, multiple teams of researchers charted pathways the U.S. could take

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[72] Xcel IRP, chapter 4, p. 2.
[73] Xcel response to CEOs IR No. 1, Modeling Output Files, EO-2024 IRP – Base Scenarios – 2024-01-31 [TRADE SECRET].
[74] Xcel IRP, Appendix F, p. 36, Table F-23.
[75] Minn. Stat. § 216H.02, subd. 1(a); "The United States of America Nationally Determined Contribution: Reducing Greenhouse Gases in the United States: A 2030 Emissions Target," (Apr. 21, 2021), https://unfccc .int/sites/default/files/NDC/2022-06/United%20States%20NDC%20April%2021%202021%20Final.pdf.
[76] Xcel IRP, chapter 3, p. 22.
[77] Xcel response to CEOs IR No. 1, Modeling Output Files, EO-2024 IRP – Base Scenarios – 2024-01-31, Emissions tab.

to achieve the emission reductions needed to limit warming to 1.5ºC.[78] In addition to uniformly stressing the need to eliminate all or virtually all unabated coal plants from the grid by 2030, these pathway studies show gas generation declining by 2030 and continuing that decline in the following two decades. One such study concluded in 2021 that "[c]utting electricity emissions in line with a 1.5ºC target also requires not building any new gas plants that lack carbon capture. The United States already has a massive oversupply of gas plants, many of which are likely to become stranded assets, and no reason exists to build more plants."[79] A more recent study by the Union of Concerned Scientists in 2023 stresses that pathways to achieve net zero by 2050 mean that "existing fossil fuel technologies are rapidly rendered redundant." This in turn indicates that the U.S. should "sharply limit the building of any new, long-lived, fossil fuel infrastructure, which would likely become a stranded asset in a carbon-constrained world."[80]

In short, either Xcel's proposed gas plants operate as modeled, threatening our ability to achieve our emission reduction goals, or they must be retired far before the end of their modeled lifetimes, meaning Xcel and its ratepayers will not recover their investment. Both these risks are even greater given the tremendous increase in warming in 2023 and 2024, which suggests we may have less time than we thought to decarbonize.

3. The Prospect that the Several New Gas Plants Xcel Proposes to Build Might Someday Burn Hydrogen Should Be Met with Skepticism

Xcel notes in its IRP that an advantage of the natural gas combustion turbines they model is that in the future they "could run at least partially on clean fuels like hydrogen."[81] In its proposal for the 420 MW Lyon County CT (submitted in the Commission's parallel Firm Dispatchable docket) Xcel discusses the option of cofiring with 30% hydrogen and states that "[t]he capability of the CTs to co-combust natural gas and hydrogen will allow Minnesota to achieve goals set in the Minnesota Next Generation Energy Act."[82] However, there are at least

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[78] *See e.g.*, Nathan Hultman, et al., *Charting an Ambitious U.S. NDC of 51% Reductions by 2030*, Univ. Md. Center for Global Sustainability (Mar. 2021), https://cgs.umd.edu/research-impact/publications/working-paper-charting-ambitious-us-ndc-51-reductions-2030; Robbie Orvis, *A 1.5 Celsius Pathway to Climate Leadership for the United States*, Energy Innovation (Feb. 2021), https://energyinnovation.org/wp-content/uploads/2021/02/A-1.5-C-Pathway-to-Climate-Leadership-for-The-United-States.pdf; *Accelerating Decarbonization of the U.S. Energy System*, National Academies of Sciences, Engineering, and Medicine, The National Academies Press (2021), https://nap.nationalacademies.org/catalog/25932/accelerating-decarbonization-of-the-us-energy-system; Eric Larson, et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts,* Princeton University (Oct. 2021), *https://netzeroamerica.princeton.edu/?explorer=pathway&state=national&table=ref&limit=200*.

79 Robbie Orvis, *A 1.5 Celsius Pathway to Climate Leadership for the United States*, Energy Innovation (Feb. 2021), at 8, https://energyinnovation.org/wp-content/uploads/2021/02/A-1.5-C-Pathway-to-Climate-Leadership-for-The-United-States.pdf.

[80] Steve Clemmer, et al., *Accelerating Clean Energy Ambition: How the United States Can Meet Its Climate Goals While Delivering Public Health and Economic Benefits,* Union of Concerned Scientists (Nov. 2023), at 10, https://www.ucsusa.org/resources/accelerating-clean-energy-ambition.

[81] Xcel IRP, chapter 1, p. 15.

[82] Xcel Energy, "Application to the Minnesota Public Utilities Commission for Approval of a Competitive Resource Acquisition Proposal: Lyon County Generating Station Proposal," *In the Matter of Xcel's Competitive Resource Acquisition Process for up to 800 Megawatts of Firm Dispatchable Generation,* Docket No. E002/CN-23-212 (Jan. 2024), at 58-59.

three reasons why the prospect of future hydrogen co-firing in the combustion turbines Xcel has modeled should be met with skepticism.

First, hydrogen's lower energy density limits how much hydrogen cofiring can reduce a natural gas plant's carbon emissions. The EPA, in its proposed rule limiting power plant GHGs, noted that many combustion turbine designs are capable of co-firing a mix of 70% natural gas and 30% hydrogen by volume.[83] However, because the energy density of hydrogen is lower than natural gas, the turbines must burn more of the methane/hydrogen blend to generate the same electricity. As a result, cofiring 30% hydrogen by volume only reduces CO_2 emissions per megawatt-hour by 12%.[84]

Second, even this modest carbon reduction depends on hydrogen being produced using the lowest-carbon methods; otherwise, hydrogen cofiring can substantially *increase* carbon emissions. Currently, over 95% of hydrogen produced in the U.S. originates from natural gas using a process called Steam Methane Reforming ("SMR").[85] SMR adds steam and heat to natural gas, ultimately yielding hydrogen and CO_2. According to the EPA, cofiring SMR-produced hydrogen in a combustion turbine actually requires more natural gas for the hydrogen production than is displaced by the hydrogen cofiring, and therefore increases overall CO_2 emissions compared to just burning 100% natural gas.[86]

Another way to make hydrogen is using electrolysis – that is, using electricity to split water into hydrogen and oxygen. However, this process uses so much electricity that if it were simply powered by the grid it would likely cause existing coal and gas plants to run more often, making the net carbon impact even higher than burning SMR-derived hydrogen. In fact, based on national average grid carbon intensity, burning hydrogen produced using grid-supported electrolysis would cause overall carbon emissions that are twice as high as burning hydrogen produced using SMR, which in turn produces overall carbon emissions higher than just burning natural gas without any hydrogen cofiring at all.[87] Moreover, even if the electrolysis is powered by carbon-free electricity sources, unless those sources are new and meet other criteria, electrolysis can still yield higher overall carbon emissions by using up existing carbon-free generation and thereby expanding generation by carbon-emitting sources.[88] Concerns over the future availability of low-GHG hydrogen at a reasonable cost, which will also likely require construction of new pipeline networks, caused the EPA to ultimately drop its proposal that new

[83] U.S. Environmental Protection Agency, *New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units, etc.*, Proposed Rule, 88 Fed. Reg. 33240, 33308 (May 23, 2023).
[84] *Id.*
[85] *Id., 33306.*
[86] *Id.*, 33307.
[87] *Id.*, 33307 and footnote 399; *see also* U.S. Department of Energy, *Pathways to Commercial Liftoff: Clean Hydrogen* (March 2023), p. 12, https://liftoff.energy.gov/wp-content/ uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB.pdf.
[88] After consulting with the EPA and Department of Energy, the Treasury Department (which administers the federal hydrogen subsidies) has determined that to avoid this problem, called "induced grid emissions," electrolysis must be powered by carbon-free generation sources that are new, that are located in the same region, and that generate in the same hour it is used to produce hydrogen. U.S. Department of Treasury, IRS, *Section 45V Credit for Production of Clean Hydrogen, etc.,* Notice of Proposed Rulemaking, 88 Fed. Reg. 89220, 89228-89233 (Dec. 26, 2023).

gas plants above a certain capacity factor cofire with 30% hydrogen by 2032.[89] If the CTs Xcel has modeled were capable of someday burning 100% hydrogen (which they are not today), Xcel would be even more dependent on a fuel supply chain that is not yet built. Moreover, Xcel would have to include in its modeling the additional generation needed to support all the additional demand from hydrogen production.

Finally, it is important to recognize that a huge amount of power is lost when using electricity to produce hydrogen that is then cofired in gas plants to produce electricity again. The "round-trip efficiency" of this process (the ratio of useful energy output to useful energy input[90]) is especially low when the gas plants are combustion turbines such as what Xcel proposes, rather than the more efficient combined-cycle plants. A recent MIT study found that the round-trip efficiency of burning electrolysis-produced hydrogen in combustion turbines is only 18-31%.[91] In other words, 69-82% of the electricity initially generated is lost in the process. By contrast, the study found that flow batteries, which can also be used for long-duration storage, had a round-trip efficiency of 60-80%.[92] And while lithium-ion batteries are not long-duration storage technologies, they have a round-trip efficiency of about 85%, according to the National Energy Renewable Laboratory.[93]

The efficiency of electrolysis will likely improve in the future, and combustion turbines may become somewhat more efficient as well. However, the round-trip efficiency of hydrogen is so far behind that of batteries – which are also improving in efficiency – that it seems unlikely hydrogen will become a significant fuel for the power sector except perhaps for limited seasonal storage purposes. While low-GHG hydrogen could have an important role to play in a fully decarbonized world, it will probably find a higher use in sectors of the economy that have fewer options than the power sector for decarbonization.

Thus, the Commission should view with skepticism any suggestion that the combustion turbines proposed by Xcel will significantly reduce their carbon emissions in the foreseeable future by partially burning hydrogen, or that hydrogen could be used to extend the gas plants' operating lives. The carbon reductions from cofiring are minimal, those reductions depend on a low-GHG hydrogen supply chain yet to be built, and cofiring with low-GHG hydrogen is a highly inefficient use of the carbon-free electricity needed to produce it.

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[89] U.S. Environmental Protection Agency, *New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units, etc.*, Final Rule, 89 Fed. Reg. 39798, 39939 (May 9, 2024).

[90] National Renewable Energy Laboratory (NREL), Annual Technology Baseline: Utility-Scale Battery Storage, web page (accessed July 23, 2024) https://atb.nrel.gov/electricity/2024/utility-scale_battery_storage .

[91] Nestor A. Sepulveda, et al., "The Design Space for Long-duration Energy Storage in Decarbonized Power Systems," *Nature Energy* 6, 506-516 (2021), Table 1, https://dspace.mit.edu/handle/1721.1/138145.2. The round-trip efficiency for electrolysis-produced hydrogen burned in combined cycle plants is 26-42%. *Id.*

[92] *Id.* The study defines Long-Duration Energy Storage as technologies suitable to storing sufficient electricity to sustain electricity production over periods of days or weeks.

[93] NREL, Annual Technology Baseline: Utility-Scale Battery Storage, web page (accessed July 23, 2024) https://atb.nrel.gov/electricity/2024/utility-scale_battery_storage.

4. Gas Peaker Plants Emit Pollutants that Harm Human Health Locally and Regionally

Even if they are cleaner than coal plants, gas plants still have significant emissions of air pollutants that contribute to disease and premature death. Of particular concern are gas plants' emissions of nitrogen oxides ("NOx"). NOx combines with other compounds in the air to form ozone, a lung-damaging pollutant, and, most dangerously, fine particulate matter ("$PM_{2.5}$"). $PM_{2.5}$ is a major public health concern because it increases the incidence of heart and lung disease, as well as contributing to early death from those diseases. While the health impacts from the gas plants are expected to be greatest in the plants' surrounding area, these pollutants also cause regional health impacts and contribute to regional haze.

Combustion turbines ("CTs") typically emit far more NOx per MWh than combined-cycle gas plants, due to CTs' lower efficiency, less effective pollution controls, and higher rates of start-up/shut down cycling. Even new CTs have far higher emissions of NOx per MWh than CCs. For example, EPA data shows that Astoria Station, a 349 MW CT that came online in South Dakota in 2021, emitted NOx/MWh in 2022 at about 3.4 times the rate of the Cottage Grove 283 MW CC.[94] As a result, even though Astoria generated less than one-third as much power as Cottage Grove in 2022, it had higher absolute emissions of NOx than Cottage Grove.[95]

We note that Xcel has modeled CTs that, according to the Company, would actually emit NOx at a higher lb/MWh rate than the Astoria CT.[96] The H-class turbine Xcel modeled would have NOx emissions of 0.32 lb/MWh, or slightly higher than Astoria's, and the F-class turbine would have NOx emissions of 0.90 lb/MWh, more than three times higher than Astoria's.[97] Thus, the Commission cannot assume that the massive build-out of CTs modeled in Xcel's Preferred Plan would have minimal health impacts because they are expected to run at relatively low capacity factors. The higher NOx emissions rate of peaker plants can make them significant sources of local and regional pollution even when operating at low rates. And as we discuss below, there is no guarantee they will operate at those low rates.

The significant emissions of health-harming pollutants from CTs are therefore yet another reason the Commission should not approve building them at anything like the scale Xcel proposes.

5. Xcel's Proposed Gas Peakers Could Operate More Than Modeled and Emit Substantial Amounts of Carbon Dioxide

There is uncertainty over how often the new gas plants Xcel proposes to build would actually run, meaning there is uncertainty over their future climate impact. CTs emit more CO_2/MWh than the more efficient CCs, making the CTs' capacity factor particularly important. Xcel refers to its firm dispatchable resources as being "designed to operate only 5-10% of the year."[98] Modeling results for Xcel's Preferred Plan shows capacity factors for the new CTs **[PROTECTED DATA BEGINS... ...PROTECTED DATA**

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[94] Astoria Station emitted NOx at an annual rate of 0.271 lb/MWh in 2022, while Cottage Grove emitted NOx at 0.079 lb/MWh. U.S. Environmental Protection Agency, eGRID 2022 database, https://www.epa.gov/egrid/download-data.
[95] *Id.* Astoria Station emitted 24 tons of NOx in 2022, while Cottage Grove emitted 23 tons of NOx.
[96] Xcel IRP, Appendix F, p. 36, Table F-23.
[97] Xcel IRP, Appendix F, p. 36, Table F-23.
[98] Xcel IRP, chapter 1, p.12.

ENDS] assuming the mid-range carbon regulatory costs that the Commission adopted in 2023, which would suppress the dispatch of the new gas plants.[99] However, if those predicted regulatory costs are delayed beyond the presumed start date of 2028, or policies creating them are ultimately not enacted or adopted, the new combustion turbines would have higher capacity factors. For example, without the dispatch-suppressing effects of the carbon regulatory cost, the new generic H-class peakers would have capacity factors **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]**.[100] Running at this higher rate would, of course, yield commensurately higher CO_2 emissions.

Xcel's Lyon County gas plant proposal, submitted in the Commission's parallel Firm Dispatchable docket, suggests just how hard these CTs could be run. Xcel says its two CT units for the Lyon County project (totaling 420 MW) are expected to have an annual capacity factor of between 5-10%, but that they "will be permitted to operate up to 35% capacity factor" because future needs may vary.[101] Xcel's proposal states that this single 420 MW CT project -- which represents less than one-fifth of the new gas CT capacity in Xcel's Preferred Plan just through 2030 -- could emit *over one million tons* CO_2 per year.[102] It is important for the Commission to recognize that any of the new gas peakers could be run at capacity factors far above their modeled ones, turning them into very large sources of CO_2.

IV. Xcel Can Achieve a Reliable Portfolio Without Adding 2GW of New Gas Peakers

The volume of gas plants in Xcel's Preferred Plan presents a serious emissions problem. Luckily, our analysis shows that firm peaking capacity is not needed in nearly the quantities Xcel proposes in order to achieve a reliable system. For example, none of the four CEO market access scenarios add new "firm peaking" (i.e., CT) capacity before 2035, aside from the one resource we fixed into the model in 2028 as it is subject to procurement in the concurrent firm dispatchable case. EFG ran each of these scenarios through the Energy Adequacy analysis Xcel performed, and the results show that replacing Xcel's proposed 2,244 MW of new CTs by 2030 with a combination of wind, battery storage and contract extensions achieves strong energy adequacy results.

EFG's Energy Adequacy analysis used the same assumptions as Xcel's. As explained in the EFG-AEC Report, "Xcel's Energy Adequacy analysis uses the historical weather years from 2016 – 2022 to develop an 8,760-hour historical demand and renewable shape for those weather years. Xcel then used those 8,760 shapes to model capacity expansion plans in 2030 under the forecasted 2030 monthly peak and energy forecasts and resource mix.[103] For each weather year modeled, MISO market interaction was turned off to determine any hours with differences

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[99] Xcel response to CEOs IR No. 1, Modeling Output Files, EO-2024 IRP – Base Scenarios – 2024-01-31 [TRADE SECRET]; Minn. Pub. Utils. Comm'n, "Order Addressing Environmental and Regulatory Costs," *In the Matter of Establishing an Updated 2022 Estimate of the Costs of Future Carbon Dioxide Regulations on Electricity Generation Under Minn. Stat. § 216H.06,* Docket No. E-999/DI-22-236 (Dec. 19, 2023).
[100] Xcel response to CEOs IR No. 1, Modeling Output Files, EO-2024 IRP – Base Scenarios – 2024-01-31 [TRADE SECRET].
[101] Xcel Energy, "Application to the Minnesota Public Utilities Commission for Approval of a Competitive Resource Acquisition Proposal: Lyon County Generating Station Proposal," *In the Matter of Xcel's Competitive Resource Acquisition Process for up to 800 Megawatts of Firm Dispatchable Generation,* Docket No. E002/CN-23-212 (Jan. 2024), chapter 4, p. 33.
[102] *Id.,* chapter 6, p. 57, Table 6-7.
[103] Xcel IRP, Appendix D, p. 5.

between Xcel's generating resources and its load, which determines the proxy 'unserved energy' or market reliance that would be needed."[104]

Before discussing the specific results, CEOs note several assumptions underlying Xcel's analysis which are problematic or make the results highly conservative.

- First, Xcel developed historical load shapes and renewable generation shapes from these seven years, but did not do the same for forced outage rates and derates for non-renewable generators. Therefore, the results are likely to be overly optimistic for portfolios relying more heavily on thermal generators.
- Second, this analysis assumes the renewable generation in Xcel's 2030 resource portfolio will have the profile of its renewable generators from 10-15 years prior, and does not consider the complementarity of generators outside Xcel's fleet. As renewable energy technology, design, and operation evolve, and as wind and solar are sited in new geographic areas with variations in weather patterns, this historical assumption is likely to under-represent the amount and distribution of renewable generation in the 2030s.
- Third, this analysis assumes the MISO market is unavailable at all hours. As we have discussed above, this is not a realistic assumption for many reasons. We understand the purpose of the Energy Adequacy analysis as identifying the scale and frequency of *reliance* on the MISO market, which can be used to inform a comprehensive risk assessment of different plans. It does <u>not</u> indicate whether a plan will actually be unreliable or result in unserved energy.

The evaluation of loss of load probability and unserved energy is an exercise that is best done, and is being done, at the regional grid level. As part of its resource accreditation reforms, MISO has identified forecasted "risk hours" which correspond to hours with expected unserved energy or tight margins, as predicted by its LOLE model using data for numerous historical weather years. A large majority MISO's RA hours for the North-Central Region occur in summer months and few occur in fall or spring.[105] It is also worth remembering that each identified risk hour is a very low probability event, with probabilities ranging from 0.001598 to 0.01402.[106]

EFG's analysis evaluated each of the CEO market access scenarios in 2030 under Xcel's Energy Adequacy assumptions, and identified energy adequacy metrics for each weather year, including: "MISO market purchase hours," i.e., the number of hours in each modeled year when Xcel's load exceeds generation and Xcel would be a net purchaser from MISO; average shortfall/purchase intensity (MW); the longest shortfall/purchase event; the peak capacity shortfall/purchase (MW); the month of the peak shortfall/purchase; and total MISO market purchases in MWh. For all of the scenarios and weather years, EFG found there were hours showing extremely small market purchase amounts in the range of .001-.002 MW,[107] (1-2 kW) which obscured events with larger purchases in the summary data. Additionally, market purchase amounts this small do not pose significant reliability or economic risk, and could be

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[104] EFG-AEC Report, Section 4.
[105] MISO, Resource Adequacy Hours Planning Year 2024-25 (Sep. 29, 2023). https://cdn.misoenergy.org/RA%20Hours%20PY%2024%2025630518.xlsx
[106] MISO Resource Adequacy Subcommittee (RASC), Meeting Materials, Agenda Item 5a, EUE Outage Gen and Load Data for PY23-24 DLOL calculations (Feb. 23, 2024), https://www.misoenergy.org/events/2024/resource-adequacy-subcommittee-rasc---february-28-2024/.
[107] EFG-AEC Report, Section 4.

mitigated through any number of targeted resource options. Therefore, EFG focused on hours with purchase amounts above 1 MW. The table below summarizes EFG's energy adequacy results for the 0% Market Access Scenario.

EFG Table 20. CEO 0% Market Energy Adequacy Results for 2030

Weather Year	MISO Market Purchase Hours	Average Shortfall/ Purchase Intensity (MW)	Longest Shortfall/ Purchase Event (Hrs.)	Peak Capacity Shortfall/ Purchase (MW)	Month of Peak Shortfall/ Purchase	MISO Market Purchases (MWh)
2016	1	30	1	30	AUGUST	30
2017	0	-	-	-	-	0
2018	4	367	2	629	OCTOBER	1,469
2019	2	39	2	66	JULY	79
2020	2	378	2	517	SEPTEMBER	756
2021	23	473	7	1,298	OCTOBER	10,873
2022	0	-	-	-	-	0

The table above shows several interesting findings. First, we can see that in most of the weather scenarios run, the maximum "shortfall/purchase amount" is not large and the longest event is no more than two hours. The outlier is the 2021 weather year which includes a seven-hour purchase event and a maximum hourly purchase amount of around 1,300 MW, which occurs during October. Several of the other market access scenarios have similar results, where the model is predicting larger reliance on the market in the fall. The table below summarizes EFG's energy adequacy results for the 25% market access scenario.

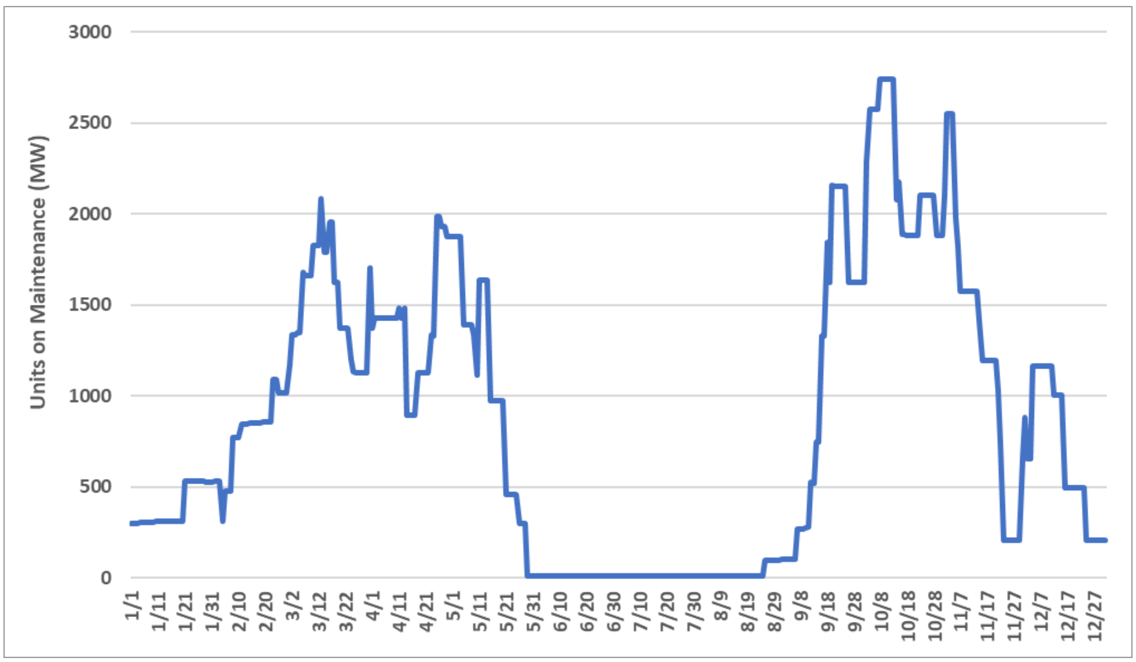
EFG Table 21. CEO 25% Market Energy Adequacy Results for 2030

Weather Year	MISO Market Purchase Hours	Average Shortfall/ Purchase Intensity (MW)	Longest Shortfall/ Purchase Event (Hrs.)	Peak Capacity Shortfall/ Purchase (MW)	Month of Peak Shortfall/ Purchase	MISO Market Purchases (MWh)
2016	8	345	4	638	AUGUST	2,762
2017	9	281	4	818	OCTOBER	2,528
2018	22	259	6	830	OCTOBER	5,709
2019	16	258	5	564	JULY	4,130
2020	20	326	3	1,011	SEPTEMBER	6,516
2021	40	488	18	1,569	OCTOBER	19,537
2022	2	225	1	339	AUGUST	450

Similarly, under this resource plan scenario, most of the weather years modeled result in relatively short "shortfall/purchase events" and in these years the hourly purchase intensity does not exceed 850 MW. The two exceptions are the 2020 and 2021 weather years, where there are larger purchase events that occur in September and October. In fact, in four of the seven years modeled, we see the peak shortfall/purchase occurring in September or October.

EFG looked further into the assumptions underlying the energy adequacy assessment to understand what might be driving this concentration of results in the fall months. It appears that the maintenance schedule for Xcel's thermal units is heavily weighted toward September and October. In fact, it appears that there is a solid two-month period from mid-September through mid-November during which at least 1,500 MW, and as much as 2,750 MW, are out for maintenance. EFG notes that "Xcel has indicated there is some flexibility in scheduling non-nuclear units for maintenance.[108] Adjustments to Xcel's maintenance schedules could help to mitigate the duration or size of MISO market purchase events in the fall season."[109] CEOs therefore recommend that the Commission direct Xcel to, in its next IRP, examine the impact of scheduled maintenance on energy adequacy and evaluate whether it is appropriate to adjust maintenance schedules or increase the flexibility of maintenance schedules to enhance reliability or moderate market exposure.

EFG Figure 1. Units on Scheduled Maintenance (MW)



Reviewing results for all four market access scenarios reveals that plans that are developed assuming access to the MISO market have more shortfall/market purchase hours and larger market purchases, as we would expect. Importantly, however, "across the four CEO Market Access Scenarios, none of the weather years tested resulted in an hourly import need larger than Xcel's 2,300 MW market access assumption."[110] Therefore, there is no reason to believe that these periods represent likely periods of unserved energy instead of periods of market purchases.

These results indicate that each of the CEOs' four market access scenarios provides a *reasonable* level of market reliance. Another way to phrase this is that, under seven different sets

[108] Xcel response to CEOs IR No. 75.
[109] EFG-AEC Report, Section 4.
[110] EFG-AEC Report, Section 4.

of historical weather conditions, none of the scenarios would have unserved energy using the market access assumptions used to develop Xcel's last IRP. There is, of course, a range of market reliance in these results, with larger import events seen in the 50% and 100% market access scenarios. CEOs see all the plans as reasonable, but containing different tradeoffs and falling on a spectrum from highly conservative and more expensive to less conservative and less expensive.

However, even under the highly conservative and imperfect methodology used in Xcel's Energy Adequacy analysis, the resource builds recommended by CEOs (discussed in Section II.G) are likely to see extremely low levels of market reliance. CEOs are recommending an Action Plan directing Xcel to acquire 800-1,200 MW of storage capacity by 2030, with the potential for a portion of storage resources to have durations longer than four hours. Due to this scale of storage additions, the energy adequacy results for the 0% and 25% market access scenarios are most indicative of what the results would be for CEOs' Action Plan.

The energy adequacy results for the 0% market access scenario shows that this plan would have extremely low reliance on the MISO market outside of fall months, based on the historical weather assumptions used. The energy adequacy results for the 25% market access scenario show that this plan would rely more on the MISO market, but to a very reasonable degree, and again, largely in fall months. While we suggest above that Xcel should examine its maintenance schedules to evaluate whether adjustments would improve reliability, relying on the market for some imports during the fall is not likely to pose a reliability risk. Fall is not a season that has frequent tight system conditions and recent resource adequacy forecasts for the 2029-30 planning year indicate that the fall season will likely be in a strong capacity position.[111] Additionally, the capacity import limit for zone 1 is significantly larger in the fall (6,500 MW compared to 4,900 MW in winter).[112] These factors mean that it is especially reasonable to see some market reliance in the fall, when there is low risk of a MISO-wide shortfall event and ample ability to import from neighbors.

In addition to relying on a reasonable level of market purchases (and potentially adjusting maintenance schedules), Xcel could also address the projected future purchase events with new or expanded demand response products. The projected purchase events are rare enough that it may make more sense to address them with demand response rather than with new supply, particularly if that new supply requires building new, long-lived carbon-emitting resources. Moreover, Minnesota law explicitly favors such a demand-side approach, requiring any utility seeking a certificate of need for a new large energy facility to "show that demand for electricity cannot be met more cost effectively through energy conservation and load-management measures."[113]

V. CEOs' Analysis of Other Issues in Xcel's Plan

A. The Growth of New Large Loads, Particularly Data Centers

Across the nation, utilities are increasingly faced with the prospect of new economic development, particularly in the form of large new data center loads, which threatens years of

[111] The 2024 OMS-MISO Survey Results forecast that, based on known and announced resource additions only, the fall season in the 2029/30 planning year will have between a 0.6 GW deficit and an 18.4 GW surplus. OMS and MISO, *2024 OMS-MISO Survey Results* (June 20, 2024), https://cdn.misoenergy.org/20240620%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation635585.pdf.
[112] Xcel IRP, chapter 3, p. 10, Table 3-3.
[113] Minn. Stat. § 216B.243, subd. 3.

load stability for the industry. Xcel does not appear to be immune from this nationwide trend. The Company suggests that a significant share of new load growth is driven primarily by forecasted large new data center loads, as well as the accelerated adoption of electric vehicles and overall electrification trends.[114] In its base forecast, Xcel forecasts an average annual peak demand growth rate of **[PROTECTED DATA BEGINS…**

…**PROTECTED DATA ENDS]**. On an energy basis, the Company forecasts approximately **[PROTECTED DATA BEGINS…**

…PROTECTED DATA ENDS]. By way of comparison, between 2019-2022, electric energy requirements for Xcel grew only 0.2%. In order to meet this projected rising load, the Company has proposed an additional 2,244 of firm peaking capacity over the next five years, as well as additional renewable and storage resources.

Data center load is particularly unique in the context of new load growth for the electric sector. Regardless of the type of data center customer, these new loads are expected to operate at significantly high load factors, and often demand low-carbon resources to meet that load, based on corporate renewable objectives. This multi-pronged challenge is unique for a number of reasons. In recent decades, utilities have forecasted annual energy growth rates around 0.5%. Today, forecasters suggest that cumulative electric growth rates might double from 2.6% to 4.7% over the next five years, with 38 GW of new demand coming online.[115] While challenging in today's context, utilities are no strangers to load growth. Previous periods of economic development saw five-year average annual electricity growth rates of up to 10%.[116]

Placing the Company's load growth in the context of the industry is important. While the Company is detailing significant new load on the NSP system, these challenges pale in comparison to what some other utilities might face in the coming years. The Electric Reliability Coordinator of Texas ("ERCOT") anticipates 5.5 GW of new load by 2028, a 6.6% increase. Other utilities, such as Duke Energy, Georgia Power, and Arizona Public Service anticipate 2028 peak demand increases of 5.9%, 6.4%, and 10.9%, respectively. As a result of this national load growth trajectory, utilities have proposed thousands of megawatts of new fossil fuel-based energy and peaking resources.

Like others, the Company states that new load and potential reliability concerns require the construction of new firm dispatchable resources, such as the proposed combustion turbines in the Company's Preferred Plan.

It's important to note that much new data center load remains speculative. Given the capital expense and long lifetime of new proposed generation assets, changing load forecasts should be heavily scrutinized to ensure some guarantee of projected load growth from large, high load factor demand. Forecasts of projected data center demand and energy usage vary widely and rely significantly on assumptions about the nascent industry's trajectory. Some sources suggest anywhere from 15 to 30 GW of new data center demand nationwide by 2030.[117] Energy forecasts remain even more speculative in light of ongoing developments in AI processing, energy efficiency measures, and microchip efficiency. A recent analysis from consulting firm E3 suggests that efficiency gains from chip producers will cut down on future energy demand and

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[114] Xcel IRP, chapter 1, p. 7.
[115] Isabel Riu, et al., Load Growth is Here to Stay, but are Data Centers? Energy and Environmental Economics ("E3") (July 2024), p. 8, https://www.ethree.com/wp-content/uploads/2024/07/E3-White-Paper-2024-Load-Growth-Is-Here-to-Stay-but-Are-Data-Centers.pdf.
[116] *Id.*, p. 9.
[117] *Id.*, p. 10.

thus reduce required generation capacity. NVIDIA's recently announced superchip consumes 50% less power than similar chips, and would reduce 20 GW of projected energy demand down to 15 GW, according to E3. [118] Ensuring clarity in the projected data center forecasts from the Company as we describe further below is critical to ensure that supply-side investments are prudent and warranted.

Regardless of the certainty of the forecast, there are numerous opportunities to meet new data center demand without, or in combination with, new dispatchable resources. Below, we describe opportunities for the Company to ensure greater certainty in data center load forecasting, while also providing innovative solutions to meet new demand.

1. Ensure Clarity and Certainty in New Large Load Forecasts

Xcel should provide more clarity on the type and certainty of new demand, particularly for high load factor demand that would place a significant burden on the existing system. In response to discovery requests from parties, Xcel states that "the growth forecast shown in Figure 1-3 reflects data center requests we had identified as being highly likely to occur,"[119] but also indicated that as of April 16, 2024, only one of the projects in its data center forecast had executed an interconnection agreement and energy services agreement, and only **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]** had executed a System Impact Study Agreement.[120] The Company noted that several of the projects on its list "are considering locations outside the NSP territory and/or possibly in other states. There is also the potential for multiple sites across the territory and region."[121]

Investments made based on load additions premised only on informal commitments are significantly different from investments made on known load additions with energy service agreements. It is important to avoid double-counting new load, ensuring higher fidelity in load forecasts. While the utility, market, intervenors, and the general public have clear insight into proposed generation via the interconnection queue, this level of transparency does not exist for proposed new load. More transparent reporting and data requirements would help provide clearer insight into future load projections, and subsequently help improve proactive planning for large loads. It is especially imperative that any load that is touted as driving the need for new fossil fuel generators be clearly supported.

Forecasting a new industry with large loads, high load factor, and high uncertainties is a challenge; however, there are best practices emerging for accomplishing advance planning without over-estimating load based on speculative projects. For example, Microsoft raised a concern in Georgia Power's most recent resource plan that the utility was including in its forecast projects that were considering its service area, but were also considering siting elsewhere.[122] Microsoft noted that several other utilities in the region with significant data center experience base their forecasts "primarily on known projects that have made various levels of financial commitment in their respective service territory."[123] Microsoft recommended that Georgia Power

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[118] *Id.*, p. 11.
[119] Xcel response to XLI IR No. 6.
[120] Xcel response to CEOs IR No. 2.
[121] Xcel response to CEOs IR No. 2.
[122] Microsoft Corporation, "Microsoft Comments on Georgia Power's 2023 Integrated Resource Plan Update," Georgia Public Service Commission, Docket No. 55378 (April 1, 2024) pp. 4-5, https://psc.ga.gov/search/facts-document/?documentId=218199.
[123] *Id.*

instead develop a forecast that "relies on a standardized set of assumptions based on the commitment level associated with the load,"[124] i.e., applying standardized discount factors to load projections based on the commitment milestones each potential project had achieved.

This is a reasonable approach and would provide more transparency into the certainty and commitment of various projects, which will benefit the Commission's decision making. CEOs respectfully request that in Reply Comments, Xcel:

- Describe in general the steps that new large loads proceed through before completing energization with Xcel, including the approximate (or relative) financial commitments of each stage, and
- Address the idea of utilizing standardized discount factors to develop a "best guess" forecast by discounting the potential load for less-certain new customers, and discuss how discount factors could be established.

2. Improve Planning and Integration of New Data Center and Large Loads to Ensure Reliability and Emissions Reductions

At a time when load growth is abundant and generation can be hard to procure, regulators and utilities need to deploy a suite of tools to meet demand challenges. The most obvious is leveraging self-generation from new load sources. Numerous large customers have proposed innovative tariff and financing structures to help bring generation resources online faster than a traditional utility or PPA process. In Georgia, intervening parties recommended a "bring your own supply" program, in which large customers could procure generation resources and pass them through the utility to directly serve their new load.[125] In Nevada, Google announced the innovative Clean Transition Tariff ("CTT") that would help bring online a new enhanced geothermal project. The CTT enables the customer - Google - to procure the resource directly with the developer, and then sleeve the transaction through the utility.[126] The customer assumes all associated costs and receives the energy and capacity services. Similar innovative structures to bring generation online faster to meet rising demand are being explored in Ohio, North Carolina, Arizona, and elsewhere.

Other methods to improve the flexibility and efficiency of new loads are being explored as well, and the Company should seek direction from new load customers to understand the potential for load flexibility or load shifting. As we see in Section 4 of the attached EFG-AEC Report, reliability risk is often defined by a handful of hours per year. These short-duration events are potential opportunities to explore demand response or other load shifting measures. Google, for example, stated that it has piloted ways to reduce data center electricity usage at critical peak

[124] Id., p. 5.
[125] Jeff St. John, "Data centers want clean electricity. Can Georgia power deliver it?" *Canary Media* (Apr. 22, 2024) https://www.canarymedia.com/articles/utilities/data-centers-want-clean-electricity-can-georgia-power-deliver-it.
[126] Emma Penrod, "NV Energy seeks new tariff to supply Google with 24/7 power from Fervo geothermal plant," *UtilityDive,* (June 21, 2024) https://www.utilitydive.com/news/google-fervo-nv-energy-nevada-puc-clean-energy-tariff/719472.

times. Task shifting and interruptible tariff designs, as well as new demand response programs, can also help reduce the impact of new loads on system reliability.[127]

B. Equity in the 2024 Xcel Integrated Resource Plan

1. Impact of IRP on Rates

As discussed throughout the CEOs' Comments, we are concerned about the ratepayer impacts of the Company's Preferred Plan, particularly considering the volume of new proposed gas plants. The costs associated with constructing new gas plants, including financing, construction, operation, and potential future decommissioning, will be passed on to consumers in rates. Advancements in energy storage and other clean firm technologies have the potential to make such gas plants uneconomic or obsolete early in the 40-year life of these assets, which may burden ratepayers with significant stranded costs. CEOs are particularly concerned about the risks of these investments for low-income customers, and also those customers in the middle class.

The price tag for building new gas plant infrastructure is substantial and passing these costs through to customers inevitably puts upward pressure on rates. With the costs of housing, goods, and services in the economy increasing, many ratepayers cannot afford increases in their utility rates. While Xcel Energy does provide some assistance to low-income customers, currently its energy assistance programs are serving only a small fraction of those customers who are eligible. And while Xcel Energy's new Automatic Bill Credit Program, if approved by the Commission, has the potential to serve many more low-income customers, increases in rates will have a significant effect on middle-income customers as well. While the middle class may not face the same immediate and severe impacts as disadvantaged communities, they still experience significant effects related to energy costs, health, and environmental quality. An increase in rates can strain low-income and middle-class budgets and reduce the amount of disposable income available for other household needs or savings. Increasing electric rates can also make statewide efforts to electrify heating and transportation more difficult – especially for lower-income customers. The impact of increased utility rates on low-income and middle-income customers underscores the importance of considering affordability and equity in energy planning decisions. The energy transition will require significant utility investments in grid infrastructure, advanced tools and software, renewable energy and storage resources and clean dispatchable technologies. We cannot afford, particularly disadvantaged communities cannot afford, to pay for new gas plants that are likely to be retired early or to require significant future capital investment in emissions-reducing upgrades.

2. Equity Stakeholder Advisory Group

In its 2021 Order approving Xcel's last IRP, the Commission ordered Xcel Energy to create the Equity Stakeholder Advisory Group ("ESAG"). CEOs appreciate the Commission's action and recognition of the importance of energy equity in that proceeding, especially creation of the ESAG. The ESAG was a productive opportunity for the Company to build deeper relationships with communities of color and better understand their needs and challenges.

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[127] Isabel Riu, et al., *Load Growth is Here to Stay, but are Data Centers?* Energy and Environmental Economics ("E3") (July 2024), p.24, https://www.ethree.com/wp-content/uploads/2024/07/E3-White-Paper-2024-Load-Growth-Is-Here-to-Stay-but-Are-Data-Centers.pdf.

CEOs also appreciate the efforts Xcel Energy made to ensure the ESAG was a productive process. Some members of the CEOs served on the ESAG; therefore, we are aware that the ESAG process was challenging at times as conversations relating to historical discrimination and systemic racism often can be. We appreciate the commitment of both the Company and ESAG members to continue to engage in these difficult conversations which are necessary for societal growth. While conversations about race and economic disparities can be uncomfortable, walking away from these conversations can silence those who are most impacted by racial and economic disparities. Listening and engaging with those who are affected is crucial to validate their experiences and work toward solutions.

CEOs are pleased to see a concrete outcome of the ESAG, specifically, the Automatic Bill Credit Pilot Petition filed by Xcel Energy earlier this year. That Pilot Petition, developed in concert with ESAG members, aims to address a well-known problem in providing energy assistance to those who need it. Currently, many customers that are eligible for energy assistance are not receiving it. Indeed, nationally, only approximately 20% of those eligible for the Low-Income Home Energy Assistance Program ("LIHEAP"), the federal government's energy assistance program, actually receive it. In Minnesota, the percentage of those eligible receiving LIHEAP assistance was 23% in 2023. To address this problem, Xcel Energy and the ESAG developed a proposal that, if approved, will significantly increase the number of customers receiving energy assistance and importantly, will reach many low-income customers who have been difficult to reach to date. A docket is currently open on the Pilot Petition.

CEOs believe that the Automatic Bill Credit Pilot Petition is an excellent first step in better serving traditionally under-served communities. But as many ESAG members noted, what underserved communities want and deserve are not just subsidies, but more investment in their communities as well as the opportunity to truly participate in the clean energy transition and the clean energy economy.

3. Increased Access to Energy Efficiency

ESAG members expressed their desire for people in their communities to have better access to energy efficiency measures. CEOs support this desire. We believe that allowing low-income customers to benefit from energy efficiency measures is critical as it allows those who need it most to benefit from the monetary savings associated with energy efficiency. People living in very low-income communities often live in subpar buildings and face a higher energy burden while lacking ready access to energy efficiency and weatherization programming. With lower incomes, energy efficiency is even more important as a tool to create cost savings and bill stabilization for households, and is thus a key component of equitable energy policy. Reaching customers in these areas requires a different level and kind of support.

Using Xcel Energy's mapping tool that the ESAG used to develop the Automatic Bill Credit Pilot Proposal, CEOs isolated all census block groups ("CBGs") with a median income below $40,000 and the percentage of customers receiving energy efficiency measures in each. The chart is below; in short, what the chart shows is that the percentage of customers receiving energy efficiency measures in very low-income communities is extremely low, with many CBGs at 0% and all less than 10%. The largest clusters of low-income CBGs are as follows: Minneapolis (41); St. Paul (31); St. Cloud (8); Mankato (5); Brooklyn Park (4).

CEOs Table 9. Percentage of Low-Income Customers Receiving Energy Efficiency Measures

Census Tract #	City	Median Household Income	% of Customers Receiving Low Income Energy Efficiency Measures
MN270531262011	Minneapolis	$8,125	0
MN271230334002	Saint Paul	$11,127	0
MN270531016004	Minneapolis	$12,488	1.6
MN270530202013	Brooklyn Center	$12,679	0
MN270531048011	Minneapolis	$13,064	0
MN270531019002	Minneapolis	$14,359	1.6
MN270531060003	Minneapolis	$15,227	0
MN271230337002	Saint Paul	$15,417	0
MN270531263003	Minneapolis	$15,485	0
MN270531064001	Minneapolis	$16,875	0
MN270531049024	Minneapolis	$18,846	0
MN270530059011	Minneapolis	$19,089	0.8
MN271696705001	Winona	$20,568	0
MN270531260003	Minneapolis	$20,694	0
MN270531256003	Minneapolis	$21,083	0
MN271230317025	Saint Paul	$21,136	0
MN271230342042	Saint Paul	$21,311	0
MN270531039002	Minneapolis	$21,918	0
MN270531041003	Minneapolis	$22,500	0.4
MN271230371001	Saint Paul	$22,870	1.5
MN270131706003	Mankato	$23,097	0
MN270370601054	West Saint Paul	$23,304	0
MN270531048012	Minneapolis	$23,772	0
MN271450003041	Saint Cloud	$23,803	5.3
MN270530082001	Minneapolis	$24,973	0.2
MN271230318015	Saint Paul	$25,000	0.8
MN270531060002	Minneapolis	$25,491	2.4
MN270531049023	Minneapolis	$25,600	0
MN270131707001	Mankato	$25,925	0
MN270539801002	Fort Snelling	$25,950	0
MN270530215022	New Hope	$26,250	0
MN270531048023	Minneapolis	$26,458	1
MN271230346013	Saint Paul	$27,169	0.4
MN270530038012	Minneapolis	$27,379	0
MN270131711012	Mankato	$27,594	0.1
MN271696705002	Winona	$27,638	7.9
MN270530248022	Richfield	$27,937	0
MN270531056001	Minneapolis	$28,118	0.1
MN270531048022	Minneapolis	$28,229	0.2
MN270530268193	Brooklyn Park	$28,320	0
MN271450005012	Waite Park	$28,556	0.2

MN271230335002	Saint Paul	$28,618	0.4
MN271230321001	Saint Paul	$28,625	1.4
MN270270301121	Dilworth	$28,705	0.4
MN270090212015	Saint Cloud	$28,956	0.1
MN270531054001	Minneapolis	$29,144	8.5
MN270531025003	Minneapolis	$29,354	0.2
MN270490802011	Red Wing	$29,635	0.2
MN271450116003	Saint Cloud	$29,886	1.6
MN270530059012	Minneapolis	$30,000	0
MN270270301082	Moorhead	$30,057	0
MN270490801011	Red Wing	$30,625	0
MN271230325001	Saint Paul	$30,797	2.7
MN270531069003	Minneapolis	$30,846	0.2
MN270530059013	Minneapolis	$31,083	0
MN271230322001	Saint Paul	$31,591	0
MN271230310004	Saint Paul	$31,926	0.4
MN271230355002	Saint Paul	$32,308	0
MN271230336001	Saint Paul	$32,336	5.7
MN270531260004	Minneapolis	$32,356	0.7
MN270530038022	Minneapolis	$32,557	0
MN270530232023	Hopkins	$32,639	0
MN271230312001	Saint Paul	$32,833	0.5
MN271450010021	Saint Cloud	$32,946	0
MN270531039001	Minneapolis	$33,214	0
MN271617905002	Waseca	$33,333	0
MN270131712023	Mankato	$33,522	1.2
MN270530268272	Brooklyn Park	$33,608	1.4
MN271230428003	Saint Paul	$34,000	0
MN270531074001	Minneapolis	$34,125	0.3
MN271450008014	Saint Cloud	$34,189	0.9
MN271479604002	Owatonna	$34,258	0
MN271230306014	Saint Paul	$34,397	0.5
MN271219704003	Glenwood	$34,464	1.2
MN270531060001	Minneapolis	$34,615	1
MN270530215031	New Hope	$34,714	0
MN271310708012	Faribault	$34,943	8.4
MN271450003032	Saint Cloud	$35,000	0
MN270530213001	Robbinsdale	$35,045	0
MN271230304001	Saint Paul	$35,087	1.6
MN270531028003	Minneapolis	$35,446	1.5
MN271230317023	Saint Paul	$35,500	0
MN270531259001	Minneapolis	$35,507	0.3
MN270531002003	Minneapolis	$35,661	1.7
MN271696704003	Winona	$35,775	0.6
MN270531057001	Minneapolis	$35,833	1.1

MN271230313002	Saint Paul	$35,893	6.5
MN271230324003	Saint Paul	$36,199	0.8
MN271230337001	Saint Paul	$36,226	0
MN271696707001	Winona	$36,462	0.8
MN271230331001	Saint Paul	$36,667	0.9
MN270370607351	Eagan	$36,766	0
MN271230325002	Saint Paul	$36,845	1.6
MN271174603001	Sweet	$36,979	9.9
MN271230326002	Saint Paul	$37,143	3.4
MN270530032001	Minneapolis	$37,222	2.3
MN270531056002	Minneapolis	$37,298	0
MN271450005023	Saint Cloud	$37,346	0.5
MN270530210014	Crystal	$37,431	0
MN271630709073	Oakdale	$37,614	1
MN271230374033	Saint Paul	$37,833	0
MN271450003043	Saint Cloud	$37,842	0
MN270530240042	Edina	$37,939	0
MN270490802023	Red Wing	$38,125	0
MN270530214003	Robbinsdale	$38,237	0.6
MN270531056004	Minneapolis	$38,370	0
MN271230315002	Saint Paul	$38,438	0.7
MN270833607001	Monroe	$38,466	0
MN271310708021	Faribault	$38,500	0
MN271630701032	Forest Lake	$38,558	0
MN271230347013	Saint Paul	$38,798	0
MN270530268183	Brooklyn Park	$38,800	3.9
MN271630709103	Landfall	$38,971	0.7
MN270131712024	Mankato	$38,996	0.1
MN271230342016	Saint Paul	$39,101	0
MN270531048021	Minneapolis	$39,177	0
MN270531069001	Minneapolis	$39,208	0
MN270530022001	Minneapolis	$39,485	1.6
MN271230426022	North Saint Paul	$39,653	0
MN270530268192	Brooklyn Park	$39,750	0
MN271310709021	Faribault	$39,750	2.5
MN271174603003	Pipestone	$39,792	0

CEOs encourage the Company to target energy efficiency efforts toward low-income communities and focus on ensuring that the energy efficiency measures are not just those that create minor energy savings (*e.g.,* LED light bulbs, low-flow sink aerators and showerheads) but importantly, those programs that offer deeper savings (*e.g.,* insulation, air-sealing, major improvements to HVAC systems). These deeper measures often improve air quality, comfort, and home health as well. We believe the Commission should monitor energy efficiency progress in these very low-income areas to ensure the customers in these communities can benefit from energy efficiency savings. To effectuate this, CEOs recommend the Commission ask Xcel to set goals for year-over-year improvements in energy efficiency measures in these census block groups.

4. Workforce Opportunities in the Clean Energy Economy

In addition to better access to energy efficiency, the ESAG pressed the importance of having access to workforce opportunities that would allow more people of color to participate in the clean energy economy. Communities want access to jobs both within Xcel Energy as well as opportunities to serve as contactors that provide goods and services to Xcel Energy.

As the Commission is aware, the clean energy sector is growing rapidly and offers jobs with family-sustaining wages. Ensuring that people with diverse backgrounds have access to these opportunities supports broader economic growth and promotes stability, benefiting society as a whole. People of color often live in communities that have been subject to systemic discrimination resulting in geographic concentrations of poverty where people live in older and less efficient homes and have less access to job opportunities. By offering job opportunities to people of color, Xcel can help individuals contribute directly to their families and communities and improve the conditions of their lives and communities. There are at least two ways to promote diversity in the clean energy economy. More detail on those two ways are listed below, but in addition to the recommendations provided in the next two sections, CEOs recommend that Xcel Energy work closely with the forthcoming Environmental Justice Accountability Board on these workforce issues. The EJAB will likely have better insight and feedback into whether the programs Xcel Energy has created to increase workforce diversity and supplier diversity are designed to serve their communities and whether modifications to existing programs or new programs may be necessary to more effectively reach diverse populations.

5. Xcel Energy Workforce Diversity

CEOs appreciate the Commission's directive to require the Company to create a plan to diversify its workforce. While the Company provides numerous initiatives intended to increase diversity within its ranks, CEOs urge the Commission to continue to press the importance of diversity within Xcel Energy's workforce and to monitor the numbers reported by the Company. While the Company's programs are designed to increase diversity, whether that translates into an increase in the number of diverse employees remains an open question. By monitoring the year-over-year numbers, the Commission can better understand whether the efforts pursued by the Company are achieving their intended purpose, that is, to increase the number of diverse employees. To the extent the Company's workforce diversity statistics are not improving, the Commission may wish to urge the Company to pursue other strategies.

In particular, CEOs encourage the Commission to monitor the number of diverse employees within Xcel Energy's leadership and management ranks. Having diversity in leadership roles sends a strong message about the Company's commitment to diversity and inclusion and can help to create a welcoming and supportive environment for all employees. Having a critical mass of leaders from diverse backgrounds can help to reduce the burden on any single individual to represent or advocate for diversity-related issues. With increased diversity among leaders and employees, there is a greater chance that diverse voices will be heard and respected. Achieving a critical mass of people from diverse backgrounds is a step toward systemic change as it can challenge and change structures, norms, and biases that may perpetuate inequities and create a more equitable and just workplace culture that benefits everyone.

6. Xcel Energy Supplier Diversity

CEOs applaud the Company for its internal goal of achieving 25% of sourceable spend with small and diverse suppliers by 2025. Supplier diversity programs are an important way to combat social injustice in the United States.[128] Many companies are making commitments to broaden their pool of diverse suppliers because of the economic impact that diverse suppliers can have on the communities in which they operate by creating job opportunities and benefits, thus driving toward economic equality. Utilities have significant economic power that extends across the supply chain and historically, minority contractors have been underrepresented in utility contract awards. Setting goals for spending with diverse suppliers and monitoring spending can lead to an increase in the economic benefits for diverse suppliers and diverse communities. Also, adding diverse suppliers to the potential sourcing pool can help increase competition for contracts which can, in turn, improve quality, boost innovation, and cut costs. Indeed, some state Commissions, including the Public Service Commission of the District of Columbia and the Maryland Public Service Commission, have entered into a Memorandum of Understanding ("MoU") with their utilities whereby the utilities voluntarily agree to set aspirational targets of spending on goods and services with local, diverse suppliers. The MoUs require the utilities to set short-term, medium-term, and long-term goals for the utilization of diverse suppliers. The MoUs do not require preferences or quotas, but rather encourage utilities to employ a variety of initiatives designed to increase the pool of qualified diverse suppliers. The MoUs require the utilities to file an annual report with disaggregated data on progress towards targets and also requires the utilities to participate in an annual hearing to report on their progress toward the targets. These MoUs have been an effective tool in broadening the pool of contractors utilities use to provide goods and services.

CEOs encourage the Commission to monitor the Company's spending with diverse suppliers to determine whether it has met its goals. Fresh Energy also encourages the Commission to create an opportunity to hear directly from a broad swath of Xcel Energy's diverse suppliers to better understand how the process is working from the diverse supplier perspective, what is working well, and where there are opportunities for improvement.

7. Environmental Justice Accountability Board

CEOs look forward to the Company's creation of the Environmental Justice Accountability Board ("EJAB") and are hopeful the EJAB will build on the work started by the ESAG. CEOs believe that the presence of an executive at EJAB meetings will help the Company to continue to build trust and credibility with communities of color. Direct interaction with community members allows executives to gain firsthand insights into their needs, concerns, and aspirations. This understanding is crucial for making informed decisions that positively impact the community. In addition, executive presence at EJAB meetings will promote transparency and accountability. It will allow EJAB members to ask questions and hold leaders accountable for the Company's actions and polices. CEOs recommend that an executive that reports directly to the Company CEO and/or the President of Xcel Energy in Minnesota attend each EJAB meeting.

CEOs are pleased to see that the Company is offering compensation to members of the EJAB. The members of the ESAG gave a considerable amount of their time attending meetings, preparing for meetings, participating in the development of the Automatic Bill Credit Pilot

[128] *See* Alexis Bateman, et al., "Why You Need a Supplier-Diversity Program" *Harvard Business Review* (Aug. 17, 2020) https://hbr.org/2020/08/why-you-need-a-supplier-diversity-program.

Petition, and developing other ideas to enhance the participation of communities of color in the energy transition. However, ESAG members were not compensated for their efforts. Providing compensation to members of the EJAB acknowledges and respects the value of intellectual labor and the time, effort and resources it takes to generate innovative ideas. In addition, providing compensation can help to level the playing field, enabling people from underrepresented and marginalized communities to participate and have their voices heard.

Generally, the CEOs encourage Xcel Energy to consult with members of the EJAB on how to ensure under-served communities can participate and benefit from the clean energy economy. Listening to EJAB members and incorporating their feedback can foster positive relationships and give the Company confidence that it is operating with the community's input.

8. Community Benefits of IRP Resources

CEOs note that our country's policy and regulatory frameworks are increasingly emphasizing the importance of equity and justice and specifically addressing the needs of disadvantaged communities. In 2021, President Joe Biden signed Executive Order 14008 establishing the Justice40 initiative. The Justice40 Initiative aims to ensure that federal investments in climate and clean energy benefits reach disadvantaged communities that have historically been marginalized, underserved, and overburdened by pollution and other systemic injustices. The initiative sets a goal for 40% of the overall benefits of certain federal investments to flow to these disadvantaged communities. A national commitment to environmental justice of this magnitude has never before been made.

To meet the Justice40 goals, the Federal government is in the process of transforming hundreds of Federal programs to ensure that disadvantaged communities receive the benefits of new and existing Federal investments. The aim is for these investments to help address decades of underinvestment in disadvantaged communities and bring critical resources to communities that have been overburdened by legacy pollution and environmental hazards. The Justice40 Initiative strongly encourages practices and frameworks that ensure benefits flow directly to disadvantaged communities and recommends community benefit plans as an effective tool to realize these benefits. Community benefit plans are agreements or frameworks designed to ensure that investments provide tangible benefits to the local communities in which they are implemented. These benefits can include job creation, environmental improvements, and other social and economic benefits that address the specific needs of the community.

CEOs support the goals of the Justice40 initiative and believe that Xcel Energy can play a major role in ensuring disadvantaged communities in Minnesota benefit equally from modern energy investments. Xcel's Integrated Resource Plan will result in significant investments in utility infrastructure and services. These investments will create job opportunities and stimulate economic development in the areas where resources are sited. Siting resources in disadvantaged communities that are interested in hosting clean energy projects and providing jobs to workers in those communities can be one way to reduce economic disparities and support community development.

CEOs encourage the Company to work both internally and with third party contractors to support development of projects in under-served communities. To ensure that benefits flow to these communities, we recommend that Xcel Energy work with the EJAB to better understand how to prioritize and incentivize investments in under-served communities. CEOs are also interested in hearing the Company's feedback on other ways Justice40 principles can be reflected in the IRP or resulting procurements. Is it in the public interest for a portion of the investment opportunities that result from this Integrated Resource Plan to go directly toward supporting under-resourced communities? Or for the Company to prioritize projects in under-resourced communities that support the development? CEOs look forward to reading other stakeholder responses to these questions.

C. Xcel's Treatment of Distributed Generation and Demand-Side Resources

The Commission's 2021 Order on Xcel's 2019 IRP included the following order points directing the Company's consideration of distributed energy demand-side resources in the IRP:

> 9. Xcel shall take steps to better align distribution and resource planning, including:
>
> …
>
> E. Plan for aggregated distributed energy resources to provide system value including energy/capacity during peak hours.
>
> 15. Xcel shall work with stakeholders to develop a modeling construct that enables Xcel, as part of its next resource plan, to model solar-powered generators connected to the company's distribution grid as a resource. Xcel and stakeholders shall address the following factors in developing the modeling construct:
>
> A. Using a "bundled" approach as is used to model energy efficiency and demand response.
> B. The costs borne by the utility and the costs borne by the customer.
> C. Cost effectiveness tests.
> D. Other topics as identified by stakeholders.
>
> Xcel shall include improved load flexibility and demand response modeling methodologies prospectively, including in its next resource plan.

1. Distributed Solar Generation

CEOs supported Xcel expanding its treatment of solar DG in the last IRP and are pleased that Xcel has markedly improved how it models this resource. The amount of small-scale solar PV is significantly larger in this plan compared with Xcel's last IRP. Between 2026 and 2030, the Company plans to add nearly 1,100 MW of new distributed generation and community solar capacity—or 218 MW per year.[129] In the previous IRP, the Company only forecasted adding 76 MW of capacity in the same period—or roughly 15 MW per year. A comparison of these plans through 2034 is shown below in CEOs Figure 4.

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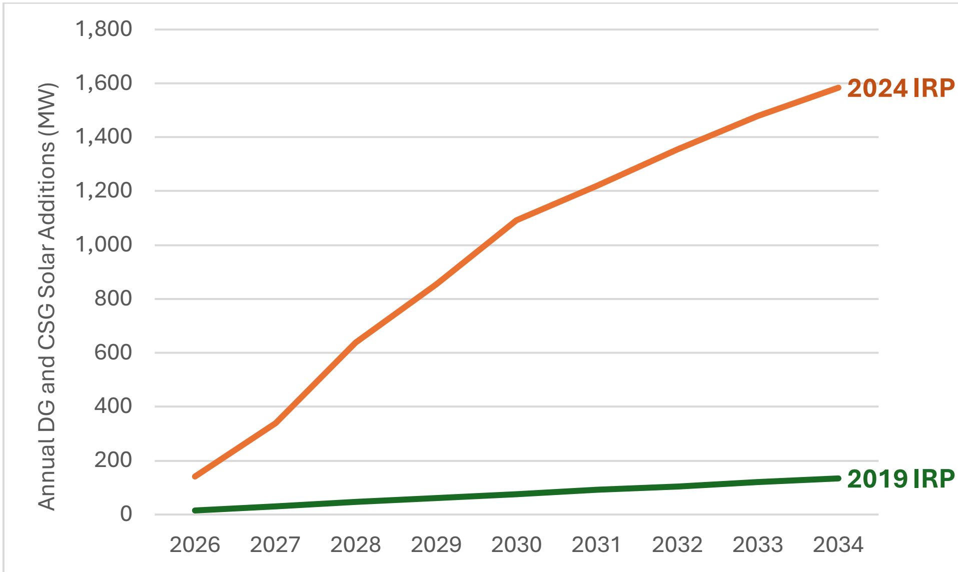
[129] Xcel IRP, Appendix F, p. 38, Table F-20.

CEOs Figure 4: Xcel Small-Scale Solar Additions in 2024 and 2019 IRPs[130]



This substantial increase in small-scale solar results from Xcel forecasting a high level of "non-legacy" community solar capacity and compliance with the 3% distributed solar energy standard ("DSES") due to legislative changes in 2023.[131] The Company also conducted a "special study" that incorporated feedback from stakeholders on how to better model solar adoption. This modeling effort created bundles of DG solar, whose costs were based on the costs of the Company's incentives to potential solar adopters. This study made small-scale solar selectable in the model and led to an additional 273 MW of small-scale solar, 60 MW of additional storage, 800 MW of additional wind resources and 900 MW fewer utility-scale solar resources compared to Xcel's Preferred Plan.[132] (Amounts of firm peaking resources were unchanged).

2. Demand-Side Management

CEOs appreciate the Company's commitment and performance on energy efficiency and demand-side management ("DSM"). Xcel has a long record of success with these resources, and the IRP keeps the Company moving on that positive trajectory. The Company's forecast in its most recent Energy Conservation and Optimization ("ECO") plan shows savings of greater than 2% annually on the electric side and 1.5% annually on the natural gas side. Xcel's Preferred Plan includes its base and programmatic energy efficiency bundles (Bundles 1 and 2) which provide 3,667 GWh of energy savings and 698 MW of demand reduction by 2030.[133]

CEOs asked our experts at EFG to evaluate Xcel's energy efficiency and demand response programs and identify opportunities for potential improvement. The attached EFG-AEC Report

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[130] Xcel Energy, "Upper Midwest Integrated Resource Plan 2020-2034 Supplement," *In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy,* Docket No. E-002/RP-19-368, Attachment A, pp. 37, 65 (June 30, 2020); Xcel 2024 IRP, Appendix F, p. 38, Table F-20
[131] Xcel IRP, chapter 4, p.9.
[132] Xcel IRP, chapter 5, p. 37.
[133] Xcel IRP, Appendix F, p. 8, Table F-6.

outlines several areas where Xcel's forecast appears overly modest and shows potential for increased energy or demand reduction. EFG used this information to develop a "virtual power plant"—a combination of distributed energy and demand-side resources that can be controlled and optimized collectively—that could serve as a template for Xcel. EFG recommends that Xcel further evaluate the opportunity for expanding the following energy efficiency ("EE") measures in future ECO plans:

- **Heat pump water heaters:** Xcel's ECO plan assumes very low adoption levels compared to other states, and there is likely room to grow this measure. Heat pump water heaters provide more efficient electric heating than resistance or combustion technologies; and they provide opportunities for direct load control and grid flexibility.
- **Performance-based shell measures:** Additional air sealing and insulation also shows room for expansion as well. These measures will become even more crucial with increased electrification which puts pressure on the grid and, if unabated by such efficiency measures, will increase costs of capacity. Shell measures can be especially helpful to contain costs and improve comfort for low-income customers.
- **Cold climate heat pumps:** The level of adoption forecasted by Xcel for income-qualified households is extremely low and could be expanded with improved incentives and pairing heat pumps with weatherization or shell measures.
- **Residential new construction:** There is significant room to improve efficiency and decarbonization gains in this measure. Xcel should consider limiting these incentives to all-electric construction and adopting higher efficiency standards like Passive House U.S. Zero to be at the forefront of energy efficient construction.
- **Networked lighting controls:** The 2024-2026 ECO plan added this measure for business customers but assumed zero participation for new business construction. Xcel should look to other examples of utilities that have actively pursued business participation.
- **Data center efficiency:** Xcel assumes only modest adoption of computer room air conditioning equipment measures. There may also be opportunities to expand the measures or incentives for data center efficiency with the growth of this industry.

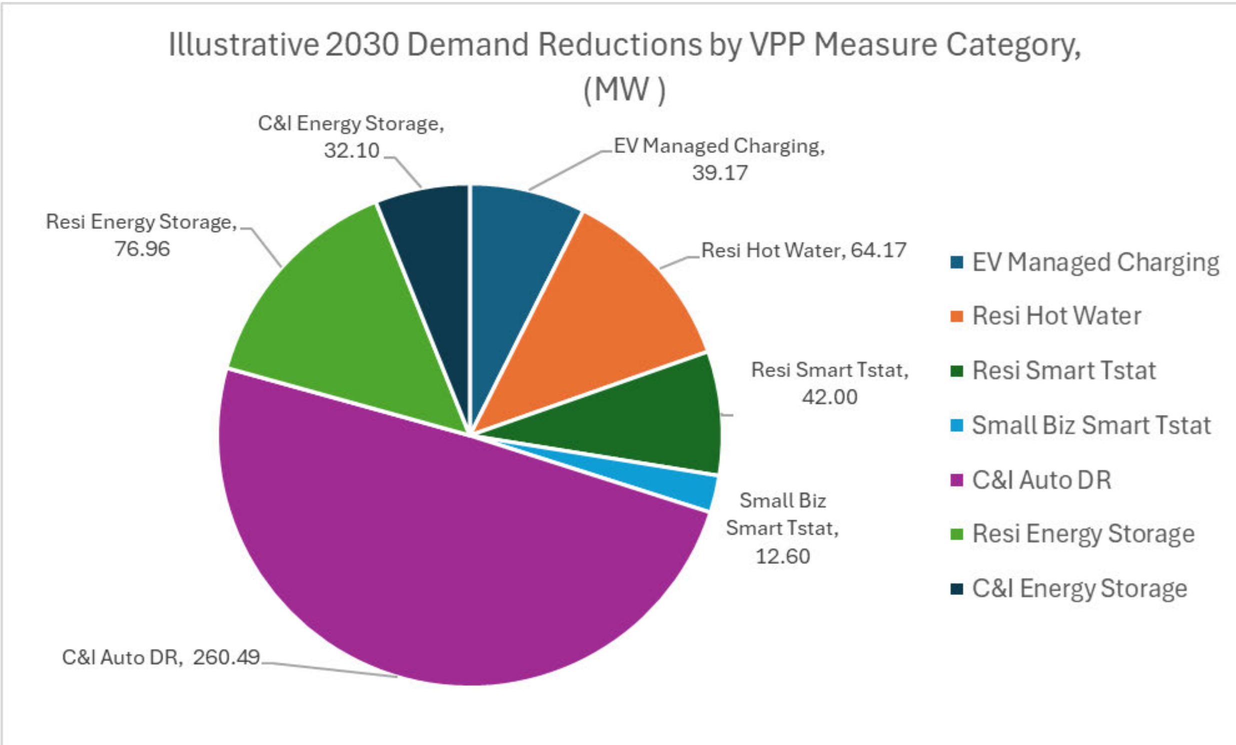
On demand response ("DR"), there are also potential areas for improvement in load flexibility measures such as increased participation in smart water heating and smart electric vehicle ("EV") charging. EFG also points out that Xcel is uniquely positioned to encourage fuel switching due to its involvement in both gas and electric distribution.

As noted above, EFG developed an indicative portfolio of demand management and distributed generation resources that could be aggregated and used to manage peak demand through a VPP model. This illustrative VPP includes:

- Automated Demand Response ("Auto DR") using advanced building controls for commercial and industrial customers
- Behind the meter battery storage for residential customers
- Behind the meter battery storage for commercial customers
- Managed EV charging
- Grid interactive domestic hot water heating

EFG recommends that by 2030 the Company be required to pursue at least 400 MW of demand reduction through a VPP. Our experts also proposed an illustrative example of such a VPP, customized for Xcel's territory—shown below in Figure 5.

CEOs Figure 5: Illustrative VPP Measures in 2030



We are glad to see that Xcel is addressing EE and DR improvements in its planning, but we see room for improvement going forward. The trends in electrification and advancing technologies provide further opportunities for demand-side resources to provide energy and emissions reductions.

D. Xcel's Modeling Fails to Fully Comply with the Commission's 2023 Order in the Regulatory Cost of Carbon Docket

In 2023, the Commission issued an order updating its projected regulatory cost of carbon and instructing utilities on how future regulatory costs should be modeled.[134] In that order, the Commission required utilities, when modeling regulatory costs for purposes of analyzing alternative scenarios in a resource plan, to "identify the future regulatory costs of each scenario

[134] Minn. Pub. Utils. Comm'n, "Order Addressing Environmental and Regulatory Costs," *In the Matter of Establishing an Updated 2022 Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minn. Stat. § 216H.06,* Docket No. E-999/DI-22-236 (Dec. 19, 2023).

as part of its Present Value of Revenue Requirement."[135] However, the limited number of PVRRs Xcel presents in its IRP do *not* reflect the Commission's projected carbon regulatory costs. [136]

Xcel did include carbon regulatory costs in the modeling runs that provide the basis of the PVSC estimates of its Preferred Plan and sensitivities (with those regulatory costs appropriately modeled as a dispatch adder). However, Xcel does not present the PVRR from any of those runs in its IRP.[137] Xcel only includes in its IRP the PVRRs for its Base Case runs (which model its Preferred Plan and the two scenarios with earlier nuclear retirement dates) and for its Carbon-Free sensitivity, and these PVRR values are derived from separate production cost runs that did not include carbon regulatory costs.[138] Xcel's approach means that the PVRR of Xcel's Preferred Plan with the projected regulatory costs is not apparent from the IRP, nor is the PVRR with regulatory costs reported for any of the sensitivities. The Commission should instruct Xcel to make apparent in future IRPs the PVRR for its Preferred Plan (and sensitivities considered) including projected carbon regulatory costs.

CEOs do not object to Xcel also illustrating what its PVRR would be *without* the projected carbon regulatory costs, to reflect what happens in the event such regulatory costs do not materialize in 2028 as projected; indeed, this can be useful information. It is also useful to know what the impact of these projected regulatory costs are upon projected CO_2 emissions. In the case of Xcel's Preferred Plan, we note that the projected mid-range regulatory costs suppress dispatch of Xcel's carbon-emitting plants enough that it reduces the plan's projected CO_2 emissions substantially. For example, for the year 2030, Xcel's Preferred Plan has carbon emissions in its PVSC run (which includes carbon regulatory costs) of 3.4 million tons, whereas in Xcel's PVRR run (which does *not* include carbon regulatory costs) its Preferred Plan has carbon emissions of 6.4 million tons.[139] In other words, if the carbon regulatory costs the Commission has projected do not manifest, Xcel's emissions will be much higher than the projections reported in its IRP.

In addition, the Commission ordered utilities to analyze potential resources under a range of assumptions about future carbon regulatory and externality costs, including lower and higher regulatory costs.[140] Xcel does model scenarios with low and high regulatory cost assumptions (combined with low and high externality cost assumptions), but it allows the model to reoptimize in response to those low and high regulatory costs, which caused the model to select a different resource mix than the resources included in Xcel's Preferred Plan.[141] As a result of doing the analysis this way, Xcel's IRP does not reveal what its Preferred Plan would cost under the low

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[135] *Id.*, at 19.

[136] Xcel IRP, Appendix K, p. 6. In response to CEOs' inquiry, Xcel confirmed that "In the PVRR production cost modeling scenario, carbon regulatory costs and externality costs for both carbon and non-carbon emissions are not considered." Xcel response to CEOs IR No. 40. *See also* Xcel response to CEOs IR No. 38 ("The regulatory cost of carbon is not included in the dispatch run for the High Externality, Mid Externality, Low Externality, or PVRR sensitivities.")

[137] Xcel IRP, Appendix G.

[138] *Id;* Xcel responses to CEOs IRs Nos. 38 and 40.

[139] Xcel response to CEOs IR No. 1, Modeling Output Files, EO-2024 IRP – Base Scenarios – 2024-01-31 [TRADE SECRET]. Xcel has granted CEOs permission to treat these emissions numbers as nonprotected data.

[140] Minn. Pub. Utils. Comm'n, "Order Addressing Environmental and Regulatory Costs," *In the Matter of Establishing an Updated 2022 Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minn. Stat. § 216H.06,* Docket No. E-999/DI-22-236 (Dec. 19, 2023)at 18.

[141] Xcel response to CEOs IR No. 1, Modeling Output Files (comparing Base Scenarios with Sensitivities J and K).

and high regulatory cost assumptions, which CEOs believe was the Commission's intent in requiring analysis of multiple scenarios. The Commission should order Xcel in future IRPs to fix the resources in its Preferred Plan (that is, to not allow the model to reoptimize) when modeling the required alternative regulatory cost scenarios so that the Preferred Plan can be assessed under the specified range of assumptions. CEOs have no objection if Xcel also wants to show what alternative plan its model would select under the various carbon cost assumptions.

VI. Recommendations for Resource Procurements

In the Commission's Order on Xcel's 2019 IRP, the Commission directed that,

> 6. Regarding resource acquisition:
>   A. Xcel shall use the No-Bid/Track 1 and Xcel-Bid Auditor/Modified Track 2 bidding processes for the solar, wind, and storage resources approved in Ordering Paragraph 2, and use the Xcel-Bid Contested Case/Track 2 contested case bidding process for the firm dispatchable resources as identified in Ordering Paragraph 3 and subject to its requirements.
>   B. Documents issued by Xcel making a request for proposals for peaking resources must be technology neutral.
>   C. Xcel shall use the Commission-approved No-Bid/Track 1 process and Xcel-Bid Auditor/Modified Track 2 process whenever Xcel intends to acquire at least 100 MW of solar, wind, or storage capacity for more than five years.
>   D. When Xcel exercises its Right of First Offer provision to acquire a resource, Xcel shall not recover capital costs exceeding the resource's net book value.

CEOs have tracked the many procurements that resulted from the last IRP and are intervenors in the Track 2 contested case procurement for up to 800 MW of firm dispatchable capacity (docket 23-212). CEOs recommend that the Commission give the Company similar direction regarding procurements resulting from this 2024 IRP, with some modifications.

CEOs continue to believe it is critical that procurements for peaking or dispatchable resources be technology neutral. Throughout Xcel's IRP, the Company uses the terms "firm peaking" and "firm dispatchable" to indicate that it is modeling a resource type that can be fulfilled by a variety of different generation technologies, and where new technology options will become available over time. There are many promising carbon-free dispatchable energy generation technologies entering the market or under development and it will be important for Xcel to be continuously evaluating technology readiness and opportunities that will benefit its customers and its carbon-free goals. These carbon-free dispatchable technologies include the three that Xcel examined in its "special studies"—hydrogen, small modular nuclear, and long-duration energy storage—as well as enhanced geothermal power generation,[142] thermal energy storage,[143] and others.

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[142] U.S. Department of Energy, Pathways to Commercial Liftoff: Next-Generation Geothermal Power (March 2024), https://liftoff.energy.gov/wp-content/uploads/2024/03/LIFTOFF_DOE_NextGen_Geothermal_v14.pdf.

[143] International Renewable Energy Agency, Innovation Outlook: Thermal Energy Storage (2020), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Nov/IRENA_Innovation_Outlook_TES_2020.pdf.

Running technology-neutral procurements is an important measure to ensure that various technology and resource types have the ability to compete on a level playing field and provides an opportunity to evaluate real projects from new vendors and technology types. However, CEOs recommend the Commission use the term "dispatchable" rather than "peaking" to be more inclusive of new carbon-free dispatchable technology types that may require or benefit from operating at higher capacity factors.

The second change CEOs recommend is to remove the requirement that generic dispatchable resources are approved through a Track 2 contested case proceeding. While there are transparency benefits to this procurement model, it also comes with a significant level of complexity for bidders, the Company, state agencies, and other intervenors. CEOs believe that using Track 1 or the modified Track 2 process, as appropriate depending on whether the Company is bidding into the RFP, will provide equally strong results on a faster timeline and with fewer procedural costs. As we have seen from the current firm dispatchable case, docket 23-212, a timeline of at least 12-15 months is required to proceed through all steps of a contested case when detailed economic and transmission modeling is at issue. This timeline means the procurement decision in that case will not be made until after the decision in this IRP. Such a resource-intensive and lengthy process will not be viable for all vendors—in the firm dispatchable case, one vendor has withdrawn due to the procedural complexity and timeline entailed—and may be inconsistent with Minnesota's broader goals of bringing new clean generating capacity online in a timely, efficient manner.

As discussed in section III.C, it is also imperative that any procurements in which grid stability or critical reliability services are at issue are designed to enable comparison of GFM-equipped renewable energy or storage resources with thermal resources, and thereby enable identification of the best solution. To address this concern, CEOs recommend that the Commission direct Xcel to identify in future procurements whether the procurement is intended to address any location-specific or grid stability related concerns, explain what those concerns are, and detail how the procurement process will enable comparison of different resource types that may have the capability to resolve the concerns.

For these reasons, CEO recommend that the Commission adopt similar recommendations on resource procurement as it did in the last IRP, with some modifications:

6. Regarding resource acquisition:
    A. Xcel shall use the No-Bid/Track 1 and Xcel-Bid Auditor/Modified Track 2 bidding processes for the solar, wind, ~~and~~ storage, and dispatchable resources approved in Ordering Paragraph [ ].~~2, and use the Xcel-Bid Contested Case/Track 2 contested case bidding process for the firm dispatchable resources as identified in Ordering Paragraph 3 and subject to its requirements.~~
    B. Documents issued by Xcel making a request for proposals for ~~peaking~~ dispatchable resources must be technology neutral.
    C. Xcel shall use the Commission-approved No-Bid/Track 1 process and Xcel-Bid Auditor/Modified Track 2 process whenever Xcel intends to acquire at least 100 MW of solar, wind, or storage capacity for more than five years.
    D. When Xcel exercises its Right of First Offer provision to acquire a resource, Xcel shall not recover capital costs exceeding the resource's net book value.
    E. Xcel shall identify in each procurement whether the procurement is intended to address any location-specific or grid stability related concerns, explain what those

concerns are, and detail how the procurement process will enable comparison of different resource types that may have the capability to resolve the concerns.

CONCLUSION

CEOs appreciate the Commission's consideration of these comments. For the forgoing reasons, CEOs recommend the Commission not approve Xcel's Preferred Plan and instead adopt the CEOs' Five-Year Action Plan.

Respectfully submitted,

/s/ Amelia Vohs
Amelia Vohs
Climate Director
Minnesota Center for Environmental Advocacy
1919 University Ave W, Suite 515
St. Paul, MN, 55104
avohs@mncenter.org

/s/ Allen Gleckner
Allen Gleckner
Exec. Lead Policy & Programs
Fresh Energy
408 St Peter St, #350
St. Paul, MN, 55102
gleckner@fresh-energy.org