APPENDIX K: DETAILED ANALYSIS SECTION

This Appendix contains the support and approach for the analysis discussed in Section V of Minnesota Power's 2021 Integrated Resource Plan ("2021 IRP"). This appendix is broken into two sections:

1. Screening of Power Generation Alternatives
2. Additional Analysis further supporting Minnesota Power's preferred plan ("2021 Plan")
    a. Additional Results for the Capacity Expansion Plan Analysis (Step 1)
    b. Additional Results for "Swim Lane" Sensitivity Analysis (Step 2)

Due to time constraints with onboarding the new EnCompass modeling for the February 1 submittal, Minnesota Power will be providing a supplement to Appendix K that includes the remaining environmental futures that will include the Low Environmental Cost, High Environmental Cost and Low Carbon Regulation Cost and Low Environmental Cost insights for the Swim Lane analysis.

Screening of Power Generation Alternatives

This section explains how Minnesota Power (or the "Company") screened generation and supply side alternatives to be included in the expansion plan modeling using the EnCompass model. This was a necessary first step due to limitations in the number of alternatives the EnCompass model can evaluate simultaneously in the Capacity Expansion analysis. However, with the expanded capabilities of EnCompass, the Company was able to model more resource alternatives than what was capable with Strategist. For the 2021 IRP, Minnesota Power continued the precedent set in prior IRPs to consider a number of new and emerging generation resources in addition to mature technologies.

Consistent with the Minnesota Power's Energy***Forward*** strategy, only carbon-minimizing or carbon-free energy resources were considered as viable power generation alternatives. These supply side and demand side resource options include renewable resources, energy efficiency, energy storage technologies, hydrogen capable natural gas-fired technologies, nuclear, and carbon dioxide ("CO_2") sequestration technology combined with a mature coal-fired technology.

The power supply alternatives Minnesota Power considered represent a diverse range of generation technologies including traditional baseload, intermediate and peaking options, as well as renewable generation and energy storage. In order to compare technologies with similar operational characteristics through an initial screening process, the alternatives were organized into three primary generation categories – Baseload/Intermediate, Peaking, and Renewable/Storage/Energy Efficiency.

Intermittent <u>*renewable resources*</u> like solar and wind are typically must-take energy, meaning when the wind is blowing or the sun is shining, this energy needs to be allowed onto the system. This is accomplished by using dispatchable resources such as coal and natural gas to either increase or decrease their generation to allow more renewables on the system or replace renewable energy when not available. Because wind has a variable generation pattern, dispatchable generation needs to be available to respond to changes in wind generation 24-hours a day. Such changes can occur overnight, when demand is low, or during the peak time of the day, as customer demand is quickly increasing.

Renewable technologies can vary in their capabilities; however, they are largely intermittent and cannot be called upon when needed, except with the integration of energy storage. With the onset of energy storage and continued improvements in technology, when coupled with energy storage it can change the renewable energy production profile to mimic a dispatchable resource such as peaking and combined-cycle gas generation. As Minnesota Power transitions the power supply to 100 percent carbon-free energy it will be critical to continue monitoring advancements in combining renewables with storage, and evaluating how it could be used to meet the energy needs of customers. Absent of energy storage, renewable generation typically has a capacity factor between 20 and 55 percent, depending on type of technology and regional climate factors

Typically, a *baseload generation resource* is used to supply energy to customer load that is constant (such customer demand is commonly referred to as “base load”). Because a constant supply of generation is needed, energy production with a low variable cost is a general trademark of a baseload generation resource, such as coal or nuclear generation. A baseload generation resource produces electricity 7 days a week, 24 hours a day, to meet the base requirements and provide system reliability. In Figure 1 below, the “Baseload” area of the graph represents the energy served by baseload generation. Baseload generation resources typically have a capacity factor between 50 to 80 percent.

As load requirements increase throughout a typical day, *intermediate generation resources* are relied upon to supply the next step up in load requirements. In addition to energy production cost with moderate variable cost, operational flexibility is another important characteristic of an intermediate generation resource such as a combined cycle (“CC”) unit, giving this type of resource the flexibility to dispatch around renewable generation. The typical operation for an intermediate generation resource is to produce energy over the course of 10 to 16 peak energy demand hours during the day and produce no energy overnight, as shown in Figure 1. With the recent trend in low natural gas prices, intermediate generation has operated more like a baseload type resource for short periods of time in some areas of the country. Like baseload generation resources, intermediate generation resources typically have a high capacity factor between 30 to 65 percent.

During peak load hours when all baseload and intermediate generating capacity are already producing energy for customers, *peaking generation resources and demand response* are used to fulfill the remaining power supply requirements. Peaking generation, such as a combustion turbine or aero derivative, is typically characterized by very flexible operations with high variable costs. The typical operation for a peaking generation resource is to produce energy for short periods of time ranging from 1 to 4 hours, as shown in Figure 1. Demand response can also offset a portion of the peaking energy requirements, providing a carbon-free resource to reduce customer demand during peak demand periods. Peaking generation resources typically have a capacity factor between 5 and 20 percent.

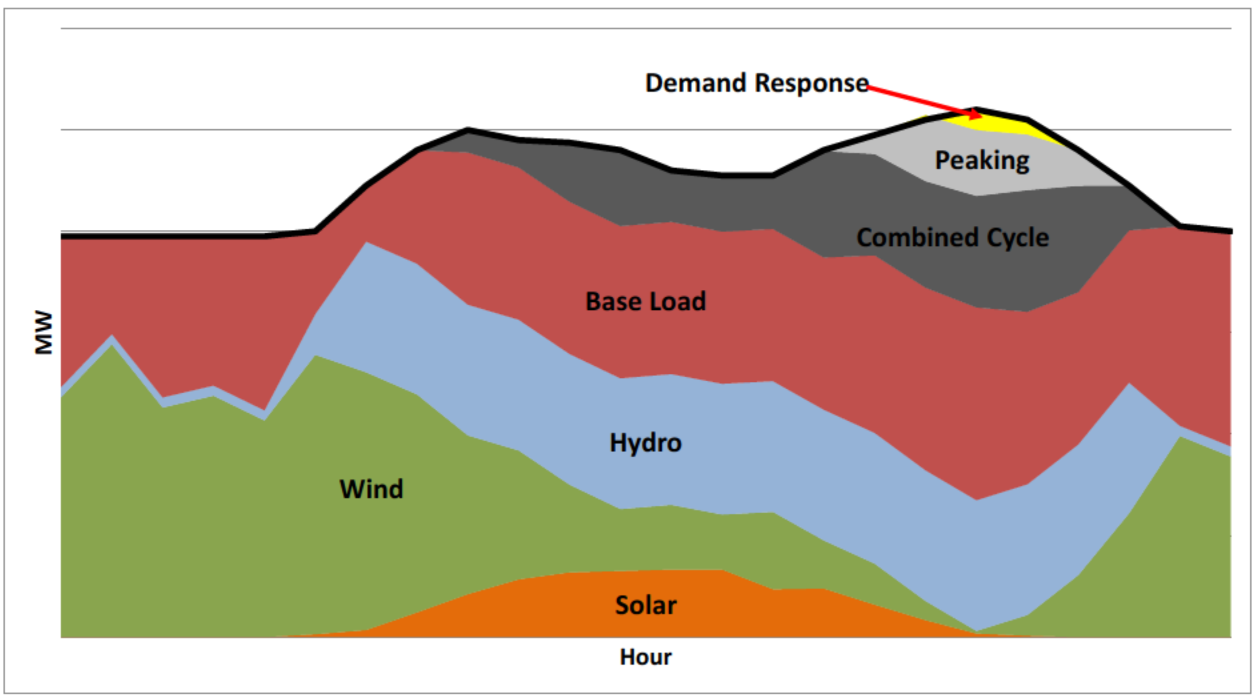
Demand response resources, like central air conditioning (“CAC”), electric hot water heater (“HW”) peak-shaving programs, or industrial demand response with curtailable hours for economic (i.e. Minnesota Power’s Demand Response Product B), are only effective when that demand is present. CAC is only effective at reducing peak load during the summer months because utilization of air conditioning units is effectively zero during the winter months in northern Minnesota. HW peak-shaving programs can only be used in conjunction with electric hot water heaters, which limits the potential base of customers because households with natural gas hot water heating are unable to participate. Demand timing for most residential hot water systems is not often correlated to peak hours and so the effectiveness of HW programs at reducing peak demand is diminished. A benefit to industrial demand response is that it is typically available during all seasons and is effective at reducing a large volume during a peak or emergency event. CAC and HW peak-shaving programs have characteristics that make them similar to peaking resources, but are only available when the devices controlled are in demand due to weather or typical usage patterns.

Battery (energy) storage technologies have unique characteristics that closely resemble those of peaking resources with some exceptions. Energy storage technologies must be charged prior to being called upon and charging times differ between energy storage technologies. Storage discharge is an inverse function of both time and magnitude – more energy can be released for a shorter amount of time or less energy can be released for a longer time depending on present needs. These characteristics make storage resources appear similar to peaking resources.

Minnesota Power notes with the increase in renewables seen today and expected to continue, the role traditional generation resources had typically provided in the past will continue to evolve. For example, with Minnesota Power moving Boswell Energy Center ("BEC") Unit 3 ("BEC3") to economic dispatch operations its energy characteristics will mimic those of a CC generation unit. Coal generation is not as flexible as CC generation – the technology limits it ability to turn on and off for a day, but it is capable of running for a couple of days and coming offline during periods of low demand or high renewable production. It is evident to Minnesota Power that having a flexible and dispatchable portfolio will be important to compliment renewables as new technologies develop and advance.

Figure 1 shows a load curve for a representative day (24 hours) and how different types of generation resources are generally dispatched to meet load requirements and to balance intermittent renewable generation.

Figure 1: Representative load generation curve



The following list contains the set of resource technologies that were considered in the initial screening process.

New Thermal or Combustion Generation

3. Baseload Generation
4. Nuclear
5. 165 MW Small Modular Reactor ("Nuclear SMR")
6. Coal-Fired with Carbon Capture
7. 391 MW Supercritical Pulverized Coal ("SCPC w/ Carbon Capture")

<u>Natural gas-fired</u>

8. Peaking
    - 280 MW Hydrogen Ready Simple Cycle Gas Turbine – Combustion Turbine ("SC GT")
    - 114 MW Simple Cycle Aero Derivative ("SC Aero 114MW")
    - 48 MW Simple Cycle Aero Derivative ("SC Aero 48MW")
    - 110 MW Simple Cycle Reciprocating Internal Combustion Engine ("RICE")
9. Intermediate
    - 591 MW Hydrogen Ready Combined Cycle Gas Turbine ("1x1 CCGT")

Renewable Generation

<u>Dispatchable generation</u>

10. 50 MW Biomass ("Biomass")

<u>Intermittent generation</u>

11. 100 MW Wind ("Wind")
12. 100 MW Photovoltaic Solar ("Solar")

Energy Storage

<u>Batteries</u>

13. 100 MW / 400 MWh Lithium Ion Battery ("4 Hr Li-ion Storage")
14. 100 MW / 800 MWh Lithium Ion Battery ("8 Hr Li-ion Storage")
15. 100 MW / 1,200 MWh Flow Battery ("12 Hr Flow Storage")
16. Other Storage Technologies
17. 200 MW / 2,000 MWh Pumped Storage Hydroelectricity ("10 Hr Pumped Hydro Storage")
18. 200 MW / 1,600 MWh Adiabatic Compressed Air Energy Storage ("8 Hr Compressed Air Storage")

Demand-Side Management and Conservation

Minnesota Power remains a state leader in the successful implementation of its conservation programs, and exceeding the 1.5 percent requirement established by Minnesota's Next Generation Energy Act of 2007 for the last decade. All historic and planned conservation impacts that exceeded the energy savings requirement are being reflected in Minnesota

Power's 2020 Annual Electric Utility Forecast Report and associated energy and demand forecasts. In addition to the conservation programs assumed in the load forecast, incremental efficiency above the approximate 2.5 percent approved in the Company's recent Conservation Improvement Program Triennial Plan (Docket No. E015/CIP-20-476) and peak shaving or demand response alternatives were also considered in Minnesota Power's 2021 IRP.

19. Incremental Energy Efficiency ("EE High Scenario" and "EE Very Scenario")

The economic feasibility of demand side management alternatives cannot be compared on the same $/MWh basis as new generation alternatives for a screening assessment. The industrial demand response and residential/commercial peak shaving programs were evaluated against supply-side options in later Capacity Expansion Analysis using the EnCompass model.

20. Central Air Conditioning ("CAC") Cycling Peak Shave Program

21. Electric Hot Water Heater ("HW") Cycling Peak Shave Program

22. Industrial Demand Response Product B – Long Term Capacity with Firm Load Control

23. Industrial Demand Response Product D – Long-Term Emergency Capacity

Screening Analysis Results

The screening analysis was completed by developing and comparing a levelized busbar cost of each resource over a 20-year period. The levelized busbar approach is a simple and effective method to screen generation alternatives for consideration in expansion planning by removing the higher cost alternatives. The levelized busbar cost for each power generation alternative included estimated capital, transmission, operation and maintenance (fixed and variable), and fuel costs. Busbar costs for resources were compared with the mid carbon regulation cost in the Reference Case Scenario ($15.00/ton starting in 2025). As previously discussed, the alternatives were organized into three primary categories for screening purposes – Baseload/Intermediate, Peaking, and Renewable/Storage/EE. All of the alternatives were then grouped based on these primary categories with the purpose of selecting the most cost-competitive resources for further evaluation in the expansion plan process. Figures 2 – 4 show the $/MWh levelized busbar cost comparison by category. Tables 1 – 3 show the alternative net plant cost in 2021$/kW. The busbar cost is shown over a range of assumed capacity factors for each resource alternative assuming a 7.0639 percent discount rate and a 2021 in-service date.

Figure 2: Baseload/Intermediate Alternatives 20-year Levelized Busbar Cost

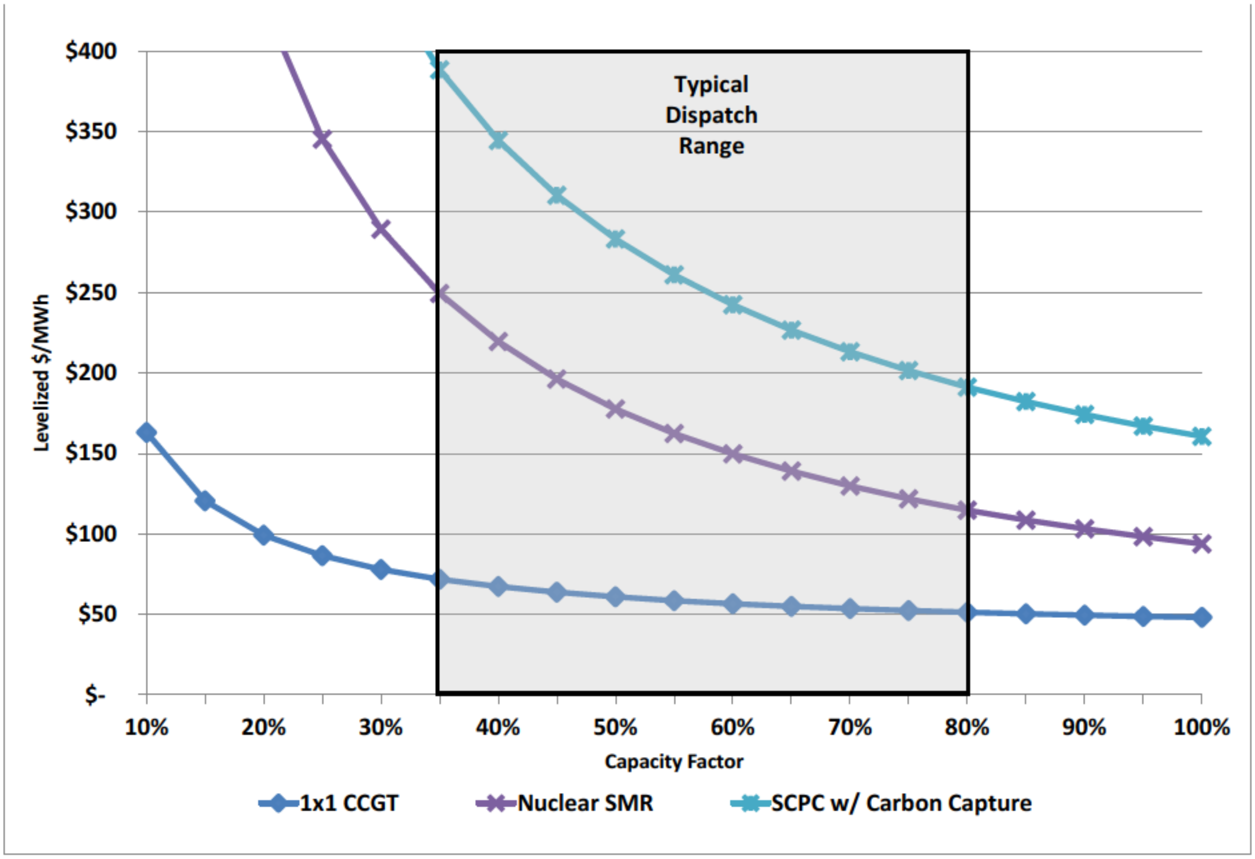


Table 1: Baseload/Intermediate Alternatives Net Plant Cost, 2021$/kW

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The 1x1 CC represented the lowest levelized busbar cost across all capacity factors for the baseload/intermediate generation resource alternatives. Additionally, nuclear generation face some development risk at both the state and the national levels due to waste storage. Based on the screening results of the baseload/intermediate alternatives, the 1x1 CC alternative was carried forward for further analysis within the EnCompass Capacity Expansion Analysis.

Figure 3: Peaking Alternative 20-year Levelized Busbar Cost

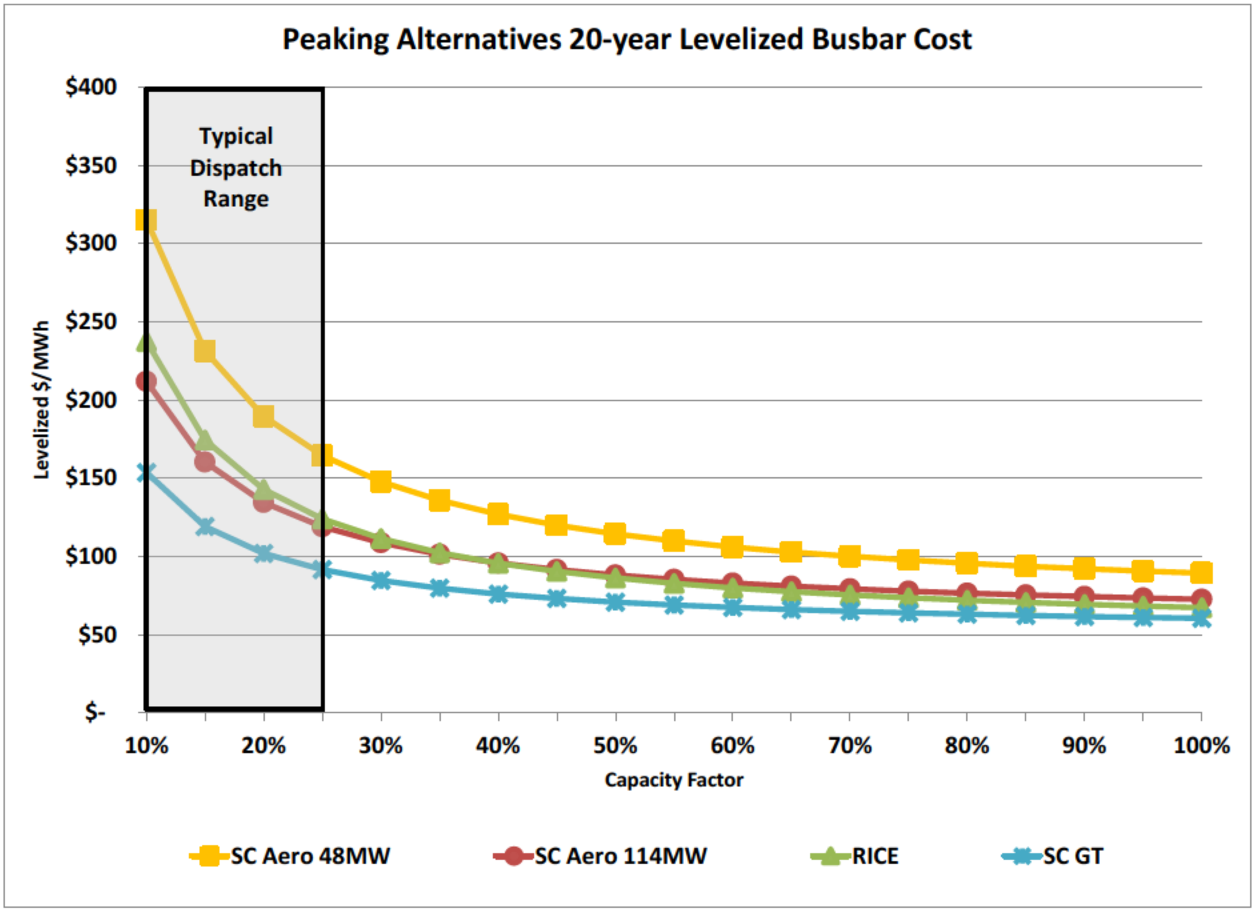

Table 2: Peaking Alternative Net Plant Cost, 2021$/kW

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For peaking resources, the SC GT, also referred to as a combustion turbine, represented the lowest levelized busbar cost across all capacity factors. The RICE and the SC Aero 114MW options had the next lowest levelized busbar costs. Based on the screening results of the peaking alternatives, the combustion turbine, RICE, and SC Aero 114MW options were carried forward for further analysis within the EnCompass Capacity Expansion Analysis.

Figure 4: Renewable/Storage/Energy Efficiency Options 20-year Levelized Busbar Cost

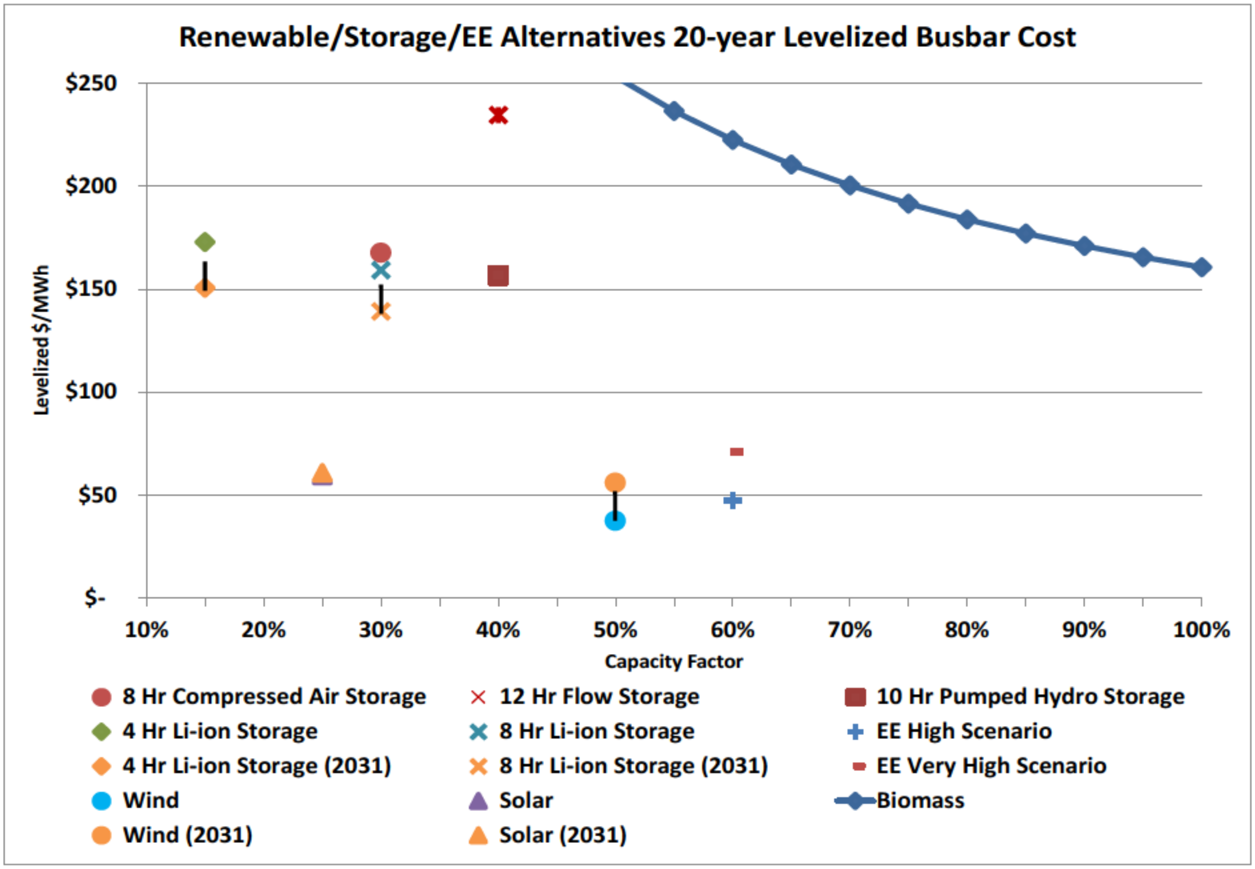

Table 3: Renewable/Storage/Energy Efficiency Options Net Plant Cost, 2021$/kW

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[redacted]

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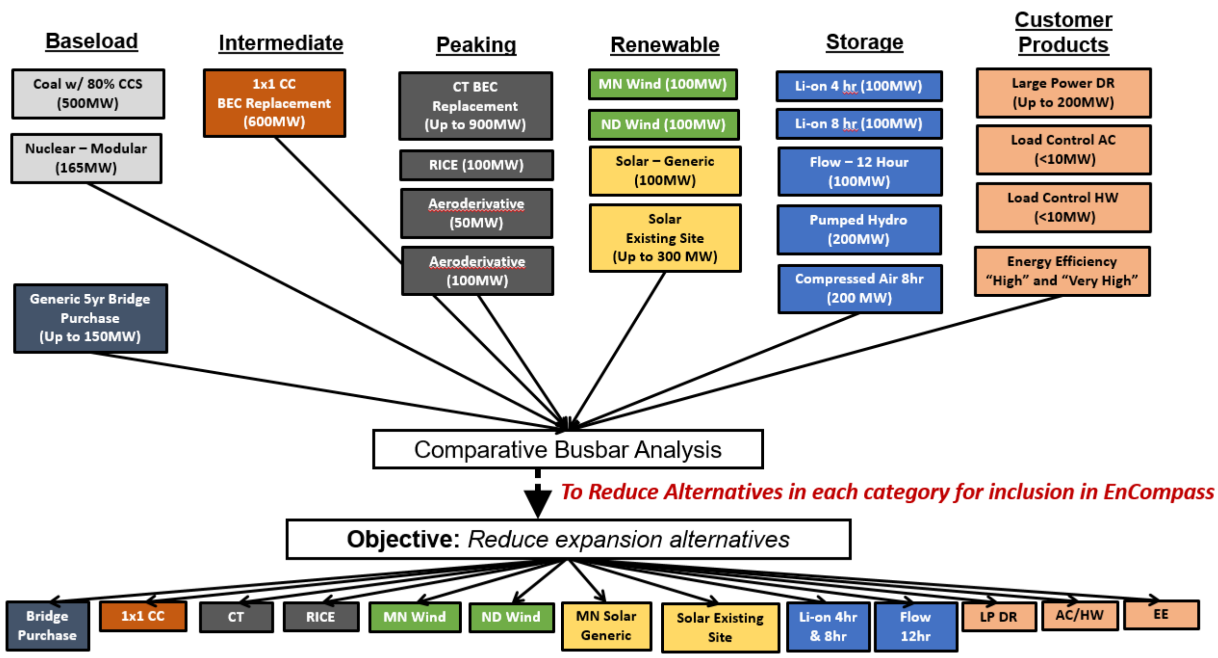
With the exception of biomass generation and energy storage, the renewable options represent an intermittent source of power supply. Energy storage is shown at its theoretical max energy if it were to charge and discharge approximately once a day ("round trip cycle efficiency"). Therefore, the levelized busbar costs are shown as representative capacity factors based on expected hourly production curves or round trip cycle efficiency assumptions. The wind alternative represented the lowest levelized busbar. Solar and High Energy Efficiency alternatives have the second lowest levelized busbar. Note that the solar busbar cost represents a generic solar facility; and Minnesota Power included solar located at BEC or another utility owned site, which takes advantage of existing infrastructure and avoids costly MISO interconnection cost. The levelized busbar cost of solar located at an existing site is approximately $10/MWh lower cost than the generic solar. Based on screening results, wind, solar (generic and located at an existing site), and both energy efficiency scenarios were carried forward for further analysis within the EnCompass Capacity Expansion Analysis.

Minnesota Power observed that the levelized busbar cost batteries were slightly higher than the cost of peaking generation shown in Figure 3. Given this observation, the li-ion batteries and flow batteries were also carried forward for further analysis within the EnCompass Capacity Expansion Analysis.

The levelized busbar cost is a simple and effective methodology for screening potential resource alternatives to be considered in greater detail within the EnCompass model. However, the screening analysis does not show the interaction of long term capacity requirements, utility load factor, and existing resource mix that also factor into the expansion plan analysis. Therefore, this screening depicted in Figure 5 is only the first step to determining Minnesota Power's 2021 Plan.

Figure 5: Narrowing of Resource Alternatives Modeled in EnCompass



With the resource alternatives reduced to a manageable level for the EnCompass model, the focus of this section will transition to the 2021 IRP modeling results that supports the 2021 Plan.

Additional Analysis that Further Supports Minnesota Power's 2021 Plan

The intent of this section is to provide further support for Minnesota Power's 2021 Plan by providing additional insight into the results from the Steps 1 and 2 discussed in Section V. To help manage the large amount of data gathered for the study, this section is organized as follows:

Additional Results for the Capacity Expansion Plan Analysis (Step 1)

Additional Results for "Swim Lane" Sensitivity Analysis (Step 2)

Additional Results for the Capacity Expansion Plan Analysis (Step 1)

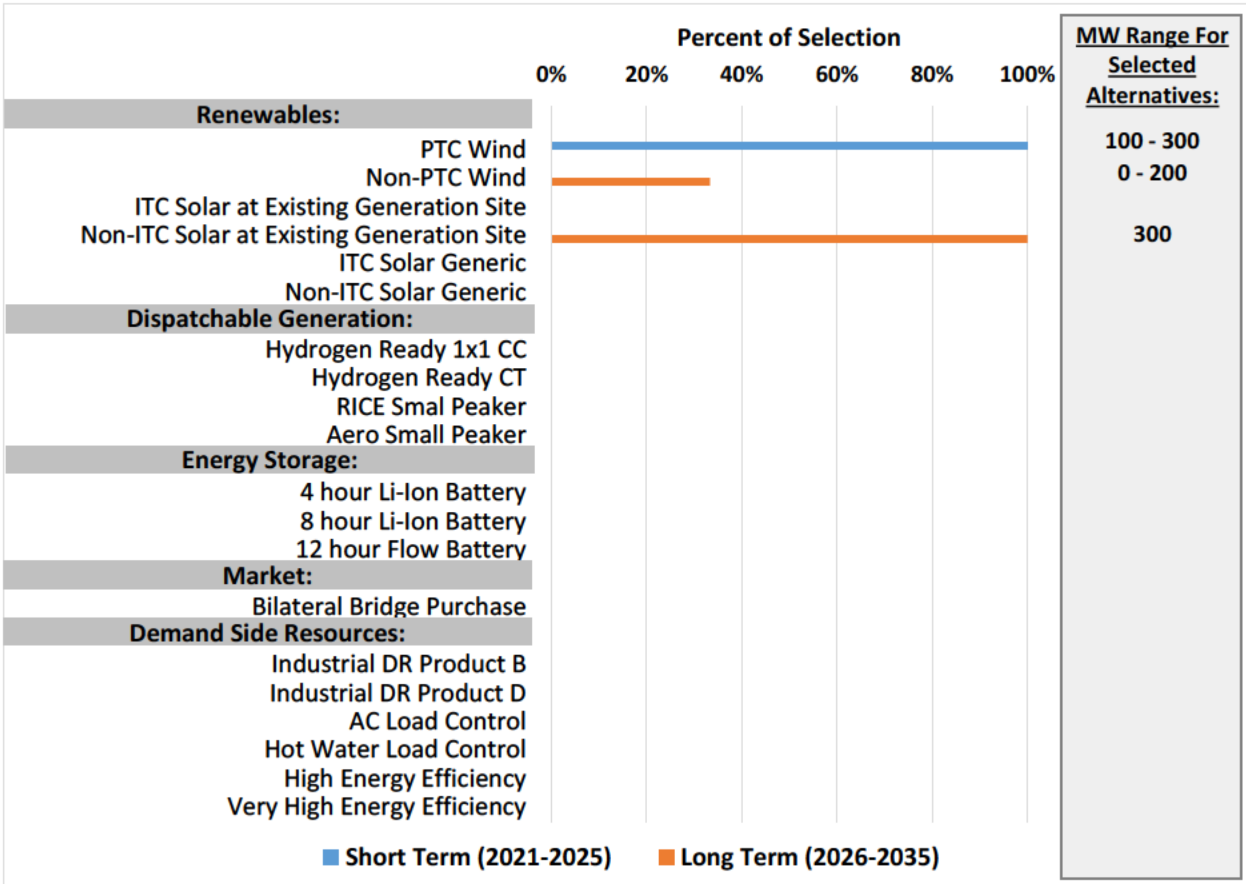
This section summarizes the additional results from the Capacity Expansion Analysis for the other BEC3 & 4 retirement scenarios not shown in Section V. Below is a list of the BEC retirement scenarios discussed here:[1]

1. Retire BEC3 Early as Feasible: BEC3 Retires in 2025
2. Retire BEC4 Early as Feasible: BEC4 Retires in 2030
3. Expedited Retirement of BEC3 & 4: BEC3 retires in 2025 and BEC4 retires in 2030
4. Base Case: no retirement action is taken at BEC

[1] Retirement occurs at the end of the year. For example, a 2025 retirement occurs on 12/31/2025.

A summary of the EnCompass capacity expansion results are shown in Figures 6 through 9. Note that the resource selections shown below are based on the following futures: the Reference Case, High Carbon Regulation Cost and High Environmental Costs, and No Carbon Regulation Costs and No Environmental Costs.[2]

Figure 6: Capacity Expansion Analysis for Retire BEC3 Early as Feasible: BEC3 Retires in 2025



[2] The Reference Case and High Carbon Regulation Cost and High Environmental Cost are required to be evaluated as part of the IRP process per the Order Establishing 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Costs, Docket Nos. E999/CI-07-1199 and E999/DI-19-406 (Sep. 30, 2020). Minnesota Power chose to include a "no carbon regulation cost and no environmental cost" scenario to provide an additional perspective that captures a market without a carbon tax.

Figure 7: Capacity Expansion Analysis for Retire BEC4 Early as Feasible: BEC4 Retires in 2030

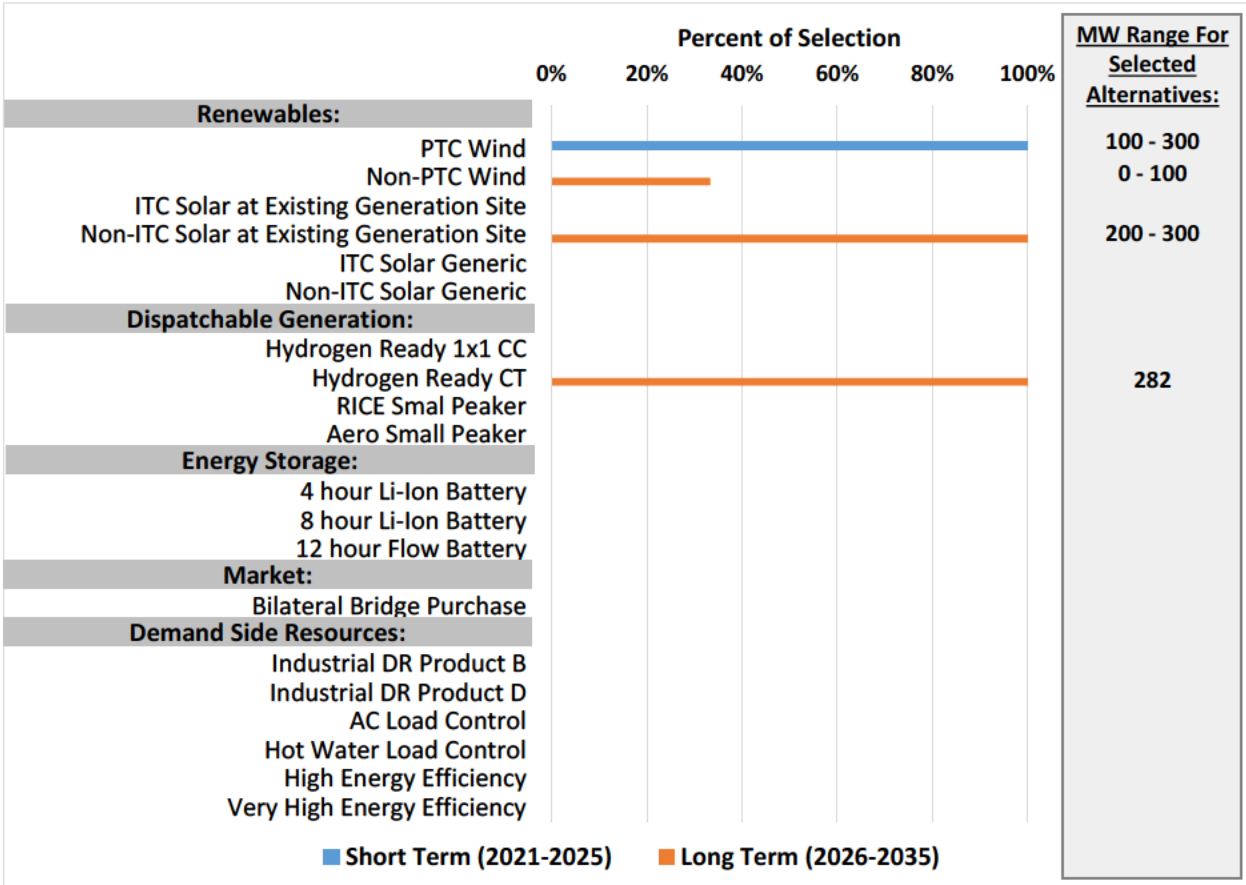


Figure 8: Capacity Expansion Analysis for Expedited Retirement of BEC3-4: BEC3 retires in 2025 and BEC4 retires in 2030

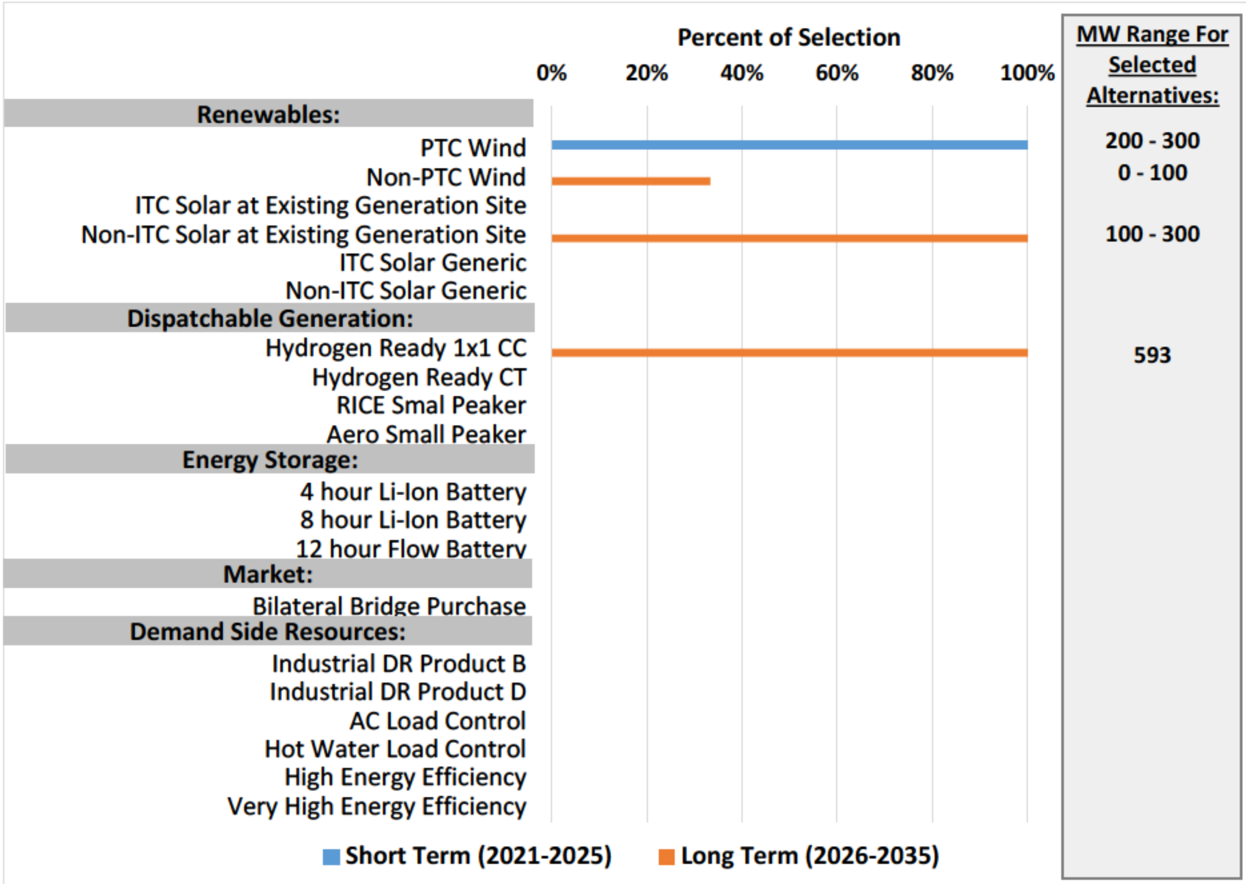
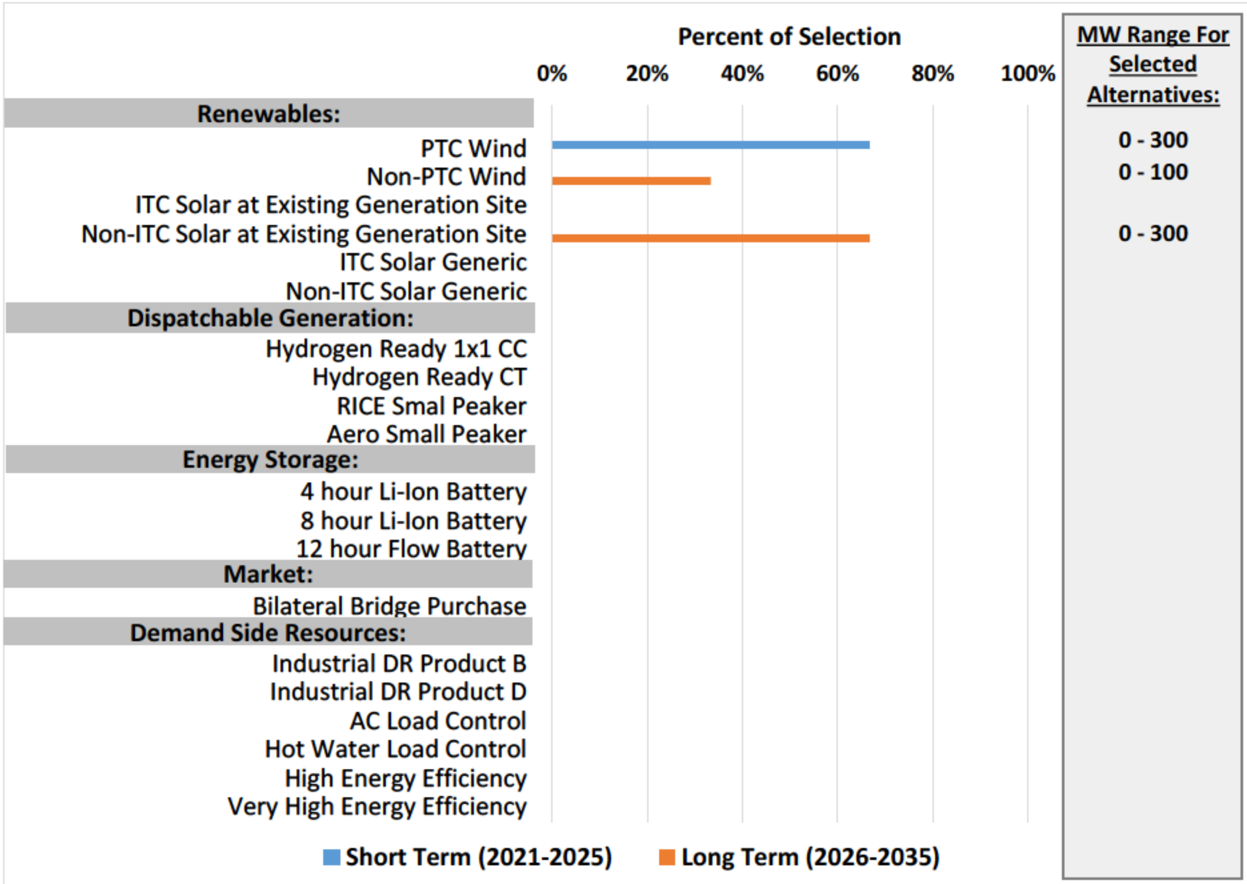


Figure 9: Capacity Expansion Analysis for Base Case: No BEC Units 3-4 Retirement



Key Insights from Capacity Expansion Analysis:

- 100 MW to 300 MW of Wind that qualifies for the production tax credit ("PTC") was selected in nearly all BEC retirement scenarios.
- Typically, 100 to 300 MW of solar located at BEC or another utility site was selected near the time of a BEC retirement.
- In the scenario where only BEC3 is retired implementing new transmission solutions to address reliability issues related to retirement was selected instead of building new gas generation.
- In the BEC4 retirement scenario specifically, gas generation was selected to avoid building the required significant high kV transmission projects needed to maintain grid reliability. When only BEC4 retired a 282 MW Hydrogen Ready SC CT was selected and when BEC3 and BEC4 is retired a 593 MW Hydrogen 1x1 CC is selected

The results from Step 1 helped Minnesota Power develop the new resource additions added to the 2021 Plan and alternative swim lanes. A summary of the new resource additions that build upon small coal options for the Preferred Plan and alternative swim lanes is shown in Figure 10.

Figure 10: Alternative Power Supply Portfolios ("Swim Lanes") Evaluated in Step 2

2021 Plan	"Expedited" Retirement of BEC 3-4	Retire BEC 3 Early as Feasible	Retire BEC 4 Early as Feasible	Base Case "Do Nothing"
2025 *200MW PTC Wind*	**2025** *200MW PTC Wind*	**2025** *200MW PTC Wind*	**2025** *200MW PTC Wind*	
	2025/2026 *BEC 3 Retires 2025** *BEC 3 Transmission* *200MW MP Facility Solar*	**2025/2026** *BEC 3 Retires 2025** *BEC 3 Transmission* *200MW MP Facility Solar*		
2029/2030 *BEC 3 Retires 2029** *BEC 3 Transmission* *200MW MP Facility Solar*	**2029/2030** *BEC 4 Retires 2030** *593MW 1x1 CC Gas*		**2030/2031** *BEC 4 Retires 2030** *282 MW CT Gas +* *Transmission* *200MW MP Facility Solar*	

**Retired at end of the year*

Short-term actions common to all alternative swim lanes include the addition of 200 MW of wind in 2025. Longer term actions common to all other alternative swim lanes is the addition of 200 MW of solar (located at an existing site) at the time of the first BEC unit retirement.

For the BEC4 retirement scenarios gas generation was added at the time of retirement. For the BEC4 only retirement scenario a 282 MW SC CT was added, along with transmission solutions to address reliability issues – note this transmission solution is similar in cost and scope to the transmission solution for a BEC3 retirement. For the scenario where both BEC3 & 4 are retired, a 593 MW 1x1 CC is added in 2031.

For the scenarios that only retire BEC3 the transmission solution to address reliability issues was added at time of retirement.

Additional Results for "Swim Lane" Sensitivity Analysis (Step 2)

This section summarizes the additional results from the "Swim Lane" sensitivity analysis for the remaining environmental futures not shown in Section V. Not all the environmental futures that are required for resource planning analysis are included in the sensitivity analysis below. The Company is planning to file a supplemental analysis that includes the remaining environmental futures. For clarity, here is a list of the environmental futures included here and what will be included in the supplemental:

February 1 Filing:

- Reference Case Scenario (Shown in Section V)
- High Carbon Regulation Cost and High Environmental Cost (Appendix K)

Supplemental Filing:

- Low Environmental Cost
- High Environmental Cost
- Low Carbon Regulation Cost and Low Environmental Cost

For each environmental future, the swim lane alternatives and 2021 Plan were put through a series of 37 sensitivities that stressed the main drivers for resource decisions. A summary of the EnCompass sensitivity analysis results are shown in Table 4.

The results of the sensitivity analysis shown below, along with the results from the Reference Case Scenario shown in Section V, clearly indicates that the 2021 Plan for customers is least cost across the majority of the sensitivities. The “High Carbon Regulation Cost and High Environmental Cost” supports the optimal retirement timing for one unit is 2030, similar to the observation Minnesota Power made in Section V for the Reference Case Scenario.

Table 4: Step 2 Sensitivity Analysis - 2021 NPV of Cost for High Carbon Cost and High Environmental Cost Scenario ($millions)

	Single Unit Retirement			Two Unit Retirement	
EnCompass Sensitivities	2021 Plan *Retire BEC3 in 2029*	Retire BEC3 Early as Feasible	Retire BEC4 Early as Feasible	Expedited Retirement of BEC3 and 4	Base Case "Do Nothing"
Base Case	$8,276	$8,302	$8,281	$8,366	$8,379
Coal +20%	$8,115	$8,143	$8,130	$8,217	$8,199
Coal -10%	$8,366	$8,389	$8,361	$8,440	$8,479
Biomass +15%	$8,271	$8,289	$8,280	$8,353	$8,380
Biomass -15%	$8,299	$8,314	$8,293	$8,371	$8,392
Lower Gas -50%	$8,178	$8,212	$8,168	$8,240	$8,265
Low Gas -25%	$8,254	$8,286	$8,256	$8,340	$8,350
High Gas +25%	$8,414	$8,441	$8,441	$8,500	$8,530
Higher Gas +50%	$8,496	$8,519	$8,520	$8,587	$8,614
Highest Gas +100%	$8,713	$8,715	$8,741	$8,773	$8,904
Energy Market -50%	$6,857	$6,913	$6,903	$7,062	$6,810
Energy Market -25%	$7,639	$7,675	$7,679	$7,824	$7,659
Energy Market +25%	$8,843	$8,846	$8,834	$8,830	$9,034
Energy Market +50%	$9,153	$9,144	$9,121	$9,066	$9,400
Capital Costs -30%	$8,276	$8,304	$8,264	$8,306	$8,381
Capital Costs +30%	$8,277	$8,308	$8,309	$8,425	$8,377
No Market Sales	$8,101	$8,141	$8,118	$8,218	$8,181
No Sales and Purchases	$9,975	$10,231	$9,761	$9,885	$10,046
Market Access -50%	$8,815	$8,875	$8,722	$8,815	$8,928
Low Interconnect Costs	$8,265	$8,290	$8,266	$8,344	$8,379
ITC & PTC Extension	$8,276	$8,299	$8,277	$8,360	$8,381
Wind Cost Curve Low	$8,277	$8,312	$8,280	$8,372	$8,376
Wind Cost Curve High	$8,285	$8,309	$8,284	$8,369	$8,381
Solar Cost Curve Low	$8,266	$8,295	$8,273	$8,357	$8,383
Solar Cost Curve High	$8,301	$8,322	$8,314	$8,394	$8,377
Storage Cost Curve Low	$8,277	$8,300	$8,286	$8,371	$8,382
Storage Cost Curve High	$8,277	$8,309	$8,289	$8,370	$8,379
AFR 2020 Low Scenario	$7,919	$7,942	$7,947	$8,036	$7,998
AFR 2020 Load w Keetac	$8,827	$8,847	$8,770	$8,859	$8,936
AFR 2020 High Scenario	$8,863	$8,900	$8,839	$8,915	$8,986
Residential TOU	$8,276	$8,296	$8,280	$8,360	$8,370
Higher DG & EV Growth	$8,280	$8,301	$8,284	$8,376	$8,375
Renewable ELCC -2.5%	$8,284	$8,316	$8,280	$8,365	$8,380
Renewable ELCC +2.5%	$8,279	$8,293	$8,283	$8,361	$8,374
PRM -2%	$8,281	$8,292	$8,283	$8,366	$8,377
PRM +2%	$8,283	$8,321	$8,280	$8,366	$8,378
MISO CF -2%	$8,277	$8,296	$8,284	$8,366	$8,373
MISO CF +2%	$8,290	$8,316	$8,289	$8,372	$8,382
Sum of Least Cost Runs	**23**	**0**	**12**	**2**	**1**

Supplemental Analysis that Further Supports Minnesota Power's 2021 Plan

The intent of this supplemental section is to provide additional support for Minnesota Power's 2021 Plan by incorporating the insights from the additional Low Environmental Cost, High Environmental Cost and Low Carbon Regulation Cost and Low Environmental Cost runs into the Step 1 and Step 2 results discussed in the original Appendix K and Section V. To help manage the large amount of data gathered for the study, this section is organized as follows:

Additional Results for the Capacity Expansion Plan Analysis (Step 1)

Additional Results for "Swim Lane" Sensitivity Analysis (Step 2)

Additional Results for the Capacity Expansion Plan Analysis (Step 1)

This section summarizes the results from the Capacity Expansion Analysis for all the BEC 3 & 4 retirement scenarios studied in this IRP. Below is a list of the BEC retirement scenarios discussed here:[3]

1. Retire BEC3 Early: BEC3 Retires in 2029
2. Retire BEC3 Early as Feasible: BEC3 Retires in 2025
3. Retire BEC4 Early as Feasible: BEC4 Retires in 2030
4. Expedited Retirement of BEC3 & 4: BEC3 retires in 2025 and BEC4 retires in 2030
5. Base Case: no retirement action is taken at BEC

Figures 11 through 15 capture the expansion planning results from the:

- Reference Case (Mid-Carbon Regulation and Mid-Environmental Costs),
- High Carbon Regulation Cost and High Environmental Costs,
- Low Carbon Regulation Cost and Low Environmental Costs (New),
- High Environmental Costs (New),
- Low Environmental Costs (New), and
- No Carbon Regulation Costs and No Environmental Costs.[4]

It should be noted that due to the process for modeling environmental costs within EnCompass, the expansion planning selections for the High Environmental Costs, Low Environmental Costs, and No Carbon Regulation Costs and No Environmental Costs futures are identical. This is caused by the way EnCompass calculates the impacts of environmental costs when making unit

[3] Retirement occurs at the end of the year. For example, a 2025 retirement occurs on 12/31/2025.

[4] The Reference Case, High Carbon Regulation Cost and High Environmental Cost, Low Carbon Regulation Cost and Low Environmental Cost, Low Environmental Cost, and High Environmental Cost are required to be evaluated as part of the IRP process per the Order Establishing 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Costs, Docket Nos. E999/CI-07-1199 and E999/DI-19-406 (Sep. 30, 2020). Minnesota Power chose to include a "no carbon regulation cost and no environmental cost" scenario to provide an additional perspective that captures a market without a carbon tax.

selection and dispatch decisions. EnCompass disregards environmental costs during the expansion planning and production cost modeling and then adds the environmental costs after the runs are complete. This means impacts of unit selection and dispatch between units with different emission profiles are disregarded until the environmental costs are calculated and included at the end of the run.

Figure 11: Capacity Expansion Analysis for Retire BEC3 Early: BEC3 Retires in 2029 (2021 Plan)

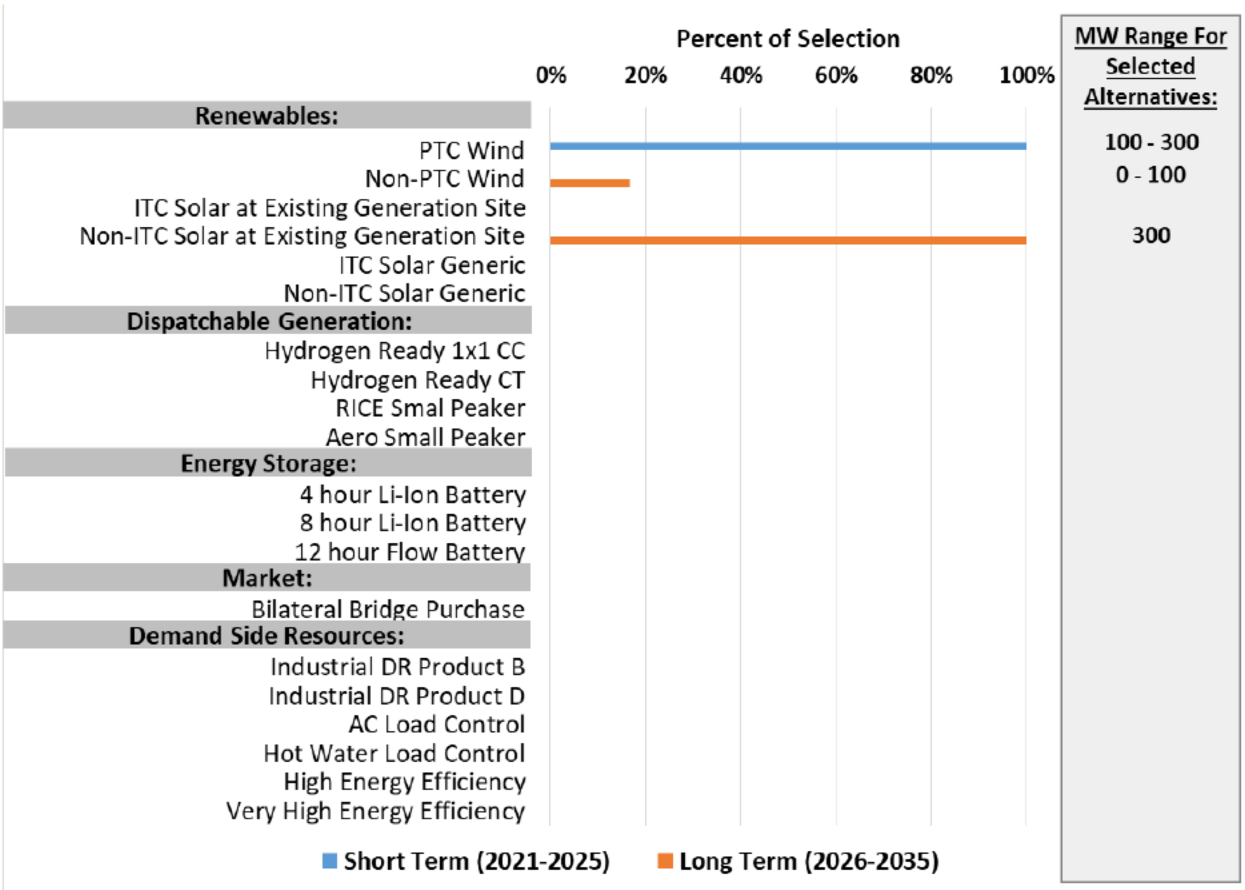


Figure 12: Capacity Expansion Analysis for Retire BEC3 Early as Feasible: BEC3 Retires in 2025

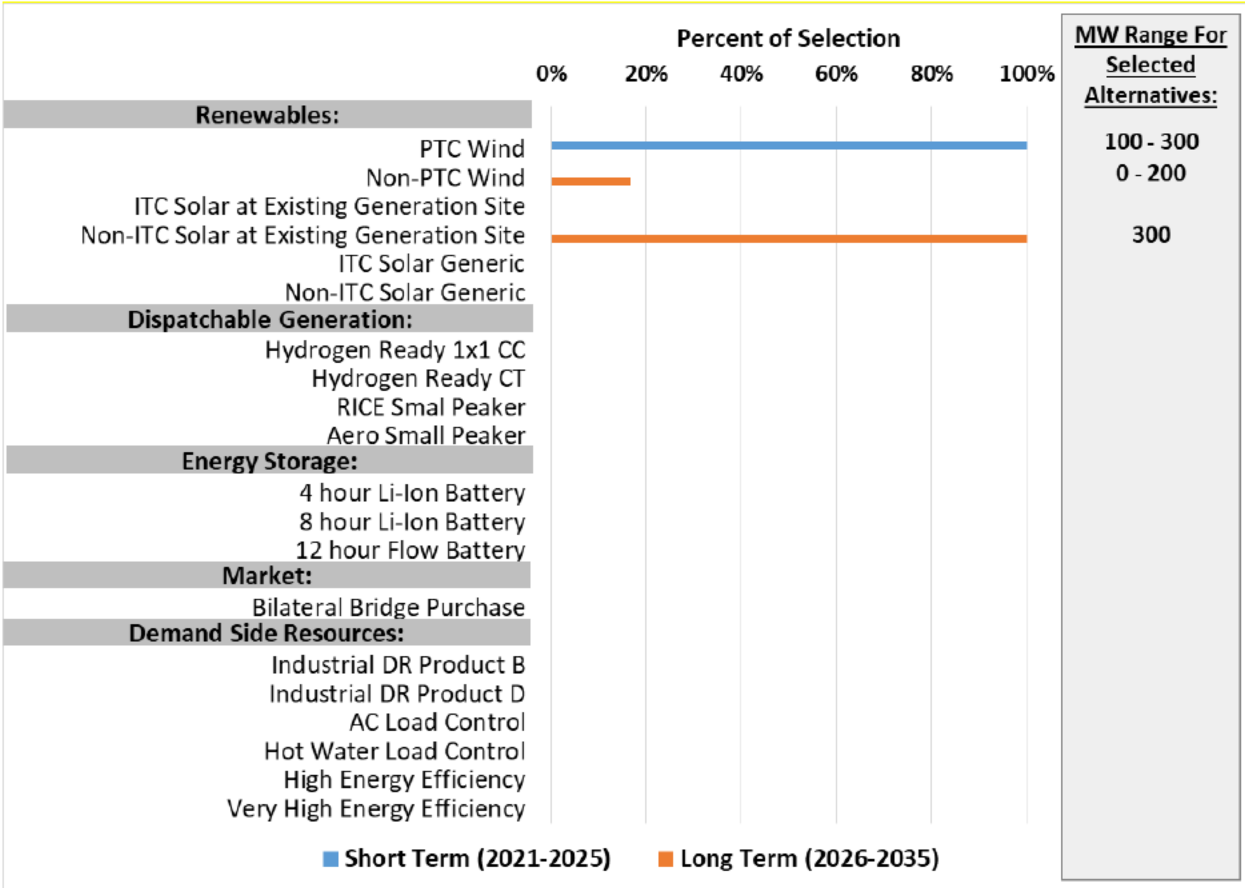


Figure 13: Capacity Expansion Analysis for Retire BEC4 Early as Feasible: BEC4 Retires in 2030

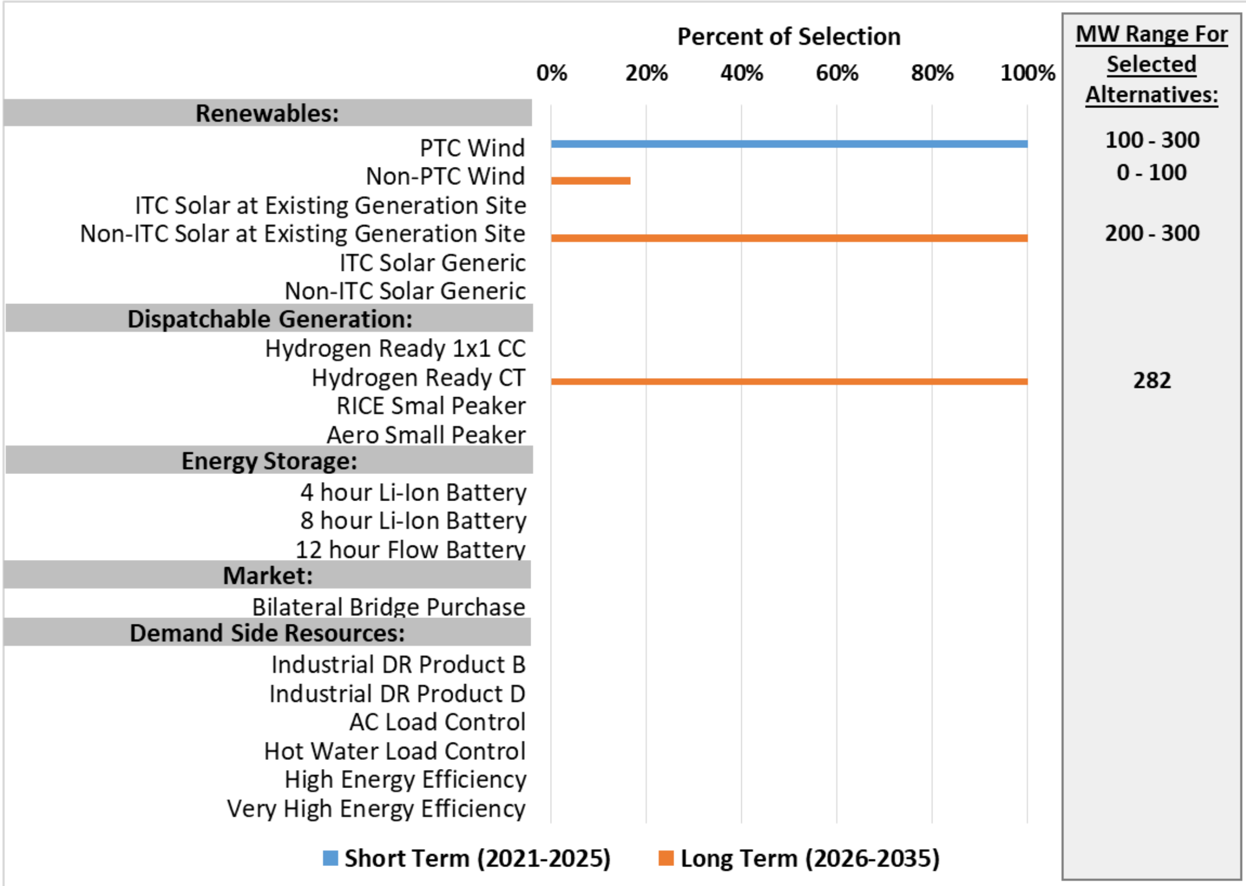


Figure 14: Capacity Expansion Analysis for Expedited Retirement of BEC3-4: BEC3 retires in 2025 and BEC4 retires in 2030

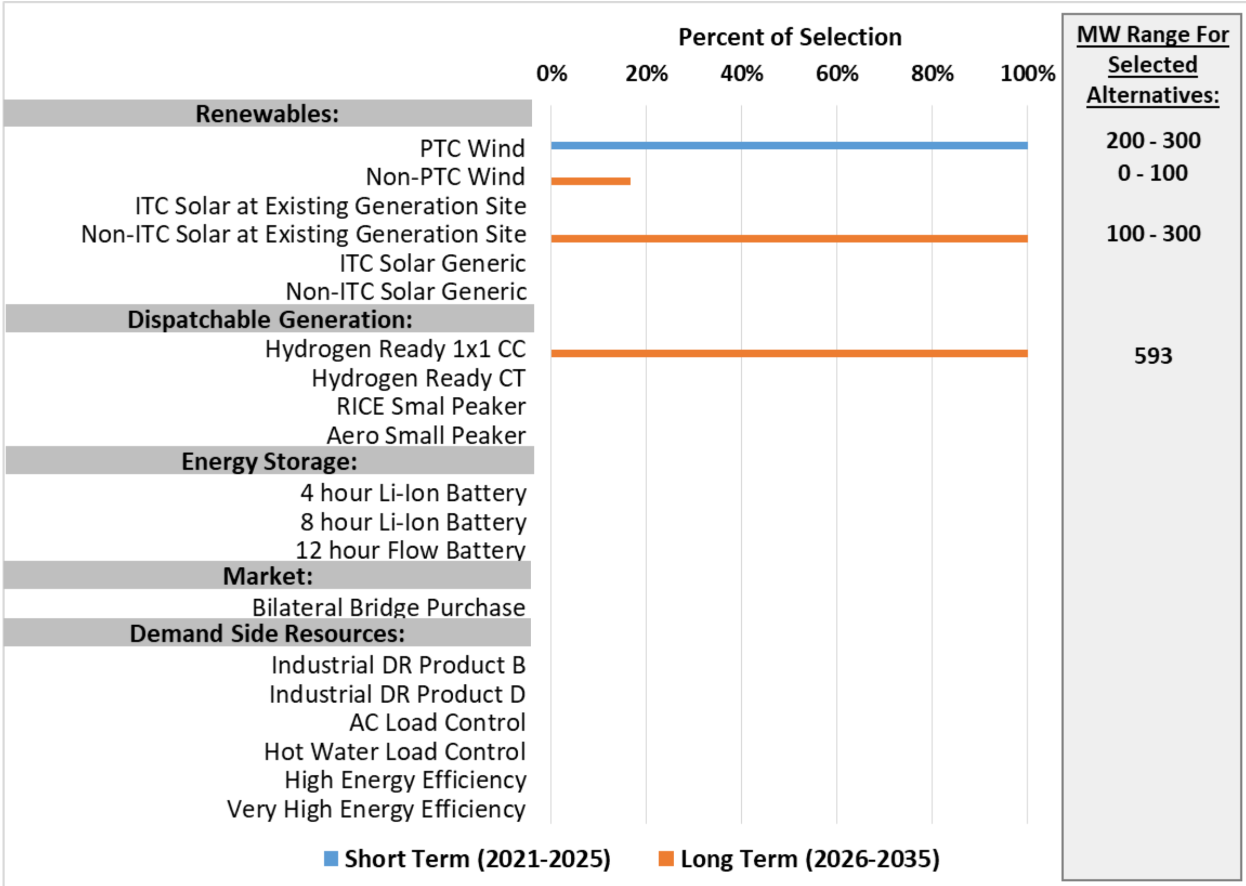
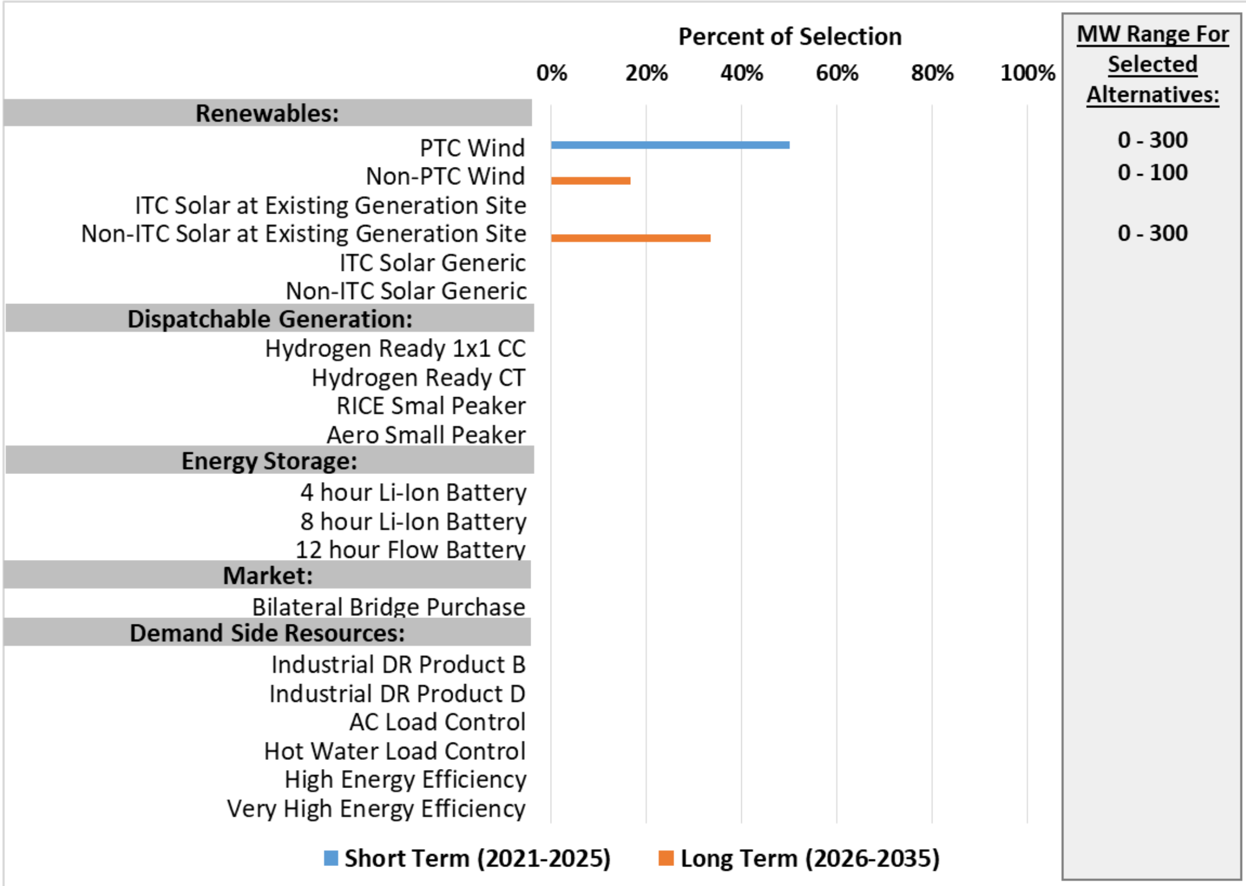


Figure 15: Capacity Expansion Analysis for Base Case: No BEC Units 3-4 Retirement



Key Insights from the Supplemental Capacity Expansion Analysis:

- Additional Futures continue to support the same levels of PTC Wind and Solar located at Boswell.
- No changes to the selection of the new transmission and/or hydrogen ready alternatives.
- The additional environmental futures and lower cost carbon future reduce the selection rate for non-PTC wind which continues to support the decision to exclude non-PTC wind form the Step 2 analysis.

The results, including the supplemental step 1 analysis, continue to support the Step 2 “swim Lane” Alternative Power Supply Portfolios outlined in Figure 10. No changes were made to the Alternative Power Supply Portfolios setup for the Step 2 supplemental analysis.

Additional Results for "Swim Lane" Sensitivity Analysis (Step 2)

This section summarizes the supplemental results from the "Swim Lane" sensitivity analysis for the remaining environmental futures not shown in Section V or above in Appendix K. For clarity, here is a list of the environmental futures included in this section:

- Low Carbon Regulation Cost and Low Environmental Cost
- Low Environmental Cost
- High Environmental Cost

For each environmental future, the swim lane alternatives and 2021 Plan were put through a series of 37 sensitivities that stressed the main drivers for resource decisions. A summary of the EnCompass sensitivity analysis results for each future listed above are shown in Tables 5 through 7.

As discussed previously, the results from the Reference future in Section V and the "High Carbon Regulation Cost and High Environmental Cost" future in Appendix K above clearly indicate the 2021 Plan is the least cost for customers across the majority of the sensitivities.

In the "Low Carbon Regulation and Low Environmental Cost" future shown below, the State Environmental Futures makes the evaluation of large baseload transition more difficult. While the cost deltas between the two retirement dates for BEC 3 are less than $10 million dollars NPV apart on average, the results demonstrate a environmental future design shortcoming.

As discussed in the Supplemental Step 1 analysis, EnCompass does not add Environmental Costs to the total power supply costs until after the unit dispatch is completed. EnCompass does include the cost of a carbon regulation tax when dispatching units, but disregards Environmental Costs when dispatching generation. When the carbon regulation tax is zero to minimal, as is the case in the "Low Carbon Regulation Cost and Low Environmental Cost" future, EnCompass does not shift dispatch towards lower carbon emitting resources. The units in the EnCompass model with the highest carbon intensity also have the highest environmental criteria pollutant intensity. Since the model does not avoid dispatching the high intensity units to avoid the environmental costs, the results are biased towards earlier and more aggressive retirement's scenarios.

This modeling phenomenon can be observed when comparing the results between the "Low Carbon Regulation and Lower Environmental Cost" and "Reference Case" with mid carbon regulation and mid environmental cost", where higher carbon regulation cost and higher environmental costs in the Reference Case support the later retirement for BEC 3 versus the "Low Carbon Regulation and Lower Environmental Cost" support earlier retirement for BEC 3 – this is counterintuitive given how higher carbon regulation cost and higher environmental cost typically support earlier retirement date for some coal assets.

Furthermore, in the "Low Environmental Costs" and "High Environmental Costs" futures shown below, the impacts of this environmental future design shortcoming are even more pronounced. Because EnCompass does not have any price signal (i.e. Carbon Regulation Tax) to dispatch around in these futures, the model is heavily biased towards the plans that replace higher emission intense resources with lower emission intense resources. In the "Two Unit Retirement" swimlane, Minnesota Power's existing coal fleet is replaced entirely by natural gas fired resources. When dispatching these futures, EnCompass does not know that it is accruing

Environmental Costs, so the total plan NPV shown in the tables will constantly be less among swimlanes which include natural gas resources.

When factoring in this modeling shortcoming with Environmental Costs, Minnesota Power strongly believes the 2021 Plan is in the best interests of customers based on the futures involving Carbon Regulation Costs and stakeholder input.

Table 5: Step 2 Sensitivity Analysis - 2021 NPV of Cost for Low Carbon Regulation and Low Environmental Cost Scenario ($millions)

	Single Unit Retirement			Two Unit Retirement	
EnCompass Sensitivities	2021 Plan *Retire BEC3 in 2029*	Retire BEC3 Early as Feasible	Retire BEC4 Early as Feasible	Expedited Retirement of BEC3 and 4	Base Case "Do Nothing"
Base Case	$7,494	$7,486	$7,537	$7,502	$7,632
Coal +20%	$7,398	$7,413	$7,430	$7,446	$7,506
Coal -10%	$7,546	$7,539	$7,589	$7,533	$7,697
Biomass +15%	$7,498	$7,489	$7,543	$7,502	$7,634
Biomass -15%	$7,489	$7,489	$7,540	$7,505	$7,631
Lower Gas -50%	$7,355	$7,374	$7,337	$7,358	$7,458
Low Gas -25%	$7,456	$7,465	$7,461	$7,469	$7,576
High Gas +25%	$7,681	$7,667	$7,721	$7,663	$7,858
Higher Gas +50%	$7,783	$7,753	$7,826	$7,759	$7,962
Highest Gas +100%	$7,904	$7,876	$7,943	$7,905	$8,079
Energy Market -50%	$6,417	$6,478	$6,465	$6,596	$6,342
Energy Market -25%	$7,090	$7,122	$7,133	$7,187	$7,141
Energy Market +25%	$7,799	$7,801	$7,836	$7,777	$7,967
Energy Market +50%	$7,948	$7,948	$7,976	$7,900	$8,127
Capital Costs -30%	$7,494	$7,493	$7,518	$7,446	$7,631
Capital Costs +30%	$7,497	$7,493	$7,563	$7,565	$7,626
No Market Sales	$7,350	$7,373	$7,396	$7,416	$7,448
No Sales and Purchases	$8,668	$8,853	$8,470	$8,657	$8,597
Market Access -50%	$7,764	$7,835	$7,759	$7,776	$7,866
Low Interconnect Costs	$7,472	$7,470	$7,523	$7,485	$7,631
ITC & PTC Extension	$7,486	$7,481	$7,536	$7,501	$7,636
Wind Cost Curve Low	$7,496	$7,492	$7,541	$7,504	$7,636
Wind Cost Curve High	$7,500	$7,494	$7,547	$7,508	$7,630
Solar Cost Curve Low	$7,480	$7,485	$7,529	$7,493	$7,635
Solar Cost Curve High	$7,512	$7,507	$7,563	$7,528	$7,639
Storage Cost Curve Low	$7,497	$7,489	$7,543	$7,505	$7,636
Storage Cost Curve High	$7,496	$7,493	$7,546	$7,506	$7,634
AFR 2020 Low Scenario	$7,220	$7,224	$7,269	$7,257	$7,335
AFR 2020 Load w Keetac	$7,920	$7,917	$7,933	$7,883	$8,055
AFR 2020 High Scenario	$7,950	$7,953	$7,963	$7,922	$8,092
Residential TOU	$7,490	$7,488	$7,537	$7,500	$7,629
Higher DG & EV Growth	$7,493	$7,493	$7,540	$7,503	$7,626
Renewable ELCC -2.5%	$7,503	$7,500	$7,541	$7,514	$7,630
Renewable ELCC +2.5%	$7,491	$7,490	$7,540	$7,501	$7,632
PRM -2%	$7,490	$7,487	$7,540	$7,508	$7,633
PRM +2%	$7,500	$7,504	$7,538	$7,514	$7,630
MISO CF -2%	$7,493	$7,485	$7,536	$7,501	$7,628
MISO CF +2%	$7,504	$7,506	$7,548	$7,513	$7,640
Sum of Least Cost Runs	**9**	**18**	**3**	**7**	**1**

Table 6: Step 2 Sensitivity Analysis - 2021 NPV of Cost for Low Environmental Cost Scenario ($millions)

	Single Unit Retirement			Two Unit Retirement	
EnCompass Sensitivities	2021 Plan *Retire BEC3 in 2029*	Retire BEC3 Early as Feasible	Retire BEC4 Early as Feasible	Expedited Retirement of BEC3 and 4	Base Case "Do Nothing"
Base Case	$7,814	$7,781	$7,852	$7,707	$8,061
Coal +20%	$7,648	$7,628	$7,688	$7,609	$7,845
Coal -10%	$7,912	$7,851	$7,952	$7,765	$8,200
Biomass +15%	$7,816	$7,779	$7,845	$7,705	$8,071
Biomass -15%	$7,812	$7,784	$7,850	$7,712	$8,065
Lower Gas -50%	$7,621	$7,602	$7,587	$7,541	$7,796
Low Gas -25%	$7,732	$7,709	$7,756	$7,658	$7,940
High Gas +25%	$8,031	$7,968	$8,067	$7,893	$8,321
Higher Gas +50%	$8,094	$8,012	$8,117	$7,949	$8,371
Highest Gas +100%	$8,194	$8,116	$8,226	$8,064	$8,471
Energy Market -50%	$6,582	$6,636	$6,623	$6,691	$6,593
Energy Market -25%	$7,398	$7,385	$7,424	$7,363	$7,572
Energy Market +25%	$8,111	$8,082	$8,145	$7,980	$8,400
Energy Market +50%	$8,259	$8,226	$8,285	$8,115	$8,550
Capital Costs -30%	$7,818	$7,786	$7,831	$7,650	$8,068
Capital Costs +30%	$7,815	$7,782	$7,871	$7,772	$8,075
No Market Sales	$7,606	$7,603	$7,653	$7,563	$7,815
No Sales and Purchases	$8,894	$9,169	$8,753	$8,825	$8,962
Market Access -50%	$8,043	$8,075	$8,027	$7,969	$8,252
Low Interconnect Costs	$7,799	$7,764	$7,830	$7,692	$8,072
ITC & PTC Extension	$7,814	$7,773	$7,840	$7,703	$8,076
Wind Cost Curve Low	$7,812	$7,784	$7,845	$7,713	$8,065
Wind Cost Curve High	$7,815	$7,787	$7,847	$7,710	$8,066
Solar Cost Curve Low	$7,803	$7,769	$7,836	$7,699	$8,074
Solar Cost Curve High	$7,835	$7,798	$7,863	$7,729	$8,072
Storage Cost Curve Low	$7,816	$7,779	$7,841	$7,712	$8,070
Storage Cost Curve High	$7,818	$7,779	$7,847	$7,708	$8,067
AFR 2020 Low Scenario	$7,520	$7,494	$7,564	$7,440	$7,752
AFR 2020 Load w Keetac	$8,257	$8,219	$8,263	$8,104	$8,512
AFR 2020 High Scenario	$8,292	$8,255	$8,298	$8,143	$8,554
Residential TOU	$7,806	$7,779	$7,846	$7,697	$8,059
Higher DG & EV Growth	$7,809	$7,784	$7,848	$7,712	$8,071
Renewable ELCC -2.5%	$7,816	$7,794	$7,849	$7,714	$8,075
Renewable ELCC +2.5%	$7,816	$7,784	$7,849	$7,706	$8,074
PRM -2%	$7,813	$7,780	$7,846	$7,711	$8,070
PRM +2%	$7,822	$7,793	$7,849	$7,719	$8,077
MISO CF -2%	$7,807	$7,777	$7,842	$7,710	$8,069
MISO CF +2%	$7,819	$7,801	$7,852	$7,715	$8,071
Sum of Least Cost Runs	**1**	**0**	**1**	**36**	**0**

Table 7: Step 2 Sensitivity Analysis - 2021 NPV of Cost for High Environmental Cost Scenario ($millions)

	Single Unit Retirement			Two Unit Retirement	
EnCompass Sensitivities	**2021 Plan** ***Retire BEC3 in 2029***	**Retire BEC3 Early as Feasible**	**Retire BEC4 Early as Feasible**	**Expedited Retirement of BEC3 and 4**	**Base Case "Do Nothing"**
Base Case	$9,727	$9,607	$9,721	$9,290	$10,337
Coal +20%	$9,274	$9,206	$9,297	$9,008	$9,772
Coal -10%	$9,994	$9,813	$9,997	$9,451	$10,693
Biomass +15%	$9,700	$9,571	$9,699	$9,256	$10,320
Biomass -15%	$9,761	$9,633	$9,761	$9,341	$10,384
Lower Gas -50%	$9,456	$9,364	$9,360	$9,147	$9,930
Low Gas -25%	$9,587	$9,470	$9,559	$9,240	$10,105
High Gas +25%	$10,068	$9,849	$10,046	$9,499	$10,747
Higher Gas +50%	$10,144	$9,915	$10,127	$9,563	$10,821
Highest Gas +100%	$10,237	$10,001	$10,206	$9,623	$10,929
Energy Market -50%	$7,377	$7,408	$7,379	$7,347	$7,519
Energy Market -25%	$8,857	$8,776	$8,854	$8,547	$9,309
Energy Market +25%	$10,286	$10,147	$10,282	$9,783	$10,967
Energy Market +50%	$10,587	$10,440	$10,574	$10,060	$11,281
Capital Costs -30%	$9,728	$9,593	$9,697	$9,230	$10,324
Capital Costs +30%	$9,718	$9,608	$9,750	$9,371	$10,343
No Market Sales	$9,223	$9,145	$9,230	$8,889	$9,740
No Sales and Purchases	$11,052	$11,121	$10,799	$10,620	$11,396
Market Access -50%	$10,012	$9,988	$9,958	$9,604	$10,576
Low Interconnect Costs	$9,713	$9,585	$9,700	$9,266	$10,344
ITC & PTC Extension	$9,734	$9,598	$9,708	$9,279	$10,337
Wind Cost Curve Low	$9,723	$9,602	$9,717	$9,275	$10,341
Wind Cost Curve High	$9,743	$9,606	$9,722	$9,299	$10,340
Solar Cost Curve Low	$9,704	$9,589	$9,713	$9,272	$10,335
Solar Cost Curve High	$9,751	$9,619	$9,741	$9,307	$10,342
Storage Cost Curve Low	$9,734	$9,606	$9,721	$9,283	$10,343
Storage Cost Curve High	$9,721	$9,600	$9,714	$9,279	$10,335
AFR 2020 Low Scenario	$9,278	$9,159	$9,270	$8,883	$9,848
AFR 2020 Load w Keetac	$10,381	$10,235	$10,356	$9,875	$11,036
AFR 2020 High Scenario	$10,438	$10,294	$10,413	$9,918	$11,092
Residential TOU	$9,718	$9,589	$9,717	$9,270	$10,333
Higher DG & EV Growth	$9,716	$9,603	$9,723	$9,299	$10,338
Renewable ELCC -2.5%	$9,731	$9,613	$9,724	$9,296	$10,327
Renewable ELCC +2.5%	$9,734	$9,597	$9,728	$9,286	$10,336
PRM -2%	$9,741	$9,601	$9,727	$9,294	$10,349
PRM +2%	$9,733	$9,609	$9,728	$9,287	$10,346
MISO CF -2%	$9,714	$9,598	$9,720	$9,271	$10,337
MISO CF +2%	$9,747	$9,615	$9,740	$9,300	$10,343
Sum of Least Cost Runs	**0**	**0**	**0**	**38**	**0**