Clean Energy Alternatives to Xcel's 2024 Integrated Resource Plan

By: Chelsea Hotaling, Energy Futures Group
Tyler Comings, Applied Economics Clinic

On behalf of Fresh Energy, Minnesota Center for Environmental Advocacy, Sierra Club, and Clean Grid Alliance

August 9, 2024

1. TABLE OF CONTENTS

1. CLEAN ENERGY ORGANIZATIONS' ENCOMPASS MODELING RUNS

Energy Futures Group ("EFG") and Applied Economics Clinic ("AEC") were asked to conduct an independent technical review of Xcel's Integrated Resource Plan ("IRP"), making corrections, as deemed appropriate in our professional opinions, to Xcel's EnCompass modeling assumptions, and exploring alternative combinations of unit additions that would better fit the policy preferences outlined in Commission orders and state statutes.

The following sections discuss the modifications that we made to Xcel's EnCompass database to perform the Clean Energy Organizations ("CEO") modeling runs.

Our modeling approach was to examine four CEO portfolios with different assumptions around the level of market access allowed in the capacity expansion plan step in addition to a rerun of Xcel's Preferred Plan:

1) CEO Market Access 0%
2) CEO Market Access 25%
3) CEO Market Access 50%
4) CEO Market Access 100%
5) Rerun of Xcel's Preferred Plan

1.1 UPDATES AND OTHER CORRECTIONS TO XCEL'S ENCOMPASS MODELING

The changes we made to Xcel's modeling are discussed in the sections that follow. Except where otherwise noted, these changes were all applied to all modeling runs conducted.

1.1.1 CHANGES TO RENEWABLE COST ASSUMPTIONS

The Company's calculations of the levelized costs of solar and wind did not properly include inflation. With levelized costs, a project is paid for throughout its life on a per-MWh basis. Xcel based its solar and wind costs, in terms of dollars per MWh, on the levelized costs calculated in the 2023 National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB"). The NREL ATB produces a <u>real</u> levelized cost value, meaning a fixed dollar amount that takes out the effect of inflation: for instance, NREL might forecast a real levelized cost for wind of $20 per MWh in 2021 dollars. But the costs used in Xcel's Encompass model are in nominal dollars, meaning that they include the effect of inflation in each year. Because the EnCompass model uses nominal dollar values, the levelized costs over each year of a project's life need to include the effects of inflation.

The Company presented what it called a "nominal levelized cost" where it took the NREL real levelized cost values and inflated them to correspond to the installation year only. But this is not sufficient because it does not account for inflation for subsequent years of the project's life. What the Company has entered into the Encompass model in every year of a project's life is actually the real levelized cost for the installation year held constant: for instance, its 2030 project cost assumption is the real levelized cost in 2030 dollars. But that same dollar value cannot be used to represent the cost of a 2030 project in future years (2031, 2032, etc.)

without applying inflation if the model is in nominal terms. Instead, 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 used); or 2) incorporated an escalation rate to its real levelized cost over every year of the project's life so that it would continually increase in each year of the project's life. In our modeling, we did the latter. Thus, our levelized costs are higher for both solar and wind when compared to Xcel's. These changes have been applied to all of our modeling runs, including our re-run of Xcel's plan.

1.1.2 CHANGES TO COMBUSTION TURBINE ("CT") CAPITAL COSTS

The Company's assumed costs for new natural gas combustion turbines ("CTs") included certain resource costs that were not justified, leading the model to be biased towards the selection of a certain type of new gas plant in its plans. Xcel provided costs for both F-class and H-class CT technologies. Xcel's cost assumptions for H-class CTs were substantially cheaper and lacked sufficient justification. The Company's assumed cost for a new H-class turbine was $749 per kW while the cost of an F-class turbine was $954 per kW—27 percent higher than the H-class.[1] Because the model was fed these two options for gas costs, unsurprisingly it chose to build the lower-cost 374-MW H-class units.[2] These H-class costs were not adequately supported by Xcel, and likely underestimate the costs of future new gas plants.

The Company provided recent, detailed supporting documentation for its F-class turbine costs, but not its H-class costs. The Company stated that it had not reviewed any CT cost estimates in the past two years, other than the bids received in its recent firm dispatchable docket. The F-class costs were based on the estimate for a project at the Company's Pawnee plant site in Colorado with an apparent escalation factor.[3] However, the only basis for the H-class costs Xcel was the Sherco combined cycle ("CC") project, which was proposed in the Company's 2019 IRP and then abandoned in 2021. Xcel did not provide any more details on the source of the H-class costs and did not cite any other examples of H-class turbine cost estimates.

As a result of the lack of sufficient evidence for the H-class costs, we changed the costs of new CTs to use the Company's F-class turbine capital costs. This is a reasonable proxy for generic, new peaking (or "firm dispatchable") capacity additions going forward. We use the term "dispatchable" throughout this report, which more accurately captures the primary differentiating attribute of this resource type.

---

[1] Xcel 2024 IRP, Appendix F, Table F-23.
[2] Xcel 2024 IRP, Appendix F, Table F-23; Figure 1-6. The H-class unit size is 374 MW. Nearly every gas addition from 2027-2040 in Xcel's preferred plan is either one or two of these units, with the exception of one 225 MW F-class unit added in 2032.
[3] Company supplemental response to CEO IR 19.

1.1.3 CONTRACT EXTENSIONS

As Xcel discussed in the IRP, there are numerous power purchase agreement ("PPA") resources in Xcel's fleet with contracts that expire during the planning period, with 1700 MW of PPAs expiring between 2025 and 2028.[4] Three of the significant near-term contract expirations are the Cannon Falls CTs, the Mankato Energy Center, and LSP Cottage Grove. These three resources represent a total of 968 MW (winter capacity basis).

When asked in discovery if any of the PPAs were ineligible for extension, Xcel stated that "No, at this time, no other PPAs expiring in the next ten years are ineligible for extension."[5] Given that the PPAs are not ineligible for extension, we modeled these resources with a ten-year extension. This extension term was selected because it matches the minimum term considered in Xcel's recent firm dispatchable procurement[6] and would not extend the resources past 2040. Table 1 shows the PPA expiration date modeled by Xcel and the dates included in the CEO modeling with the 10-year extension.

Table 1. Contract Extensions Modeled

Resource	Winter Capacity (MW)	Xcel Modeled	Extension
Cannon Falls CTs	356	5/31/2028	5/31/2038
Mankato Energy Center CC	350	8/31/2028	8/31/2038
Cottage Grove CC	262	9/30/2027	9/30/2037

The costs for these PPAs were modeled based on escalating the costs included in Xcel's EnCompass database.

1.1.4 GEN-TIE LINE RESOURCES

Xcel's modeling included the optimization of new resource builds for resources connecting to the Sherco and King generation tie lines which will re-use the interconnection rights at these retiring coal facilities. Since the use of generation tie lines was approved in the last IRP and procurements are already underway to select a significant portion of these resources,[7] we fixed the gen-tie resources from Xcel's Preferred Plan into our modeling runs. We set Xcel's builds as the minimum amount to be added and then allowed the model to optimize for additional resource builds if the model found it economic to add those resources. Table 2 below shows the gen-tie resource capacity that was fixed in the modeling runs.

Xcel has indicated that approximately 374 MWs of the 2028 firm dispatchable need is located on the re-optimized Sherco generation tie line and is pending regulatory approvals from the

[4] Xcel 2024 IRP, Chapter 1, p. 12
[5] Xcel response to CEO IR No. 23(b)(i).
[6] Xcel Notice Petition, Appendix A "Resource Attributes Matrix", November 13, 2023, Docket No. E002/CN-23-212. See Attributes 6 and 7.
[7] See dockets 23-342, 23-212, and 24-230

Commission.[8] Since this decision will be made in a separate case, we assumed that the 2028 resource will be 374 MW of CT capacity to be aligned with Xcel's Preferred Plan, however, we consider this to be a placeholder for generic dispatchable capacity to be selected in that separate case.

Table 2. Xcel Preferred Plan Sherco and King Gen-tie Resources (MW)

	King Tie Line	Sherco Tie Line			
	Solar	**Solar**	**Wind**	**Battery**	**Dispatchable**
2028	0	0	2,000	0	374
2029	0	0	800	120	0
2030	400	0	0	0	0
2031	300	0	800	240	0
2032	0	200	600	360	0
2033	0	600	0	0	0
Total	**700**	**800**	**4,200**	**720**	**374**

1.1.5 MARKET ACCESS

Within EnCompass, the MISO market access representation for exchange between Xcel and the market represents the level of MWs that can be imported or exported on an hourly basis. Xcel's modeling included an assumption that the hourly import/export limit modeled in EnCompass is 2,300 MW. Xcel reported that this number was developed for the 2019 IRP based on PROMOD modeling and historical transfer data.[9]

For this IRP, Xcel took a different approach to modeling market access and conducted nearly all of the capacity expansion runs without any access to the MISO market. Xcel did allow market access in its production cost modeling of all plans—and we did not change that approach. However, the production cost modeling comes after the capacity expansion modeling stage, in which the level of market access has a large influence over the portfolio. Once you reach the production cost modeling stage, the capacity expansion portfolio is already fixed. Table 3 shows the different market access assumptions that the CEOs included in the capacity expansion modeling of the CEO plans to evaluate the impact that the market access assumption has on the resource build and the costs of the plan.

Table 3. Market Access Assumption in EnCompass

Market Access Assumption	CEOs MW Import/Export	Xcel MW Import/Export
0%	0	0
25%	575	-
50%	1,150	-
100%	2,300	-

[8] Xcel 2024 IRP, Chapter 4 at 9.
[9] Xcel 2024 IRP, Chapter 5 at 4.

1.1.6 SUMMARY OF CHANGES

The changes described above were used to develop the CEO portfolios with varying levels of market access and for the rerun of Xcel's Preferred Plan. It is important to note that we did not re-optimize Xcel's Preferred Plan. We took the plan as it was in the EnCompass database and updated the costs for the renewable escalation and the revised H-Class CT capital cost. Table 4 shows the summary of the CEO modeling changes.

Table 4. CEO Modeling Changes Summary

Modeling Change	CEO 0% Market	CEO 25% Market	CEO 50% Market	CEO 100% Market	Rerun Xcel Preferred
Renewable Cost Escalation	✓	✓	✓	✓	✓
Revised H-Class CT Capital Cost	✓	✓	✓	✓	✓
Contract Extensions	✓	✓	✓	✓	-
Gen-Tie Resources	✓	✓	✓	✓	-
Market Access	✓	✓	✓	✓	-

2. MODELING METHODOLOGY

Xcel implemented several changes to its modeling approach with its 2024 IRP. The following subsections will discuss Xcel's modeling approach and the approach taken by the CEOs to develop the CEO portfolios.

2.1 XCEL'S MODELING METHODOLOGY

Xcel determined that a different modeling approach was needed when evaluating the scenarios and sensitivities for this IRP due to the model yielding plans with "prominent levels of unserved energy."[10] The approach that Xcel used for the 2019 IRP, and the one we usually see utilities use, is to model the capacity expansion step using representative days, often based on typical on- and off-peak days per month. Since the capacity expansion modeling step is computationally intensive due to the problem size, modeling representative days is a common way to manage problem size and resulting run times.

Xcel reported that it first developed expansion plans based on a typical on and off-peak day per month for the optimization horizon 2027-2055.[11] However, Xcel reported that it encountered solve time and feasibility issues with this approach so modifications to the settings were made, which included reducing the daily intervals to 11 total time blocks per day versus the 24 time blocks per day (every hour) that it had used when modeling on and off-peak days.[12]

Xcel also reported that it added a second step of expansion planning to model more granular time periods and minimize unserved energy. Xcel implemented three modeling changes for this step. The first change was to use all calendar days instead of the typical on and off-peak days per month. [13] Modeling an increased number of days comes with a tradeoff on run time and increased problem size. In order to combat the increased run time, Xcel then implemented the second modeling change which was to use a setting that allows the model to split the optimization period. Instead of optimizing the full planning horizon from 2027-2055 in one step, Xcel set the optimization horizon to every four years for the period 2024-2055. [14] This means that the model will solve several (approximately eight) capacity expansion steps over the course of the planning period and the model will not have insight into changes that are happening after that four-year window.

The third modeling change Xcel made was to carry over the wind and solar resource additions from the first step capacity expansion plan. [15] These resource additions became the floor or minimum level of resources in the second step expansion plan, but the model can

---

[10] Xcel 2024 IRP, Chapter 5 at 20.
[11] Xcel 2024 IRP, Chapter 5 at 20.
[12] Xcel 2024 IRP, Chapter 5 at 21.
[13] Xcel 2024 IRP, Chapter 5 at page 22.
[14] Xcel 2024 IRP, Chapter 5 at page 22.
[15] Xcel 2024 IRP, Chapter 5 at page 22.

select additional levels of renewables if it found it economic to do so in the second step expansion plan. For example, if 100 MW of solar was added in 2027 and 200 MW of wind in 2028 in the step one expansion, those builds were carried over to the step two expansion as a fixed decision. The model could then decide if it wanted to add more wind or solar resources above those levels in 2027 and 2028.

In addition to these changes to the model settings, Xcel also developed both capacity expansion plan steps with the assumption that there was no interchange allowed with the MISO market representation in EnCompass. Xcel stated that it implemented this change because of the levels of “market reliance” observed in the Market Access Optimization run, which was developed with market access allowed. Xcel maintained the assumption of no market interaction for the development of its capacity expansion plans and then allowed access to the MISO market in the production cost step.

2.2 CEO MODELING METHODOLOGY

For the development of the CEO portfolios, we first started with evaluating the plans under the settings that Xcel used for the step one capacity expansion step, which are the typical on and off-peak day and the 11 time blocks modeled for those representative days. We wanted to see if there were significant levels of unserved energy in the production cost runs under this approach. Since we did not see any unserved energy in production cost runs, we decided to utilize these settings for the capacity expansion plans instead of Xcel’s two step capacity expansion modeling approach.

We also had concerns about the shortened optimization periods that Xcel had moved to in order to help manage the run time that resulted from switching from the on and off-peak representative days to all calendar days. Using a four-year optimization window means that the model will be solving several different expansion plans within the planning period. This means that the model will develop a capacity expansion plan for the time step of 2024 – 2027, then it will solve for 2028 – 2031, then 2032 – 2035, and so on until it reaches the end of the planning period. With the timeline for this case, we did not have enough time to explore the potential impacts of modeling different optimization windows. As a result, we chose to model the entire optimization period instead of splitting into the four-year optimization window.

The second modeling difference is that we developed several CEO portfolios based on different assumptions for the MISO market access allowed. As outlined in Section 1.1.5, we developed plans based on 0%, 25%, 50%, and 100% market access using Xcel’s assumption that, when the market is accessible, its system can import or export up to 2,300 MW in any hour over the planning period. We wanted to evaluate the impact of the MISO market access assumption on unserved energy in the production cost run, the new resource builds selected, and cost of the portfolios as there is a significant cost tradeoff of this assumption even in Xcel’s own modeling. The Present Value of Societal Cost (“PVSC”) for 2024-2047 of Xcel’s as-filed Preferred Plan that was developed with no market access is $62.7 billion and the PVSC of Xcel's one run with market access[16] is $58.1 billion ($4.6 billion lower). This cost difference reflects the tradeoff of developing capacity expansion plans with the assumption that the system is an island versus allowing for market access.

Xcel did acknowledge the benefit of the MISO market. The Company said:

> *While we have optimized our portfolio without access to the market, we will continue to benefit from the access to the MISO market as we have in the past. We will continue to dispatch our resources on an economic basis. We will purchase from the market when market purchases are lower cost than using our own resources, and we will sell excess generation into the market to benefit our customers. While we optimized the capacity expansion additions without market reliance, we conduct a dispatch run in the Encompass model with market access to reflect these market interaction benefits.*[17]

Given the implications that the market access assumption has on the cost and composition of portfolios, we decided to evaluate different levels of access for the CEO portfolios.

[16] Xcel modeled this assumption under Sensitivity R.
[17] Xcel 2024 IRP, Chapter 5 at page 12.

3. CEO MODELING RESULTS

This section discusses the capacity expansion results for the CEO portfolios with different assumptions around the level of market access allowed in the model.

3.1 CAPACITY EXPANSION

Table 5, Table 6, and Table 7 below show the new resource/contract extension comparison between the CEO portfolios and Xcel's Preferred Plan for 2030, 2035, and 2040. All CEO portfolios include the contract extensions for the three thermal PPAs discussed above, with the last PPA expiring in 2038.

The level of build-out for wind and storage resources illustrates how the expansion plan changes with different levels of MISO market access. Most notably, when the model sees the ability to import/export, the model adds more wind and when the model sees limited or no availability to import/export, the model adds more battery storage resources.

All four CEO scenarios result in a build of 400 MW by 2030 and 1,500 MW of solar by 2035, which is consistent with Xcel's Preferred Plan. The CEO plans have a lower amount of new dispatchable capacity when compared to Xcel's Preferred Plan. All CEO scenarios include the fixed 374 MW[18] in 2028. By 2035, cumulative dispatchable additions range from 374-599 MW, and by 2040 range from 1,122 to 1,347 MW. The CEO scenarios range in new wind resources from 2,800 – 4,800 MW by 2030,4,600 – 8,200 MW by 2035 and 7,600 MW – 10,800 MW by 2040. For battery storage resources, the CEO plans range from 240 – 1,320 MW by 2030, 1,800 – 2,460 MW by 2035 and 3,660 MW – 3,960 MW by 2040.

In addition to the supply side resources, the model also has additions for demand response, energy efficiency, and distributed solar. These resource selections are consistent across the various scenarios (including Xcel's Preferred Plan), with the exception of the CEO 0% Market Access Scenario where the model chooses to add the high energy efficiency bundle for 2024-2029 and an additional demand response bundle.

[18] This is the CT resource that was fixed on the gen-tie line.

Table 5. New Builds/Contract Extensions by 2030 (MW)

Resource Type	CEO 0% Market	CEO 25% Market	CEO 50% Market	CEO 100% Market	Xcel Preferred
Solar	400	400	400	400	400
Wind	2,800	2,800	3,200	4,800	3,200
Battery Storage	1,320	1,020	540	240	600
Contract Extension	968	968	968	968	0
Dispatchable	374	374	374	374	2,244

Table 6. New Builds/Contract Extensions by 2035 (MW)

Resource Type	CEO 0% Market	CEO 25% Market	CEO 50% Market	CEO 100% Market	Xcel Preferred
Solar	1,500	1,500	1,500	1,500	1,500
Wind	4,600	5,400	6,400	8,200	5,800
Battery Storage	2,460	2,460	2,100	1,800	1,320
Contract Extension	968	968	968	968	0
Dispatchable	599	374	374	374	2,470

Table 7. New Builds/Contract Extensions by 2040 (MW)

Resource Type	CEO 0% Market	CEO 25% Market	CEO 50% Market	CEO 100% Market	Xcel Preferred
Solar	1,500	1,500	1,500	1,500	1,500
Wind	7,600	8,200	9,400	10,800	8,400
Battery Storage	3,960	3,840	3,660	3,960	2,100
Contract Extension	0	0	0	0	0
Dispatchable	1,347	1,496	1,496	1,122	3,592

Table 8 through Table 17 show the load and capability projections out to 2035 for each of the CEO Market Access Plans for the summer and winter seasons. In these tables “NSP Load” represents Xcel’s forecasted peak after adjustments for existing energy efficiency, electric vehicles, and beneficial electrification.

Table 8. Load and Capability Table (MW) – CEO 0% Market Summer

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
NSP Load	9,408	9,526	9,946	10,311	10,511	10,643	10,835	11,040	11,331	11,573	11,902	12,212
Existing and Approved Resources												
Demand Response	1,011	1,015	1,019	1,021	1,021	1,020	1,016	1,012	1,008	1,004	1,001	997
Coal	1,475	1,475	1,475	883	883	461	461	0	0	0	0	0
Nuclear	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747
Natural Gas/Oil	4,020	3,719	3,962	3,962	3,988	3,988	3,715	3,599	3,305	3,305	3,305	3,305
Biomass/RDF	110	61	61	61	61	61	61	61	61	61	61	38
Storage	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	659	170	169	169	169	169	169	169	100	97	80	78
Wind	785	780	744	743	737	706	704	683	674	585	573	566
Solar (Utility Scale)	147	259	464	396	362	329	296	262	256	249	242	236
Solar (CSGs)	438	367	341	233	214	195	176	157	153	150	147	143
Solar (Distributed)	121	102	81	85	87	90	89	89	95	102	110	116
Contract	342	0	0	0	0	0	0	0	0	0	0	0
Total Existing and Approved	**10,855**	**9,696**	**10,064**	**9,301**	**9,271**	**8,766**	**8,434**	**7,779**	**7,400**	**7,301**	**7,266**	**7,227**
(Need)/Surplus	**1,447**	**170**	**118**	**-1,010**	**-1,240**	**-1,876**	**-2,401**	**-3,261**	**-3,931**	**-4,272**	**-4,637**	**-4,985**
New Resources												
Energy Efficiency	144	272	406	547	688	818	895	982	1,061	1,138	1,219	1,293
Demand Response	244	232	232	231	230	229	227	225	223	221	219	217
Natural Gas/Oil	0	0	0	0	314	314	314	314	314	314	314	514
Storage	0	0	0	1,062	1,043	1,125	1,104	1,427	1,860	2,003	2,150	2,194
Wind	0	0	0	0	361	505	504	648	748	739	731	791
Solar (Utility Scale)	0	0	0	0	0	0	103	161	201	328	319	310
Solar (CSGs)	8	40	74	102	118	130	137	140	150	159	168	176
Solar (Distributed)	0	0	0	21	78	107	128	114	114	114	114	113
Total New	**395**	**545**	**711**	**1,963**	**2,833**	**3,228**	**3,414**	**4,010**	**4,671**	**5,016**	**5,233**	**5,608**
(Need)/Surplus	**1,842**	**714**	**830**	**953**	**1,593**	**1,352**	**1,013**	**749**	**740**	**744**	**596**	**623**
Summer Reserve Margin	**19.58%**	**7.50%**	**8.34%**	**9.25%**	**15.15%**	**12.70%**	**9.35%**	**6.79%**	**6.53%**	**6.43%**	**5.01%**	**5.10%**

Table 9. Load and Capability Table (MW) – CEO 0% Market Winter

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
NSP Load	6,612	6,889	7,225	7,377	7,526	7,596	7,750	7,913	8,146	8,428	8,641	8,899
Existing and Approved Resources												
Demand Response	441	421	423	447	447	447	447	447	447	447	423	423
Coal	1,562	1,562	1,562	938	938	469	469	0	0	0	0	0
Nuclear	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826
Natural Gas/Oil	4,372	4,204	4,204	4,204	4,227	4,227	4,227	3,724	3,724	3,451	3,451	3,451
Biomass/RDF	96	52	52	52	52	52	52	52	52	52	52	29
Storage	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	610	169	169	169	169	169	169	169	100	100	80	78
Wind	2,146	1,831	1,600	1,596	1,582	1,507	1,472	1,442	1,392	1,193	1,109	1,073
Solar (Utility Scale)	1	58	50	50	42	34	27	19	11	23	45	56
Solar (CSGs)	5	34	30	29	25	20	16	11	7	14	27	34
Solar (Distributed)	0	8	12	12	12	11	10	8	5	11	26	33
Contract	-342	0	0	0	0	0	0	0	0	0	0	0
Total Existing and Approved	**10,717**	**10,166**	**9,928**	**9,323**	**9,319**	**8,763**	**8,713**	**7,698**	**7,564**	**7,116**	**7,040**	**7,004**
(Need)/Surplus	**4,104**	**3,276**	**2,703**	**1,946**	**1,793**	**1,167**	**964**	**-215**	**-582**	**-1,312**	**-1,601**	**-1,894**
New Resources												
Energy Efficiency	163	305	455	620	779	926	1,013	1,110	1,199	1,286	1,359	1,441
Demand Response	62	47	45	47	46	45	45	44	43	43	40	39
Natural Gas/Oil	0	0	0	0	299	299	299	299	299	299	299	480
Storage	0	0	0	1,082	1,062	1,147	1,125	1,455	1,820	1,954	2,128	2,165
Wind	0	0	0	0	773	1,071	1,059	1,347	1,554	1,508	1,415	1,500
Solar (Utility Scale)	0	0	0	0	0	0	9	12	9	30	59	74
Solar (CSGs)	1	5	9	13	14	14	12	10	7	14	31	42
Solar (Distributed)	0	0	0	3	9	11	12	8	5	10	21	27
Total New	**226**	**357**	**508**	**1,764**	**2,982**	**3,512**	**3,575**	**4,285**	**4,937**	**5,144**	**5,353**	**5,766**
(Need)/Surplus	**4,330**	**3,633**	**3,211**	**3,710**	**4,776**	**4,680**	**4,539**	**4,069**	**4,354**	**3,832**	**3,752**	**3,872**
Winter Reserve Margin	**65.49%**	**52.73%**	**44.45%**	**50.29%**	**63.46%**	**61.61%**	**58.57%**	**51.43%**	**53.45%**	**45.47%**	**43.42%**	**43.51%**

Table 10. Load and Capability Table (MW) – CEO 25% Market Summer

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
NSP Load	9,408	9,526	9,946	10,311	10,511	10,643	10,835	11,040	11,331	11,573	11,902	12,212
Existing and Approved Resources												
Demand Response	1,011	1,015	1,019	1,021	1,021	1,020	1,016	1,012	1,008	1,004	1,001	997
Coal	1,475	1,475	1,475	883	883	461	461	0	0	0	0	0
Nuclear	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747
Natural Gas/Oil	4,020	3,719	3,962	3,962	3,988	3,988	3,715	3,599	3,305	3,305	3,305	3,305
Biomass/RDF	110	61	61	61	61	61	61	61	61	61	61	38
Storage	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	659	170	169	169	169	169	169	169	100	97	80	78
Wind	785	780	744	743	737	706	704	683	674	585	573	566
Solar (Utility Scale)	147	259	464	396	362	329	296	262	256	249	242	236
Solar (CSGs)	438	367	341	233	214	195	176	157	153	150	147	143
Solar (Distributed)	121	102	81	85	87	90	89	89	95	102	110	116
Contract	342	0	0	0	0	0	0	0	0	0	0	0
Total Existing and Approved	**10,855**	**9,696**	**10,064**	**9,301**	**9,271**	**8,766**	**8,434**	**7,779**	**7,400**	**7,301**	**7,266**	**7,227**
(Need)/Surplus	**1,447**	**170**	**118**	**-1,010**	**-1,240**	**-1,876**	**-2,401**	**-3,261**	**-3,931**	**-4,272**	**-4,637**	**-4,985**
New Resources												
Energy Efficiency	114	215	321	426	528	628	712	801	883	963	1,047	1,125
Demand Response	177	178	179	179	179	178	177	175	174	172	171	169
Natural Gas/Oil	0	0	0	0	314	314	314	314	314	314	314	314
Storage	0	0	0	690	678	767	853	1,181	1,609	1,798	2,045	2,194
Wind	0	0	0	0	361	505	504	648	748	810	835	929
Solar (Utility Scale)	0	0	0	0	0	0	103	161	201	328	319	310
Solar (CSGs)	8	40	74	102	118	130	137	140	150	159	168	176
Solar (Distributed)	0	0	0	21	78	107	128	114	114	114	114	113
Total New	**299**	**432**	**573**	**1,418**	**2,256**	**2,629**	**2,929**	**3,533**	**4,193**	**4,658**	**5,012**	**5,330**
(Need)/Surplus	**1,746**	**602**	**691**	**408**	**1,016**	**753**	**528**	**272**	**262**	**386**	**376**	**345**
Summer Reserve Margin	**18.56%**	**6.32%**	**6.95%**	**3.96%**	**9.66%**	**7.07%**	**4.88%**	**2.47%**	**2.31%**	**3.33%**	**3.16%**	**2.82%**

Table 11. Load and Capability Table (MW) – CEO 25% Market Winter

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
NSP Load	6,612	6,889	7,225	7,377	7,526	7,596	7,750	7,913	8,146	8,428	8,641	8,899
Existing and Approved Resources												
Demand Response	441	421	423	447	447	447	447	447	447	447	423	423
Coal	1,562	1,562	1,562	938	938	469	469	0	0	0	0	0
Nuclear	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826
Natural Gas/Oil	4,372	4,204	4,204	4,204	4,227	4,227	4,227	3,724	3,724	3,451	3,451	3,451
Biomass/RDF	96	52	52	52	52	52	52	52	52	52	52	29
Storage	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	610	169	169	169	169	169	169	169	100	100	80	78
Wind	2,146	1,831	1,600	1,596	1,582	1,507	1,472	1,442	1,392	1,193	1,109	1,073
Solar (Utility Scale)	1	58	50	50	42	34	27	19	11	23	45	56
Solar (CSGs)	5	34	30	29	25	20	16	11	7	14	27	34
Solar (Distributed)	0	8	12	12	12	11	10	8	5	11	26	33
Contract	-342	0	0	0	0	0	0	0	0	0	0	0
Total Existing and Approved	**10,717**	**10,166**	**9,928**	**9,323**	**9,319**	**8,763**	**8,713**	**7,698**	**7,564**	**7,116**	**7,040**	**7,004**
(Need)/Surplus	**4,104**	**3,276**	**2,703**	**1,946**	**1,793**	**1,167**	**964**	**-215**	**-582**	**-1,312**	**-1,601**	**-1,894**
New Resources												
Energy Efficiency	130	241	359	482	597	710	805	904	997	1,087	1,167	1,252
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas/Oil	0	0	0	0	299	299	299	299	299	299	299	299
Storage	0	0	0	703	690	782	870	1,204	1,574	1,753	2,024	2,165
Wind	0	0	0	0	773	1,071	1,059	1,347	1,554	1,651	1,618	1,760
Solar (Utility Scale)	0	0	0	0	0	0	9	12	9	30	59	74
Solar (CSGs)	1	5	9	13	14	14	12	10	7	14	31	42
Solar (Distributed)	0	0	0	3	9	11	12	8	5	10	21	27
Total New	**131**	**246**	**367**	**1,201**	**2,382**	**2,886**	**3,066**	**3,784**	**4,445**	**4,846**	**5,219**	**5,619**
(Need)/Surplus	**4,235**	**3,522**	**3,070**	**3,146**	**4,176**	**4,054**	**4,030**	**3,569**	**3,863**	**3,534**	**3,618**	**3,725**
Winter Reserve Margin	**64.05%**	**51.12%**	**42.49%**	**42.65%**	**55.49%**	**53.36%**	**52.01%**	**45.10%**	**47.42%**	**41.93%**	**41.87%**	**41.86%**

Table 12. Load and Capability Table (MW) – CEO 50% Market Summer

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
NSP Load	9,408	9,526	9,946	10,311	10,511	10,643	10,835	11,040	11,331	11,573	11,902	12,212
Existing and Approved Resources												
Demand Response	1,011	1,015	1,019	1,021	1,021	1,020	1,016	1,012	1,008	1,004	1,001	997
Coal	1,475	1,475	1,475	883	883	461	461	0	0	0	0	0
Nuclear	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747
Natural Gas/Oil	4,020	3,719	3,962	3,962	3,988	3,988	3,715	3,599	3,305	3,305	3,305	3,305
Biomass/RDF	110	61	61	61	61	61	61	61	61	61	61	38
Storage	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	659	170	169	169	169	169	169	169	100	97	80	78
Wind	785	780	744	743	737	706	704	683	674	585	573	566
Solar (Utility Scale)	147	259	464	396	362	329	296	262	256	249	242	236
Solar (CSGs)	438	367	341	233	214	195	176	157	153	150	147	143
Solar (Distributed)	121	102	81	85	87	90	89	89	95	102	110	116
Contract	342	0	0	0	0	0	0	0	0	0	0	0
Total Existing and Approved	**10,855**	**9,696**	**10,064**	**9,301**	**9,271**	**8,766**	**8,434**	**7,779**	**7,400**	**7,301**	**7,266**	**7,227**
(Need)/Surplus	**1,447**	**170**	**118**	**-1,010**	**-1,240**	**-1,876**	**-2,401**	**-3,261**	**-3,931**	**-4,272**	**-4,637**	**-4,985**
New Resources												
Energy Efficiency	114	215	321	426	528	628	712	801	883	963	1,047	1,125
Demand Response	177	178	179	179	179	178	177	175	174	172	171	169
Natural Gas/Oil	0	0	0	0	314	314	314	314	314	314	314	314
Storage	0	0	0	372	365	460	452	1,082	1,408	1,489	1,678	1,873
Wind	0	0	0	36	397	541	576	720	819	915	1,044	1,101
Solar (Utility Scale)	0	0	0	0	0	0	103	161	201	328	319	310
Solar (CSGs)	8	40	74	102	118	130	137	140	150	159	168	176
Solar (Distributed)	0	0	0	21	78	107	128	114	114	114	114	113
Total New	**299**	**432**	**573**	**1,135**	**1,979**	**2,358**	**2,600**	**3,507**	**4,063**	**4,455**	**4,854**	**5,181**
(Need)/Surplus	**1,746**	**602**	**691**	**125**	**739**	**482**	**199**	**246**	**132**	**183**	**218**	**196**
Summer Reserve Margin	**18.56%**	**6.32%**	**6.95%**	**1.22%**	**7.03%**	**4.53%**	**1.84%**	**2.23%**	**1.16%**	**1.58%**	**1.83%**	**1.60%**

Table 13. Load and Capability Table (MW) – CEO 50% Market Winter

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
NSP Load	6,612	6,889	7,225	7,377	7,526	7,596	7,750	7,913	8,146	8,428	8,641	8,899
Existing and Approved Resources												
Demand Response	441	421	423	447	447	447	447	447	447	447	423	423
Coal	1,562	1,562	1,562	938	938	469	469	0	0	0	0	0
Nuclear	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826
Natural Gas/Oil	4,372	4,204	4,204	4,204	4,227	4,227	4,227	3,724	3,724	3,451	3,451	3,451
Biomass/RDF	96	52	52	52	52	52	52	52	52	52	52	29
Storage	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	610	169	169	169	169	169	169	169	100	100	80	78
Wind	2,146	1,831	1,600	1,596	1,582	1,507	1,472	1,442	1,392	1,193	1,109	1,073
Solar (Utility Scale)	1	58	50	50	42	34	27	19	11	23	45	56
Solar (CSGs)	5	34	30	29	25	20	16	11	7	14	27	34
Solar (Distributed)	0	8	12	12	12	11	10	8	5	11	26	33
Contract	-342	0	0	0	0	0	0	0	0	0	0	0
Total Existing and Approved	**10,717**	**10,166**	**9,928**	**9,323**	**9,319**	**8,763**	**8,713**	**7,698**	**7,564**	**7,116**	**7,040**	**7,004**
(Need)/Surplus	**4,104**	**3,276**	**2,703**	**1,946**	**1,793**	**1,167**	**964**	**-215**	**-582**	**-1,312**	**-1,601**	**-1,894**
New Resources												
Energy Efficiency	130	241	359	482	597	710	805	904	997	1,087	1,167	1,252
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas/Oil	0	0	0	0	299	299	299	299	299	299	299	299
Storage	0	0	0	379	372	469	460	1,104	1,378	1,453	1,661	1,848
Wind	0	0	0	78	850	1,147	1,210	1,496	1,702	1,867	2,022	2,086
Solar (Utility Scale)	0	0	0	0	0	0	9	12	9	30	59	74
Solar (CSGs)	1	5	9	13	14	14	12	10	7	14	31	42
Solar (Distributed)	0	0	0	3	9	11	12	8	5	10	21	27
Total New	**131**	**246**	**367**	**954**	**2,141**	**2,650**	**2,808**	**3,834**	**4,396**	**4,760**	**5,260**	**5,628**
(Need)/Surplus	**4,235**	**3,522**	**3,070**	**2,900**	**3,934**	**3,817**	**3,772**	**3,618**	**3,814**	**3,449**	**3,659**	**3,734**
Winter Reserve Margin	**64.05%**	**51.12%**	**42.49%**	**39.31%**	**52.28%**	**50.25%**	**48.68%**	**45.73%**	**46.82%**	**40.92%**	**42.35%**	**41.96%**

Table 14. Load and Capability Table (MW) – CEO 100% Market Summer

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
NSP Load	9,408	9,526	9,946	10,311	10,511	10,643	10,835	11,040	11,331	11,573	11,902	12,212
Existing and Approved Resources												
Demand Response	1,011	1,015	1,019	1,021	1,021	1,020	1,016	1,012	1,008	1,004	1,001	997
Coal	1,475	1,475	1,475	883	883	461	461	0	0	0	0	0
Nuclear	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747
Natural Gas/Oil	4,020	3,719	3,962	3,962	3,988	3,988	3,715	3,599	3,305	3,305	3,305	3,305
Biomass/RDF	110	61	61	61	61	61	61	61	61	61	61	38
Storage	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	659	170	169	169	169	169	169	169	100	97	80	78
Wind	785	780	744	743	737	706	704	683	674	585	573	566
Solar (Utility Scale)	147	259	464	396	362	329	296	262	256	249	242	236
Solar (CSGs)	438	367	341	233	214	195	176	157	153	150	147	143
Solar (Distributed)	121	102	81	85	87	90	89	89	95	102	110	116
Contract	342	0	0	0	0	0	0	0	0	0	0	0
Total Existing and Approved	**10,855**	**9,696**	**10,064**	**9,301**	**9,271**	**8,766**	**8,434**	**7,779**	**7,400**	**7,301**	**7,266**	**7,227**
(Need)/Surplus	**1,447**	**170**	**118**	**-1,010**	**-1,240**	**-1,876**	**-2,401**	**-3,261**	**-3,931**	**-4,272**	**-4,637**	**-4,985**
New Resources												
Energy Efficiency	114	215	321	426	528	628	712	801	883	963	1,047	1,125
Demand Response	177	178	179	179	179	178	177	175	174	172	171	169
Natural Gas/Oil	0	0	0	0	314	314	314	314	314	314	314	314
Storage	0	0	0	53	52	153	201	640	1,056	1,233	1,416	1,606
Wind	0	0	0	289	649	793	865	1,008	1,104	1,232	1,322	1,410
Solar (Utility Scale)	0	0	0	0	0	0	103	161	201	328	319	310
Solar (CSGs)	8	40	74	102	118	130	137	140	150	159	168	176
Solar (Distributed)	0	0	0	21	78	107	128	114	114	114	114	113
Total New	**299**	**432**	**573**	**1,070**	**1,919**	**2,304**	**2,637**	**3,352**	**3,996**	**4,515**	**4,870**	**5,223**
(Need)/Surplus	**1,746**	**602**	**691**	**59**	**679**	**427**	**236**	**91**	**65**	**243**	**234**	**238**
Summer Reserve Margin	**18.56%**	**6.32%**	**6.95%**	**0.58%**	**6.46%**	**4.01%**	**2.18%**	**0.83%**	**0.57%**	**2.10%**	**1.96%**	**1.95%**

Table 15. Load and Capability Table (MW) – CEO 100% Market Winter

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
NSP Load	6,612	6,889	7,225	7,377	7,526	7,596	7,750	7,913	8,146	8,428	8,641	8,899
Existing and Approved Resources												
Demand Response	441	421	423	447	447	447	447	447	447	447	423	423
Coal	1,562	1,562	1,562	938	938	469	469	0	0	0	0	0
Nuclear	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826
Natural Gas/Oil	4,372	4,204	4,204	4,204	4,227	4,227	4,227	3,724	3,724	3,451	3,451	3,451
Biomass/RDF	96	52	52	52	52	52	52	52	52	52	52	29
Storage	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	610	169	169	169	169	169	169	169	100	100	80	78
Wind	2,146	1,831	1,600	1,596	1,582	1,507	1,472	1,442	1,392	1,193	1,109	1,073
Solar (Utility Scale)	1	58	50	50	42	34	27	19	11	23	45	56
Solar (CSGs)	5	34	30	29	25	20	16	11	7	14	27	34
Solar (Distributed)	0	8	12	12	12	11	10	8	5	11	26	33
Contract	-342	0	0	0	0	0	0	0	0	0	0	0
Total Existing and Approved	**10,717**	**10,166**	**9,928**	**9,323**	**9,319**	**8,763**	**8,713**	**7,698**	**7,564**	**7,116**	**7,040**	**7,004**
(Need)/Surplus	**4,104**	**3,276**	**2,703**	**1,946**	**1,793**	**1,167**	**964**	**-215**	**-582**	**-1,312**	**-1,601**	**-1,894**
New Resources												
Energy Efficiency	130	241	359	482	597	710	805	904	997	1,087	1,167	1,252
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas/Oil	0	0	0	0	299	299	299	299	299	299	299	299
Storage	0	0	0	54	53	156	205	652	1,033	1,202	1,401	1,584
Wind	0	0	0	625	1,391	1,682	1,816	2,095	2,294	2,513	2,561	2,673
Solar (Utility Scale)	0	0	0	0	0	0	9	12	9	30	59	74
Solar (CSGs)	1	5	9	13	14	14	12	10	7	14	31	42
Solar (Distributed)	0	0	0	3	9	11	12	8	5	10	21	27
Total New	**131**	**246**	**367**	**1,177**	**2,364**	**2,873**	**3,158**	**3,981**	**4,644**	**5,156**	**5,540**	**5,951**
(Need)/Surplus	**4,235**	**3,522**	**3,070**	**3,123**	**4,157**	**4,040**	**4,122**	**3,765**	**4,062**	**3,844**	**3,939**	**4,057**
Winter Reserve Margin	**64.05%**	**51.12%**	**42.49%**	**42.33%**	**55.24%**	**53.18%**	**53.19%**	**47.58%**	**49.86%**	**45.61%**	**45.58%**	**45.59%**

Table 16. Load and Capability Table (MW) – Rerun Xcel Preferred Plan Summer

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
NSP Load	9,408	9,526	9,946	10,311	10,511	10,643	10,835	11,040	11,331	11,573	11,902	12,212
Existing and Approved Resources												
Demand Response	1,011	1,015	1,019	1,021	1,021	1,020	1,016	1,012	1,008	1,004	1,001	997
Coal	1,475	1,475	1,475	883	883	461	461	0	0	0	0	0
Nuclear	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747
Natural Gas/Oil	4,020	3,719	3,962	3,962	3,445	3,117	2,843	2,727	2,433	2,433	2,433	2,433
Biomass/RDF	110	61	61	61	61	61	61	61	61	61	61	38
Storage	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	659	170	169	169	169	169	169	169	100	97	80	78
Wind	785	780	744	743	737	706	704	683	674	585	573	566
Solar (Utility Scale)	147	259	464	396	362	329	296	262	256	249	242	236
Solar (CSGs)	438	367	341	233	214	195	176	157	153	150	147	143
Solar (Distributed)	121	102	81	85	87	90	89	89	95	102	110	116
Contract	342	0	0	0	0	0	0	0	0	0	0	0
Total Existing and Approved	**10,855**	**9,696**	**10,064**	**9,301**	**8,728**	**7,895**	**7,563**	**6,907**	**6,528**	**6,429**	**6,394**	**6,355**
(Need)/Surplus	**1,447**	**170**	**118**	**-1,010**	**-1,783**	**-2,748**	**-3,273**	**-4,133**	**-4,803**	**-5,144**	**-5,508**	**-5,857**
New Resources												
Energy Efficiency	114	215	321	426	528	628	712	801	883	963	1,047	1,125
Demand Response	244	232	232	231	230	229	227	225	223	221	219	217
Natural Gas/Oil	0	0	0	629	1,257	1,257	1,886	1,886	2,086	2,086	2,086	2,086
Storage	0	0	0	425	417	512	502	689	1,006	1,079	1,154	1,177
Wind	0	0	0	72	433	577	576	720	819	915	974	998
Solar (Utility Scale)	0	0	0	0	0	0	103	161	201	328	319	310
Solar (CSGs)	8	40	74	102	118	130	137	140	150	159	168	176
Solar (Distributed)	0	0	0	21	78	107	128	114	114	114	114	113
Total New	**366**	**487**	**626**	**1,905**	**3,062**	**3,439**	**4,272**	**4,735**	**5,481**	**5,865**	**6,080**	**6,201**
(Need)/Surplus	**1,812**	**657**	**744**	**895**	**1,279**	**691**	**1,000**	**602**	**679**	**721**	**572**	**344**
Summer Reserve Margin	**19.27%**	**6.89%**	**7.48%**	**8.68%**	**12.17%**	**6.49%**	**9.22%**	**5.45%**	**5.99%**	**6.23%**	**4.80%**	**2.82%**

Table 17. Load and Capability Table (MW) – Rerun Xcel Preferred Plan Winter

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
NSP Load	6,612	6,889	7,225	7,377	7,526	7,596	7,750	7,913	8,146	8,428	8,641	8,899
Existing and Approved Resources												
Demand Response	441	421	423	447	447	447	447	447	447	447	423	423
Coal	1,562	1,562	1,562	938	938	469	469	0	0	0	0	0
Nuclear	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826
Natural Gas/Oil	4,372	4,204	4,204	4,204	3,997	3,255	3,255	2,753	2,753	2,480	2,480	2,480
Biomass/RDF	96	52	52	52	52	52	52	52	52	52	52	29
Storage	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	610	169	169	169	169	169	169	169	100	100	80	78
Wind	2,146	1,831	1,600	1,596	1,582	1,507	1,472	1,442	1,392	1,193	1,109	1,073
Solar (Utility Scale)	1	58	50	50	42	34	27	19	11	23	45	56
Solar (CSGs)	5	34	30	29	25	20	16	11	7	14	27	34
Solar (Distributed)	0	8	12	12	12	11	10	8	5	11	26	33
Contract	-342	0	0	0	0	0	0	0	0	0	0	0
Total Existing and Approved	**10,717**	**10,166**	**9,928**	**9,323**	**9,089**	**7,792**	**7,742**	**6,726**	**6,592**	**6,145**	**6,069**	**6,033**
(Need)/Surplus	**4,104**	**3,276**	**2,703**	**1,946**	**1,563**	**196**	**-8**	**-1,187**	**-1,554**	**-2,283**	**-2,573**	**-2,866**
New Resources												
Energy Efficiency	130	241	359	482	597	710	805	904	997	1,087	1,167	1,252
Demand Response	62	47	45	47	46	45	45	44	43	43	40	39
Natural Gas/Oil	0	0	0	598	1,197	1,197	1,795	1,795	1,976	1,976	1,976	1,976
Storage	0	0	0	433	425	521	512	702	984	1,052	1,142	1,162
Wind	0	0	0	156	928	1,224	1,210	1,496	1,702	1,867	1,887	1,891
Solar (Utility Scale)	0	0	0	0	0	0	9	12	9	30	59	74
Solar (CSGs)	1	5	9	13	14	14	12	10	7	14	31	42
Solar (Distributed)	0	0	0	3	9	11	12	8	5	10	21	27
Total New	**192**	**292**	**412**	**1,732**	**3,215**	**3,722**	**4,400**	**4,972**	**5,722**	**6,079**	**6,323**	**6,462**
(Need)/Surplus	**4,297**	**3,568**	**3,115**	**3,677**	**4,778**	**3,917**	**4,393**	**3,785**	**4,169**	**3,795**	**3,750**	**3,596**
Winter Reserve Margin	**64.98%**	**51.79%**	**43.12%**	**49.85%**	**63.49%**	**51.57%**	**56.68%**	**47.84%**	**51.17%**	**45.03%**	**43.40%**	**40.41%**

3.2 PRESENT VALUE REVENUE REQUIREMENT ("PVRR") AND PRESENT VALUE SOCIETAL COST ("PVSC") COST RESULTS

In this section, we provide the PVRR and PVSC cost results for the CEO Portfolios and the rerun of Xcel's Preferred Plan. Table 18 shows the PVRR and PVSC results for the 2024-2050 time period and Table 19 shows the results for the 2024-2040 time period. In these tables, the "PVRR" column reflects the PVRR coming directly from the EnCompass outputs, which includes the PUC's mid-range Regulatory Cost of Carbon. The "Externality" column reflects the externality costs of emissions that need to be added outside of the model since those costs are not part of the optimization within EnCompass. This is the typical approach to externalities since in reality they are not reflected in a utility's revenue requirement and would not affect dispatch. The "Adjustment" column adds the impact from the emissions related to the market interaction for each portfolio.[19] The "PVSC" column adds together the "PVRR", "Externality", and "Adjustment" columns.

Since the CEO portfolios reflect different levels of MISO market access in the capacity expansion step, and Xcel's Preferred Plan was developed under the assumption of no MISO market access, the two plans that are most comparable are the Rerun of Xcel's Preferred Plan and the CEO 0% Market Plan. The difference in the PVSC between the Rerun of Xcel's Preferred Plan and the CEO 0% Market Plan is about 0.53% for the PVRR and 0.67% for the PVSC for the 2024-2050 time period. Since these differences are less than 1%, the costs between the two plans are very comparable, illustrating that extending existing contracts and adding storage resources is very similar in cost to Xcel's proposal.

The CEO portfolio costs can be compared against one another to see the cost differences that arise from using different market access assumptions. These results show $700 million-$3.9 billion in savings between 2024-2050 under plans that allow for greater levels of market access.

Table 18. PVRR and PVSC Results for CEO Modeling ($ Millions) for 2024-2050

Modeling Run	PVRR	Externality	Adjustment	PVSC
Rerun Xcel Preferred Plan	$50,369	$17,302	$1,015	$68,687
CEO 0% Market	$50,635	$17,071	$1,444	$69,149
CEO 25% Market	$49,974	$17,146	$1,351	$68,471
CEO 50% Market	$49,570	$16,600	$1,005	$67,174
CEO 100% Market	$49,360	$15,316	$551	$65,227

[19] Difference between the carbon emissions from purchases and sales.

Table 19. PVRR and PVSC Results for CEO Modeling ($ Millions) for 2024-2040

Modeling Run	PVRR	Externality	Adjustment	PVSC
Rerun Xcel Preferred Pan	$34,833	$15,495	$279	$50,607
CEO 0% Market	$34,869	$15,570	$483	$50,922
CEO 25% Market	$34,170	$15,664	$460	$50,294
CEO 50% Market	$33,729	$15,270	$217	$49,217
CEO 100% Market	$33,372	$14,187	$(131)	$47,428

3.3 CARBON EMISSIONS

Figure 1 shows the annual comparison of carbon emissions between the various CEO Market Access Scenarios and the Rerun of the Xcel Preferred Plan. The plans with higher levels of market access have larger wind builds that offset thermal generation and result in the lowest carbon emissions.

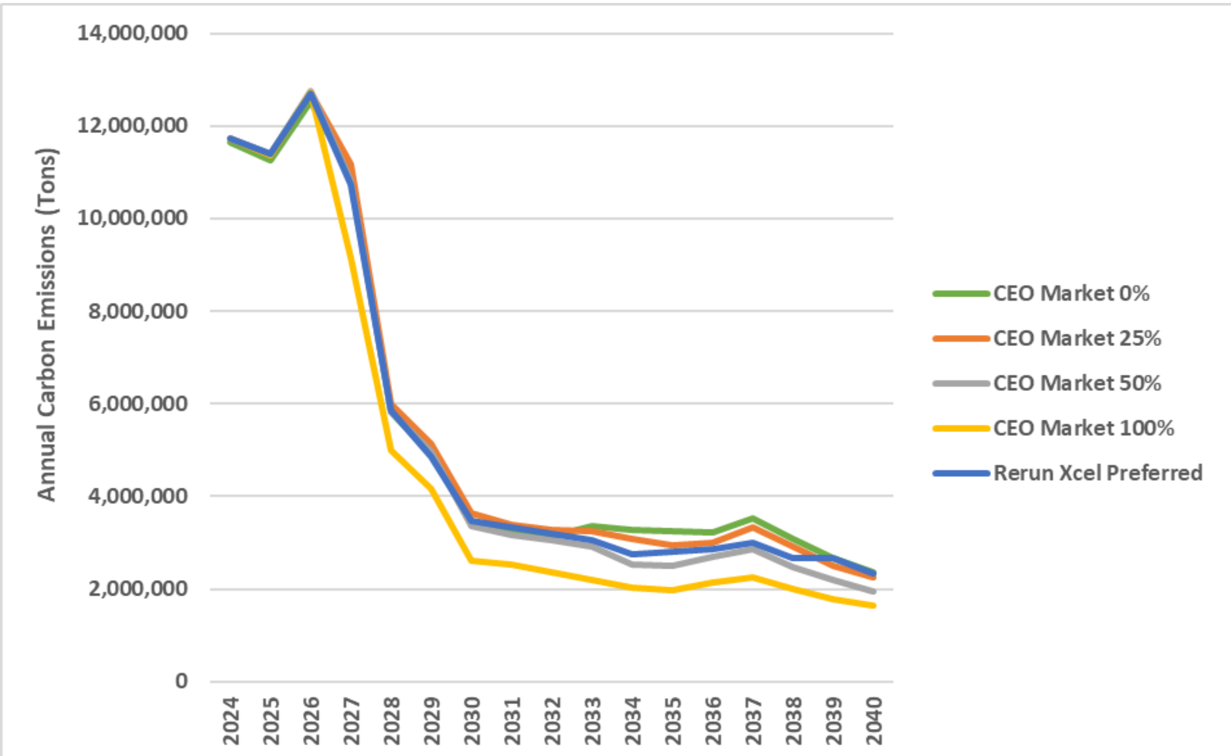

Figure 1. Annual Carbon Emissions (Tons)

4. ENERGY ADEQUACY MODELING

After Xcel developed its capacity expansion plans and put those plans through the production cost modeling step, Xcel passed a select number of plans onto the Energy Adequacy analysis step. 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.[20] For each weather year modeled, MISO market interaction was turned off to determine any hours with differences between Xcel's generating resources and its load, which determines the proxy 'unserved energy' or market reliance that would be needed.

We put each of the CEO Market Access Scenarios through the energy adequacy step for 2030. The results are shown in Table 20, Table 21, Table 22, and Table 23. The following metrics were calculated for each weather year:

1. MISO Market Purchase Hours: Total number of hours the plan would need a market purchase to account for differences between load and generation.
2. Average Shortfall/Market Purchase Intensity: Average shortfall/market purchase (MW)
3. Longest Shortfall/Market Purchase Event: Longest duration in hours of the shortfall/market purchase events in each year.
4. Peak Capacity Shortfall/Market Purchase: Maximum capacity shortfall/market purchase (MW)
5. Month of Peak Capacity Shortfall/Market Purchase: The month with the maximum capacity shortfall/market purchase.
6. MISO Market Purchases: Total amount of MISO market purchases (MWh) needed.

It is important to note that while Xcel used the term "Shortfall" in the metrics presented in the IRP, we are labeling these as "Shortfall/Market Purchase". Since the Energy Adequacy modeling was performed without access to the market, the hours when there is a difference between Xcel's load and its generation are representative of hours when they could turn to a market purchase to make up the difference.

When we put the four CEO Market Access Scenarios through the Energy Adequacy step for 2030, there were hours shown in the EnCompass output that indicated there would be MISO market purchases needed. Since a large portion of these hours were in the range of .001 - .002 MW, we only counted hours with market purchases of 1 MW or greater and those results are shown in the tables below.

[20] Xcel 2024 IRP, Appendix D at page 5.

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

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

Table 22. CEO 50% 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	26	381	5	1,099	AUGUST	9,896
2017	25	276	4	846	OCTOBER	6,907
2018	45	304	8	975	OCTOBER	13,676
2019	40	333	6	999	JULY	13,319
2020	45	391	6	1,391	SEPTEMBER	17,609
2021	73	403	18	1,519	OCTOBER	29,410
2022	7	293	2	778	AUGUST	2,049

Table 23. CEO 100% 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	42	346	5	1,213	AUGUST	14,543
2017	26	359	5	1,081	OCTOBER	9,325
2018	63	289	12	959	JULY	18,214
2019	51	382	6	1,041	NOVEMEBER	19,500
2020	64	383	7	1,505	SEPTEMBER	24,503
2021	67	361	8	1,389	JULY	24,196
2022	8	405	3	817	AUGUST	3,244

EFG notes a few key takeaways from this analysis. The first is that none of the "peak capacity shortfall/purchase" events are larger than Xcel's 2,300 MW market access assumption. Because the energy adequacy runs are done *without* allowing any market access, any "shortfalls" shown are periods when Xcel would rely on the market. All of the "shortfalls" across all scenarios and weather years are under 2,300 MW, and thus within the market access limit Xcel used to develop its last IRP and within the market access limit assumed during production cost modeling in this IRP.

The second takeaway is that there appears to be a pattern of the largest and longest "shortfall" or market purchase events occurring in the fall, particularly September or October. After looking further into what was driving this result, we found that the timing of maintenance for Xcel's thermal and nuclear units is a large driver of the "shortfall" periods in the fall. Figure 2 shows the level of capacity out for maintenance across the year – this pattern is consistent for each historical weather year. The schedule highlights that a large portion of the thermal fleet is scheduled for maintenance during the September to October timeframe. Xcel has indicated there is some flexibility in scheduling non-nuclear units for maintenance.[21] Adjustments to Xcel's maintenance schedules could help to mitigate the duration or size of "shortfall" or MISO market import events in the fall season.

Additionally, the capacity import limit (CIL) for Zone 1 is highest in fall. While winter has a CIL of 4,900 MW and Summer CIL is 5,300 MW, fall has a CIL of 6,500 MW.[22] Xcel is approximately half the demand in Zone 1.

---

[21] Xcel response to CEO IR No. 75.
[22] Xcel IRP, Table 3-3

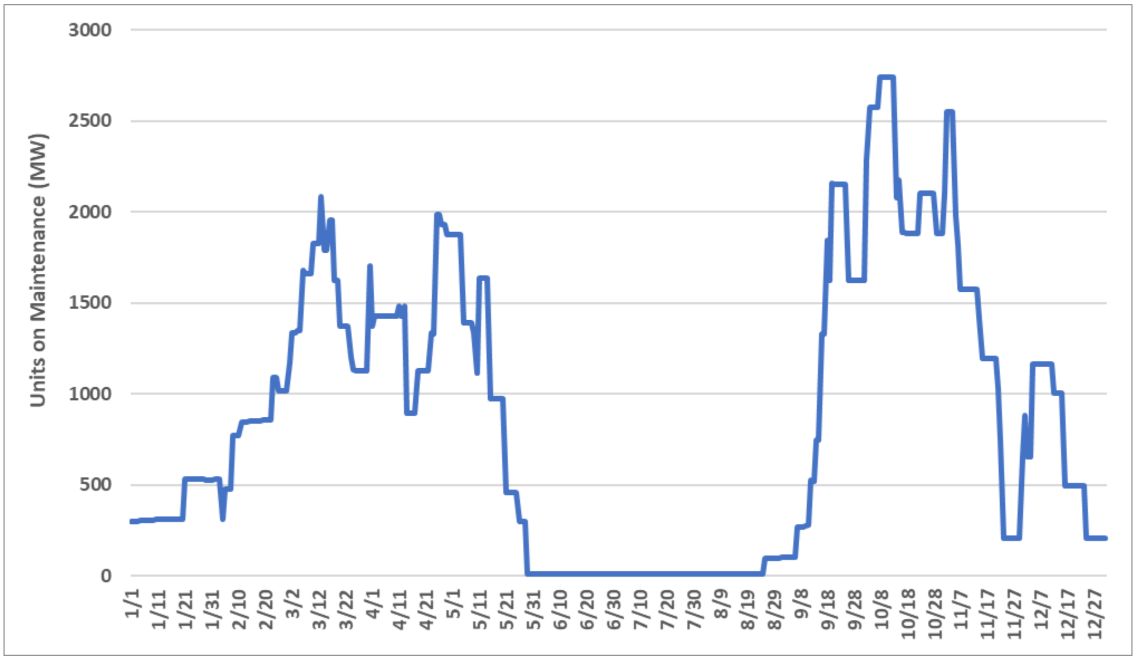

Figure 2. Units on Scheduled Maintenance (MW)

The third takeaway is that several of the weather years have "shortfall" or import events with a duration that could be addressed through additional demand response programs. The EFG report on DSM describes a potential portfolio of Virtual Power Plant ("VPP") resources totaling 527 MW by 2030.[23] We have not included this portfolio in Encompass modeling at this time due to uncertainty and forthcoming changes in the MISO resource accreditation rules for load modifying resources; however we anticipate that this uncertainty will resolve as MISO completes work on LMR accreditation.

[23] EFG "Evaluation of Energy Efficiency, Demand Response and Other Demand Side Resources in the 2024 Xcel IRP," at 20-21.