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A Clean Energy Future for Xcel

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1 Clean Energy Organizations' EnCompass Modeling Runs

The following sections discuss the modifications that we made to Xcel's EnCompass database to perform the Clean Energy Organizations ("CEO") modeling runs. CEO modeling runs were performed using EnCompass V5.0.2.[1,2]

Our modeling approach was to examine three portfolios:

1) Xcel's Preferred Plan as filed,
2) a reoptimized Revised Xcel Preferred Plan that includes the Sherco CC, and
3) an alternative, all renewable and storage expansion plan we call the CEO Preferred Plan.

We evaluated these portfolios under two main scenarios: 1) minor corrections and changes to Xcel's Base Case assumptions ("Xcel Corrected Base Case") and 2) more significant updates of inputs in Xcel's Base Case that are now over a year old and/or are inconsistent with other assumptions ("CEO Base Case") and 3) the changes from the prior two scenarios plus lower wind and solar interconnection costs. We also modeled these portfolios under three of Xcel's sensitivities ("high gas price and high market prices", "low gas price and low market prices" and "low load forecast"). In addition, we used EnCompass to determine the value of extending one of Xcel's Manitoba Hydro contracts in an effort to demonstrate the value of preserving that optionality. Finally, we replicated the EnCompass-based "reliability analysis" that Xcel provided in its Supplemental IRP filing for the two portfolios we created.

Our findings are that the EnCompass modeling described in this report demonstrates that a portfolio of renewable and storage resources with no new fossil generation has:

1. Consistently similar or lower costs than a portfolio that includes the Sherco CC;
2. Offer similar levels of reliability as a portfolio that includes the Sherco CC; and
3. Offers further, material CO_2 emission reductions.

1.1 Scenario One: Xcel Corrected Base Case

The first set of input assumption changes we made to Xcel's modeling are discussed in the section that follow and constitute what we call the Xcel Corrected Base Case scenario. The changes involved including projects already approved by the Minnesota Public Utilities Commission ("Commission" or "PUC") that were not a part of Xcel's original IRP filing, correcting errors in Xcel's development of costs for battery storage and solar resources, allowing the model to select partial battery storage resources, allowing the model to select solar hybrid resources, and including 6- and 8-hour flow batteries between

[1] The CEO modeling runs can only be executed using at least Version 5.0.2 of EnCompass due to limitations that exist in prior versions related to partial project additions and hybrid resources.

[2] Our version of EnCompass interprets Xcel's modeling database differently and adds extra EE and DR resources between 2020 and 2022 in all runs discussed in this report – washing out the net effect between runs. Removing these extra resources does not appear to affect subsequent resource additions, but we will confirm this and offer any clarifying information in reply comments as necessary.

2040 and 2045. We also tested whether EnCompass viewed the addition of the Sherco CC as "optimal." These changes are discussed in more detail in the sections below.

1.1.1 Adding Approved Projects

Since the filing of Xcel's supplemental IRP on June 30, 2020, the Commission has approved the construction/acquisition of the Elk Creek, Mower County, and Deuel Harvest renewable projects. Those projects were not part of Xcel's June 30th filing and we, therefore, wanted to update both Xcel's Preferred Plan[3] as well as our own modeling to include these projects.[4] Table 1 provides information on the approved projects included in the CEO modeling runs and is consistent with the project information Xcel provided in its wind repowering proceeding, Docket No. M-20-620.

Table 1. Approved Projects Included in All CEO Modeling Runs

Project	Size (MW)	Online Date	Technology
Deuel Harvest	100	12/31/2021	Wind
Mower– Owned	98.9	12/1/2020	Wind
Elk Creek	78.8	12/31/2021	Solar

1.1.2 Corrections to Xcel's Underlying Resource Cost Assumptions

In addition, there were certain corrections to Xcel's EnCompass database that needed to be reflected. Xcel already accounted for a number of these corrections in its Errata filing from August 25, 2020, which we also incorporated into our modeling, but there were additional corrections needed. First, Xcel's battery storage costs were derived from the National Renewable Energy Lab's ("NREL") 2019 Annual Technology Baseline ("ATB") which gives costs in real 2017 dollars. Even so, Xcel used a nominal (rather than real) fixed charge rate ("FCR") to levelize those costs. Xcel argued that "the WACC [weighted average cost of capital] does not affect this calculation"[5] but we do not see how this could be the case because the WACC is an input into the FCR. The FCR formula is given by:

$$\frac{i(1+i)^n}{(1+i)^n-1}$$

where:
i = discount rate
n = number of years

[3] Xcel's Preferred Plan is Scenario 9 from the Supplemental IRP Filing.
[4] Xcel's EnCompass modeling in its Wind Repowering proceeding, Docket No. M-20-620, also included these approved projects.
[5] Xcel response to Sierra Club IR 184, Docket No. E002/RO-19-368.

Since Xcel's discount rate <u>is</u> its WACC it is not possible that the choice of a nominal or real discount rate *would not* influence the FCR and therefore the levelization calculation. In the development of the costs for battery storage resources, Xcel used a FCR of [TRADE SECRET BEGINS… …TRADE SECRET ENDS]. We were unable to recreate this FCR value as a battery life of 10 years ("*n*"). Instead, using a real WACC of [TRADE SECRET BEGINS… …TRADE SECRET ENDS] ("*i*"), translates into a FCR of [TRADE SECRET BEGINS… …TRADE SECRET ENDS]. We therefore corrected the fixed charge rate to account for a real WACC, which reduced the battery storage levelized cost.

Second, rather than trying to replicate Xcel's approach of levelizing battery storage fixed operations and maintenance ("FOM") costs over the battery storage lifetime we converted it to an annual expense. This change served to increase battery storage costs somewhat relative to Xcel's assumption.

Third, we increased the battery storage lifetime to 15 years rather than using Xcel's assumption of 10 years. This was not only consistent with the ATB's assumption for battery storage lifetimes, but is the lower end of the range we have seen in several all-source RFPs across the country. This change also served to reduce levelized battery storage costs.

Fourth, we allowed EnCompass to choose a smaller, more realistic sized hybrid option which lowered the hybrid battery size as well. For stand-alone batteries we relaxed Xcel's integer constraint that forced EnCompass to take batteries in 321 MW increments. Because batteries are highly modular, letting the model optimize to less than 321 MW sizes was more realistic and had the benefit of reducing model run times.

Finally, with regards to solar, we corrected the application of the Investment Tax Credit ("ITC"). Xcel applied the ITC to the total project cost, including FOM, rather than to just the capital cost as is required by the credit. This change served to increase solar costs relative to Xcel's assumption.

1.1.3 Solar-Battery Hybrid Resources

In the supplemental IRP filing, Xcel evaluated solar-battery hybrid resources in a sensitivity run that looked at including a solar hybrid resource in 2025 only. That is, Xcel did not let the model choose solar hybrid projects in any year other than 2025, and it only considered solar hybrids in one sensitivity run. Xcel described this sensitivity in its supplemental IRP filing as necessary to limit run times, but we believe it is likely that one of the errors corrected in Xcel's August errata filing was the cause of those long run times, not the inclusion of the hybrids. Our change was to make solar-battery hybrids available to the model in years 2025-2040. Presenting the option to add solar hybrids between 2025 and 2040 did not create untenably long run times in our simulations.

1.1.4 Flow Batteries

Upon review of our initial modeling runs, we noticed that the relative differences between portfolios were being heavily influenced by the results in the years 2040 – 2045. Due to the significant amount of resources retiring between 2040 and 2045, especially the Monticello nuclear unit, a dramatic uptick in the amount and costs of "purchases" could be seen in the modeling results between 2040 and 2045. This drove a significant difference in overall revenue requirements between our two primary capacity expansion plans: the CEO Preferred Plan and the Revised Xcel Preferred Plan (both discussed in Section 3.1).

Those "purchase" costs included significant quantities of "unserved energy", which Xcel prices at [TRADE SECRET BEGINS… …TRADE SECRET ENDS]. This "unserved energy" result was driven by Xcel's assumption limiting the total amount of MISO market purchases along with the volume of resource retirements including the Monticello nuclear unit.

Figure 1 shows how the revenue requirements difference between portfolios changes dramatically in the years 2040-2045, driving significant total cost differences between our two primary resource portfolios.

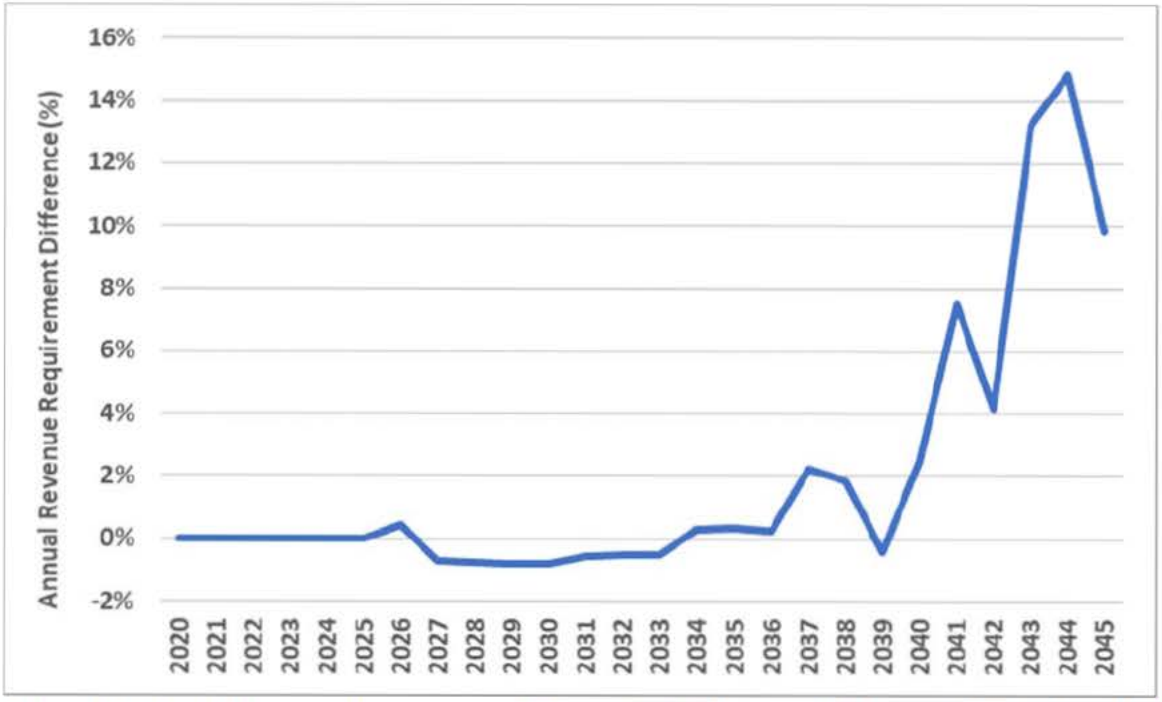

Figure 1. Annual Revenue Requirement Percentage Difference Between CEO Preferred Plan and Revised Xcel Preferred Plan Under Corrected Xcel Base Case Without Flow Batteries

While unserved energy was a problem in both the Revised Xcel and CEO Preferred plans, the volume of unserved energy was "switching" results and having an unrealistic impact on the total costs. Thus, in order to make these runs more realistic, we included 6- and 8-hour flow batteries between 2040 and

2045 to provide longer duration storage resources that could help with some of the periods where the model was hitting Xcel's market purchase limit.

The technical and cost information for these batteries is given in Table 2, below. Information for the flow batteries was taken from a technology assessment report using information provided by Burns and McDonnell that Vectren (an Indiana based utility) included with its 2019-2020 IRP filing.[6] The NREL ATB Moderate cost curve was applied to the starting capital costs to account for an expected improvement in cost over the next 20 plus years.

Table 2. Flow Battery Technical and Cost Information

	6 Hour	8 Hour
Size (MW)	50	50
Operating Life (Years)	20	20
Round Trip Efficiency	68%	68%
Cost per kW 2019 $	3,910	4,830
Fixed O&M 2019 $ (Mill.)	2.1	2.1

1.1.5 Allowing the Model to Choose the Sherco CC

All EnCompass modeling runs discussed by Xcel in its Supplemental IRP filing included the Sherco combined cycle ("CC") as a hardcoded resource. Since Xcel did not present any runs without the Sherco CC, it was not possible to ascertain if the Sherco CC was indeed an optimal choice. Xcel did provide a scenario in its EnCompass database that was set up with a constraint to prevent the model from adding the Sherco CC but the results of that run were not provided nor discussed in the IRP. For these reasons, we set up an initial run in which we removed Xcel's constraint forcing in the Sherco CC and allowed EnCompass to choose the resource (or not) as part of its optimal plan. When the constraint was removed, the Sherco CC is not selected by EnCompass. Because EnCompass did not view the Sherco CC as "optimal", the constraint forcing the addition of the Sherco CC was removed for all CEO modeling runs, with the exception of the "Revised Xcel Preferred Plan". We left the Sherco CC as a fixed resource in our "Revised Xcel Preferred Plan" capacity expansion resource portfolio (explained below), so that a resource portfolio with the Sherco CC could be compared directly with the "CEO Preferred Plan" capacity expansion resource portfolio (also explained below in Section 3.1).

[6] Vectren 2019-2020 IRP Volume 2, Attachment 2.1, p.23. Retrieved from https://www.vectren.com/assets/downloads/planning/irp/2019-2020%20Vectren%20IRP%20-%20Volume%202%20of%202.pdf

1.1.6 Creating Capacity Expansion Resource Portfolios: Revised Xcel Preferred Plan and CEO Preferred Plan

The changes described above: the "Xcel Corrected Base Case" were then used to develop the two primary capacity expansion resource portfolios that we use for the remainder of our modeling analysis. This approach was chosen to symmetrically account for the changes in costs described above, while also analyzing the cost impact of the Sherco CC.

To create these two capacity expansion resource portfolios, we reran Xcel's Preferred Plan, with the Sherco CC included as a fixed resource, under the new assumptions described above (Xcel Corrected Base Case) to create a portfolio we are calling "Revised Xcel Preferred Plan". In this way, we allowed the model to optimize the resource additions outside of the Sherco CC.

Second, we allowed the model to select a fully optimized plan with the same Xcel Corrected Base Case assumptions. We refer to this portfolio as the "CEO Preferred Plan". The only difference between the two in terms of inputs and settings is that the CEO Preferred Plan did not force in the Sherco CC because, as described above, EnCompass had not found that resource to be "optimal." However, the model still had the option of choosing the Sherco CC or a similar "generic" combined cycle unit, which it did not ultimately choose.

The overall intent of this Corrected Xcel Base Case scenario was to evaluate whether a different resource portfolio would result from making the corrections and modest, reasonable changes discussed here in Section 1.1. The resource expansion plans and cost comparisons that result from these runs are discussed in Section 3.

1.2 Scenario Two: CEO Base Case

Our second scenario of assumption changes, called "CEO Base Case", seeks to incorporate what we believe to be more up-to-date renewable and storage costs and assumptions.

At roughly the same time that Xcel released its supplemental IRP in June 2020, NREL released the 2020 version of its ATB.[7] Just as Xcel updated its renewable costs from the 2018 to 2019 ATB for its supplemental IRP, it is reasonable to again update costs to reflect the 2020 ATB. These updated wind and solar costs from the ATB were the first component of our CEO Base Case scenario. Second, rather than use the 2020 ATB projected storage costs, we chose to base our estimates on actual contract prices that were finalized in mid-2020 for projects coming online in 2022. Energy Futures Group has been involved in the review of storage bids submitted to four recent all-source RFPs and we believe that the NREL starting point was not reflective of where the current market for utility scale storage stands.

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[7] NREL (National Renewable Energy Laboratory). 2020. "2020 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/.

Table 3 below shows Public Service of New Mexico ("PNM")'s solar-battery hybrid project pricing that we used to develop the battery prices included in the CEO Base Case. The market for utility scale batteries has grown dramatically since 2019[8] with thousands of megawatts of batteries expected to come online in the next three years.[9] As that data become more available, we would expect the ATB to absorb it, but in the meantime benchmarking costs against actual project cost data seems preferable and more accurate. These solar-battery projects have a 20-year project life so we also adopted that assumption for our modeling. We also applied the NREL Mid case cost reduction curve to the PNM battery project pricing.

Table 3. PNM Battery Storage Project Pricing[10]

	With ITC $/kW-Mo	No ITC $/kW-Mo
Jicarilla	$9.97	$13.47
Arroyo	$7.46	$10.08
Bidder #5	$7.99	$10.80
Bidder #2	$7.70	$10.41
Avg	**$8.28**	**$11.19**

Our third change was to update the solar capacity factor used both for purposes of levelizing capital costs as well for EnCompass' dispatch simulation. Solar capacity factors assumed in the 2020 NREL ATB have gone up at least in part because NREL is now presuming the DC rating of installed panels relative to the AC rating of the inverters is increasing.[11] This oversizing also pushes a project's capacity factor up and is a material change from the 2019 ATB. However, we wanted to make sure our capacity factor assumption also captured this change. We therefore used NREL solar irradiance data to develop a generation profile for all new generic solar. We used a list of sites in Minnesota and the Dakotas in Xcel, Otter Tail Power and Great River Energy service territories that MISO has used to characterize the likely build out of solar. This profile produces an average 25.5% capacity factor, which is nearly identical to the 22 year average of the NREL ATB's projection of solar capacity factors - 25.4%. This capacity factor is higher than the [TRADE SECRET BEGINS... ...TRADE SECRET ENDS] Xcel modeled for new solar resources. This change served to reduce solar costs.

[8] As NREL described in its documentation of its storage assumptions, "Battery cost and performance projections in the 2020 ATB are based on a literature review of 19 sources published in 2018 or 2019..." See https://atb.nrel.gov/electricity/2020/index.php?t=st.

[9] Energy Information Administration. "Battery Storage in the United States: An Update on Market Trends". July 2020. P. 26 Available at: https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

[10] Project pricing from NMPRC Case No. 20-00182-UT Direct Testimony of Thomas Fallgren, PNM Table TGF-1, p. 11.

[11] This is commonly referred to as the "inverter loading ratio".

Fourth, we also adjusted the calculation of wind levelized costs to reflect the [TRADE SECRET BEGINS… …TRADE SECRET ENDS] capacity factor that Xcel actually modeled. Xcel's original wind levelization calculation (which accounts for capacity factor) was based on a [TRADE SECRET BEGINS… …TRADE SECRET ENDS] capacity factor rather than the capacity factor the Company actually modeled. This change served to reduce wind costs.

Finally, we adjusted Xcel's methodology for including the interconnection costs in its financial calculation for wind and solar costs. Xcel's approach was to add the interconnection costs on top of the levelized capital costs for each resource. However, we were not able to replicate Xcel's calculation, which seemed to overstate interconnection charges. However, the NREL ATB is set up in a manner that allows interconnection costs to be included directly as a component of the levelized cost of energy ("LCOE") calculation. So we chose to incorporate the interconnection costs in this manner instead. This change further reduced solar and wind costs.

1.3 Scenario Three: Lower Interconnection Costs

This scenario was included to test the cost impact of reduced interconnection costs after 2030. To do so, we combined all of the changes made under the CEO Base Case scenario and added only a new trajectory of wind and solar interconnection costs. Recognizing that new transmission interconnection is currently challenging in MISO Zone 1, we kept Xcel's assumption of $500 per kW for wind and $200 per kW for solar interconnection charges through 2030. We believe it is reasonable to think that transmission interconnection will be eased as new transmission is built or existing lines upgraded. Those interconnection costs will not go away entirely, but they may well return to more normal levels. As such, we chose 2031 as a reasonable year to begin accounting for new infrastructure. To approximate those values we relied upon a Lawrence Berkeley National Laboratory paper[12] that summarized historic average interconnection costs in MISO. Using that report, we assumed that interconnection charges would be $100 per kW for solar and $200 per kW for wind in 2031 and beyond.

1.4 Scenario Four: Manitoba Hydro Contract Extension

We also wanted to test the value of a resource that could provide more optionality. Because CEO's Preferred Plan is dominated by modular solar, storage, and wind, it can be adapted to changed circumstances like new load or the addition of resources that are not currently expected. We sought to test the value of this optionality by performing a run to determine the implied value from an extension of Xcel's current primary Manitoba Hydro contract. That contract expires on April 30, 2025. This run merely extended the contract (not including the diversity exchange agreement[13]) through the end of the planning period at zero cost. The PVSC from this run was then compared to the Revised Xcel Preferred

[12] Interconnection cost inputs informed from data reported in an LBNL Report: Gorman, W., Mills, A., & Wiser, R. (2019). Improving estimates of transmission capital costs for utility-scale wind and solar projects to inform renewable energy policy. *Energy Policy*, *135*, 110994.
[13] The diversity exchange agreement provides the NSP system with 350 MWs of capacity in the summer and Manitoba Hydro receives 350 MWs of capacity in the winter.

Plan and CEO Preferred Plan to derive a hypothetical levelized value for the contract. That value is discussed in Section 3.5.

2 CEO Modeling Methodology

2.1 Setting up CEO Modeling Runs

The primary model runs we performed are described in this section. Figure 2 illustrates how modeling runs are performed in EnCompass. In short, we used the assumption changes described above in the Xcel Corrected Base Case scenario to create two new capacity expansion resource portfolios as described in Section 1 above: Revised Xcel Preferred Plan, which includes the Sherco CC, and the CEO Preferred Plan, which does not include the Sherco CC or any new fossil generation.

In addition, we also ran a scenario to develop a hypothetical value for a Manitoba Hydro extension. Finally, we replicated three of Xcel's primary sensitivities with our new resource portfolios.

EnCompass differs from Strategist, Xcel's prior IRP software, in several ways including the manner in which it is used. Strategist performed capacity expansion and simplified dispatch using sampled days and the results were then mapped onto the entirety of each year. EnCompass creates capacity expansion plans in the same manner, but there is a second step that was not part of Strategist. The modeler redispatches the plan while simulating all 8760 hours. The combination of the capital costs from the first run and the production costs from the redispatching of the plan are used to create the plan costs. This process is shown in Figure 2.

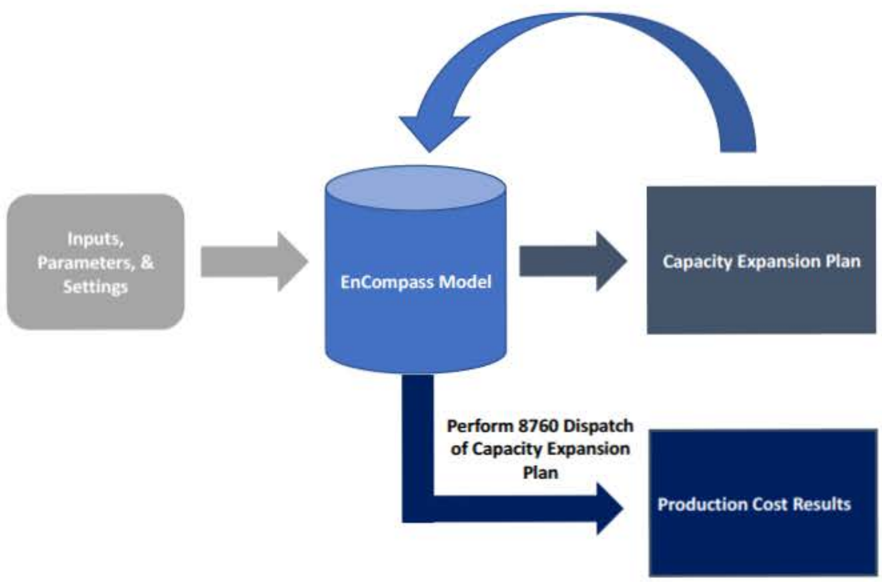

Figure 2. EnCompass Modeling Process

Figure 3 depicts how the changes discussed in Section 1 were applied to the CEO modeling runs.

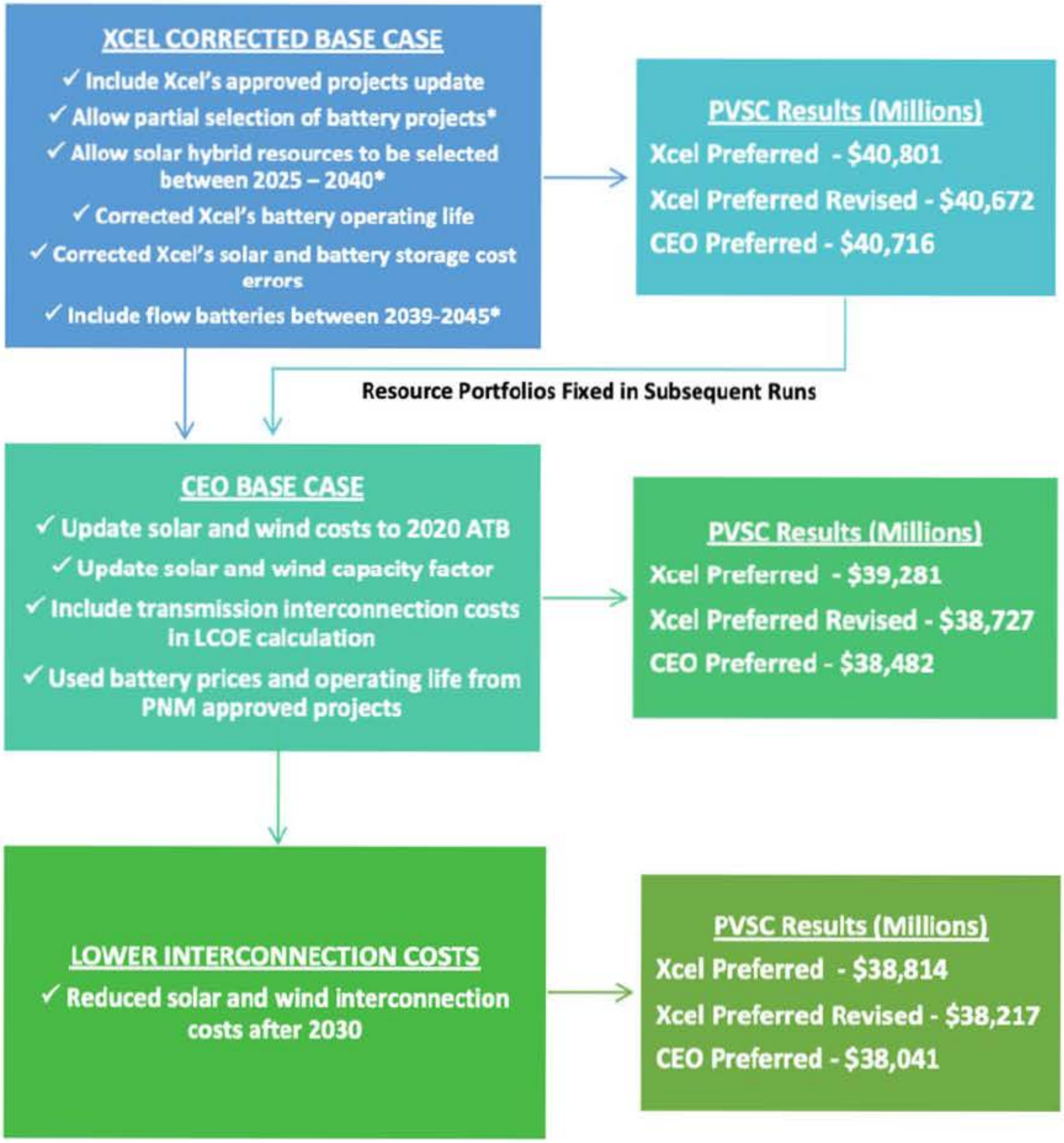

Figure 3. Flow Chart of CEO Modeling Approach

**Indicates changes that were not applied to "Xcel Preferred" since it included the fixed resources from Xcel's Supplemental IRP Filing.*

The boxes named "Xcel Corrected Base Case", "CEO Base Case", and "Lower Interconnection Costs" are the scenarios[14] and correspond to the changes that were discussed in Section 1. The boxes to the right show the resulting present value of societal costs ("PVSC") results for each run under the three portfolios evaluated, i.e. the Revised Xcel Preferred Plan, the CEO Preferred Plan and Xcel's Preferred Plan as filed.

Importantly, our two new resource portfolios were optimized under the Xcel Corrected Base Case scenario assumptions and then fixed in the runs for the remaining scenarios we evaluated. We chose to fix the capacity expansion plan from the Xcel Corrected Base Case scenario instead of reoptimizing the plans in subsequent runs because we found that when the renewable costs declined, the model added renewable capacity well in excess of the reserve margin – oftentimes double-digit reserve margins resulted.[15] We discovered that the lower cost of the renewables outcompeted even the variable cost of many of Xcel's existing thermal units and therefore the model was adding excess capacity as a form of arbitrage to back off more expensive, existing units. While this is an intriguing result because it suggests that there is significant, uneconomic thermal capacity on Xcel's system, we did not have the time to fully explore the consequences of this finding. So rather than offer a plan that resulted in significant overbuilding, we chose to fix the resource portfolios that resulted from the scenario with incremental changes, i.e., the Xcel Corrected Base Case scenario.

Our EnCompass runs also build on each other in the sense that the modifications to assumptions from one scenario flow into the next. For example, the correction removing the application of the ITC to solar fixed O&M in our Xcel Corrected Base Case scenario is carried forward into the subsequent scenarios. The stacking of these changes on top of each other is indicated by the arrows pointing directly downwards in the left-hand side of the chart.

We then make one additional change under the "Lower Interconnection Costs" scenario. This run combines all the changes in the Corrected Xcel Base Case and the CEO Base Case, with only the addition of a lower interconnection cost for new wind and solar resources after 2030, as described in Section 1.3.

The Manitoba Hydro Extension test was only run under the Xcel Corrected Base Case scenario.

Table 4 gives the specific changes made to each of the scenarios and portfolios we created on CEOs' behalf.

[14] Throughout these comments we use the term "scenario" to refer to a set of inputs into EnCompass and "portfolio" or "capacity expansion plan" to refer to the resulting set of resources that arises from those inputs.
[15] Xcel's minimum reserve margin requirement in its modeling is 3.46 percent.

Table 4. Summary of Changes Made in CEO Modeling Runs

Modeling Runs:	**Corrected Xcel Base Case**				**CEO Base Case**			**Lower Interconnection Cost**		
Changes Made	**Xcel Preferred Plan**	**Revised Xcel Preferred Plan**	**CEO Preferred Plan**	**MH Extension**	**Xcel Preferred Plan**	**Revised Xcel Preferred Plan**	**CEO Preferred Plan**	**Xcel Preferred Plan**	**Revised Xcel Preferred Plan**	**CEO Preferred Plan**
Add Approved Projects	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Allow Model to Choose Sherco CC			✓	✓			✓			✓
Force Sherco CC	✓	✓			✓	✓		✓	✓	
Smaller Battery Project Size		✓	✓	✓		✓	✓		✓	✓
Revise Solar Costs:										
Apply ITC to capital costs	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Update to 2020 ATB					✓	✓	✓	✓	✓	✓
Use 25.5% Capacity Factor					✓	✓	✓	✓	✓	✓
Interconnection cost in ATB LCOE Calculation					✓	✓	✓	✓	✓	✓
Lower interconnection cost								✓	✓	✓
Revise Battery Storage Costs:										
Apply real WACC	✓	✓	✓	✓						
Convert O&M to annual expense	✓	✓	✓	✓						
Use 15 year operating life	✓	✓	✓	✓						
Use PNM project pricing and 20 year life					✓	✓	✓	✓	✓	✓
Revise Wind Costs:										
Update to 2020 ATB					✓	✓	✓	✓	✓	✓
Interconnection cost in ATB LCOE Calculation					✓	✓	✓	✓	✓	✓
Lower interconnection cost								✓	✓	✓
Selection of solar hybrids		✓	✓	✓		✓	✓		✓	✓
Include 6 and 8-hour flow batteries		✓	✓	✓		✓	✓		✓	✓
Extend Manitoba Hydro through 2045				✓						

3 CEO Modeling Results

3.1 Capacity Expansion Portfolio Results

Figure 4 shows the cumulative installed capacity in MWs from 2020 to 2045 for our new resource portfolios and Xcel's Preferred Plan as filed. Overall, the capacity expansion results indicate a notable preference for hybrid resources. For example, the CEO Preferred Plan resource portfolio replaces the Sherco CC capacity in Revised Xcel Preferred Plan with hybrid battery-solar and standalone battery energy storage resources. The distributed solar, EE, and DR occur in the same quantities across all plans since we did not make any changes to the assumptions for those resources.

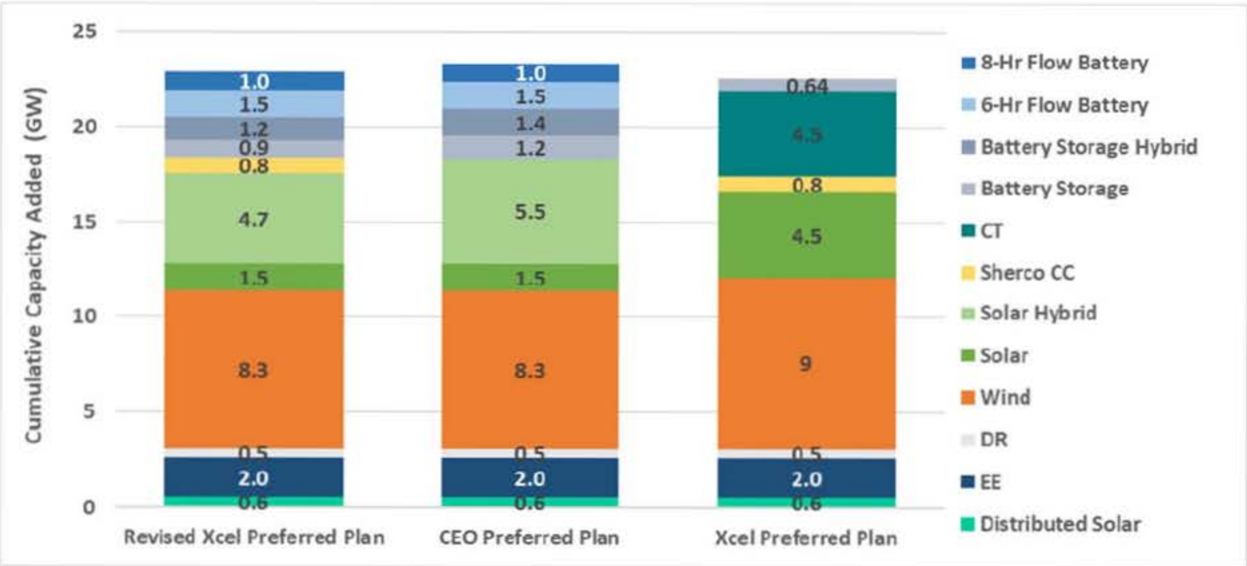

Figure 4. Cumulative New Additions (2020-2045) by Portfolio (Xcel Corrected Base Scenario)

Tables 5 and 6, show Xcel's resource (Need/Surplus) based on existing resources prior to new projects being added to the system and Xcel's reserve margin with the capacity expansion plan from the CEO Preferred Plan and the Revised Xcel Preferred Plan, respectively. The tables are reported in Unforced Capacity ("UCAP"). As the tables indicate, based on Xcel's load and DER forecasts, Xcel starts to have a resource need in 2027. The CEO Preferred Plan adds a mixture of solar hybrid resources and hybrid battery storage in 2027 to meet this need. Revised Xcel Preferred Plan includes the Sherco CC capacity in 2027 as a fixed resource. This is also the case in Xcel's Preferred Plan as filed.

Table 5. CEO Preferred Plan System Load and Resources, UCAP MW, 2020 – 2034

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak Demand	10,510	10,575	10,652	10,736	10,815	10,886	10,964	11,047	11,132	11,219	11,310	11,417	11,538	11,665	11,788
Existing Resources															
Nuclear	1642	1642	1642	1642	1642	1642	1642	1642	1642	1642	1642	1642	1642	1120	622
Combined Cycle	2078	2078	2078	2078	2078	2078	1787	1551	1551	1551	1551	1551	1275	1275	1275
Combustion Turbine	1781	1781	1781	1781	1635	1325	1325	1280	1280	1280	1280	737	737	737	737
Coal	2295	2295	2295	2295	1647	1647	1647	994	994	511	0	0	0	0	0
Hydroelectric	539	659	651	651	651	162	162	162	162	162	162	162	156	152	152
Biomass	110	110	110	86	86	61	61	61	29	29	29	19	19	19	19
Landfill	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV	495	531	614	647	632	612	591	570	548	526	503	480	456	431	435
Wind	498	623	689	663	652	648	643	641	635	613	612	597	594	528	510
Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distributed Generation	1078	1358	1505	1349	1407	1454	1470	1485	1499	1511	1518	1526	1536	1547	1560
Energy Efficiency	1562	1813	1977	1681	1782	1880	1973	2043	2123	2265	2347	2449	2533	2609	2672
Contract:Purchase	342	342	342	342	342	0	0	0	0	0	0	0	0	0	0
Contract:Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm Capacity Existing	12,419	13,230	13,683	13,215	12,553	11,509	11,302	10,430	10,463	10,089	9,643	9,163	8,947	8,419	7,983
Net Resource (Need)/Surplus	1,909	2,656	3,031	2,478	1,738	623	338	-617	-669	-1,129	-1,667	-2,254	-2,591	-3,245	-3,805
New Resources															
Wind	0	0	0	0	0	0	0	0	0	0	125	125	125	251	376
Solar	0	0	0	0	0	230	440	420	400	380	360	340	320	300	300
Solar Hybrid	0	0	0	0	0	0	0	420	400	684	756	986	928	1050	1260
Battery Storage	0	0	0	0	0	0	0	0	4	4	292	473	892	1174	1227
Battery Storage Hybrid	0	0	0	0	0	0	0	250	250	450	525	725	725	875	1050
Firm Capacity New	0	0	0	0	0	230	440	1090	1054	1518	2058	2649	2991	3649	4213
Total Firm Capacity	**12,419**	**13,230**	**13,683**	**13,215**	**12,553**	**11,739**	**11,742**	**11,520**	**11,517**	**11,607**	**11,701**	**11,812**	**11,937**	**12,068**	**12,196**
Reserve Margin	**18.17%**	**25.11%**	**28.46%**	**23.09%**	**16.08%**	**7.84%**	**7.09%**	**4.28%**	**3.46%**	**3.46%**	**3.46%**	**3.46%**	**3.46%**	**3.46%**	**3.46%**

Table 6. Revised Xcel Preferred Plan System Load and Resources, UCAP MW, 2020 - 2034

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak Demand	10,510	10,575	10,652	10,736	10,815	10,886	10,964	11,047	11,132	11,219	11,310	11,417	11,538	11,665	11,788
Existing Resources															
Nuclear	1642	1642	1642	1642	1642	1642	1642	1642	1642	1642	1642	1642	1642	1120	622
Combined Cycle	2078	2078	2078	2078	2078	2078	1787	1551	1551	1551	1551	1551	1275	1275	1275
Combustion Turbine	1781	1781	1781	1781	1635	1325	1325	1280	1280	1280	1280	737	737	737	737
Conventional	2295	2295	2295	2295	1647	1647	1647	994	994	511	0	0	0	0	0
Hydroelectric	539	659	651	651	651	162	162	162	162	162	162	162	156	152	152
Biomass	110	110	110	86	86	61	61	61	29	29	29	19	19	19	19
Landfill	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV	495	531	614	647	632	612	591	570	548	526	503	480	456	431	435
Wind	498	623	689	663	652	648	643	641	635	613	612	597	594	528	510
Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distributed Generation	1078	1358	1505	1349	1407	1454	1470	1485	1499	1511	1518	1526	1536	1547	1560
Energy Efficiency	1562	1813	1977	1681	1782	1880	1973	2043	2123	2265	2347	2449	2533	2609	2672
Contract:Purchase	342	342	342	342	342	0	0	0	0	0	0	0	0	0	0
Contract:Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm Capacity Existing	12,419	13,230	13,683	13,215	12,553	11,509	11,302	10,430	10,463	10,089	9,643	9,163	8,947	8,419	7,983
Net Resource (Need)/Surplus	1,909	2,656	3,031	2,478	1,738	623	338	-617	-669	-1,129	-1,667	-2,254	-2,591	-3,245	-3,805
New Resources															
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	125	376
Solar	0	0	0	0	0	230	440	420	400	380	360	340	320	300	300
Solar Hybrid	0	0	0	0	0	0	0	0	0	304	468	816	768	900	1110
Battery Storage	0	0	0	0	0	0	0	0	0	0	178	178	575	846	846
Battery Storage Hybrid	0	0	0	0	0	0	0	0	0	200	325	600	600	750	925
Sherco CC	0	0	0	0	0	0	0	728	728	728	728	728	728	728	728
Firm Capacity New	0	0	0	0	0	230	440	1148	1128	1612	2058	2661	2991	3649	4285
Total Firm Capacity	**12,419**	**13,230**	**13,683**	**13,215**	**12,553**	**11,739**	**11,742**	**11,577**	**11,591**	**11,701**	**11,702**	**11,824**	**11,937**	**12,068**	**12,268**
Reserve Margin	**18.17%**	**25.11%**	**28.46%**	**23.09%**	**16.08%**	**7.84%**	**7.09%**	**4.80%**	**4.12%**	**4.30%**	**3.46%**	**3.57%**	**3.46%**	**3.46%**	**4.07%**

Figure 5 shows the annual capacity expansion plan for the CEO Preferred Plan between 2020 and 2034. In year 2027, the new capacity build consists of a mix of solar-battery hybrid resources. Figure 6 shows the annual capacity expansion plan for Revised Xcel Preferred Plan between 2020 and 2034. In 2027, the CEO Preferred Plan adds 1,000 MWs of hybrid solar and 250 MWs of hybrid battery storage in place of the Sherco CC that is fixed in the Revised Xcel Preferred Plan.

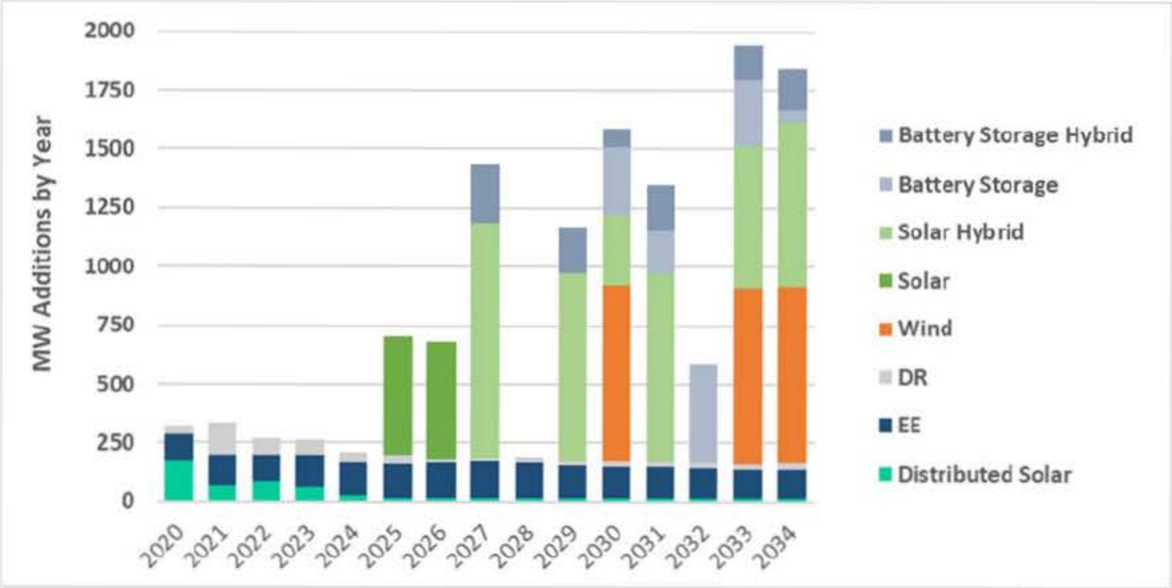

Figure 5. CEO Preferred Plan Annual Capacity Expansion Plan

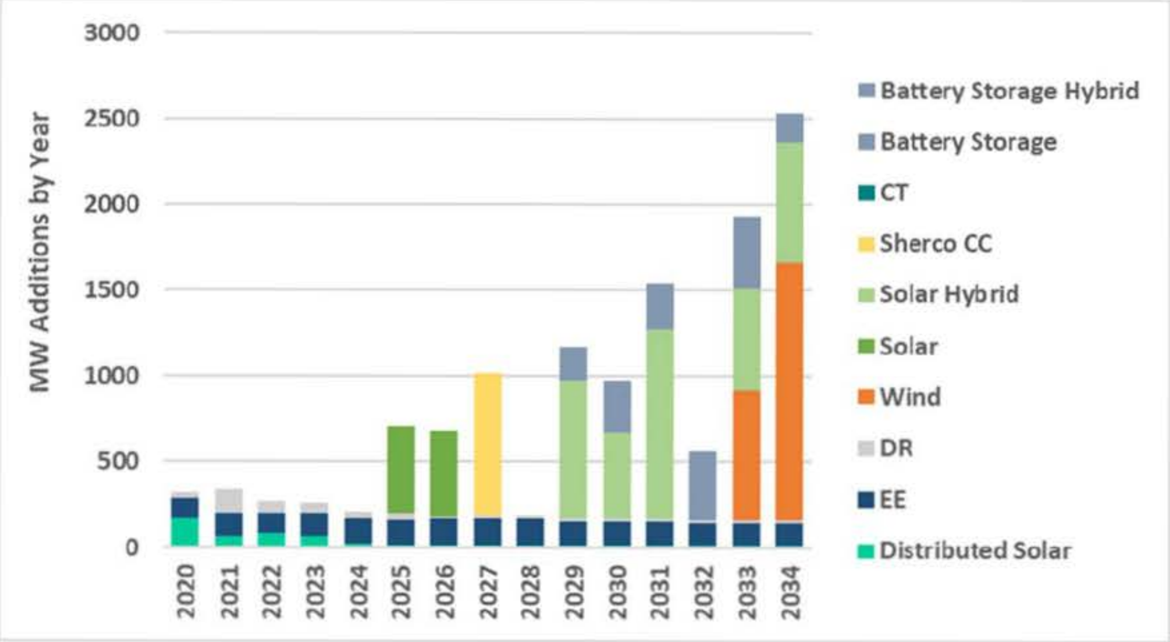

Figure 6. Revised Xcel Preferred Plan Annual Capacity Expansion Plan

3.2 PVSC and PVRR Results

In this section we provide the cost results for our two new resource portfolios – Revised Xcel Preferred Plan and CEO Preferred Plan. In its supplemental IRP filing, Xcel presented present value of revenue requirements ("PVRR") and Present Value Societal Cost ("PVSC") for the scenarios and sensitivities modeled. For the PVSC results, Xcel performs two post-processing steps in order to adjust the revenue requirements coming out of EnCompass to account for the externality costs of emissions and a carbon adjustment related to off-system sales. The steps that Xcel takes to perform this post-processing adjustment are outlined below:

Start: EnCompass Revenue Requirement
+ Externality Costs
- Carbon Sales Adjustment
= Post-Processing Revenue Requirement

Xcel adds in the externality costs of emissions since those costs are not part of the optimization within EnCompass. Xcel makes the carbon adjustment for sales under the assumption that the carbon from system sales is a reduction, since the entity purchasing energy from Xcel takes on the responsibility for counting the carbon associated with its purchase. For the PVRR results, Xcel dispatches each capacity expansion plan without a carbon price or externality costs. Xcel also removes the MISO capacity price input so capacity value is not included in the PVRR.

Table 7 and Table 8 below show the PVSC and PVRR net present value ("NPV") cost for each portfolio and scenario combination we simulated for 2020-2045. As described in Section 1.1, the Xcel Corrected Base Case only includes a handful of corrections to Xcel's assumptions. For this reason, the cost results are very close, with the Revised Xcel Preferred Plan being .1% less (or $44 million over 25 years) on a PVSC basis and even closer on a PVRR basis. When the Revised Xcel Preferred Plan and CEO Preferred Plans are evaluated under the CEO Base Case scenario, the costs are still close, but CEO Preferred Plan becomes less expensive than the Revised Xcel Preferred Plan by a wider margin – .63% (or $245 million over 25 years) on a PVSC basis. That margin is nearly the same in PVRR terms. Under the Lower Interconnection Cost scenario, again the CEO Preferred Plan is less expensive than the Revised Xcel Preferred Plan.

When we compare the results of the CEO Preferred Plan to the Xcel Preferred Plan, the differences in cost are larger. The CEO Preferred Plan is cheaper than the Xcel Preferred Plan under the Xcel Corrected Base Case, CEO Base Case, and Lower Interconnection Cost scenarios.

These results indicate that an alternative path to supply customers that does not rely on the buildout of additional fossil fuel-based generation is available to Xcel at similar or lower cost when more accurate assumptions are applied. Finally, these results show that lowering transmission interconnection costs would produce benefits for ratepayers but that even with higher interconnection costs, the buildout of additional renewables is economic.

Table 7. PVSC NPV Results for CEO Scenarios (Millions)

Name	Xcel Corrected Base Case	CEO Base Case	Lower Interconnection Costs
Xcel Preferred Plan	$40,801	$39,281	$38,814
Revised Xcel Preferred Plan	$40,672	$38,727	$38,217
CEO Preferred Plan	$40,716	$38,482	$38,041

Table 8. PVRR NPV Results for CEO Scenarios (Millions)

Name	Xcel Corrected Base Case	CEO Base Case	Lower Interconnection Costs
Xcel Preferred Plan	$37,794	$36,354	$35,888
Revised Xcel Preferred Plan	$37,687	$35,839	$35,329
CEO Preferred Plan	$37,711	$35,596	$35,155

Table 9 and Table 10 show the delta values for the combinations of modeled portfolios and scenarios. The deltas are derived by comparing the total NPV costs of each scenario to the Revised Xcel Preferred Plan under the Xcel Corrected Base Case, CEO Base Case, and the Lower Interconnection Cost scenarios. The results indicate that the CEO Preferred Plan is nearly even with or, when more accurate assumptions are applied, lower cost than the Revised Xcel Preferred Plan both in terms of PVSC and PVRR. Similar to the PVSC results, the CEO Preferred Plan is cheaper than the Xcel Preferred Plan under the Xcel Corrected Base Case, the CEO Base Case, and the Lower Interconnection Costs scenarios.

Table 9. NPV PVSC Delta for CEO Scenarios (Millions)

Description	CEO Scenario	Difference from Xcel Preferred Plan	Difference from Revised Xcel Preferred Plan
Revised Xcel Preferred Plan	Xcel Corrected Base Case	-$130	
CEO Preferred Plan	Xcel Corrected Base Case	-$86	$44
Revised Xcel Preferred Plan	CEO Base Case	-$554	
CEO Preferred Plan	CEO Base Case	-$799	-$245
Revised Xcel Preferred Plan	Lower Interconnection Costs	-$598	
CEO Preferred Plan	Lower Interconnection Costs	-$774	-$176

Table 10. NPV PVRR Delta for CEO Scenarios (Millions)

Description	CEO Scenario	Difference from Xcel Preferred Plan	Difference from Revised Xcel Preferred Plan
Revised Xcel Preferred Plan	Xcel Corrected Base Case	-$107	
CEO Preferred Plan	Xcel Corrected Base Case	-$83	$24
Revised Xcel Preferred Plan	CEO Base Case	-$515	
CEO Preferred Plan	CEO Base Case	-$758	-$243
Revised Xcel Preferred Plan	Lower Interconnection Costs	-$559	
CEO Preferred Plan	Lower Interconnection Costs	-$733	-$174

3.3 Annual Revenue Requirement Difference

The CEO Preferred Plan is less expensive on a revenue requirement basis than the Revised Xcel Preferred Plan in each year between 2027 and 2040. However, during 2040 through 2045, that dynamic switches, so much so that those years were switching the relative rankings of the plan in a way that we did not consider realistic. Section 1.1.4 discussed the inclusion of flow batteries in order to help address the bias we were seeing in the modeling due to significant resource retirement and Xcel's market purchases limit that were driving substantial "unserved energy costs" between 2040 and 2045. This period arguably holds the greatest uncertainty of all the years modeled because it is so far into the future. For example, if we look backward at IRP modeling done 20 years ago we would not see the impact of fracked gas, the tempering of load growth, nor the plummeting decline in renewables costs that we see today. But rather than address this uncertainty by simply modifying the limit on external energy purchases, we wanted to address this problem by attempting to model a technology that has a strong likelihood of being commercial by 2040. Xcel's Preferred Plan added a significant number of combustion turbines ("CT") between 2030 and 2045. In its Supplemental IRP filing, Xcel described the

CTs as "firm peaking, load-supporting resources."[16] But Xcel also said "Depending on the technology available, the cost of resources, and Commission preferences, we believe these additions could include energy storage, DR, or hydrogen, among other alternatives."[17] We agree that load management will grow, not diminish in importance, but because the characteristics of load management 20 years into the future are so hard to predict, we kept our alternatives simple and modeled a flow battery during the period 2040-2045.

Figure 7 shows the cumulative annual revenue requirement percentage difference between the CEO Preferred Plan and Revised Xcel Preferred Plan. Between 2027 and 2040, the CEO Preferred Plan is cheaper relative to the Revised Xcel Preferred Plan. However, due to the impact from unserved energy, there are several years where the CEO Preferred Plan has higher revenue requirements than the Revised Xcel Preferred Plan. We conservatively assumed that some unserved energy would remain, which continues to make the CEO Preferred Plan more expensive than it would be in practice.

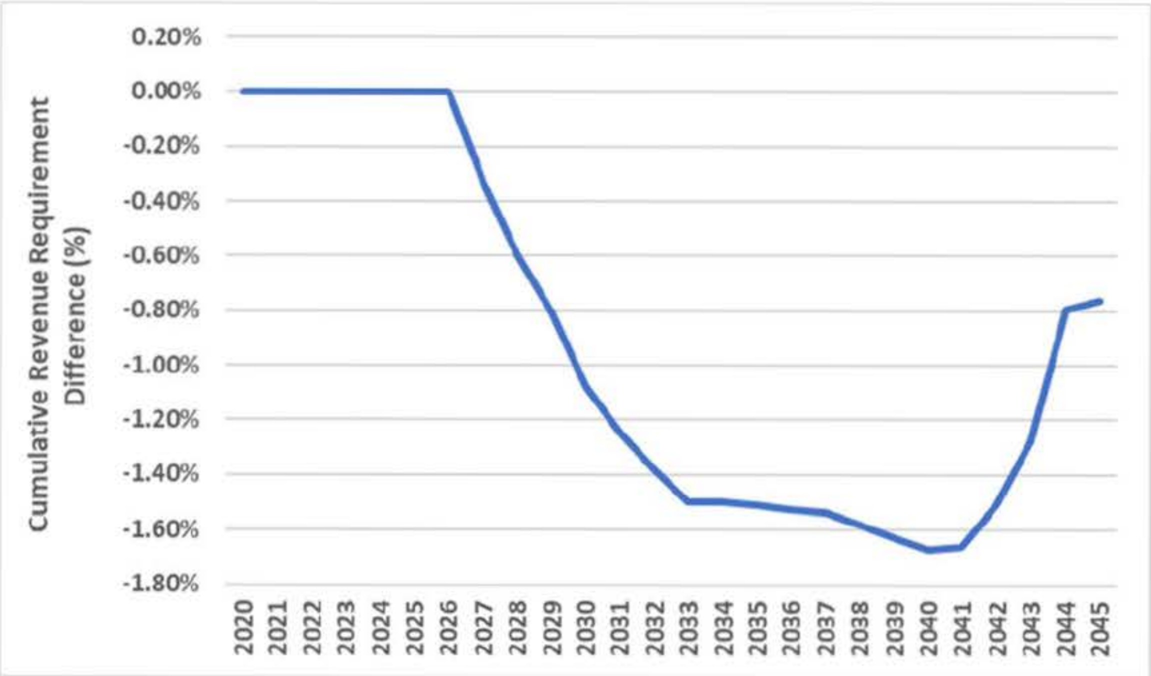

Figure 7. Cumulative Revenue Requirement Difference Between CEO Preferred Plan and Revised Xcel Preferred Plan (%)

[16] Xcel Supplemental IRP filing, Section 1, p. 2.
[17] Xcel Supplemental IRP filing, Section 1, p. 2.

3.4 Air Pollutant Emission Reduction Results

The level of carbon emission reduction between the CEO Preferred Plan and the Revised Xcel Preferred Plan is another important factor to consider when evaluating the two scenarios.

Figure 8 shows the comparison of the annual carbon emissions under the Xcel Preferred Plan, Revised Xcel Preferred Plan, and the CEO Preferred Plan evaluated under the CEO Base Case scenario assumptions. The CEO Preferred Plan has an average, annual carbon emission reduction of 21 percent between 2027 and 2045 relative to the Revised Xcel Preferred Plan.

Figure 8. CO_2 Emissions Comparison

The carbon emissions from the Sherco CC represent a significant portion of the total carbon emissions in Revised Xcel Preferred Plan. Figure 9 illustrates the proportion of the Sherco CC carbon emissions relative to Xcel's total carbon emissions in that scenario. On average, the Sherco CC accounts for 36% of Xcel's total carbon emissions between 2027 and 2045.

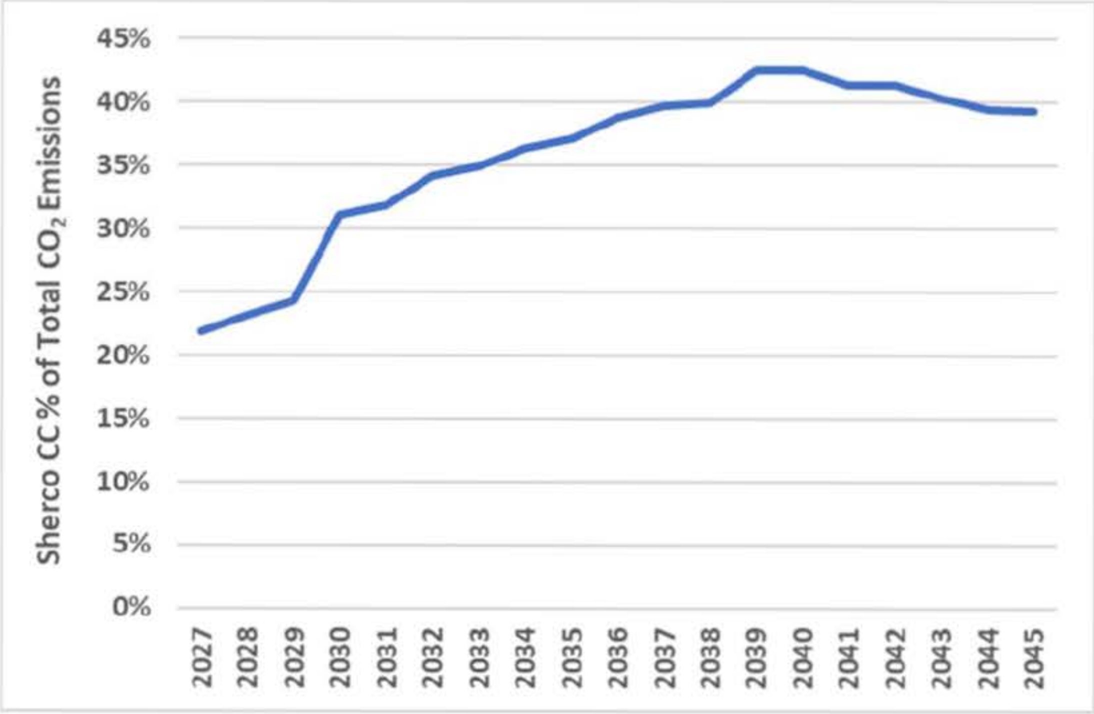

Figure 9. Sherco CC Proportion of Total Carbon Emissions (%)

Figure 10, Figure 11, and Figure 12 show the emissions comparison for NO_X, $PM_{2.5}$, and PM_{10}, respectively, for the Xcel Preferred Plan, Revised Xcel Preferred Plan, and the CEO Preferred Plan. For all three pollutants, the CEO Preferred Plan provides more emissions reductions across all three pollutants than do either plans with the Sherco CC.

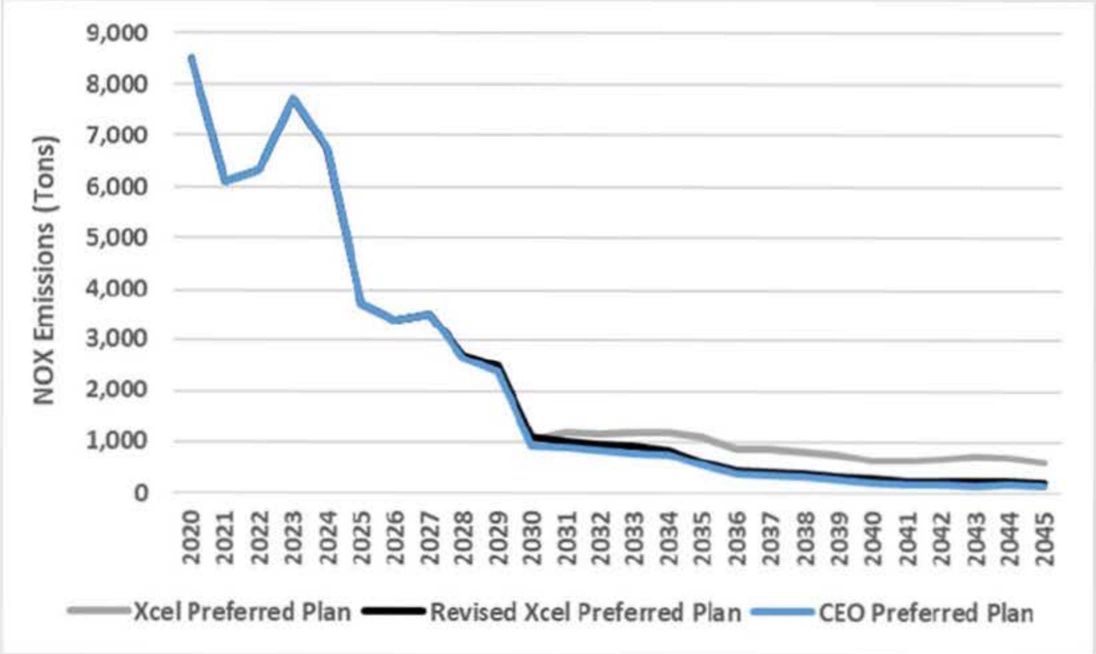

Figure 10. NOX Emissions Comparison

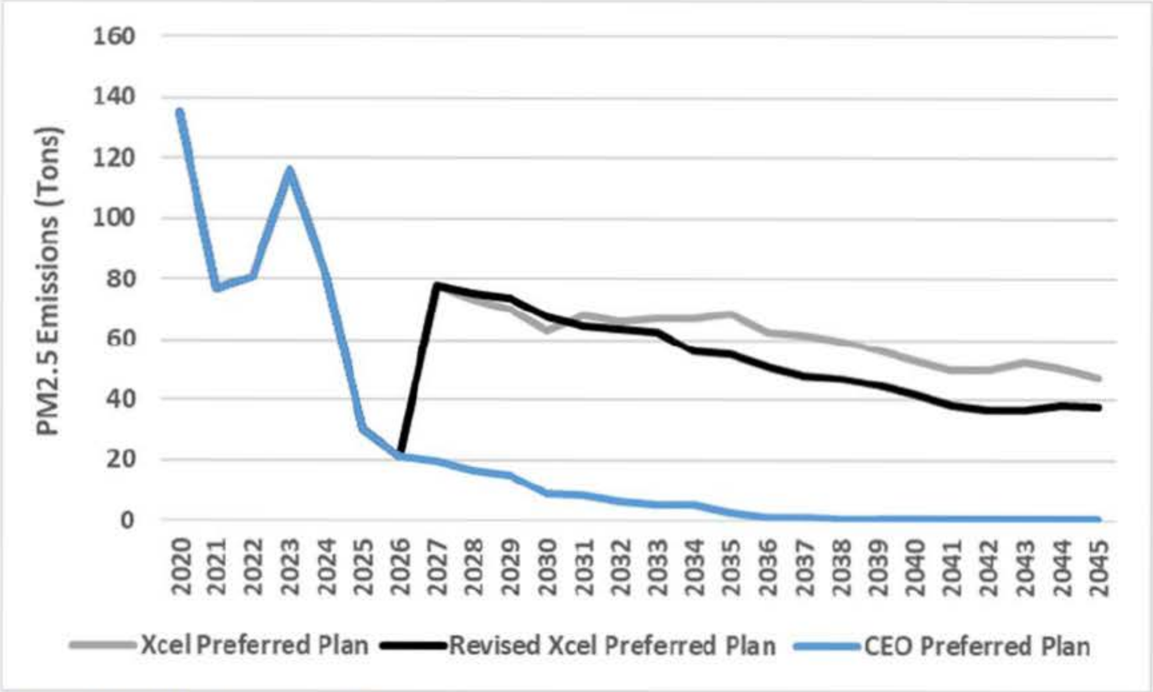

Figure 11. $PM_{2.5}$ Emissions Comparison

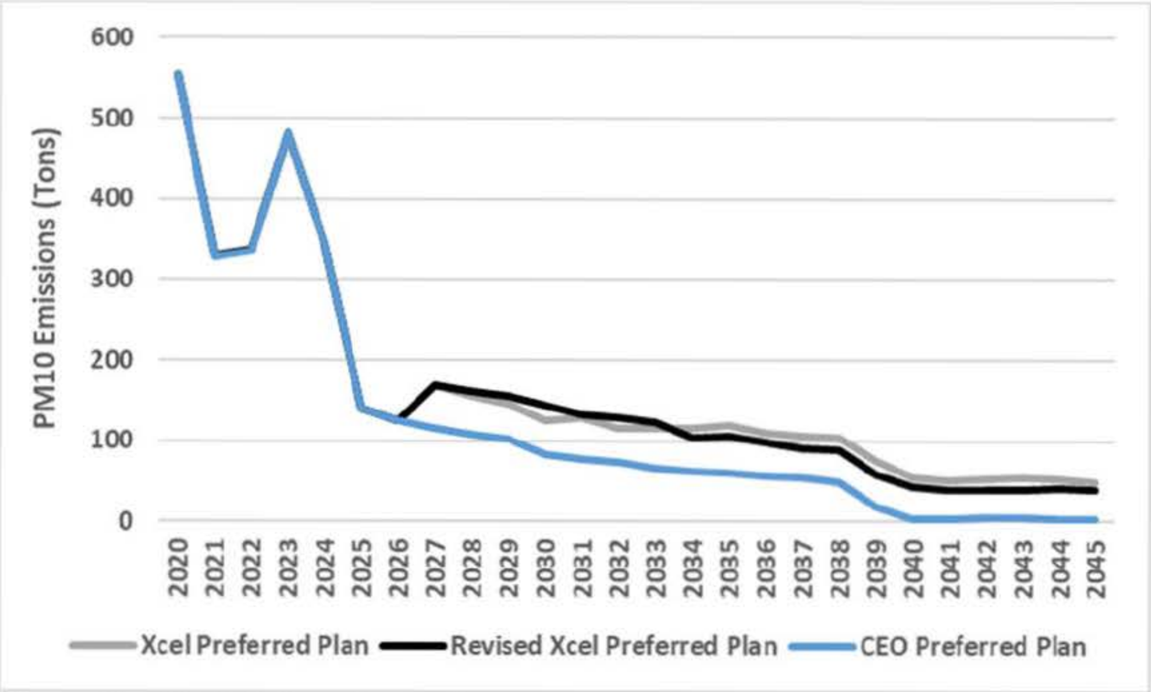

Figure 12. PM_{10} Emissions Comparison

3.5 Value of Manitoba Hydro Contract Extension Results

This run was performed to estimate a hypothetical value, described in LCOE, for an extension of the Manitoba Hydro contract. In the modeling for the Supplemental IRP, Xcel assumed that all Manitoba Hydro contracts were not renewed. In order to derive a hypothetical value of extending the primary Manitoba Hydro contract (500 MW of capacity), we constructed the Manitoba Hydro Contract Extension run to include 500 MWs of Manitoba Hydro capacity and energy through 2045 at no cost. We modeled this extension by removing the 2025 retirement date and allowing the Manitoba Hydro resource to operate through the end of 2045. We assumed this contract extension had zero cost. We derived the per MWH value of the contract by levelizing the difference between the PVSC results for Manitoba Hydro Extension portfolio and the PVSC results of the Revised Xcel Preferred Plan and CEO Preferred Plan results[18]. We then took those values and divided them by the levelized generation from the Manitoba Hydro resource.

Table **11** below shows the implied per MWh value of the Manitoba Hydro contract.

Table 11. Per MWh Value of Manitoba Hydro Contract

[TRADE SECRET BEGINS…

…TRADE SECRET ENDS]

While this analysis shows that a contract extension could provide value it is worth noting the contract price in its currently final year of 2025 will be much higher - [TRADE SECRET BEGINS… …TRADE SECRET ENDS] per MWh – suggesting that a lower contract price would have to be in place in order to make an extension worthwhile for customers.

Table 12 shows the annual load and system needs under the Manitoba Hydro Extension run. The Manitoba Hydro Extension – Xcel Corrected Base Case adds some solar hybrid resources in 2027, but not as many new resources are needed in 2027 when compared to the other scenarios, since the 500 MW of Manitoba Hydro capacity is included as an existing resource through the end of the planning period.

[18] This comparison was done using the Xcel Corrected Base Case scenario assumptions.

Table 12. Manitoba Hydro Extension System Load and Resources, UCAP MW, 2020 - 2034

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak Demand	**10,510**	**10,575**	**10,652**	**10,736**	**10,815**	**10,886**	**10,964**	**11,047**	**11,132**	**11,219**	**11,310**	**11,417**	**11,538**	**11,665**	**11,788**
Existing Resources															
Nuclear	1642	1642	1642	1642	1642	1642	1642	1642	1642	1642	1642	1642	1642	1120	622
Combined Cycle	2078	2078	2078	2078	2078	2078	1787	1551	1551	1551	1551	1551	1275	1275	1275
Combustion Turbine	1781	1781	1781	1781	1635	1325	1325	1280	1280	1280	1280	737	737	737	737
Coal	2295	2295	2295	2295	1647	1647	1647	994	994	511	0	0	0	0	0
Hydroelectric	539	659	651	651	651	651	651	651	651	651	651	651	644	641	641
Biomass	110	110	110	86	86	61	61	61	29	29	29	19	19	19	19
Landfill	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV	495	531	614	647	632	612	591	570	548	526	503	480	456	431	435
Wind	498	623	689	663	652	648	643	641	635	613	612	597	594	528	510
Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distributed Generation	1078	1358	1505	1349	1407	1454	1470	1485	1499	1511	1518	1526	1536	1547	1560
Energy Efficiency	1562	1813	1977	1681	1782	1880	1973	2043	2123	2265	2347	2449	2533	2609	2672
Contract:Purchase	342	342	342	342	342	0	0	0	0	0	0	0	0	0	0
Contract:Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm Capacity Existing	12,419	13,230	13,683	13,215	12,553	11,998	11,790	10,918	10,952	10,578	10,132	9,652	9,435	8,908	8,472
Net Resource (Need)/Surplus	1,909	2,656	3,031	2,478	1,738	1,112	826	-128	-180	-641	-1,178	-1,765	-2,103	-2,757	-3,316
New Resources															
Wind	0	0	0	0	0	0	0	0	0	0	125	125	125	251	376
Solar	0	0	0	0	0	0	0	420	400	380	360	340	320	300	300
Solar Hybrid	0	0	0	0	0	0	0	42	80	380	540	714	672	840	1050
Battery Storage	0	0	0	0	0	0	0	23	35	35	169	455	859	1069	1123
Battery Storage Hybrid	0	0	0	0	0	0	0	25	50	250	375	525	525	700	875
Firm Capacity New	0	0	0	0	0	0	0	510	565	1045	1569	2160	2502	3160	3724
Total Firm Capacity	**12,419**	**13,230**	**13,683**	**13,215**	**12,553**	**11,998**	**11,790**	**11,429**	**11,517**	**11,623**	**11,701**	**11,811**	**11,937**	**12,068**	**12,196**
Reserve Margin	**18.17%**	**25.11%**	**28.46%**	**23.09%**	**16.08%**	**10.22%**	**7.54%**	**3.46%**	**3.46%**	**3.60%**	**3.46%**	**3.46%**	**3.46%**	**3.46%**	**3.46%**

3.6 Re-Running Xcel Defined Sensitivities

We also reran the three primary resource expansion portfolios – Xcel Preferred Plan, Revised Xcel Preferred Plan and CEO Preferred Plan[19] under three sensitivities Xcel ran in its Supplemental Filing. These are sensitivities B through D. The table below outlines the changes that Xcel made under each sensitivity. Sensitivities B and C were applied to the same Revised Xcel Preferred Plan and CEO Preferred Plans described above. Xcel Sensitivity D was reoptimized since it involved a different effective load forecast. One change we made in modeling the Xcel sensitivities is that, where the model could reoptimize, we did not force any flow batteries during 2040 to 2045. Instead, we allowed the model to optimize the flow battery additions.

Table 13. Xcel Sensitivities B - D

Xcel Sensitivity	Description
B	Low Gas Prices and Market Prices
C[20]	High Gas Prices and Market Prices
D[21]	Low Load

Table 14 shows the PVSC results for these runs.

Table 14. PVSC NPV Results for Xcel Defined Sensitivities (Millions)

Description	Xcel Sensitivity	PVSC	Difference From Revised Xcel Preferred Plan
Xcel Preferred Plan	B	$39,309	
Revised Xcel Preferred Plan	B	$38,865	$-444
CEO Preferred Plan	B	$38,678	$-631
Xcel Preferred Plan	B	$39,173	
Revised Xcel Preferred Plan	C	$38,464	$-709
CEO Preferred Plan	C	$38,145	$-1,028
Xcel Preferred Plan	D	$40,669	
Revised Xcel Preferred Plan	D	$39,917	$-752
CEO Preferred Plan	D	$39,585	$-1,084

The results of running Revised Xcel Preferred Plan and CEO Preferred Plan under Xcel's Sensitivities B – D show that the CEO Preferred Plan is significantly lower on a PVSC basis.

[19] Both portfolios were run with assumptions from the CEO Base Case scenario assumptions.
[20] Xcel modeled the high and low price sensitivities for gas and market prices by adjusting the growth rate by +/- 50% from the base forecast starting in 2022.
[21] Xcel modeled the low load sensitivity by including high customer adoption-based DER growth and higher levels of EE savings.

4 EnCompass Reliability Analysis

In its supplemental IRP filing, Xcel included a section detailing an EnCompass-based reliability analysis that Xcel conducted on a handful of scenarios and sensitivities. The metrics included in the reliability analysis are outlined in Table 15, below.

Table 15. EnCompass Reliability Analysis Metric Description

Metric	Description
Native Capacity Shortall	Hours when Xcel does not have enough capacity from its own resources to serve customer load
Flexible Resource Adequacy	Maximum three-hour net load ramp calculated by taking the change in load minus variable renewable generation
Maximum Import	Number of hours that have MISO imports above 2,185 MW, which is 95% of the maximum 2,300 MW import limit)
Industry	Loss of Load Hours (LOLH) Loss of Load Equivalent (LOLE) Expected Unserved Energy (EUE)

The native capacity shortfall, flexible resource adequacy, and maximum import metrics need additional post-processing steps in order to be calculated with EnCompass, whereas the three industry metrics are reported directly from EnCompass. In order to conduct its reliability analysis, Xcel performed hourly dispatch of the scenarios and sensitivities for the year 2034. We replicated this analysis for our primary resource portfolios with some modifications.

In order to evaluate how the CEO Preferred Plan compared to Revised Xcel Preferred Plan in terms of the reliability metrics identified by Xcel, we replicated the steps that Xcel took to conduct its reliability analysis with one exception. Xcel substituted 2019 actual load and renewable hourly shapes for the typical meteorological year ("TMY") shapes used in the majority of its analysis. In the supplemental IRP, Xcel explains why it used the 2019 data, even though the reliability analysis is performed for the year 2034 saying:

> *We used actual historical hourly load and renewable shapes from 2019 to simulate how each generation portfolio would have performed given actual weather history. Using this dataset allowed us to assess generation portfolios performance under recent actual historical grid conditions as opposed to the "average" year hourly load and renewable shapes used in the majority of our Supplement Resource Plan modeling.*[22]

[22] Docket No. E002/RP-19-368, Attachment A: Supplement Details, p. 151.

While Xcel's approach sounds attractive, we believe it has two major flaws. First, it's not clear why 2019 would account for a set of conditions that are more likely to happen than those in any other recent weather year. More importantly, Xcel modified all generic renewable projects to have the same wind or solar shape, as applicable. Specifically, all new wind projects were adjusted to have the same profile as the Dakota Range wind project. Similarly, all new solar projects added in the capacity expansion were set to the 2019 shape from the North Star project. Table 16 below shows the capacity factors for new wind and solar resources using versus the 2019 data used in Xcel's reliability analysis. The difference in wind capacity factor is most surprising. Especially because it is not clear to us why the Dakota Range wind shape would be indicative of all wind projects added. There were certainly hours in 2019 in which other Xcel actual wind profiles performed notably better than Dakota Range. And a wind capacity factor of [TRADE SECRET BEGINS... ...TRADE SECRET ENDS] is dramatically different than Xcel's modeled capacity factor.

Table 16. Comparison of Solar and Wind Capacity Factors (%)

[TRADE SECRET BEGINS...

...TRADE SECRET ENDS]

Table 17 shows our reliability analysis results for Revised Xcel Preferred Plan and the CEO Preferred Plan.[23] Revised Xcel Preferred Plan and the CEO Preferred Plan both had 0 hours of native capacity shortfall events, and had reported LOLH, LOLE, and EUE of 0.[24]

The two metrics where the scenarios differ are the Flexible Resource Adequacy and Maximum Imports. The CEO Preferred Plan had a maximum three hour upward ramp of 7,000 MWs and 154 hours deemed to be high imports. Both metrics are higher than what is reported for Revised Xcel Preferred Plan. However, after looking more closely at the hourly generation information for all resources, we observed that the reasons for this were largely economics and not potential reliability events. For example, Xcel's demand response resources were not called on at all during 2034, and for a significant portion of the high import hours, Xcel's existing CTs also did not come online. We believe that this is the result of economics, where EnCompass is choosing to import power over operating existing, more expensive resources.

[23] Both portfolios were run with assumptions from the CEO Base Case scenario assumptions.

[24] We would note that we don't think these metrics mean much as a reflection of Xcel's system alone. MISO coordinates the delivery of bulk power throughout Minnesota and beyond so the LOLE, LOLH, and EUE of its entire system are more meaningful metrics. In addition, these are based on deterministic and not on stochastic simulations with enough iterations to demonstrate convergence.

Table 17. Energy and Capacity Adequacy Metrics for Revised Xcel Preferred Plan and CEO Preferred Plan

	Native Capacity Shortfall Metrics					Flexible Resource Adequacy Metric	Maximum Import Metric	Industry Metrics		
Plan	# of Native Capacity Shortfall Events	Average Duration of Shortfall Events (hours)	Average Intensity of Capacity Shortfall (MW)	Longest Shortfall Event (hours)	Peak Capacity Shortfall During 2034 (MW)	Maximum 3 - Hour Upward Ramp (MW)	# of Hours with High Imports	LOLH (Hours)	LOLE (Days)	EUE (MWH)
Revised Xcel Preferred Plan	0	0	0	0	0	6,512	23	0.00	0.00	0.00
CEO Preferred Plan	0	0	0	0	0	7,000	154	0.00	0.00	0.00

As an example, Table 18 shows the DR, CT and battery capacity available, but not dispatched, during the hours of 1 to 7 on July 17, 2034, which have been deemed as high import hours. During these hours, Xcel has CT, DR, and battery storage capacity available to come online, however, there is capacity from these resources that is not called upon despite the fact they are high import hours.[25]

Table 18. Capacity Not Used During High Import Hours 1 to 7 on July 17, 2034[26]

Date and Time	DR	CT	Battery
7/17/2034 Hr 1	861	747	34
7/17/2034 Hr 2	835	747	69
7/17/2034 Hr 3	825	747	220
7/17/2034 Hr 4	838	747	381
7/17/2034 Hr 5	895	747	576
7/17/2034 Hr 6	986	747	758
7/17/2034 Hr 7	1072	747	901

Looking across all of the high import hours in 2034, Xcel's existing CTs are dispatched in 30 of the 154 total high import hours. The explanation for this seems to be that it is cheaper to import power over operating existing resources. Demand response is also not dispatched in any hour of the CEO Preferred Plan reliability run for 2034. We believe that this is also the result of economics not an indication of a reliability concern, because Xcel's assumptions include a [TRADE SECRET BEGINS… …TRADE SECRET ENDS]/MWH dispatch adder for all demand response programs. This dispatch adder is effectively a hurdle rate that discourages the model from utilizing the resource. Xcel does not appear to have justified this adder anywhere in its filing and not surprisingly the model prefers to import power rather than call on load with the adder.

The maximum 3-hour upward ramp for the CEO Preferred Plan is 7,000 MW, which occurs between the hours of 15 and 18 on November 28, 2034.

[25] The outages for existing CT resources do not occur in July.

[26] The battery capacity column will overstate the availability of batteries in all but the first hour shown because it cannot account for the charging that would need to occur to make that battery capacity available again in subsequent hours.

Table 19 shows the difference between the available capacity of a resource and the amount that the resource generated during that given hour. Any resource with a nonzero value in the table means there was capacity available for that resource in any given hour. For example, there were 518 MWs of demand response, 802 MWs of CTs, and 2,103 MWs of battery storage available to Xcel, but not dispatched in that hour. Furthermore, during the Hours 15 to 18 *no energy was purchased* and sales were 2,300 MWs in hours 15 and 16; 1,072 MWs in Hour 17; and 586 MWs in Hour 18. Again, this suggests these ramps are economic rather than reliability events.

Table 19. Resource Capacity Not Used During Maximum 3-Hour Ramp on February 2, 2034[27]

Date and Time	DR	CT	Battery
11/28/2034 Hr 15	500	802	0
11/28/2034 Hr 16	499	802	1608
11/28/2034 Hr 17	518	802	2103
11/28/2034 Hr 18	540	802	287

The results of the reliability analysis performed for the CEO Preferred Plan did not result in any capacity shortfall events or periods where the LOLH, LOLE, or EUE were greater than 0. Our analysis of periods deemed to be high import hours in addition to the three hour maximum ramp indicate that these events are economic rather than events of potential concern for reliability.

5 Summary of Findings

The EnCompass modeling described in this report demonstrates that a resource portfolio of renewable and storage resources and no new fossil generation can:

1. Have consistently lower costs than a portfolio that includes the Sherco CC;
2. Offer similar levels of reliability as a portfolio that includes the Sherco CC; and
3. Offer further, material CO_2 emissions reductions.

These benefits are in addition to the fact that the CEO Preferred Plan better comports with Minnesota's statute preference for renewable energy and that the CEO Preferred Plan offers more modularity and flexibility to adjust to changing conditions such a load, market prices, etc.

[27] The battery capacity column will overstate the availability of batteries in all but the first hour shown because it cannot account for the charging that would need to occur to make that battery capacity available again in subsequent hours.