Evergy Missouri West

Volume 6

Integrated Resource Plan and Risk Analysis

Integrated Resource Plan

20 CSR 4240-22.060

April 2024

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Volume 6: Integrated Resource Plan and Risk Analysis

Highlights

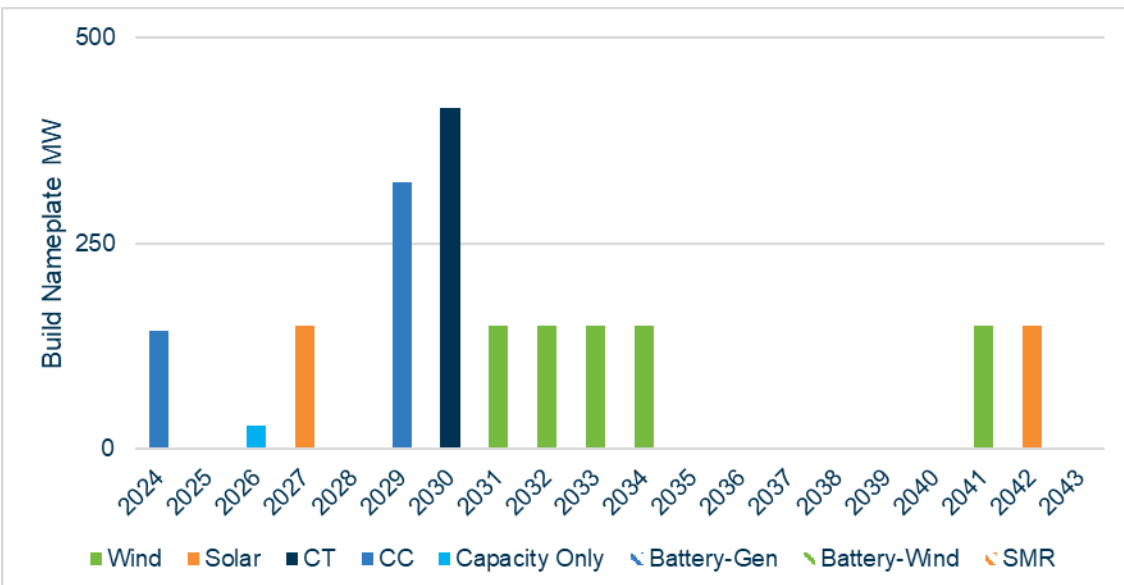
- Evergy Missouri West's long-term planning criteria includes meeting its customers' energy and capacity needs while balancing future risks.
- Alternative resource plans were developed to consider base planning options, varying future demand-side management portfolios, retirement dates, and resource additions.
- Resource plans were also developed to evaluate directed strategies such as minimum or maximum renewable additions and discrete scenarios of future environmental policy.
- Contingency plans address planning alternatives if conditions change, such the next best resource additions in the short term if execution challenges occur, and longer-term variation in resource decisions directly tied to higher and lower than expected load growth scenarios.
- Resource plans were evaluated economically based on their performance in future scenarios with varied levels of the identified critical uncertain factors: natural gas prices, CO_2 emissions restrictions, and construction costs.
- Plans were ranked based on expected net present value revenue requirements in different future scenarios and on a weighted-average risk basis. Performance measures also quantify costs and risks of each alternative resource plan.

Section 1: Overview of Preferred Resource Plan

The objectives for the Evergy Missouri West resource plan are to meet customer energy and capacity needs cost effectively, considering future risks.

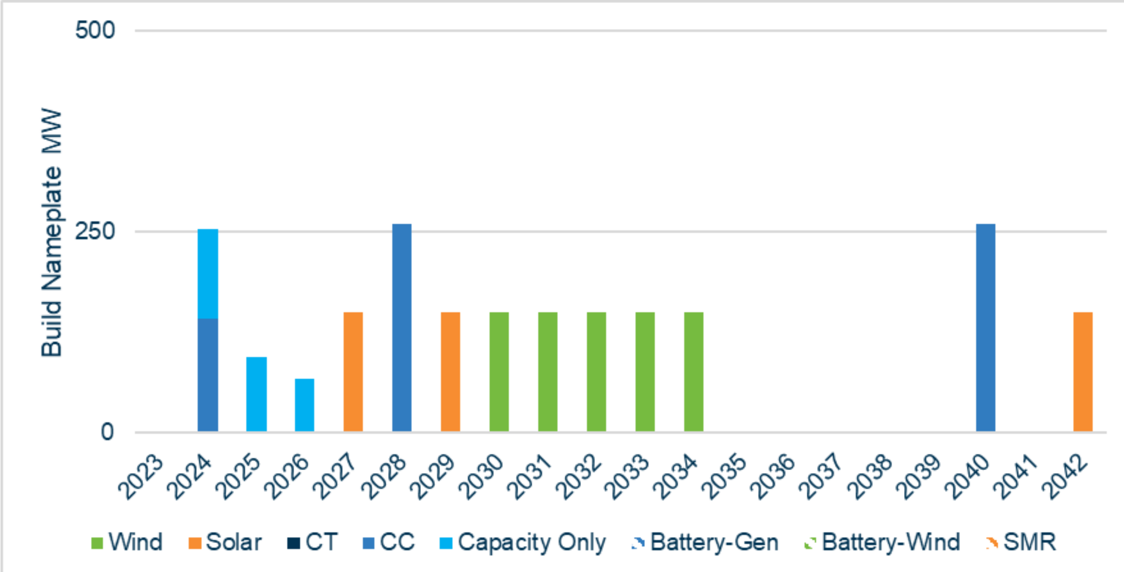
The Preferred Plan for Evergy Missouri West was chosen because it meets these objectives. The plan includes the purchase of a 22% share of Dogwood Energy Center, an existing natural-gas-fired combined cycle in 2024, an addition of 150 MW of solar in 2027, followed by additions of a ½ combined cycle in 2029 and a combustion turbine in 2030. The balance of the 20-year additions includes 750 MW wind and 150 MW solar from 2031-2043.

Figure 1: Evergy Missouri West Preferred Plan 2024 CAAA



The Preferred Plan for 2024 resembles the 2023 Preferred Plan, with some changes. The additions in the first five years include Dogwood, 150 MW solar, and 325 MW combined cycle. The ½ combined cycle is deferred one year from 2028 to 2029 in the new plan. The second new thermal capacity build, now a combustion turbine, is accelerated to 2030 from the prior plan to build another ½ combined cycle in 2040. The increase in forecasted capacity needs, due to expected increases in reserve margin requirements and enforcement of winter capacity requirements, is the primary driver of the earlier capacity resource build.

Figure 2: Evergy Missouri West Preferred Plan 2023



The similarity in resource plans keeps Evergy Missouri West on the same short-term path. A portion of the plan is already being executed through the certificate of convenience and necessity granted for Evergy Missouri West to own and operate the Dogwood Energy Facility.[1]

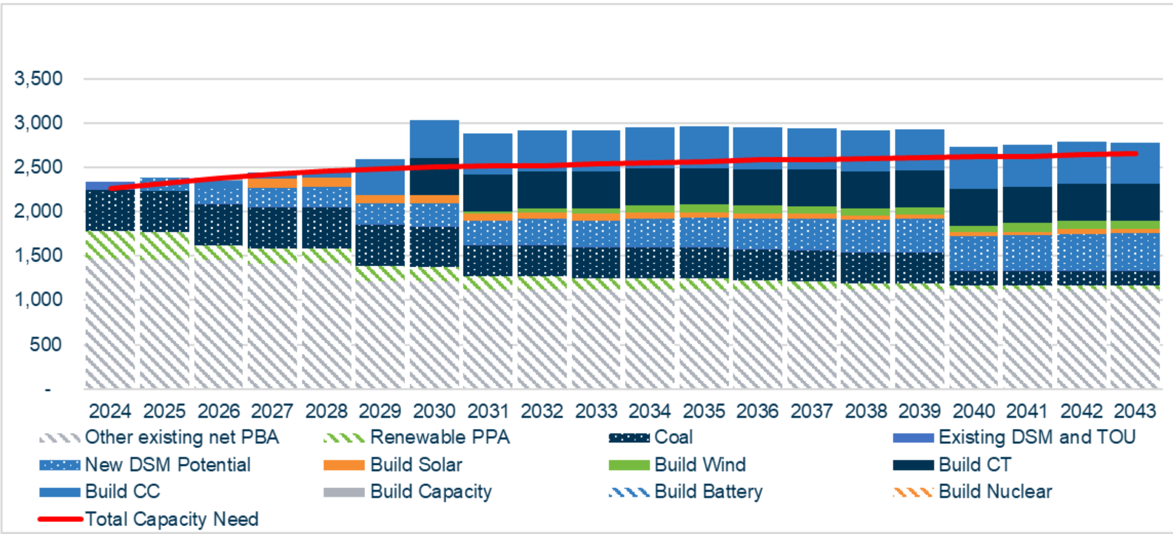
The first new resource continues to be solar. Solar resources are the first near-term builds for all Evergy utilities' preferred resource plans. There is currently very little solar in the SPP resource mix; incremental solar is expected to have high summer accreditation and provide peak-correlated energy. These attributes and the availability of solar production tax credit incentives from the Inflation Reduction Act, make early solar builds attractive to meet customer needs at lowest cost. Evergy has shortlisted offers from its 2023 RFP and has viable projects to fill the 2027 solar need.

Evergy is also working on the steps needed to develop natural-gas-fired resources in the future, including finding ideal sites, considering proximity to transmission and natural gas pipelines, environmental factors, etc.

[1] EA-2023-0291 Order Approving Stipulation and Agreement and Granting Certificate of Convenience and Necessity. Issued March 21, 2024, effective April 20, 2024.

The Preferred Plan meets expected annual summer and winter capacity requirements in all years of the planning horizon. The Evergy Missouri West Preferred Plan meets short-term summer capacity needs through addition of the RAP Plus DSM portfolio demand reductions beginning in 2025 and solar build in 2027.

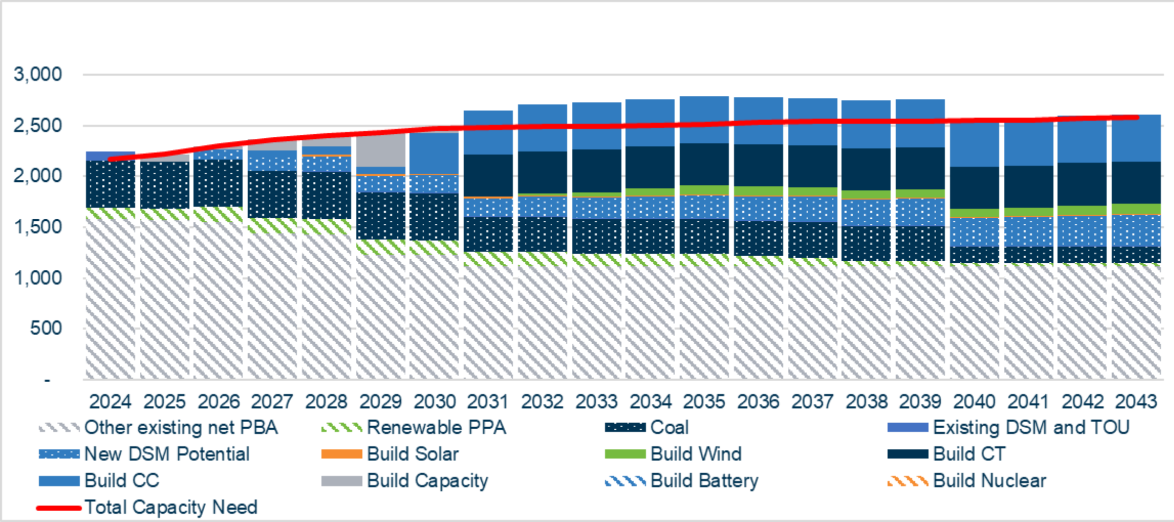
Figure 3: Preferred Plan (CAAA) Summer Capacity Position MW[2]



Evergy Missouri West is also forecasted to need winter capacity as soon as winter requirements become effective in SPP (likely in winter 2026/27). The Evergy Missouri West Preferred Plan adds short-term market capacity purchases until the first thermal resource addition in 2029, a half combined cycle, and another thermal resource in 2030, a combustion turbine, provide sizeable winter capacity.

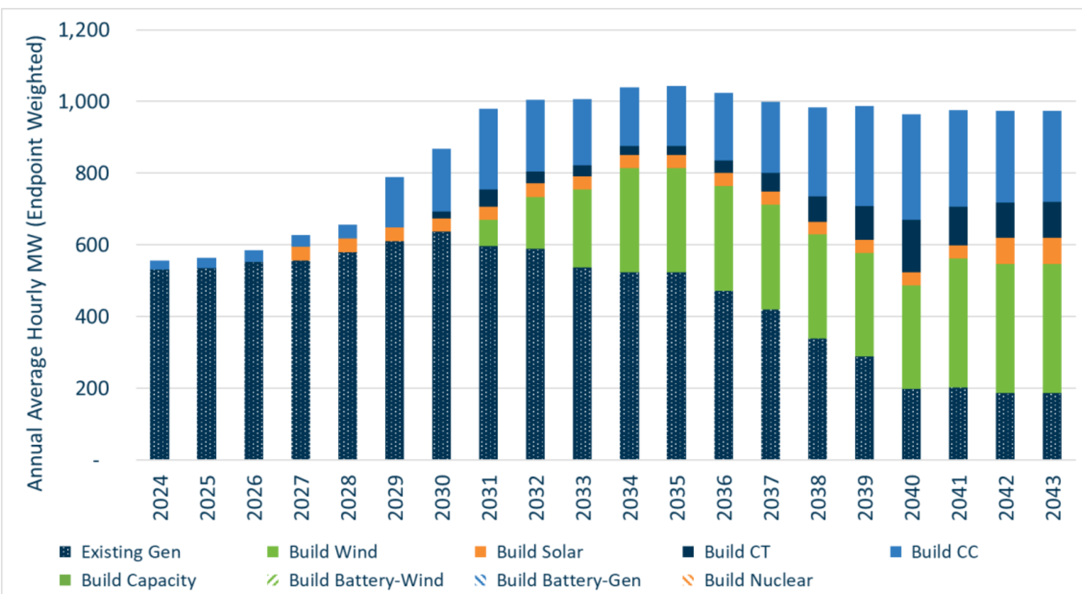
[2] 20 CSR 4240-22.060(4)(B)3. Preferred Plan shown. For all other ARPs, plots of expected summer and winter capacity provided by supply-side resources are in the plan workbook workpapers.

Figure 4: Preferred Plan (CAAA) Winter Capacity Position MW



The Preferred Plan forecasts that Evergy Missouri West's future generation mix will meet its customers energy need with the addition of the Dogwood combined cycle in 2024, additional solar generation from the addition in 2027, natural-gas generation primarily from the addition of a half combined cycle in 2029, then increasingly with wind additions (as existing wind PPAs end).

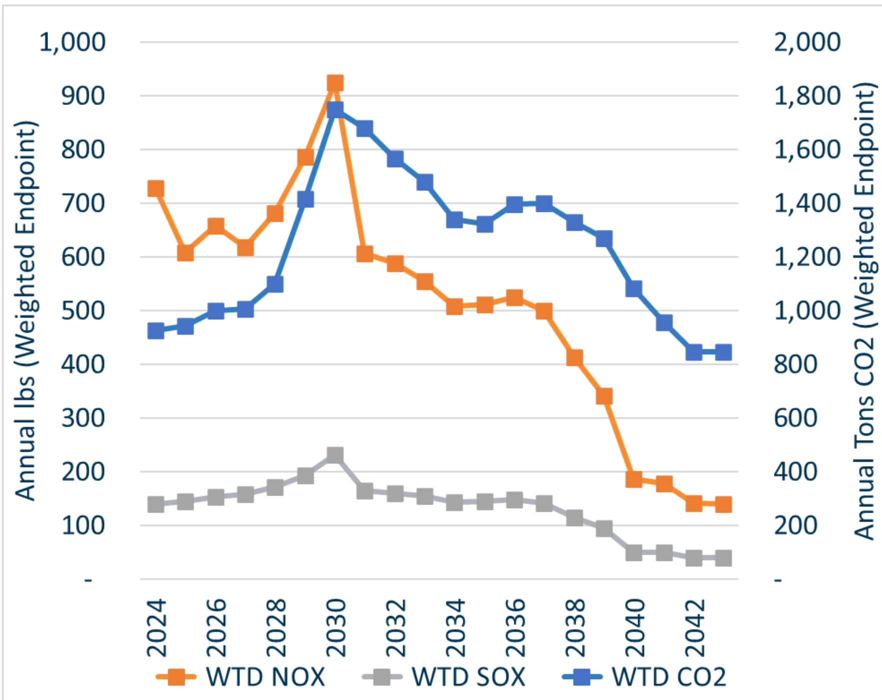
Figure 5: Preferred Plan Annual Generation[3]



[3] 20 CSR 4240-22.060(4)(B)6. Preferred Plan shown. For all other ARPs, plots of annual energy by supply-side resources are in Appendix 6B Annual Generation by ARP.

The Preferred Plan expected emissions increase over the first several years of the planning period as Missouri West adds combined cycle and combustion turbine resources to serve its load. As Missouri West meets more of its energy needs with its owned generation (as opposed to market energy purchases) its fleet emissions increase. Later in the planning horizon, emissions decrease due to emissions limits in some endpoints and the transition in the resource mix, with more energy supplied from renewables and more efficient, lower-emitting thermal resources.

Figure 6: Preferred Plan Annual Emissions[4]



Section 2: Planning Criteria

2.1 Capacity Needs[5]

Evergy Missouri West's owned and contracted resources are not sufficient to meet expected future capacity needs. For the past few years, Evergy Missouri West has been able to supplement its fleet with market capacity from affiliates and other resource owners

[4] 20 CSR 4240-22.060(4)(B)7. Preferred Plan shown. For all other ARPs, plots of annual energy by supply-side resources are in Appendix 6C Annual Emissions by ARP.

[5] 20 CSR 4240-22.060(4)(B)9. For all ARPs, capacity balances are provided in Appendix 6A Capacity Balance Spreadsheets.

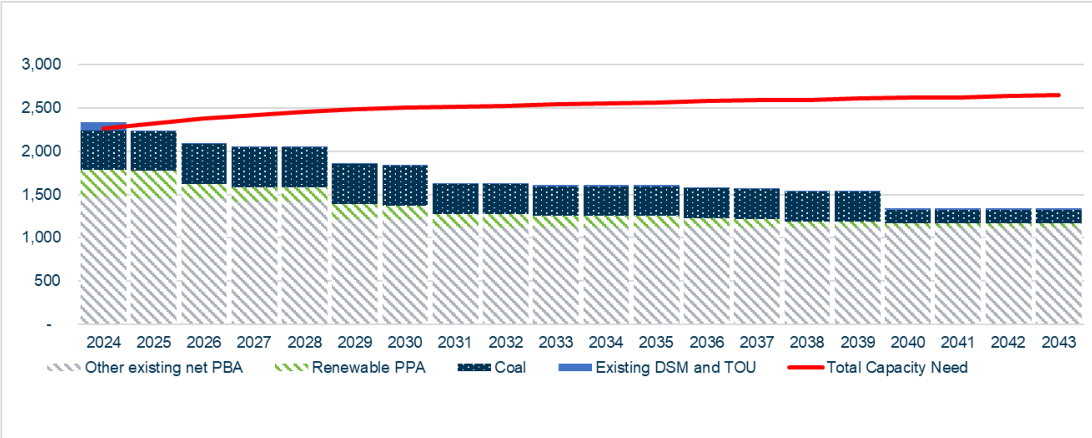
in order to meet SPP requirements. This includes a recent 200 MW- 275 MW capacity contract with Evergy Metro through summer 2028 which includes an energy scheduling option.

SPP participants, including other Evergy affiliates, have had excess capacity relative to expected needs in the past few years, allowing Evergy Missouri West to secure the additional capacity it needed at prices that were likely less than potential new resource build costs. However, Evergy does not believe this will be the case in future years. SPP is expected to significantly augment capacity requirements, including increasing reserve margins and decreasing accreditation for resources, as described in more detail in Volume 4. This will reduce the amount of “excess” capacity held by load-serving entities and available for purchase by Evergy Missouri West. Evergy has seen evidence that other utilities are forecasting potential shortfalls in capacity due to these policy changes, and are issuing RFPs and accelerating build plans. Additionally, all three Evergy utilities have are forecasting significant load growth due to economic development. Evergy affiliates will no longer have excess capacity to sell as it will be absorbed by increasing load and capacity needs.

An objective of the resource plan is for Evergy Missouri West to meet its capacity needs with its owned/contracted resources with minimal reliance on market capacity purchases due to the changing market environment.

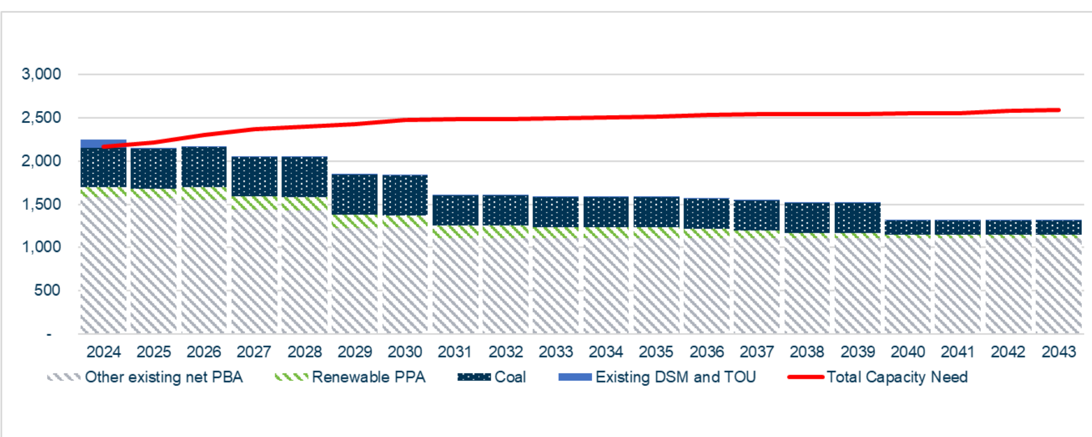
Evergy Missouri West is forecasted to need summer capacity as early as 2025. Capacity needs are forecasted to grow over time due to load growth, increasing reserve margin requirements, the expiration of renewable PPAs, and retirements of coal resources (based on the 2023 Preferred Plan retirement dates). New demand-side management programs beginning in 2025 and resource builds available beginning in 2026 are needed to meet capacity needs. Evergy Missouri West’s planning criteria was to meet the majority of the summer need with resource additions and demand-side programs, with only 20 MW of market capacity available annually beginning in 2027.

Figure 7: Missouri West Summer Capacity Position



Evergy Missouri West resource plans also include meeting the forecasted winter capacity requirement. Evergy expects SPP to impose a winter requirement beginning in the winter of 2026/2027. Evergy Missouri West is summer peaking, as are all of the Evergy utilities, however, its winter peak is closer to its summer peak due to higher prevalence of electric heating. Because Evergy Kansas Central has significant winter capacity length (due to its resource mix and lower winter peak load ratio), Evergy Missouri West's resource planning includes the option to purchase winter market capacity through winter 2029/2030, after which it must be self-sufficient except for the 20 MW annual market capacity allowance. Future demand-side management programs and renewable and storage resource builds provide less winter capacity than summer capacity, which is considered in developing the optimal resource plans to meet both winter and summer needs.

Figure 8: Missouri West Winter Capacity Position



2.2 Energy Needs

As discussed in Volume 4, Evergy Missouri West has historically been a net buyer of energy in the SPP market. The SPP market economically dispatches resources to minimize the variable costs to serve load on a short-term basis. Available resources offer energy into the SPP market based on their expected production costs. When a resource is dispatched by the SPP market it is because its marginal production costs are less than the SPP market price. If a resource is not dispatched, it is because the SPP market price is less than the resource's short-run marginal cost. The composition of Evergy Missouri West's resource fleet positions it to be a more frequent net buyer than other Evergy utilities because it has relatively less baseload generation (coal, nuclear) and relatively more peakers (oil and natural gas combustion turbines). These resources have higher production costs and, as a result, they are dispatched less frequently. If a utility is more frequently a net buyer from the market, it simply means that, at the times it is a net buyer, SPP market prices are cheaper than the production costs of its resources and thus buying from the market reduces overall costs for that utility.

Evergy expects all of its utility customers to continue to benefit from production cost savings through participation in the SPP market. However, planning is conducted in order to develop a future resource portfolio that is aligned with Evergy Missouri West customers' energy needs and not overly dependent on the SPP market. The SPP market resource mix is transitioning with expected retirements of baseload (coal) generation and additions of renewables, which have low (sometimes negative) production costs but are weather dependent. Evergy utilities and others expect load growth driven by economic development. Planning for a future resource mix that matches expected energy needs (considering seasonal and time-of-day resource limitations) at the lowest cost will provide an economic and physical hedge for Evergy Missouri West customers. All alternative resource plans assume Evergy Missouri West transitions to limit net hourly purchases and sales of energy to 200 MW/h by 2031, representing approximately 10% of peak load or 15% of average load, to restrict the level of market dependence assumed in resource planning decisions.

2.3 Future Risks

2.3.1 Critical Uncertain Factors[6]

As part of the triennial IRP process, Evergy analyzed future uncertain factors to determine which uncertainties are critical to the performance of a resource plan. Evergy identified natural gas prices, CO_2 restrictions, and construction costs (including build and interconnection costs) as the three critical uncertain factors. High, mid, and low forecasts for these factors over the 20-year time horizon were used in testing alternate resource plans through different futures to calculate expected performance given these critical uncertainties.

The probability of each factor was determined based on the business judgment of Evergy subject-matter experts regarding the likelihood of the 20-year forecast levels. These probabilities were then approved by the Evergy executive team and reviewed with IRP stakeholders.

The probabilities for natural gas price scenarios are consistent with the probabilities used in recent IRPs since the 2021 Triennial and reflect the expectation the lower natural gas prices are relatively more likely in the long-term than sustained high prices. The probabilities utilized for CO_2 emissions are also similar to weightings used in past years, but are adjusted slightly to reflect a higher relative weighting of low restrictions versus high. While the proposed Greenhouse Gas rules from the EPA ("GHG rules") are aligned with the high scenario and thus the high scenario is certainly possible, these rules have been evaluated as a discrete scenario in this IRP to develop resource plans which would comply with the proposed rules. In comparing plans' performance across scenarios, however, this high scenario can skew results dramatically given costs associated with carbon capture and sequestration (which are necessary to achieve required emissions reductions) and are included only in that high scenario. This represents a different approach than what was done in recent IRPs (where emissions reductions in the high scenario were assumed to be possible without incremental costs) and thus the weighting was slightly reduced (from 20% to 15%) for this scenario to mitigate the impact of this

6 20 CSR 4240-22.060(7), 20 CSR 4240-22.060(7)(C)1B

single set of scenarios on expected value costs. Finally, construction costs are a new critical uncertain factor in this triennial filing and these probabilities were informed by the statistical variation between the high/low and mid scenarios (e.g., the interconnection costs utilized represent the 25th and 75th percentile of the historical dataset).

Table 1: Critical Uncertain Factor Probability Weightings

	Natural Gas Price	CO_2 Emissions Restrictions	Construction Cost
Low	35%	25%	25%
Mid	50%	60%	50%
High	15%	15%	25%

A full discussion of the testing process and the results for each uncertain factor are included in Section 10.

2.3.2 Load Growth

Meeting future customer load, including energy and capacity needs is fundamental to resource planning. The load forecast is critical because it drives these needs. Higher load growth will drive the need to add more resources, while lower load growth may allow deferral of resource additions. Historically, load was added as a critical uncertain factor and used in the calculation of expected value, but the resource plans were not modified to reflect the capacity additions that would be needed or deferrals that would be enabled by the different load forecast.

In this IRP, Evergy Missouri West created alternative resource plans to analyze how the resource plan would change in response to load growth in the high and low forecast scenarios. These contingency plans will help assess how the resource plan may pivot in the future in response to the pace of electrification, technological improvement, and economic growth.

2.3.3 Future Environmental Policy

Risks of future environmental policy are included in the analysis of resource plans. Evergy complies with all local, state and federal environmental rules, and includes the expected costs of compliance in capital plans and operations and maintenance budgets, as described in Volume 4.

Evergy Missouri West also plans for probable environmental costs. The CO_2 emissions restrictions critical uncertain factor serves as a proxy for future emissions policy and impacts the expected value of the alternative resource plans. Evergy Missouri West also assumes selective catalytic reduction (SCR) will be needed on Jeffrey Units 2 & 3 if they do not retire in 2030.

Table 2: Probable Environmental Retrofits Needed **<u>Confidential</u>**

[redacted]

There is also uncertainty of the outcome of the EPA's proposed GHG rules. Evergy is not able to estimate a probable effect of these rules given that significant concerns were raised in comments, a final rule has not been issued, there is a presidential election this year, and any rule may be further challenged in the administrative process and courts. Evergy estimates that a possible outcome may be CO_2 emissions reductions that resemble the high CO_2 emissions critical uncertain factor forecast. Additional alternative resource plans were developed to assess potential compliance paths based on the proposed rules.

2.3.4 Execution and Financial Risks

Evergy may experience risks in executing on its resource plan. Alternative resource plans were developed using informed judgment of the availability and timing of potential resource additions, considering construction and interconnection timelines. As described in Volume 4, cost and timing assumptions were based on offers in Evergy's 2023 RFP, research into self-build options, SPP's interconnection queue timelines and publicly available information.

The amount of resource additions was limited in each year of the planning period to respect expected capital budget spending considerations. All alternate resource plans developed using these limits are expected to maintain Evergy Missouri West's balance sheet stability and financial metrics. Variations in spending from year to year, within these limitations, are not expected to change Evergy Missouri West's financial ratios, as other components of the company capital budget can be adjusted to accommodate higher resource spends in some years (with lower spend years making room for other priorities).

Ratemaking treatment was not factored into the expected value of alternative resource plans. In practice, Evergy Missouri West may experience lags between spending capital and recovering costs through rates, however, perfect ratemaking is assumed in resource plan economics.

Evergy Missouri West developed alternate resource plans to assess the next best planning options for execution contingencies. Additionally, alternate resource plans were created relaxing capital budget limits to illustrate more extreme planning strategies. These plans would not be expected to maintain financial ratios, and would likely need alternative financing strategies. They would also have much greater execution risk due to siting and procurement challenges in adding large volumes of resources in some years.

2.3.5 Fossil Resource Risks

There are various pressures on Evergy's existing fossil resources, particularly its coal resources. Future / tightening environmental regulations, customer / community sustainability goals (e.g., Kansas City, Missouri climate goals), expiration of existing agreements (e.g., Crossroads transmission contract, Kansas Central's lease for La Cygne 2), and operational risk or large investments needed due to age all contribute to the need to plan for the retirement of the majority of Evergy's coal fleet, and portions of its gas fleet, over the coming decades. While some of these risks are directly incorporated into IRP analysis through costs, others are not quantified / quantifiable. The current Preferred Plan order of retirements is based on current expectations of economic viability, however, changes to future conditions could change the order or cause acceleration / deceleration of the pace of retirements.

Most simplistically, however, Evergy Missouri West does not believe it is prudent to plan for a future with no coal retirements even if the order / pace of retirements could change over time. The expected risk balance is that some level of coal retirements will occur. If Evergy Missouri West does not plan for enough capacity additions to replace a retirement it may be left without options and will be forced to add resources reactively at a higher cost and/or pay deficiency payments due to not meeting resource adequacy requirements. Alternative resource plans were developed to acknowledge this baseline risk and test changes in the pace/sequencing of retirements to determine economic tradeoffs.

2.3.6 Legal Mandates[7]

Evergy Missouri West complies with the Missouri Renewable Energy Standards. Most alternative resource plans developed exceed expected future requirements, and a plan was developed to evaluate minimum compliance with the rule. Evergy Metro does not have legal mandates for demand-side resources or other resources.

[7] 20 CSR 4240-22.060(3)(A)4-5

Section 3: Development of Alternative Resource Plans

Alternative resource plans (ARPs) were developed to assess base planning options, directed strategies, discrete scenarios, and contingency plans.

3.1 Base Planning Options

Base planning options include expected options available to Evergy Missouri West over the planning horizon. These include implementation of varying portfolios of demand-side management programs, accelerated or delayed retirements of coal resources, and addition of new renewable, storage, and thermal resources in a cadence that respects capital budget and commercial availability limitations.

Table 3: Base DSM Portfolio Options

Missouri DSM Portfolios
MAP
RAP
RAP Plus
RAP Minus
None

Table 4: Base Coal Retirement Options

Coal Resource	Base Retire Year	Early Retire Year	Late Retire Year
Iatan 1	2039	2030	n/a
Iatan 2	None	2030	n/a
Jeffrey 1	2039	2030	n/a
Jeffrey 2	2030	n/a	2039
Jeffrey 3	2030	n/a	n/a

Table 5: Base Resource Addition Options

Resource Addition Type	Earliest Year Available
Battery-Wind	2026
Battery-Gen	2026
Wind	2026
Solar	2027
Combined Cycle	2028
Combustion Turbine	2028

3.2 Directed Strategies

Evergy Missouri West also developed several scenarios to reflect how changes to planning strategy would affect planned additions and economics, including the following ARPs:

- Plan for high natural gas – high carbon dioxide emissions limit future, with availability of combined-cycle with carbon capture beginning in 2035, and nuclear SMR beginning in 2039
- Plan for low natural gas – low (no) carbon dioxide emissions limit future
- Plan with only renewable additions necessary to comply with Renewable Energy Standard (RES) requirements
- Plan with only renewable and storage additions
- Plan with earliest retirement of coal fleet and only renewable and storage additions

3.3 Discrete Scenarios

Evergy Missouri West developed two scenarios intended to be extremes in planning strategy. One reflects a possible implementation of the EPA GHG rule, and optimizes the retirement and new addition decisions based on the high natural gas, high carbon dioxide emissions restriction future. The second reflects a different future with reduced expectations of environmental rules, including no emissions restrictions and no requirements for SCR additions at Jeffrey Energy Center. This plan is optimized using the low natural gas, low (no) carbon dioxide emissions future forecast.

3.4 Contingency Plans

Finally, Evergy Missouri West developed contingency plans to understand how optimal resource additions might vary based on risks around planning assumptions. One risk is near-term execution of the resource plan. If Evergy Missouri West is unable to acquire or develop a resource in the expected timeline, or does not receive regulatory approval for the resource, it may have to make changes to its plan. The two scenarios considering these near-term risks are:

- No 2027 solar build
- Retirement of Crossroads

The other risk that Evergy Missouri West considered through contingency plans is that the long-term load forecast may differ from the base planning assumption. Higher or lower load growth over the planning horizon may change the optimal timing, type, and amount of resource additions. The two alternate load forecasts considered were:

- High Load – including electrification
- Low Load

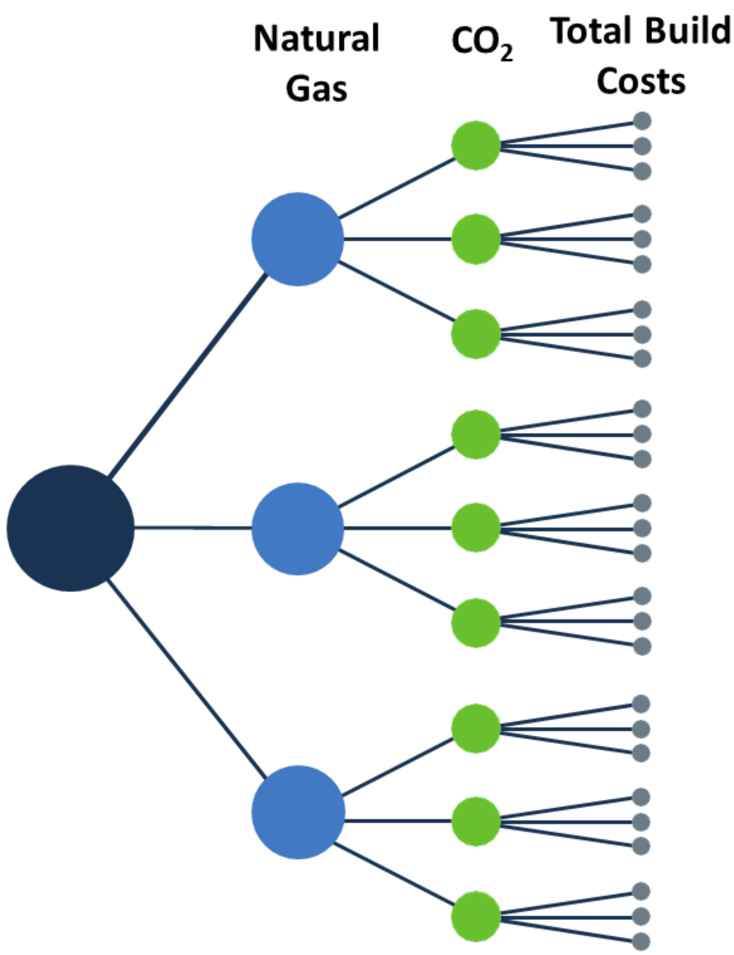
3.5 Modeling Approach

Evergy Missouri West used a three-step approach in modeling each ARP. First, a scenario was determined, based on the planning options discussed above. Next, the plan for resource additions was created for each scenario through capacity expansion modeling. Capacity expansion modeling determines the lowest total cost resource plan that meets capacity and energy needs (and other criteria if applicable), for the given scenario.

The lowest cost resource plan is based on the planning assumptions used (typically the base or “mid” case for each critical uncertain factor). However, to incorporate the risk of different future uncertainties, the optimized resource plan was then evaluated in each critical uncertain factor combination (endpoint) to determine the expected cost in that future. The resource plan meets capacity and energy needs in every endpoint, but will have differing economics due to changes in expected production costs, costs to serve load, and fixed costs. The natural gas price and carbon dioxide restriction critical uncertain factors both affect market prices, resource costs, and expected economic dispatch in the production cost model. The construction cost critical uncertain factor affects fixed costs of resource additions.

The forecasted revenue requirements associated with each endpoint were calculated based on the modeling results. The metric net present value revenue requirement (NPVRR) can be compared to determine the economic differences between plans at different endpoints.

Figure 9: Critical Uncertain Factor Scenarios



Evergy Missouri West assigned probability weightings to each critical uncertain factor based on subject-matter expert and management team's expectations for the likelihood of each forecast. Weighted average NPVRR calculations were made using these probabilities, as a metric for expected value of the plan considering future uncertainties.

3.5.1 Capacity Expansion Modeling[8]

Evergy Missouri West developed alternative resource plans through capacity expansion planning. Capacity expansion planning involves using a long-term wholesale market simulation model (Evergy Missouri West utilizes PLEXOS) which is designed to generate the lowest-cost resource plan given a set of resource options, a given market scenario (e.g., natural gas prices, wholesale energy prices, emissions constraints), and a forecasted capacity requirement (i.e., forecasted load plus planning reserve margin). Evergy Missouri West's goal in this IRP was to use Capacity Expansion to the fullest extent practical in selecting the lowest-cost resource additions. To that end, no supply-side resource additions were "hard-coded" into pre-made resource plans for the purpose of arriving at Evergy Missouri West's Preferred Plan. The only portion of the Alternative Resource Plans used in this filing which were manually tested were plant retirements and demand-side management portfolio additions. This is so that it is easier to compare different options side-by-side to see what trade-offs may exist between decisions. Even in testing these decisions, however, Capacity Expansion was still used to develop the lowest-cost portfolio of supply-side resources (e.g., if a higher level of DSM was assumed, then Capacity Expansion would build less resources as part of the optimized resource plan). This approach makes comparison somewhat more complicated than the past approach where plans could be compared on a truly apples-to-apples basis (i.e., because only one item in the whole plan changed and thus the difference in cost between the two plans is driven specifically by that one item), but it also more accurately depicts the integrated nature of resource planning, where every decision has an impact on future decisions and a portfolio should be viewed holistically as opposed to looking at an individual decision in a vacuum.

Unless otherwise noted in the description below, capacity expansion modeling was performed using the "Mid-Mid-Mid" endpoint, based on the Mid natural gas price forecast,

[8] 20 CSR 4240-22.060(4)(H)

Mid construction cost, and Mid level of carbon restrictions. This was, again, to provide easier comparisons between resource plans because a capacity expansion model will often generate different resource plans in different market scenarios. Evergy believes this approach provides a viable assessment of our current “base” expectations and that using these capacity expansion results, with revenue requirements for these Alternative Resource Plans calculated across all 27 endpoints, enables a robust analysis of these “base-case” Alternative Resource Plans across a wide variety of potential future scenarios.

Section 4: Alternative Resource Plans & Rankings

4.1 Summary of Alternative Resource Plans

Table 6: Missouri West Alternative Resource Plan Name Key

Demand Side Potential	Retirements	Coal to NG	Other
A. RAP	A. PP 2023 retirement dates	A. None	A. None
B. MAP	B. Retire Iatan 1 2030		C. No 2027 Solar
C. RAP Plus	C. Retire Jeffrey 2 2039		D. Allow More Builds
D. RAP Minus	D. Retire Jeffrey 1 2030		F. High/High
E. No Future DSM	E. Retire all Jeffrey and Iatan 2030		G. Low/Low
F. No Future DSM, No TOU	F. Retire Crossroads 2028		J. RES only
	G. No retirements		L. Only renewable/storage build, No budget constraint
			M. Allow SMR
			N. Allow Earlier SMR

Table 7: Alternative Resource Plan Descriptions[9]

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
			Wind	Solar		
Missouri West AAAA	RAP	Jeffrey 2: 2030 Jeffrey 3: 2030 Jeffrey 1: 2039 Iatan 1: 2039	150 MW 2028 150 MW 2031 150 MW 2032 150 MW 2033 150 MW 2034	150 MW 2027 150 MW 2041		143 MW CC 2024 325 MW CC 2029 415 MW CT 2030
Missouri West BAAA	MAP	Jeffrey 2: 2030 Jeffrey 3: 2030 Jeffrey 1: 2039 Iatan 1: 2039	150 MW 2026 150 MW 2028 150 MW 2031 150 MW 2032 150 MW 2033 150 MW 2034	150 MW 2027	150 MW BG 2030	143 MW CC 2024 415 MW CT 2029 325 MW CC 2039
Missouri West BEAL	MAP	Jeffrey 1: 2030 Jeffrey 2: 2030 Jeffrey 3: 2030 Iatan 1: 2030 Iatan 2: 2030	600 MW 2031 1200 MW 2033 600 MW 2042	150 MW 2028 150 MW 2032	150 MW BW 2026 150 MW BG 2029 1350 MW BG 2030 150 MW BG 2032 900 MW BG 2033 300 MW BW 2038 600 MW BW 2039 750 MW BW 2040 1200 MW BW 2041 600 MW BW 2042 750 MW BG 2042	
Missouri West CAAA	RAP+	Jeffrey 2: 2030 Jeffrey 3: 2030 Jeffrey 1: 2039 Iatan 1: 2039	150 MW 2031 150 MW 2032 150 MW 2033 150 MW 2034 150 MW 2041	150 MW 2027 150 MW 2042		143 MW CC 2024 325 MW CC 2029 415 MW CT 2030

[9] 20 CSR 4240-22.060(3)(D), BW refers to battery at wind node, BG refers to battery at generation node. All ARPs include the retirement of Lake Road 4/6 in 2030.

Missouri West CAAC	RAP+	Jeffrey 2: 2030 Jeffrey 3: 2030 Jeffrey 1: 2039 Iatan 1: 2039	150 MW 2026 150 MW 2028 150 MW 2030 150 MW 2031 150 MW 2032 150 MW 2033		150 MW BW 2027	143 MW CC 2024 415 MW CT 2029 325 MW CC 2037
Missouri West CAAD	RAP+	Jeffrey 2: 2030 Jeffrey 3: 2030 Jeffrey 1: 2039 Iatan 1: 2039	150 MW 2031 150 MW 2032 150 MW 2033 150 MW 2034 150 MW 2041	150 MW 2027 150 MW 2042		143 MW CC 2024 325 MW CC 2029 415 MW CT 2030
Missouri West CAAF	RAP+	Jeffrey 2: 2030 Jeffrey 3: 2030 Jeffrey 1: 2039 Iatan 1: 2039	150 MW 2026 150 MW 2028 150 MW 2030 150 MW 2031 150 MW 2032 150 MW 2033 150 MW 2034 150 MW 2035	150 MW 2042	150 MW BW 2027	143 MW CC 2024 415 MW CT 2029 300 MW SMR 2039
Missouri West CAAG	RAP+	Jeffrey 2: 2030 Jeffrey 3: 2030 Jeffrey 1: 2039 Iatan 1: 2039		150 MW 2027		143 MW CC 2024 325 MW CC 2029 325 MW CC 2030 325 MW CC 2039
Missouri West CAAH	RAP+	Jeffrey 2: 2030 Jeffrey 3: 2030 Jeffrey 1: 2039 Iatan 1: 2039	150 MW 2029 150 MW 2031 150 MW 2032 150 MW 2033 150 MW 2034 150 MW 2035 150 MW 2041 150 MW 2042	150 MW 2027 150 MW 2043		143 MW CC 2024 325 MW CC 2028 415 MW CT 2030 325 MW CC 2037 325 MW CC 2040
Missouri West CAAI	RAP+	Jeffrey 2: 2030 Jeffrey 3: 2030 Jeffrey 1: 2039 Iatan 1: 2039	150 MW 2030 150 MW 2031 150 MW 2032 150 MW 2033 150 MW 2034 150 MW 2035			143 MW CC 2024 415 MW CT 2029
Missouri West CAAL	RAP+	Jeffrey 2: 2030 Jeffrey 3: 2030 Jeffrey 1: 2039 Iatan 1: 2039	150 MW 2028 150 MW 2030 300 MW 2031 1350 MW 2033 300 MW 2042		150 MW BW 2026 300 MW BG 2029 600 MW BG 2030 150 MW BG 2032 600 MW BG 2033 1200 MW BW 2039 600 MW BW 2040 750 MW BW 2041 300 MW BG 2041 750 MW BW 2042 600 MW BG 2042	
Missouri West CAAM	RAP+	Jeffrey 2: 2030 Jeffrey 3: 2030 Jeffrey 1: 2039 Iatan 1: 2039	150 MW 2031 150 MW 2032 150 MW 2033 150 MW 2034 150 MW 2042	150 MW 2027 150 MW 2041		143 MW CC 2024 325 MW CC 2029 415 MW CT 2030
Missouri West CAAN	RAP+	Jeffrey 2: 2030 Jeffrey 3: 2030 Jeffrey 1: 2039 Iatan 1: 2039	150 MW 2031 150 MW 2032 150 MW 2033 150 MW 2034 150 MW 2042	150 MW 2027 150 MW 2041		143 MW CC 2024 325 MW CC 2029 415 MW CT 2030
Missouri West CBAA	RAP+	Iatan 1: 2030 Jeffrey 2: 2030 Jeffrey 3: 2030 Jeffrey 1: 2039	150 MW 2031 150 MW 2032 150 MW 2033 150 MW 2034 150 MW 2041	150 MW 2027 150 MW 2042		143 MW CC 2024 325 MW CC 2029 415 MW CT 2030

Missouri West CCAA	RAP+	Jeffrey 3: 2030 Iatan 1: 2039 Jeffrey 1: 2039 Jeffrey 2: 2039	150 MW 2030 150 MW 2031 150 MW 2032 150 MW 2033 150 MW 2034 150 MW 2042		150 MW BW 2026	143 MW CC 2024 415 MW CT 2029 325 MW CC 2039
Missouri West CDAA	RAP+	Jeffrey 1: 2030 Jeffrey 2: 2030 Jeffrey 3: 2030 Iatan 1: 2039	150 MW 2031 150 MW 2032 150 MW 2033 150 MW 2034 150 MW 2041	150 MW 2027 150 MW 2042		143 MW CC 2024 325 MW CC 2029 415 MW CT 2030
Missouri West CEAA	RAP+	Jeffrey 1: 2030 Jeffrey 2: 2030 Jeffrey 3: 2030 Iatan 1: 2030 Iatan 2: 2030	150 MW 2031 150 MW 2032 150 MW 2033 150 MW 2034	150 MW 2027 150 MW 2042		143 MW CC 2024 325 MW CC 2028 325 MW CC 2029 325 MW CC 2030
Missouri West CFAA	RAP+	Jeffrey 2: 2030 Jeffrey 3: 2030 Iatan 1: 2039 Jeffrey 1: 2039	150 MW 2031 150 MW 2032 150 MW 2033 150 MW 2034 150 MW 2042	150 MW 2027		143 MW CC 2024 325 MW CC 2028 325 MW CC 2029 415 MW CT 2030
Missouri West CGAA	RAP+		150 MW 2028 150 MW 2030 150 MW 2031 150 MW 2032 150 MW 2033 150 MW 2034	150 MW 2027 150 MW 2042		143 MW CC 2024 415 MW CT 2029
Missouri West CGAG	RAP+		150 MW 2030 150 MW 2031 150 MW 2032 150 MW 2033	150 MW 2027 150 MW 2028		143 MW CC 2024 415 MW CT 2029
Missouri West DAAA	RAP-	Jeffrey 2: 2030 Jeffrey 3: 2030 Jeffrey 1: 2039 Iatan 1: 2039	150 MW 2026 150 MW 2031 150 MW 2032 150 MW 2033 150 MW 2034	150 MW 2027		143 MW CC 2024 325 MW CC 2028 325 MW CC 2030 325 MW CC 2039
Missouri West EAAA	No Future DSM	Jeffrey 2: 2030 Jeffrey 3: 2030 Jeffrey 1: 2039 Iatan 1: 2039	150 MW 2028 150 MW 2031 150 MW 2032 150 MW 2033 150 MW 2034 150 MW 2035		150 MW BW 2026 150 MW BW 2027	143 MW CC 2024 325 MW CC 2029 325 MW CC 2030 325 MW CC 2038
Missouri West EAAJ	No Future DSM	Jeffrey 2: 2030 Jeffrey 3: 2030 Jeffrey 1: 2039 Iatan 1: 2039		5 MW 2036	150 MW BW 2026 150 MW BW 2027	143 MW CC 2024 325 MW CC 2028 325 MW CC 2030 325 MW CC 2035 325 MW CC 2039
Missouri West FAAA	No Future DSM, No TOU	Jeffrey 2: 2030 Jeffrey 3: 2030 Jeffrey 1: 2039 Iatan 1: 2039	150 MW 2031 150 MW 2032 150 MW 2033 150 MW 2034 150 MW 2041 150 MW 2042		150 MW BW 2026 150 MW BW 2027	143 MW CC 2024 325 MW CC 2028 325 MW CC 2030 325 MW CC 2037

4.2 Overall Plan Rankings

Table 8: Missouri West Overall Plan Rankings

Rank	Plan	NPVRR ($M)	Difference	Description
1	CBAA	11,067		Retire Iatan 1 2030
2	CCAA	11,076	9	Retire Jeffrey 2 2039
3	AAAA	11,081	14	RAP
4	CAAA	11,086	19	RAP Plus
5	CAAC	11,089	21	No 2027 Solar
6	DAAA	11,090	23	RAP Minus
7	CGAG	11,138	71	Low/Low, No retirements
8	CDAA	11,163	96	Retire Jeffrey 1 2030
9	CFAA	11,208	140	Retire Crossroads 2028
10	CAAF	11,241	174	High/High
11	CEAA	11,271	203	Retire all coal early
12	BAAA	11,272	204	MAP
13	EAAA	11,388	321	No Future DSM
14	FAAA	11,411	344	No Future DSM, No TOU
15	CAAG	11,636	569	Low/Low
16	EAAJ	12,288	1,220	RES only
17	CAAL	12,883	1,815	Only renewable/storage build, no budget
18	BEAL	13,752	2,684	MAP; Ret all early; Only renewable/storage build, no budget

4.3 Rankings by CO_2 Emissions Restriction

Table 9: High CO_2 Emissions Restrictions Rankings

Rank	Plan	NPVRR ($M)	Difference	Description
1	CAAF	11,267		High/High
2	DAAA	11,368	101	RAP Minus
3	CAAC	11,470	204	No 2027 Solar
4	CFAA	11,529	262	Retire Crossroads 2028
5	AAAA	11,538	272	RAP
6	CEAA	11,569	302	Retire all coal early
7	CBAA	11,589	322	Retire Iatan 1 2030
8	BAAA	11,599	333	MAP
9	CAAA	11,629	362	RAP Plus
10	EAAA	11,680	413	No Future DSM
11	FAAA	11,742	475	No Future DSM, No TOU
12	CCAA	11,755	488	Retire Jeffrey 2 2039
13	CAAG	11,955	689	Low/Low
14	CDAA	12,165	898	Retire Jeffrey 1 2030
15	CGAG	12,204	938	Low/Low, No retirements
16	EAAJ	12,352	1,085	RES only
17	CAAL	12,996	1,729	Only renewable/storage build, no budget
18	BEAL	13,875	2,608	MAP; Ret all early; Only renewable/storage build, no budget

Table 10: Mid CO_2 Emissions Restrictions Rankings

Rank	Plan	NPVRR ($M)	Difference	Description
1	CCAA	10,973		Retire Jeffrey 2 2039
2	CBAA	10,988	15	Retire Iatan 1 2030
3	CDAA	11,000	27	Retire Jeffrey 1 2030
4	CAAA	11,005	33	RAP Plus
5	AAAA	11,012	40	RAP
6	CAAC	11,030	57	No 2027 Solar
7	CGAG	11,048	75	Low/Low, No retirements
8	DAAA	11,053	80	RAP Minus
9	CFAA	11,163	190	Retire Crossroads 2028
10	BAAA	11,217	244	MAP
11	CEAA	11,222	250	Retire all coal early
12	CAAF	11,237	264	High/High
13	EAAA	11,351	378	No Future DSM
14	FAAA	11,377	405	No Future DSM, No TOU
15	CAAG	11,859	886	Low/Low
16	EAAJ	12,669	1,696	RES only
17	CAAL	12,863	1,890	Only renewable/storage build, no budget
18	BEAL	13,730	2,757	MAP; Ret all early; Only renewable/storage build, no budget

Table 11: Low CO_2 Emissions Restrictions Rankings

Rank	Plan	NPVRR ($M)	Difference	Description
1	CGAG	10,715		Low/Low, No retirements
2	CAAG	10,911	196	Low/Low
3	CCAA	10,916	201	Retire Jeffrey 2 2039
4	CBAA	10,946	231	Retire Iatan 1 2030
5	CDAA	10,954	239	Retire Jeffrey 1 2030
6	CAAA	10,956	241	RAP Plus
7	AAAA	10,972	257	RAP
8	CAAC	11,002	287	No 2027 Solar
9	DAAA	11,014	299	RAP Minus
10	CFAA	11,122	407	Retire Crossroads 2028
11	BAAA	11,207	492	MAP
12	CEAA	11,208	493	Retire all coal early
13	CAAF	11,237	522	High/High
14	FAAA	11,294	579	No Future DSM, No TOU
15	EAAA	11,304	589	No Future DSM
16	EAAJ	11,335	620	RES only
17	CAAL	12,863	2,148	Only renewable/storage build, no budget
18	BEAL	13,730	3,015	MAP; Ret all early; Only renewable/storage build, no budget

Table 12: High Natural Gas Rankings

Rank	Plan	NPVRR ($M)	Difference	Description
1	CAAC	11,702		No 2027 Solar
2	CAAF	11,737	36	High/High
3	AAAA	11,747	46	RAP
4	DAAA	11,756	55	RAP Minus
5	CGAG	11,762	61	Low/Low, No retirements
6	CCAA	11,765	64	Retire Jeffrey 2 2039
7	CAAA	11,798	96	RAP Plus
8	CBAA	11,832	131	Retire Iatan 1 2030
9	BAAA	11,859	157	MAP
10	CDAA	11,888	186	Retire Jeffrey 1 2030
11	CFAA	11,913	212	Retire Crossroads 2028
12	EAAA	12,071	370	No Future DSM
13	CEAA	12,144	442	Retire all coal early
14	FAAA	12,181	479	No Future DSM, No TOU
15	CAAG	12,476	774	Low/Low
16	EAAJ	13,174	1,473	RES only
17	CAAL	13,195	1,494	Only renewable/storage build, no budget
18	BEAL	14,157	2,455	MAP; Ret all early; Only renewable/storage build, no budget

Table 13: Mid Natural Gas Rankings

Rank	Plan	NPVRR	Difference	Description
1	CBAA	11,026		Retire Iatan 1 2030
2	CCAA	11,037	11	Retire Jeffrey 2 2039
3	AAAA	11,046	19	RAP
4	CAAA	11,048	22	RAP Plus
5	DAAA	11,057	31	RAP Minus
6	CAAC	11,058	31	No 2027 Solar
7	CGAG	11,100	74	Low/Low, No retirements
8	CDAA	11,123	97	Retire Jeffrey 1 2030
9	CFAA	11,172	146	Retire Crossroads 2028
10	CAAF	11,210	183	High/High
11	CEAA	11,225	199	Retire all coal early
12	BAAA	11,243	217	MAP
13	EAAA	11,351	325	No Future DSM
14	FAAA	11,363	337	No Future DSM, No TOU
15	CAAG	11,576	550	Low/Low
16	EAAJ	12,220	1,194	RES only
17	CAAL	12,849	1,823	Only renewable/storage build, no budget
18	BEAL	13,710	2,684	MAP; Ret all early; Only renewable/storage build, no budget

Table 14: Low Natural Gas Rankings

Rank	Plan	NPVRR	Difference	Description
1	CBAA	10,798		Retire Iatan 1 2030
2	CCAA	10,835	37	Retire Jeffrey 2 2039
3	CAAA	10,836	37	RAP Plus
4	AAAA	10,846	48	RAP
5	DAAA	10,853	55	RAP Minus
6	CAAC	10,871	72	No 2027 Solar
7	CDAA	10,909	111	Retire Jeffrey 1 2030
8	CGAG	10,925	127	Low/Low, No retirements
9	CFAA	10,956	158	Retire Crossroads 2028
10	CEAA	10,961	163	Retire all coal early
11	BAAA	11,060	262	MAP
12	CAAF	11,073	275	High/High
13	EAAA	11,150	351	No Future DSM
14	FAAA	11,151	352	No Future DSM, No TOU
15	CAAG	11,363	565	Low/Low
16	EAAJ	12,004	1,206	RES only
17	CAAL	12,797	1,998	Only renewable/storage build, no budget
18	BEAL	13,637	2,839	MAP; Ret all early; Only renewable/storage build, no budget

Table 15: High Construction Costs Rankings

Rank	Plan	NPVRR	Difference	Description
1	CBAA	11,441		Retire Iatan 1 2030
2	CCAA	11,452	11	Retire Jeffrey 2 2039
3	CAAA	11,460	19	RAP Plus
4	DAAA	11,514	73	RAP Minus
5	AAAA	11,518	77	RAP
6	CGAG	11,524	83	Low/Low, No retirements
7	CDAA	11,552	111	Retire Jeffrey 1 2030
8	CAAC	11,570	129	No 2027 Solar
9	CFAA	11,619	178	Retire Crossroads 2028
10	CEAA	11,655	214	Retire all coal early
11	BAAA	11,771	330	MAP
12	CAAG	11,780	339	Low/Low
13	FAAA	11,796	355	No Future DSM, No TOU
14	EAAA	11,856	415	No Future DSM
15	CAAF	11,900	459	High/High
16	EAAJ	12,468	1,027	RES only
17	CAAL	14,040	2,599	Only renewable/storage build, no budget
18	BEAL	15,045	3,604	MAP; Ret all early; Only renewable/storage build, no budget

Table 16: Mid Construction Costs Rankings

Rank	Plan	NPVRR	Difference	Description
1	CBAA	11,058		Retire Iatan 1 2030
2	CCAA	11,067	9	Retire Jeffrey 2 2039
3	AAAA	11,071	14	RAP
4	DAAA	11,075	17	RAP Minus
5	CAAA	11,077	19	RAP Plus
6	CAAC	11,080	22	No 2027 Solar
7	CGAG	11,136	78	Low/Low, No retirements
8	CDAA	11,138	81	Retire Jeffrey 1 2030
9	CFAA	11,188	130	Retire Crossroads 2028
10	CAAF	11,229	171	High/High
11	CEAA	11,245	188	Retire all coal early
12	BAAA	11,266	208	MAP
13	EAAA	11,356	298	No Future DSM
14	FAAA	11,377	319	No Future DSM, No TOU
15	CAAG	11,624	566	Low/Low
16	EAAJ	12,258	1,200	RES only
17	CAAL	12,746	1,688	Only renewable/storage build, no budget
18	BEAL	13,584	2,527	MAP; Ret all early; Only renewable/storage build, no budget

Table 17: Low Constructions Costs Rankings

Rank	Plan	NPVRR	Difference	Description
1	CAAF	10,607		High/High
2	CAAC	10,625	18	No 2027 Solar
3	AAAA	10,664	57	RAP
4	DAAA	10,698	91	RAP Minus
5	CBAA	10,713	106	Retire Iatan 1 2030
6	CCAA	10,718	111	Retire Jeffrey 2 2039
7	CAAA	10,732	125	RAP Plus
8	CGAG	10,756	150	Low/Low, No retirements
9	BAAA	10,784	177	MAP
10	CDAA	10,823	217	Retire Jeffrey 1 2030
11	CFAA	10,835	228	Retire Crossroads 2028
12	CEAA	10,937	331	Retire all coal early
13	EAAA	10,986	380	No Future DSM
14	FAAA	11,094	488	No Future DSM, No TOU
15	CAAG	11,517	910	Low/Low
16	CAAL	11,999	1,392	Only renewable/storage build, no budget
17	EAAJ	12,167	1,560	RES only
18	BEAL	12,794	2,187	MAP; Ret all early; Only renewable/storage build, no budget

Section 5: Analysis of Base Planning Decisions

5.1 Comparison of Demand-Side Management Potential Program Options

5.1.1 Overview of Demand-Side Management Portfolios[10]

Future demand-side programs were assumed to begin providing capacity and energy value beginning in 2025 and continue over the planning horizon, consistent with the assumptions in Volume 5.

[10] 20 CSR 4240-22.060(4)(B)1, 20 CSR 4240-22.060(4)(B)2, 20 CSR 4240-22.060(4)(B)4, 20 CSR 4240-22.060(4)(B)5

Figure 10: Missouri West Peak Load (MAP)

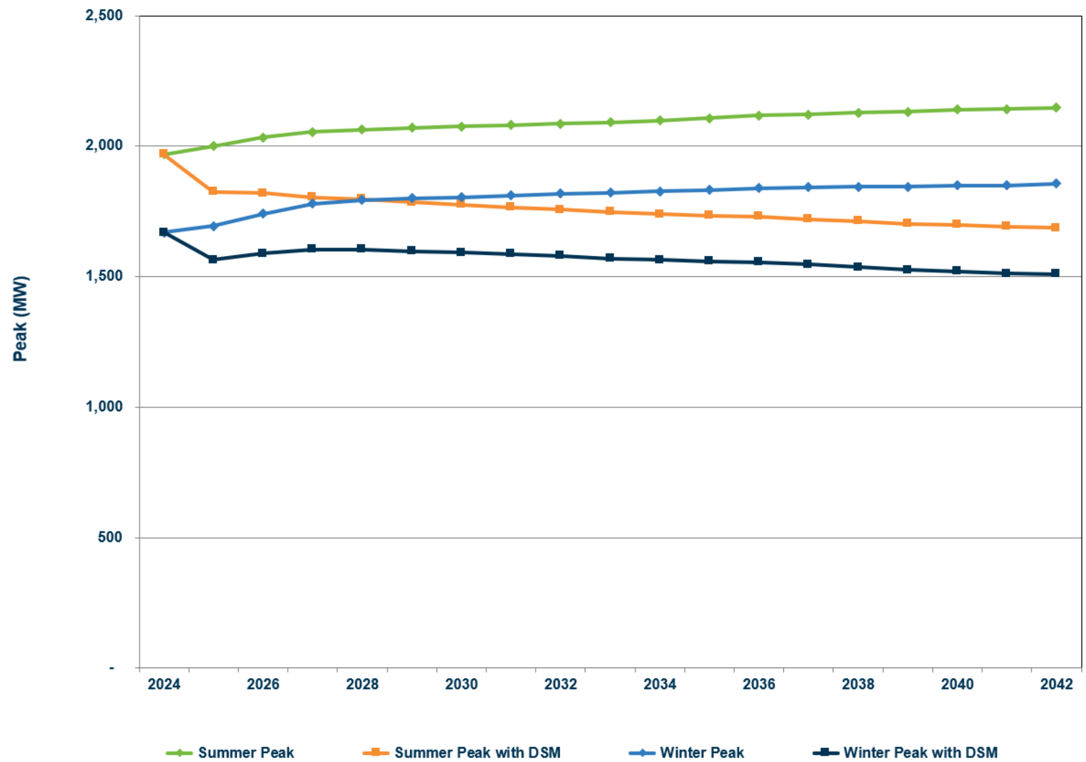


Figure 11: Missouri West DSM Capacity (MAP)

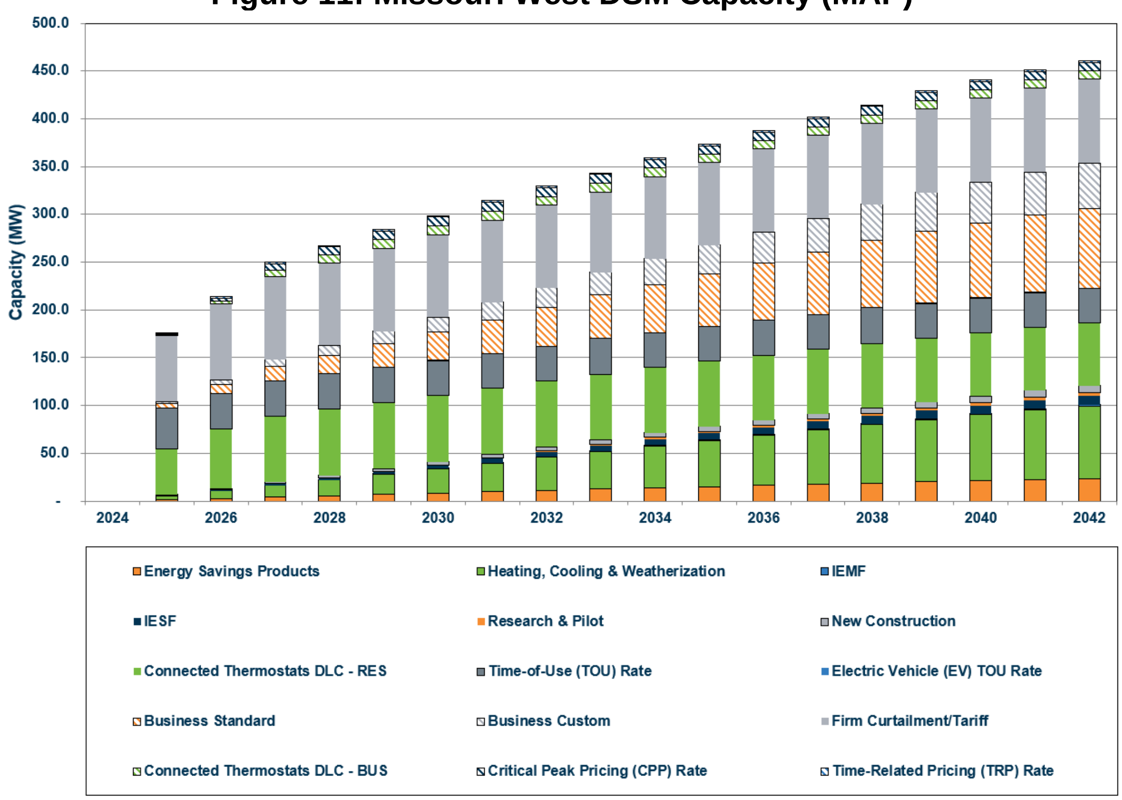


Figure 12: Missouri West Gross NSI (MAP)

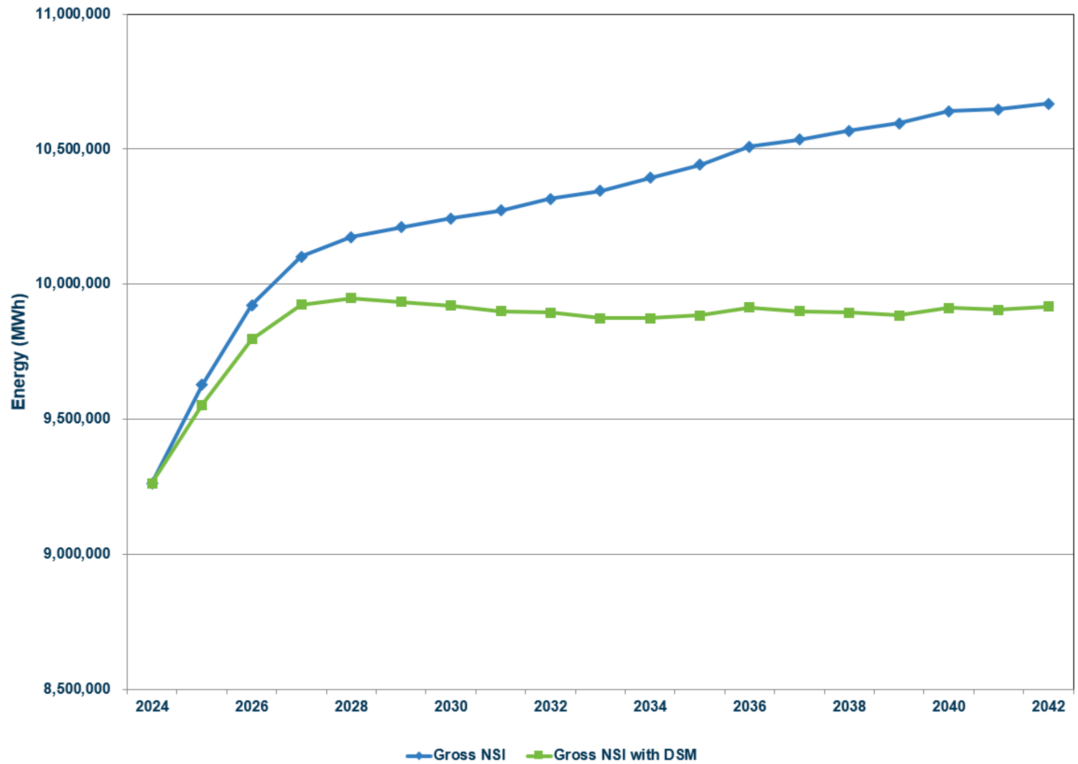


Figure 13: Missouri West DSM Energy (MAP)

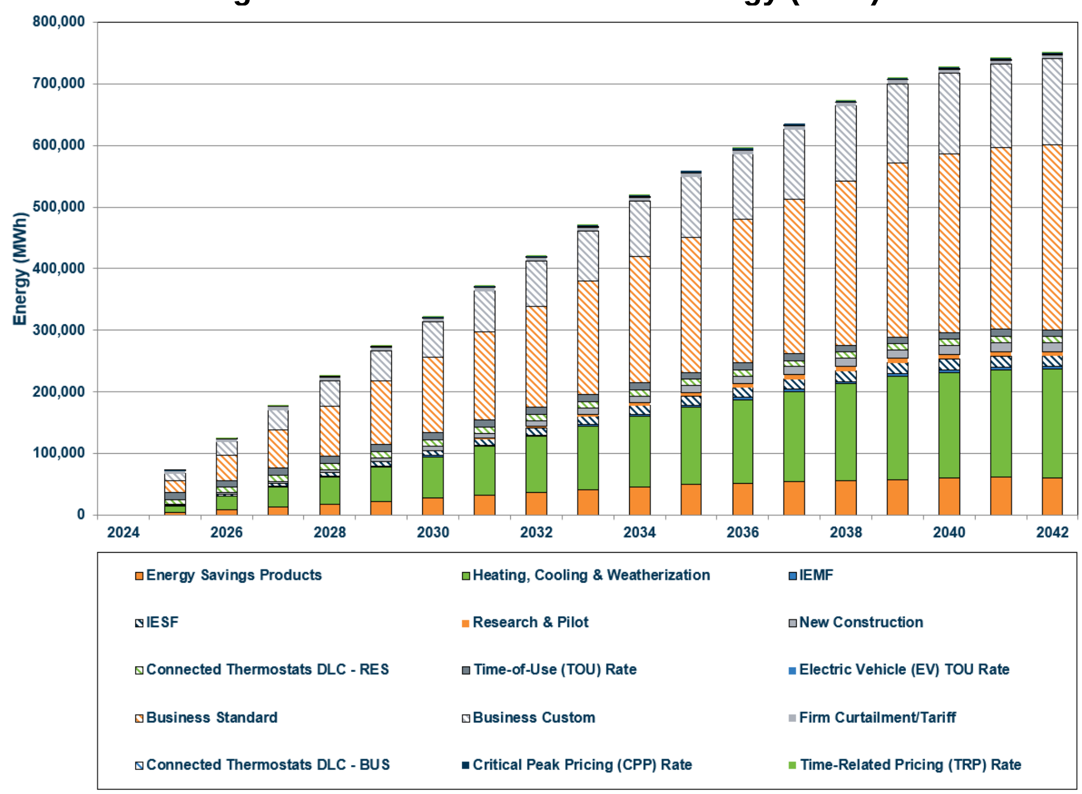


Figure 14: Missouri West Peak Load (RAP)

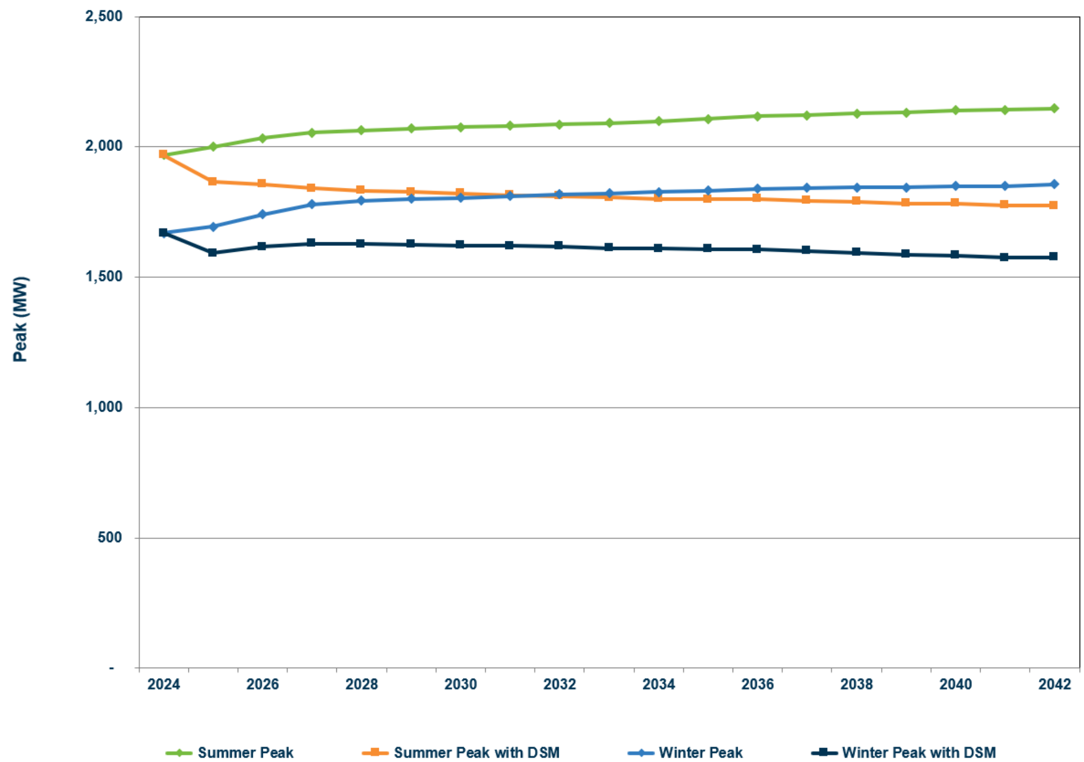


Figure 15: Missouri West DSM Capacity (RAP)

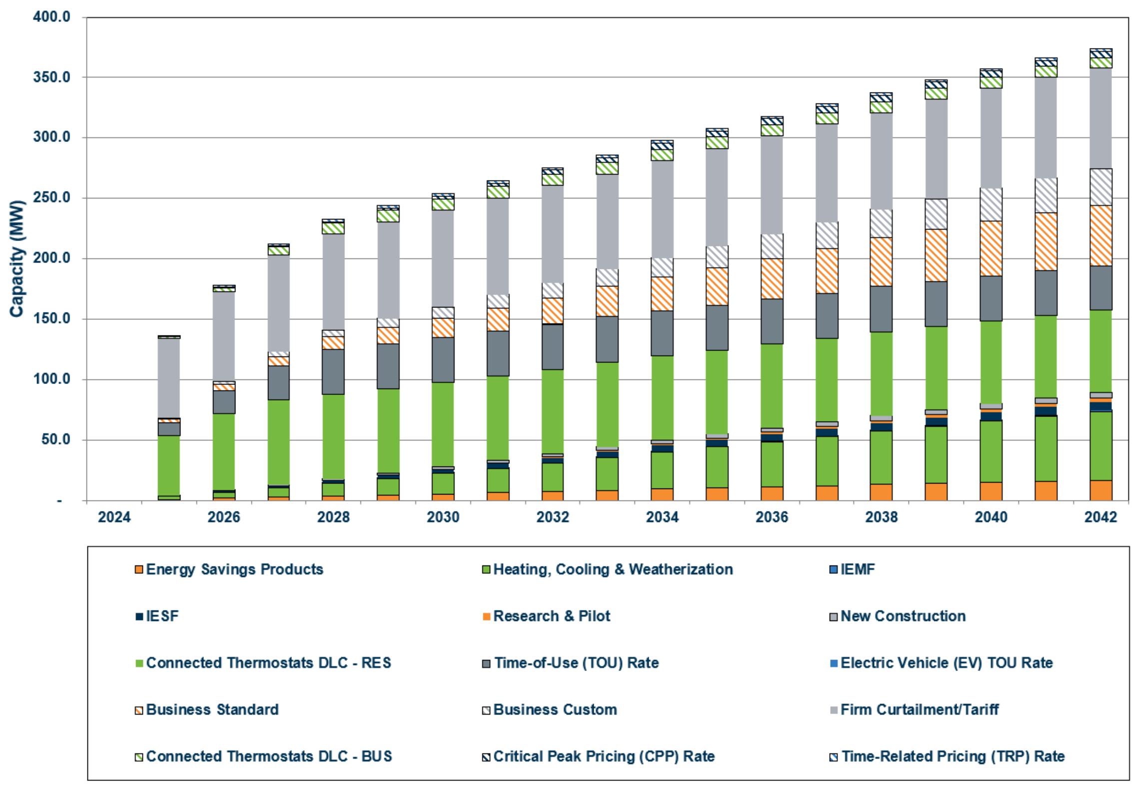


Figure 16: Missouri West Gross NSI (RAP)

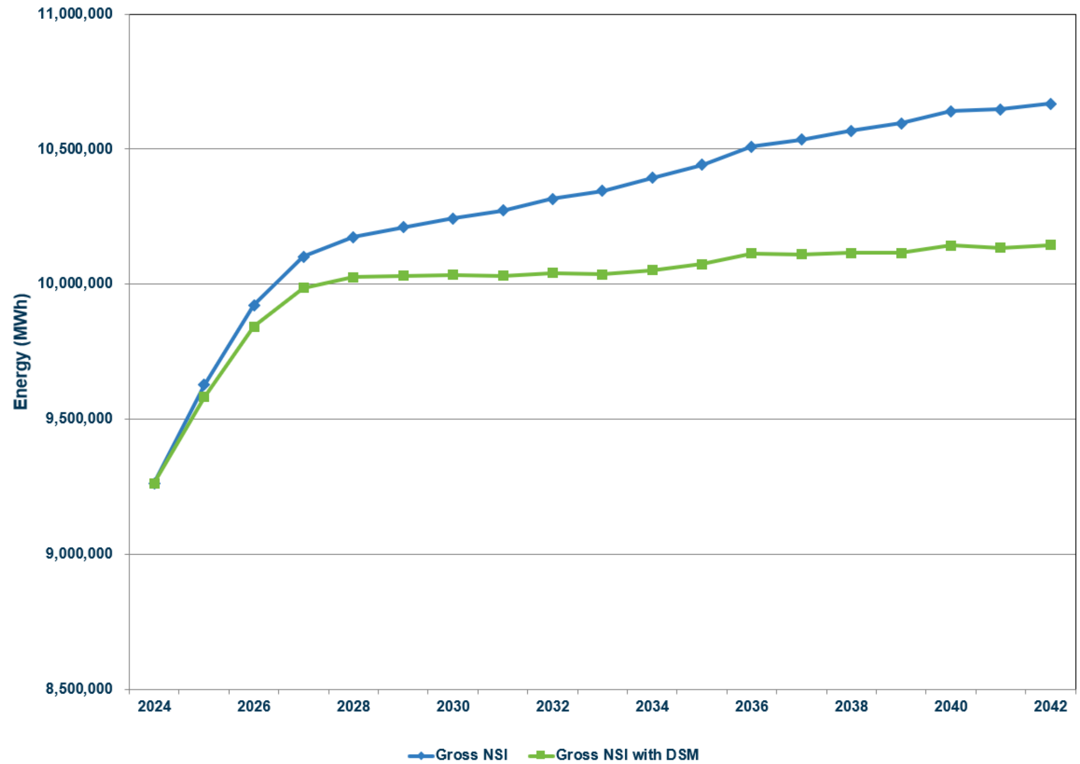


Figure 17: Missouri West DSM Energy (RAP)

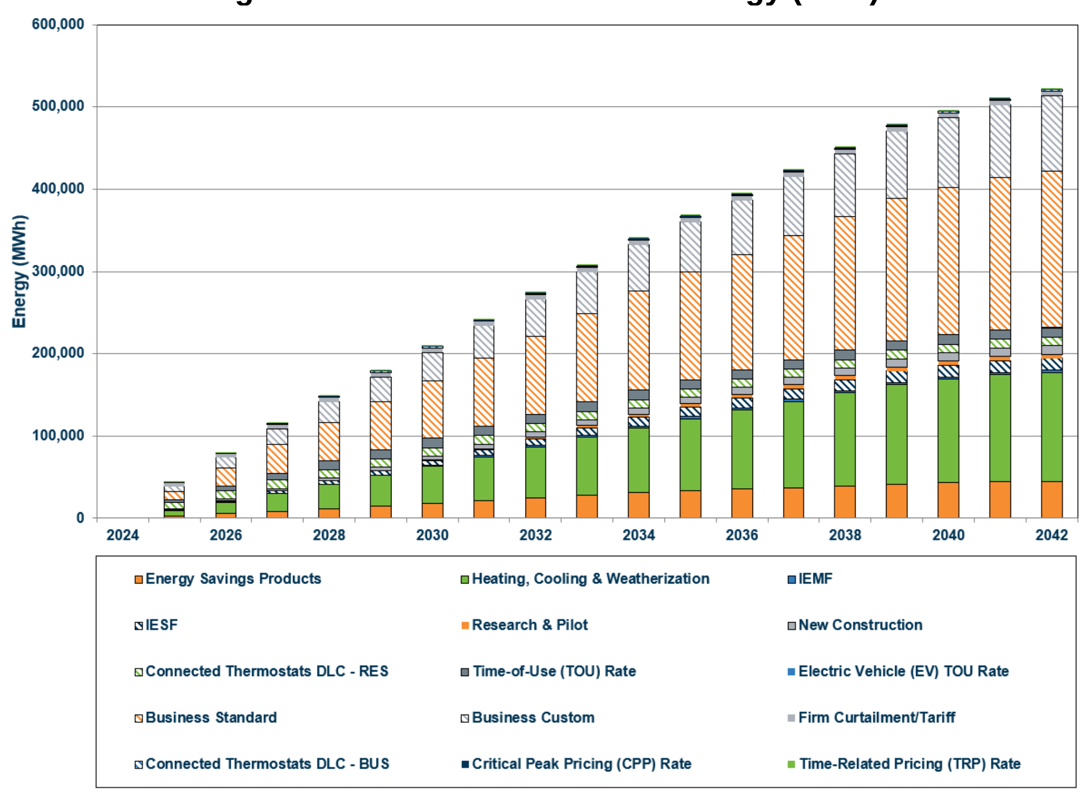


Figure 18: Missouri West Peak Load (RAP Plus)

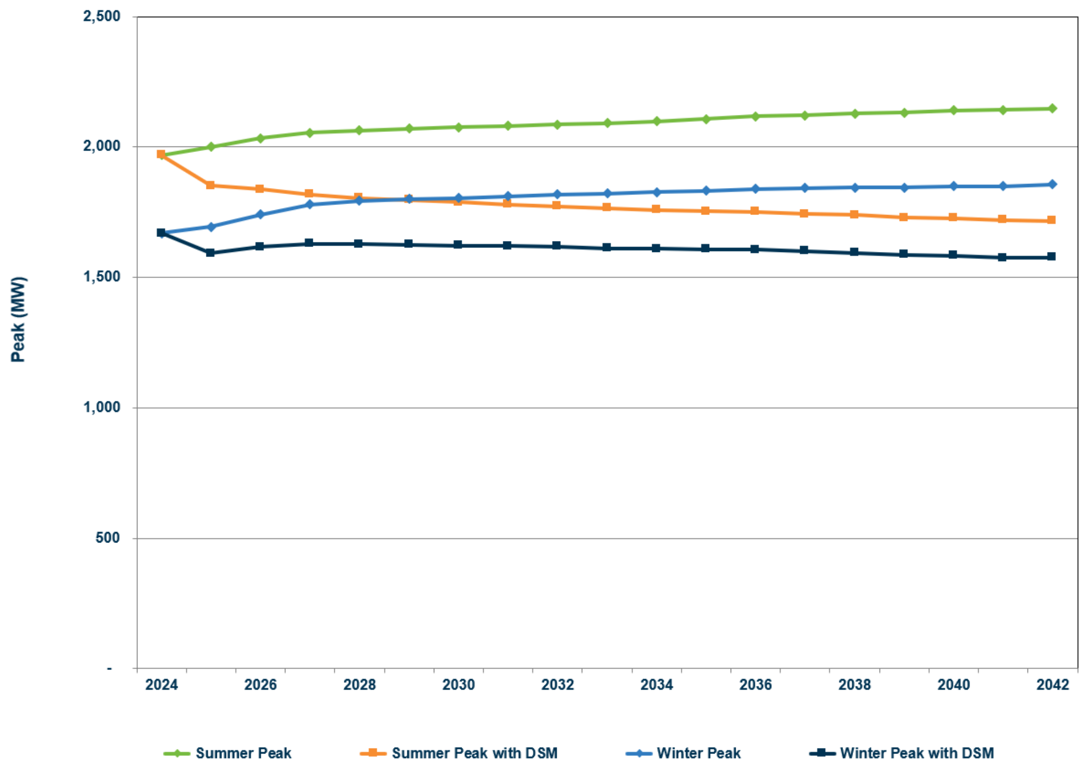


Figure 19: Missouri West DSM Capacity (RAP Plus)

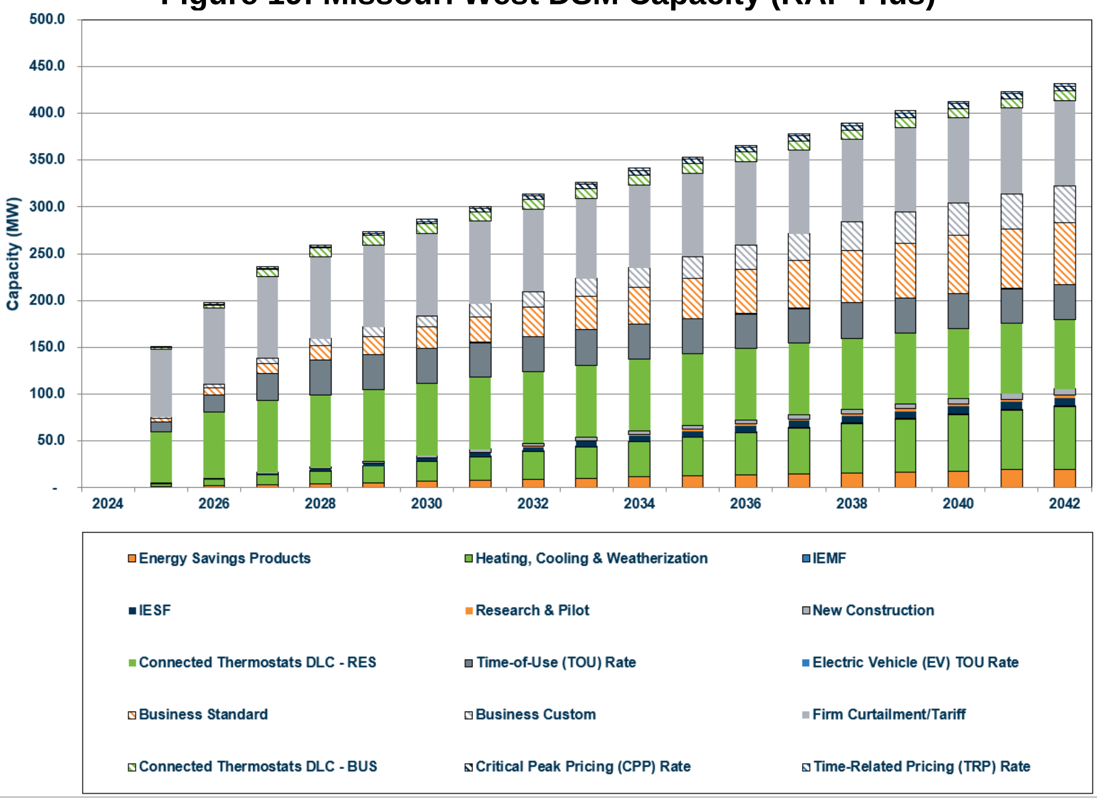


Figure 20: Missouri West Gross NSI (RAP Plus)

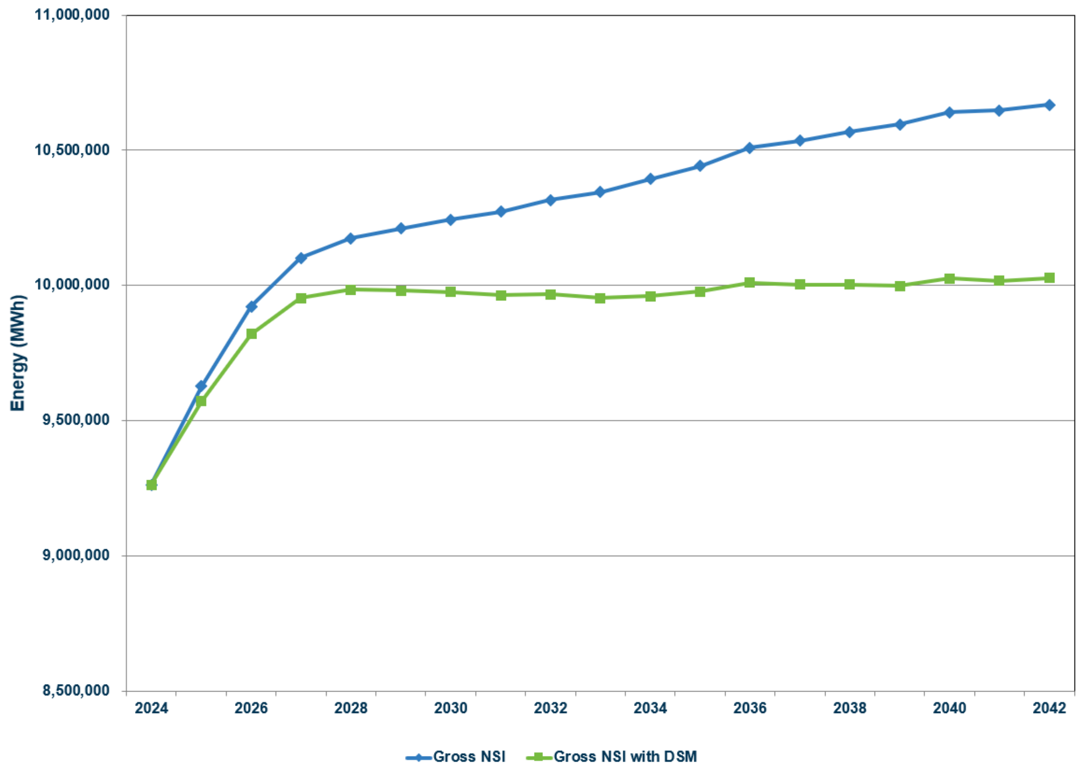


Figure 21: Missouri West DSM Energy (RAP Plus)

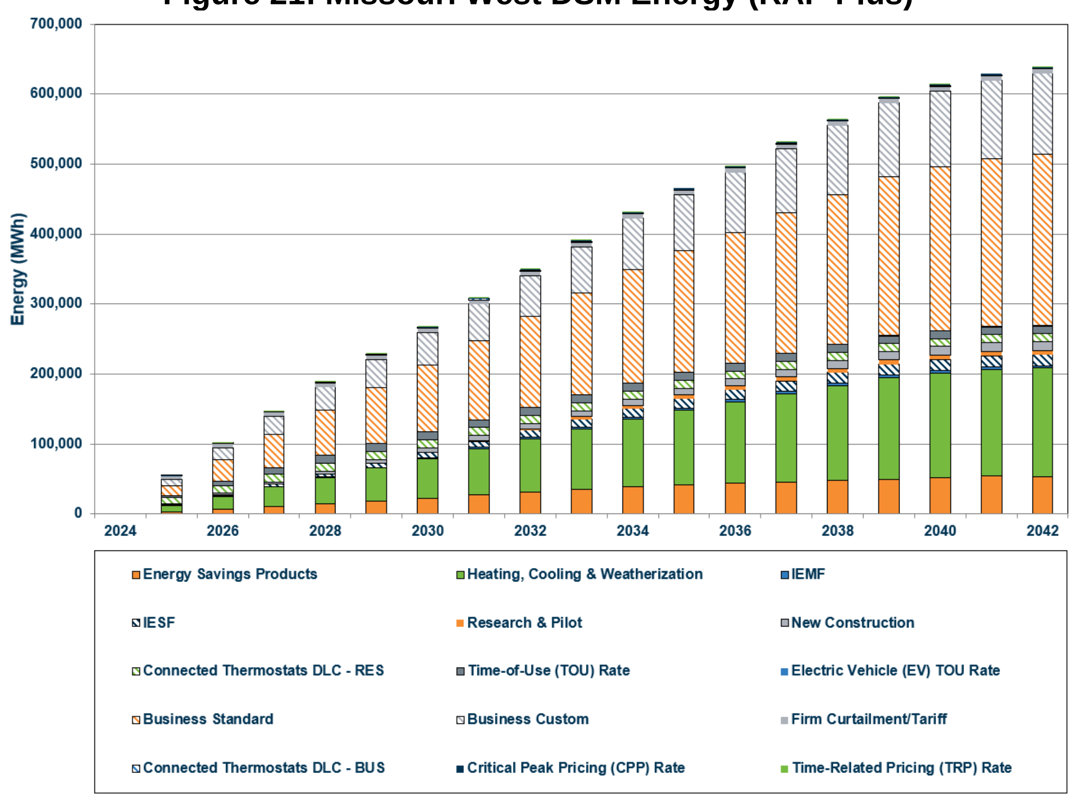


Figure 22: Missouri West Peak Load (RAP Minus)

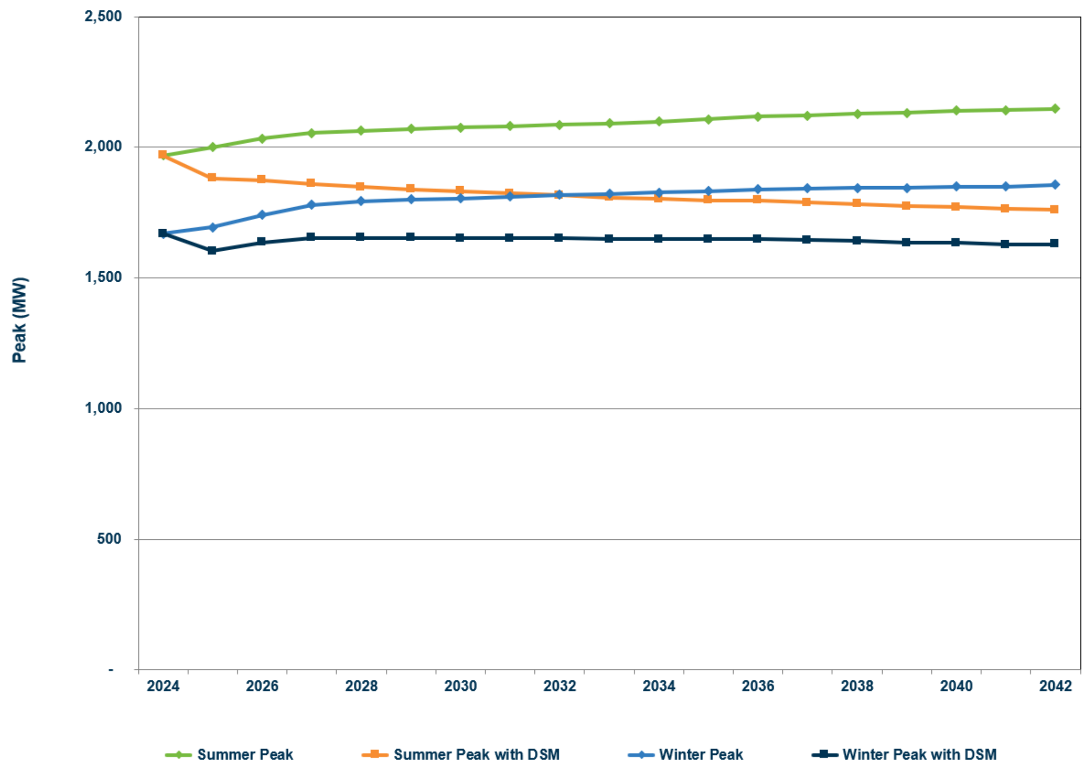


Figure 23: Missouri West DSM Capacity (RAP Minus)

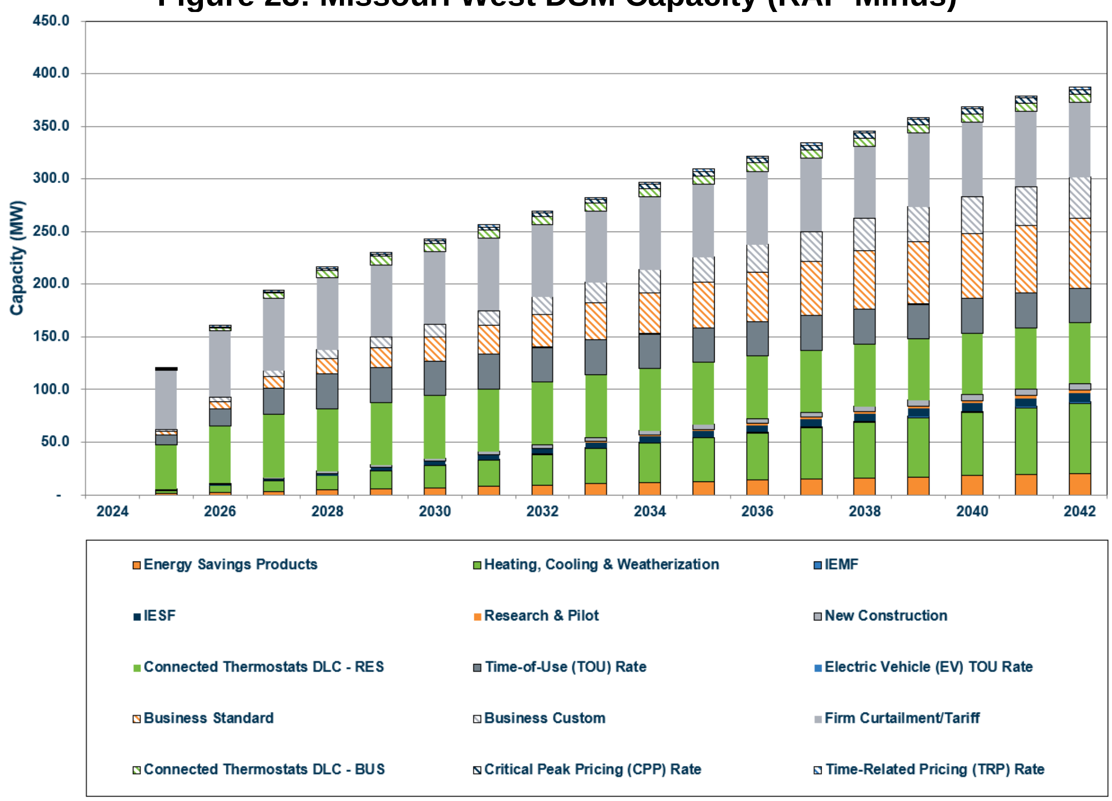


Figure 24: Missouri West Gross NSI (RAP Minus)

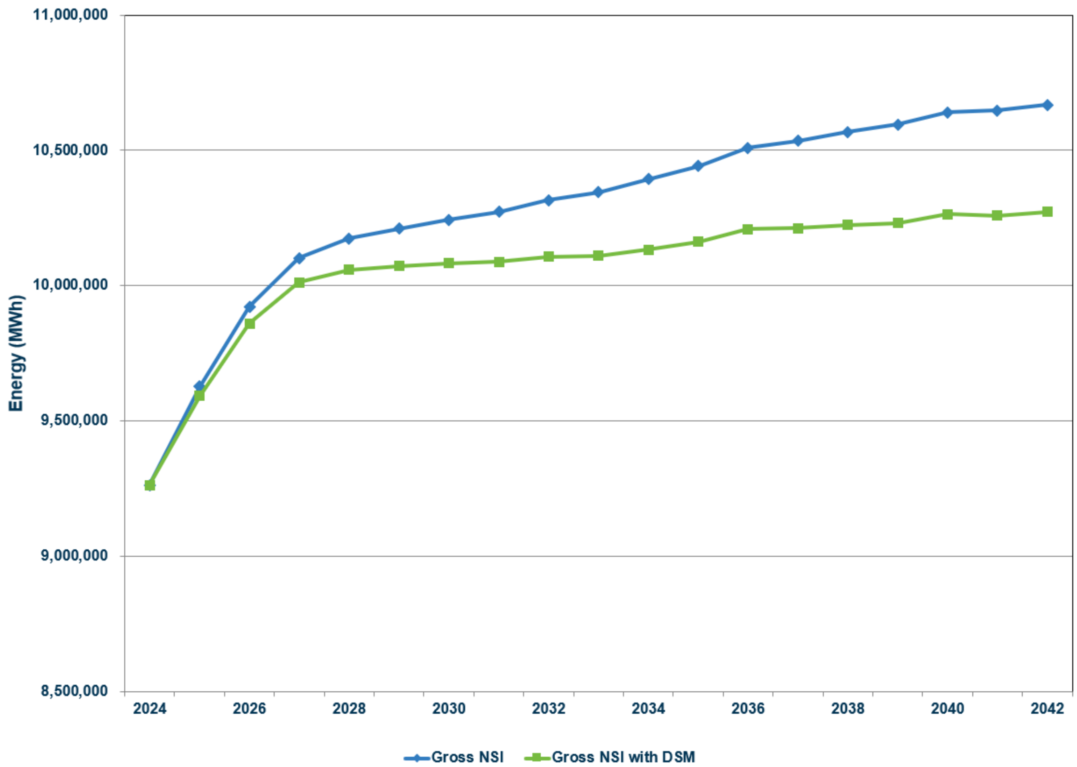
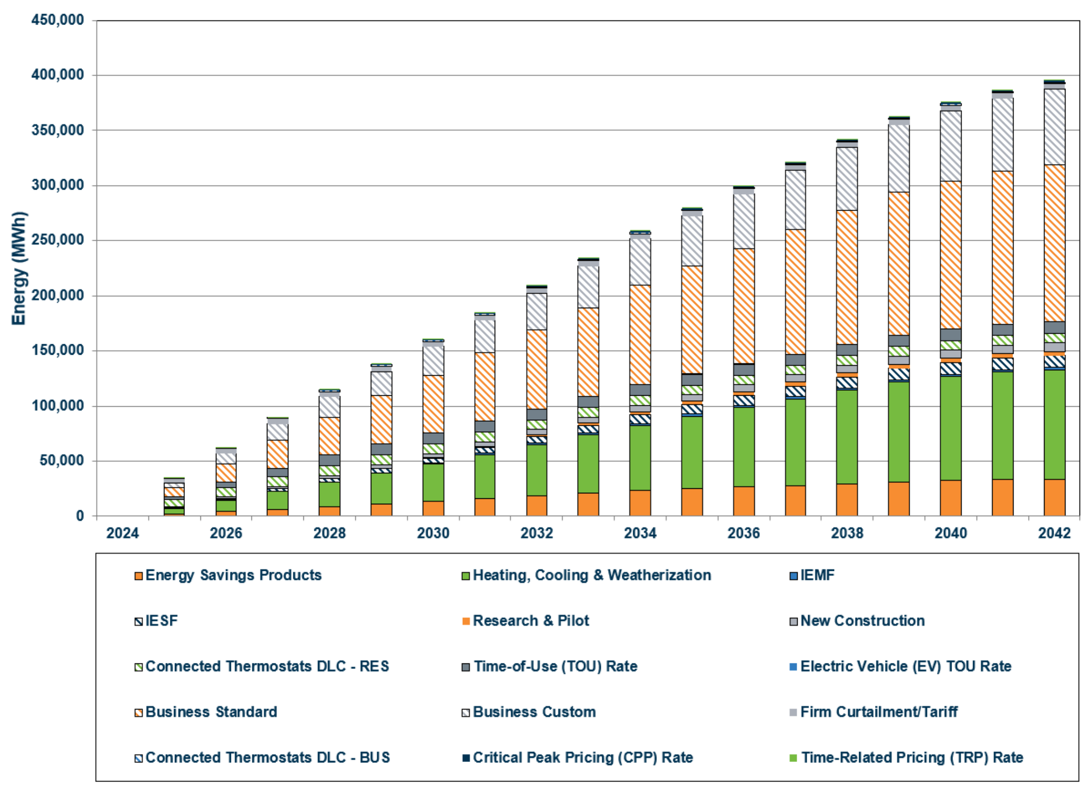


Figure 25: Missouri West DSM Energy (RAP Minus)



5.1.2 Demand-Side Management Alternative Resource Plans

An ARP for each demand-side management portfolio was created by using the same base scenario assumptions and varying only the portfolio option. Generally, the greater the amount of peak load reduction associated with a portfolio, the more it would be expected to reduce the need for other resource additions or defer additions to later in the time horizon. Maximum Achievable Potential (MAP) has the highest peak load reduction over the 20-year horizon, and the highest costs per unit of reduction. Other programs considered, in order of declining capacity value and cost, were RAP Plus, RAP, and RAP Minus. A plan without future DSM programs, after the MEEIA extension ends in 2024, was also considered.

Table 18: Rankings of Demand-Side Management Portfolio Options

Rank	Plan	NPVRR	Difference	Description
1	AAAA	11,081		RAP
2	CAAA	11,086	5	RAP Plus
3	DAAA	11,090	9	RAP Minus
4	BAAA	11,272	190	MAP
5	EAAA	11,388	307	No Future DSM

The top ranked plans were AAAA (RAP) followed by CAAA (RAP Plus). Both have very similar optimal resource plans, with a solar in 2027, a combined cycle in 2029, a combustion turbine in 2030, and wind for the next four years. The primary near-term difference is that the RAP plan includes a wind build in 2028 that is deferred until 2041 in the RAP Plus plan. The RAP Minus Plan accelerates the wind moved to 2026, accelerates the combined cycle build from 2029 to 2028, and substitutes a combined cycle for a combustion turbine in 2030. It also substitutes a combined cycle build for solar towards the end of the time horizon.

Figure 26: RAP Plan AAAA

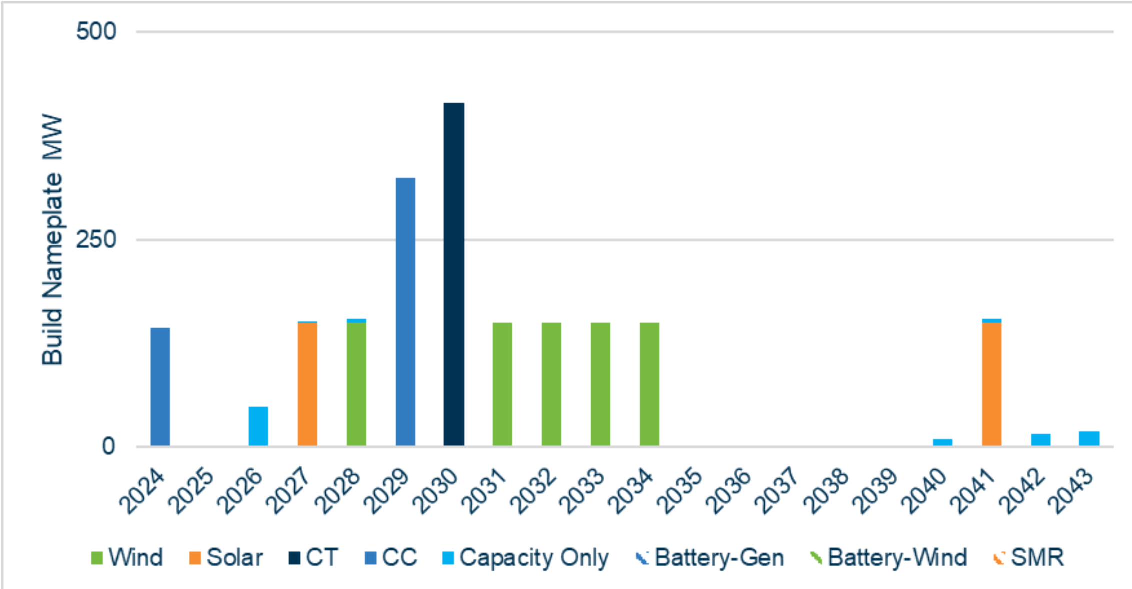


Figure 27: RAP Plus Plan CAAA

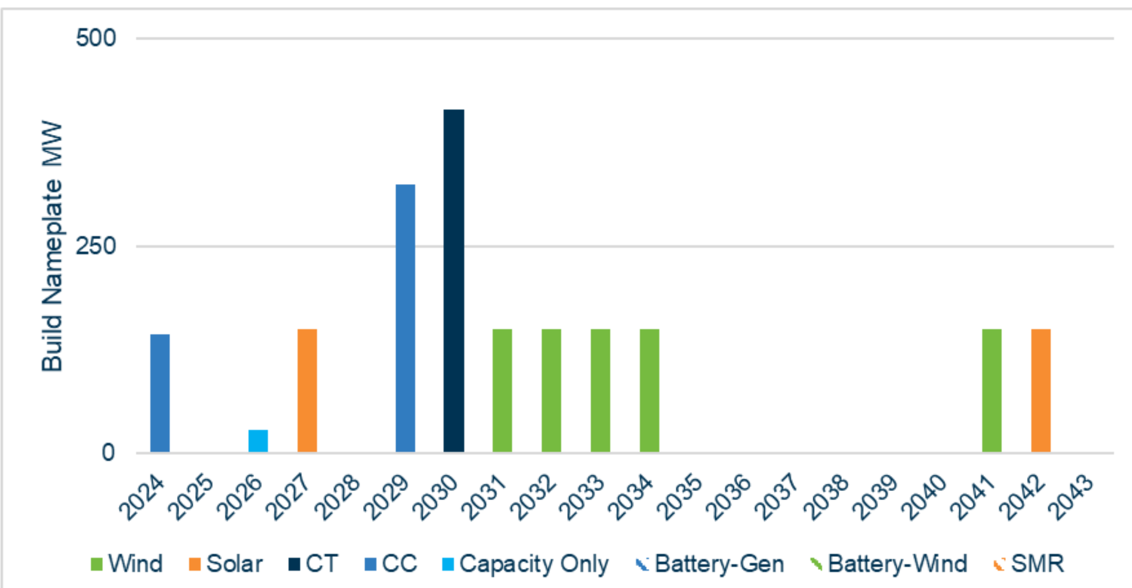
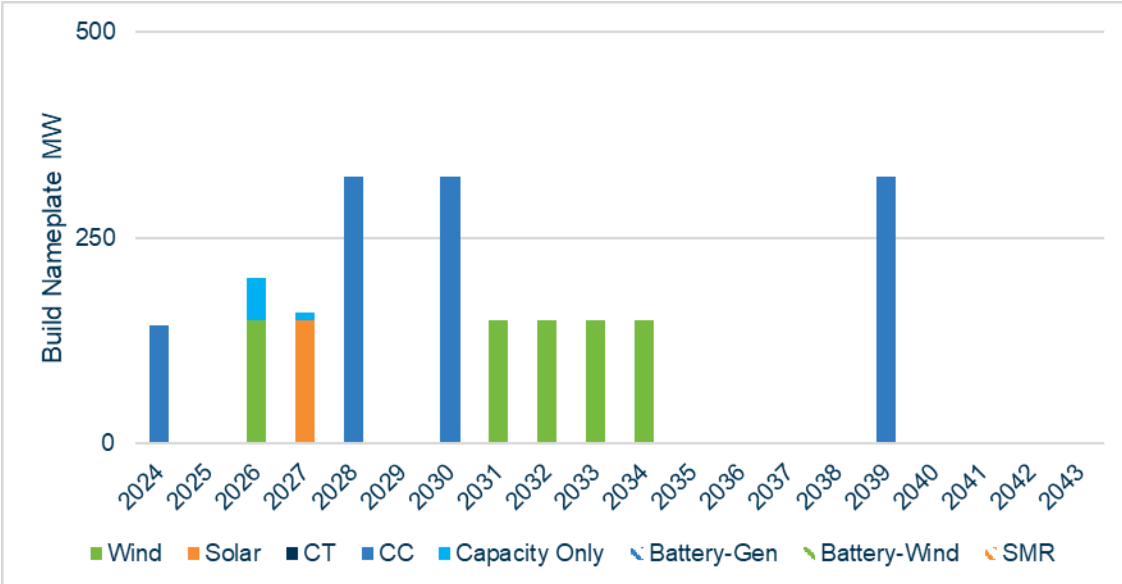


Figure 28: RAP Minus Plan DAAA



The MAP (BAAA)[11] and No DSM (EAAA)[12] plans are significantly more expensive. The MAP plan adds an additional wind in the first five years (compared to RAP and RAP Minus) and substitutes a battery for a combined cycle.

The plan with No DSM is the most expensive and includes two early battery builds, likely to meet the greater capacity need.

[11] 20 CSR 4240-22.060(3)(A)3
[12] 20 CSR 4240-22.060(3)(C)3

Figure 29: MAP Plan BAAA

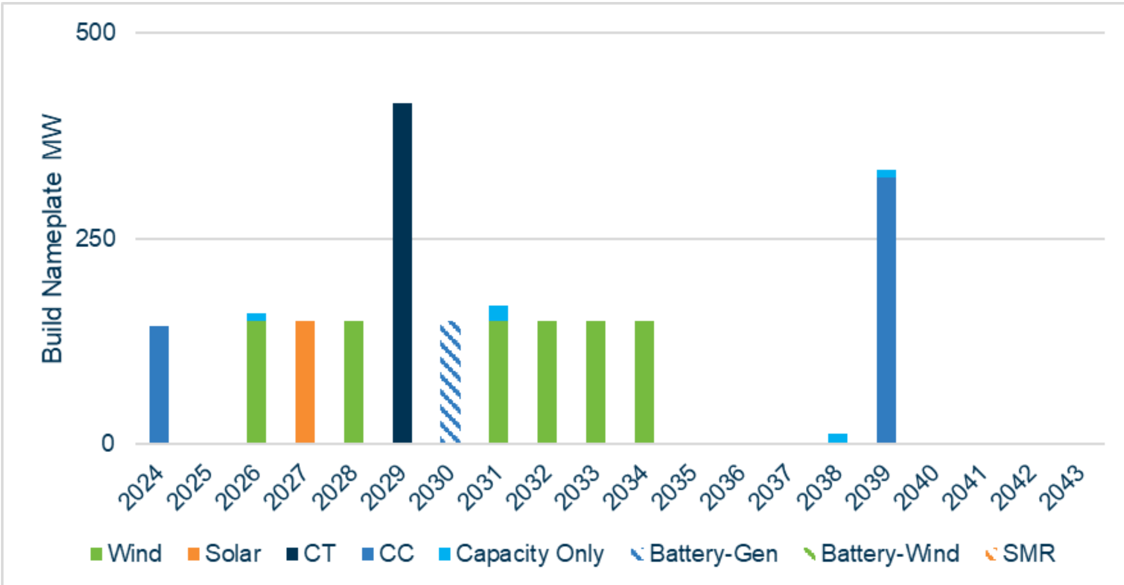
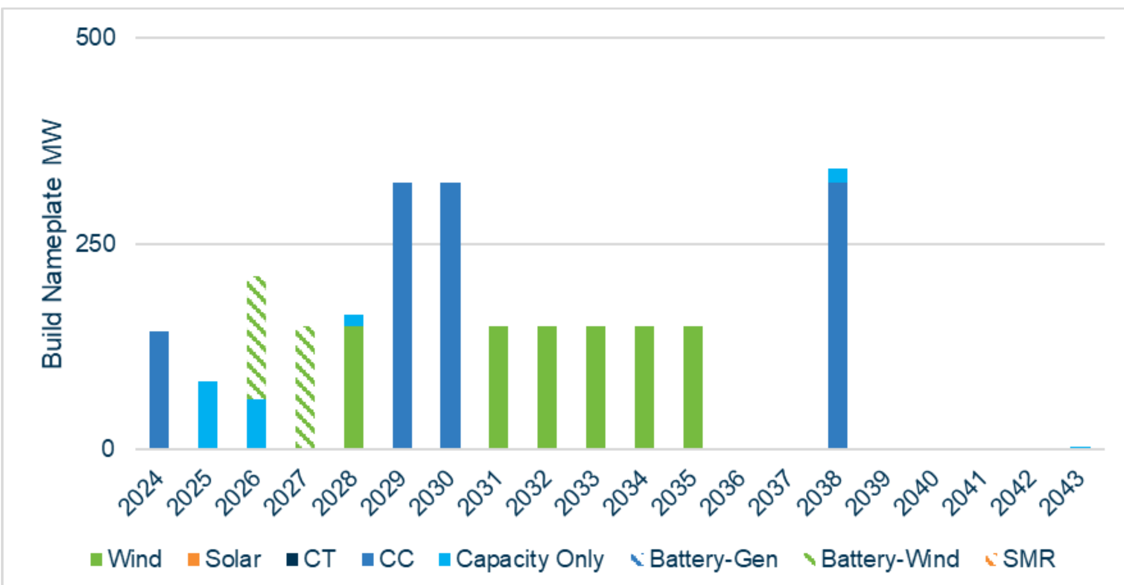


Figure 30: No DSM Plan EAAA



5.2 Comparison of Retirement Options[13]

Since Evergy Missouri West has relatively small shares of coal resources, retirements do not cause substantial losses in capacity. However, owning small shares also means

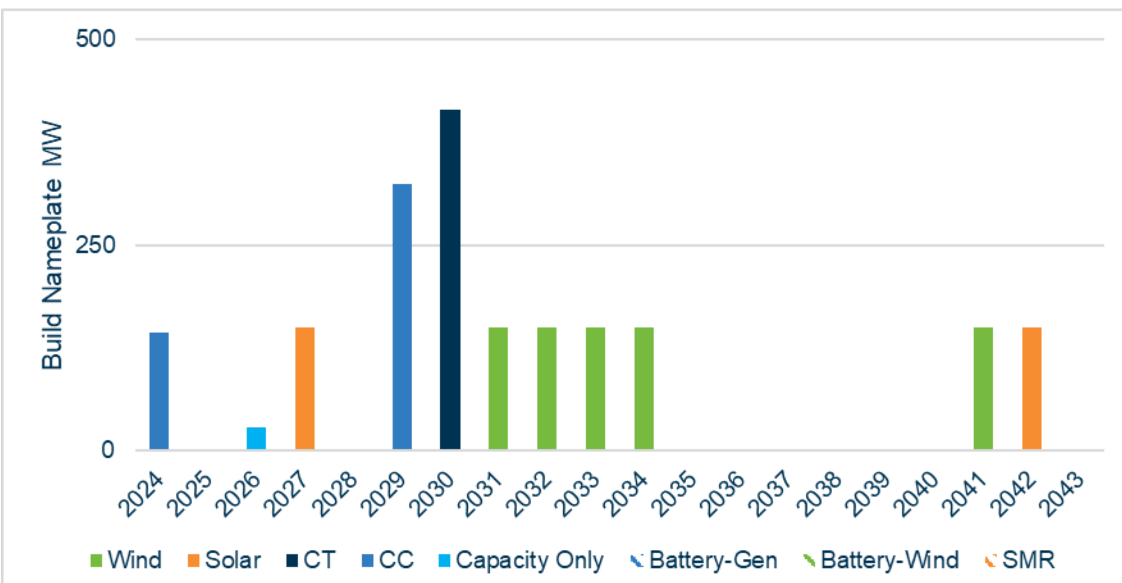
[13] 20 CSR 4240-22.060(3)(C)1

Evergy Missouri West has limited control over the retirements of its jointly-owned resources. Missouri West owns 8% share of each of the Jeffrey Units 1-3 and 18% share of Iatan Units 1 & 2.

Evergy Missouri West assumes that if it continues to operate coal resources, it will comply with all environmental and other regulations and keep the plants maintained. These costs are included in the expected value of the resource plan.[14]

The 2023 preferred resource plan included retirements of Jeffrey Units 2 and 3 in 2030 to avoid the high cost of installing SCR equipment to comply with expected environmental regulation, as well as the retirement of Jeffrey 1 and Iatan 1 in 2039. These retirements are in the base plan (CAAA) which also includes the RAP Plus demand-side portfolio. Alternative resource plans with the same demand-side portfolio were developed to compare the expected value of accelerating or postponing retirements. Plans accelerating retirements include CBAA (Iatan 1 2030), CDAA (Jeffrey 1 2030) and CEAA (all coal resources 2030). Plan CCAA postpones the Jeffrey 2 retirement to 2039.

Figure 31: Earlier Retirement Iatan 1 2030 CBAA



[14] 20 CSR 4240-22.060(3)(C)2

Figure 32: Postpone Jeffrey 2 Retirement 2039 CCAA

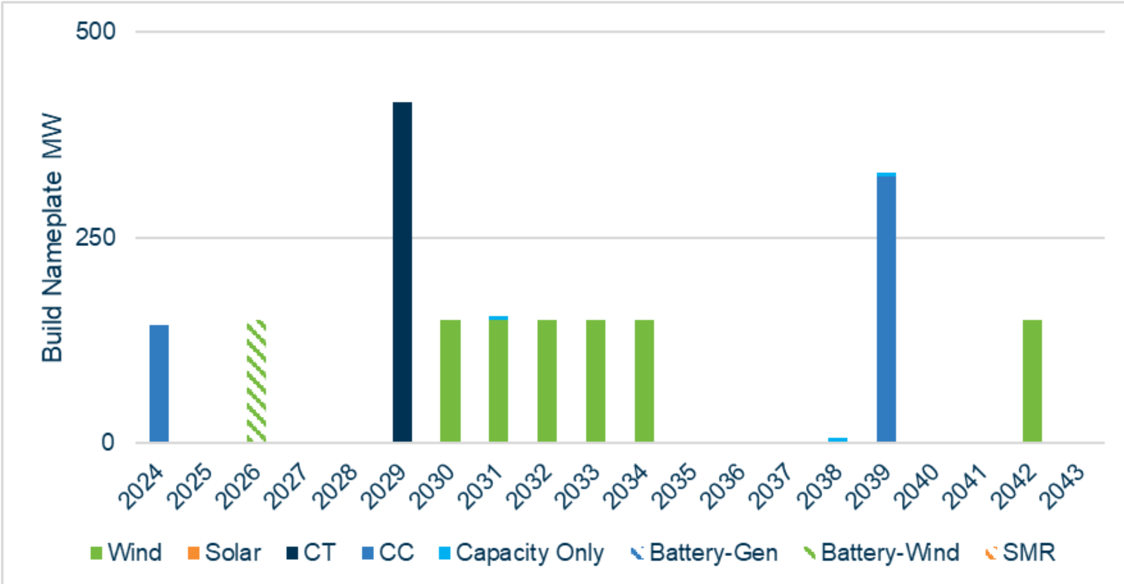


Figure 33: Earlier Retirement Jeffrey 1 2030 CDAA

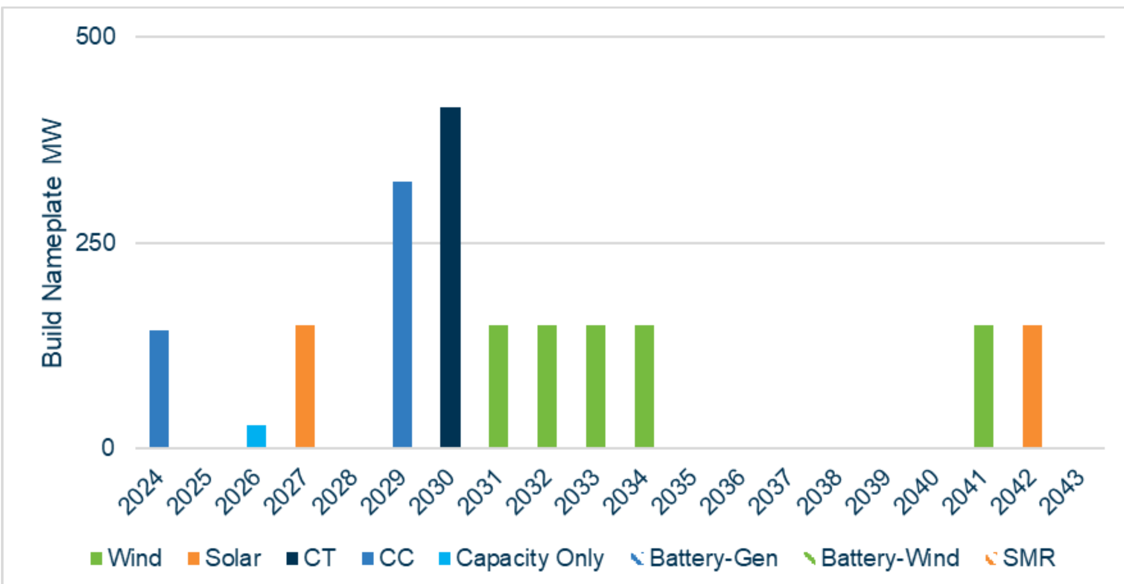
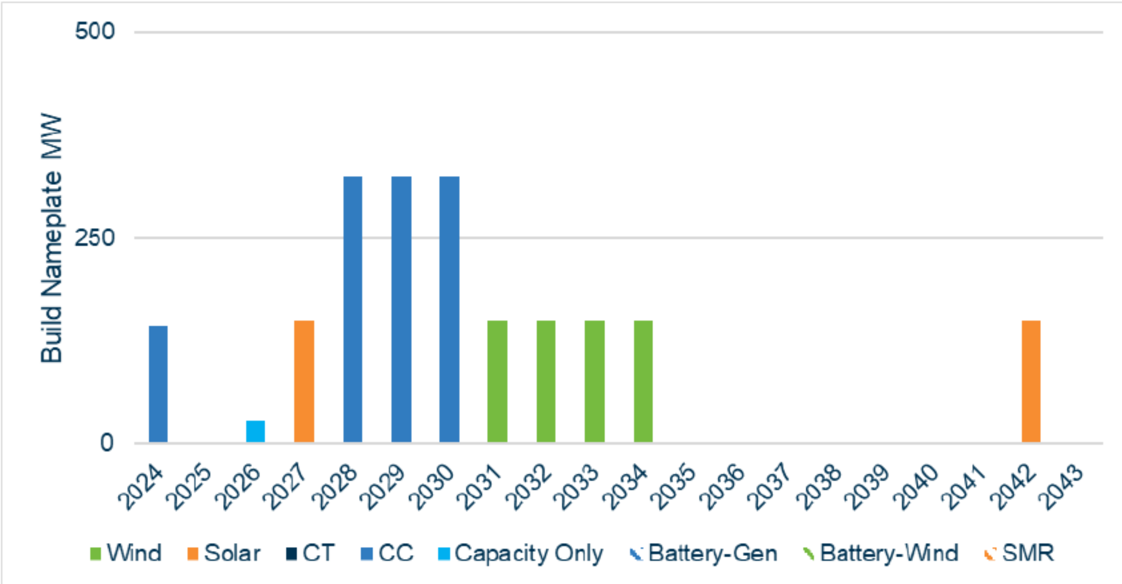


Figure 34: Earliest Retirement all Coal Resources CEAA



The plans CAAA, CBAA, and CDAA all have the same resource additions. However, CBAA, which accelerates the retirement of Iatan 1 to 2030 is the lowest cost plan, while CDAA, which accelerates the retirement of Jeffrey 1 to 2030 has the highest expected cost. The resource additions for all three plans result in an excess capacity balance for Missouri West in the years between 2031-2039, allowing additional retirements without requiring more additions. Missouri West has sufficient excess capacity in the 2030s to accelerate the retirement of either Iatan 1 or Jeffrey 1 from 2039 to 2030, but the loss of Jeffrey 1 results in greater production costs due to redispatch that outweigh fixed cost savings from early retirement, while the loss of Iatan 1 provides greater cost savings from avoided fixed costs than production cost losses.

Table 19: Missouri West Retirement Plan Rankings

Rank	Plan	NPVRR	Difference	Description
1	CBAA	11,067		Retire Iatan 1 2030
2	CCAA	11,076	9	Retire Jeffrey 2 2039
3	CAAA	11,086	19	PP 2023 retirement dates
4	CDAA	11,163	96	Retire Jeffrey 1 2030
5	CEAA	11,271	203	Retire all Jeffrey and Iatan 2030

The plan CCAA, which postpones the Jeffrey 2 retirement to 2039 is slightly lower cost than the plan that retires Jeffrey 2 in 2030. Postponing the retirement provides Evergy Missouri West with a higher capacity balance, allowing it to postpone the 2029 combined cycle build until 2039 and bridge the short-term capacity need with 150 MW of battery build rather than 2027 solar.

The plan CEAA, which retires all of Missouri West's coal resources in 2030 is the most expensive retirement option. The optimal replacement portfolio includes the addition of another ½ combined cycle in 2028 and substituting the 2030 combustion turbine with ½ combined cycle for 975 MW total combined cycle build 2028-2030. Due to Missouri West's low ownership percentage and the inconsistency of results related to accelerating the retirement of Iatan 1 between Missouri West and Metro (which owns the majority of the unit), no change is made to the Iatan 1 retirement in the 2024 Preferred Plan. Due to the small difference in revenue requirement associated with delaying the Jeffrey 2 retirement, no change is made to the Jeffrey 2 retirement in the 2024 preferred plan. Expected value revenue requirements for the 2030 and 2039 retirements of Jeffrey 2 are also very close for Evergy Kansas Central, which owns the majority of the plant. The small variation in costs indicate that this retirement will need to be assessed in future IRPs prior to making a final retirement decision.

Section 6: Analysis of Directed Strategies

6.1 Plans at Endpoints

Plans created to determine the optimal resource additions in the High Carbon Restriction – High Natural Gas Price ("High/High") future and the Low Carbon Restriction – Low Natural Gas Price ("Low/Low") future are costly on a weighted-average basis.

Table 20: Rankings of Plans Created for Specific Futures

Rank	Plan	NPVRR	Difference	Description
1	CAAA	11,086		Mid/Mid
2	CAAF	11,241	155	High/High
3	CAAG	11,636	550	Low/Low

Capacity expansion modeling performed specifically in the High/High scenario shows an increased level of wind builds compared to the Preferred Plan given the increased value of zero-carbon energy in a heavily carbon-restricted market. The plan also includes storage substituting for solar and the half combined cycle. In 2039, a 300 MW Nuclear SMR is added.

In contrast, there are no wind additions in the optimal resource plan for the Low/Low future, given the reduced value of zero-carbon energy without the imposition of carbon restrictions. The Low/Low early solar build is consistent with the Preferred Plan. Only combined cycles are added in future years. This is, again, driven by the reduced value of low- or zero-carbon energy which makes combined cycles more economic to serve Missouri West's energy and capacity needs.

Figure 35: Optimal Build Plan for High CO2/ High NG Future

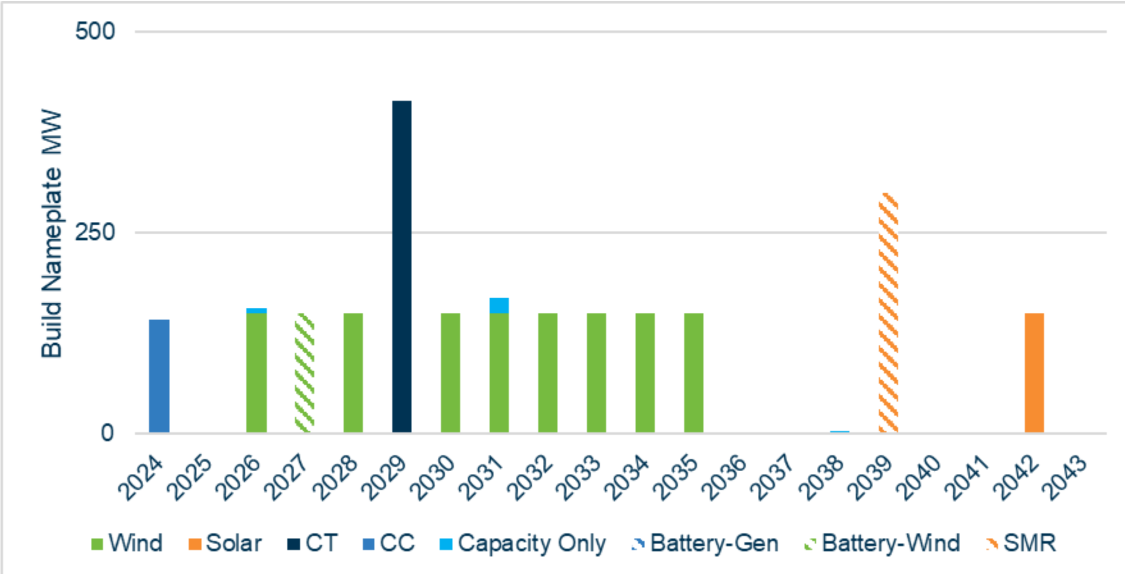
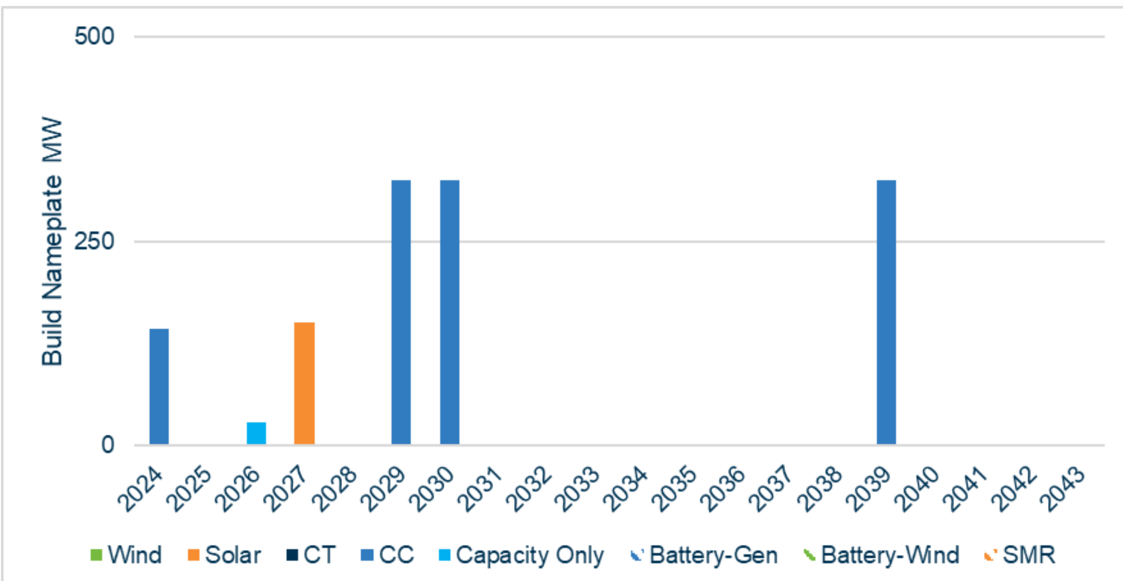


Figure 36: Optimal Build Plan for Low CO_2/ Low NG Future



6.2 RES Minimally Compliant Plan[15]

All Alternative Resource Plans comply with the Missouri renewable energy mandates (Missouri Renewable Energy Standard). The RES requirements include 15% of retail

[15] 20 CSR 4240-22.060(3)(A)1

sales to be served by non-solar renewables and 0.3% by solar renewables. Evergy Missouri West's expected compliance need is 5 MW of solar in 2036.

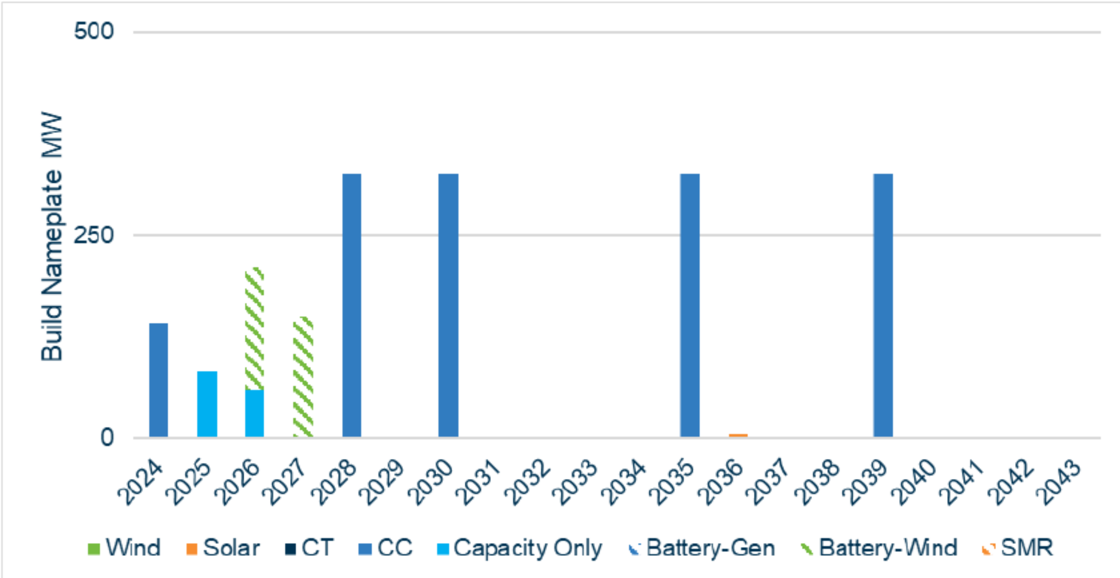
Table 21: Missouri West RES Requirements

Year	Retail Electric Sales (MWh)	Missouri RES Non-Solar Requirement	Non-Solar RES Requirement (MWh)	Missouri RES Solar Requirement	Solar RES Requirement (MWh)
2024	8,583,789	15%	1,261,817	0.3%	25,751
2025	8,967,287	15%	1,318,191	0.3%	26,902
2026	9,264,432	15%	1,361,872	0.3%	27,793
2027	9,446,063	15%	1,388,571	0.3%	28,338
2028	9,522,189	15%	1,399,762	0.3%	28,567
2029	9,526,367	15%	1,400,376	0.3%	28,579
2030	9,566,339	15%	1,406,252	0.3%	28,699
2031	9,599,899	15%	1,411,185	0.3%	28,800
2032	9,647,180	15%	1,418,135	0.3%	28,942
2033	9,678,796	15%	1,422,783	0.3%	29,036
2034	9,730,648	15%	1,430,405	0.3%	29,192
2035	9,785,084	15%	1,438,407	0.3%	29,355
2036	9,856,099	15%	1,448,847	0.3%	29,568
2037	9,889,983	15%	1,453,828	0.3%	29,670
2038	9,930,766	15%	1,459,823	0.3%	29,792
2039	9,967,014	15%	1,465,151	0.3%	29,901
2040	10,019,950	15%	1,472,933	0.3%	30,060
2041	10,037,088	15%	1,475,452	0.3%	30,111
2042	10,067,238	15%	1,479,884	0.3%	30,202
2043	10,099,598	15%	1,484,641	0.3%	30,299

One Alternative Resource Plan, EAAJ, limits solar additions to the 5 MW of solar capacity in 2036 that is expected to be needed to meet solar RES requirements. Evergy is currently expected to be compliant with non-solar RES requirements through 2043, therefore no Alternative Resource Plan included non-solar resources specifically to meet RES compliance.

Since there is no mandated DSM requirement, the minimally compliant plan assumes no additional DSM beyond what is currently in progress as part of Evergy MEEIA approved programs.

Figure 37: RES Compliant Plan EAAJ



The minimally compliant RES plan meets capacity and energy needs at the lowest cost by building 300 MW of battery storage in 2026 and 2027, and 1,300 MW of combined cycles throughout the planning horizon. The NPVRR of this plan is over $1.2 billion higher than the preferred plan which meets capacity and energy needs through a mix of resources, including wind and more solar.

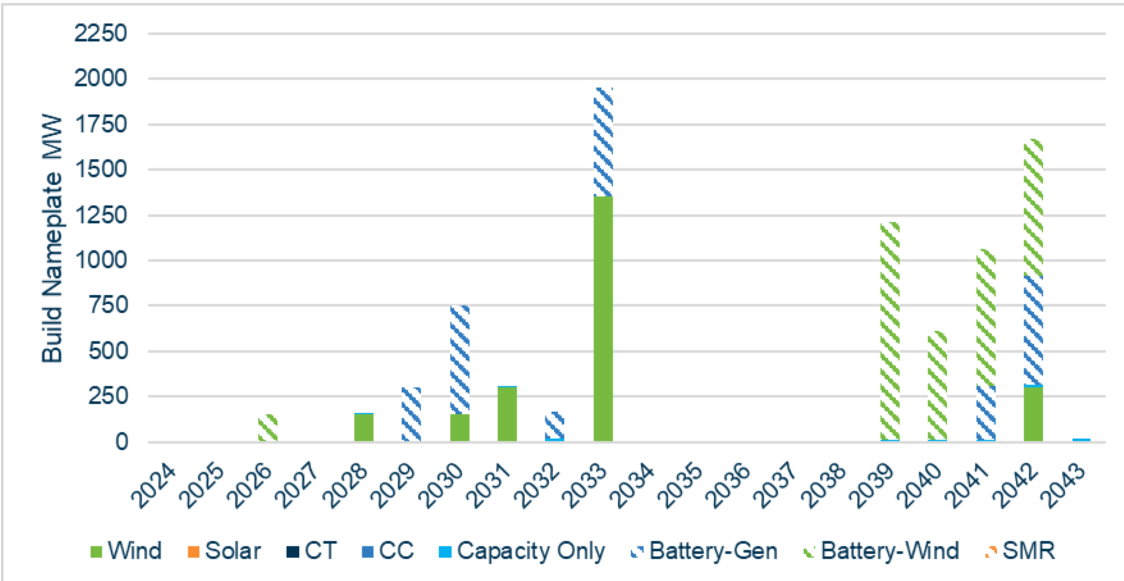
Table 22: RES Plan NPVRR Comparison

Rank	Plan	NPVRR	Difference	Description
1	CAAA	11,086		RAP Plus, Renewables allowed
2	EAAJ	12,288	1,201	RES Only

6.3 High Renewables Plans[16]

Two alternative resource plans were developed to maximize renewable resource additions. The first, CAAL used the preferred plan demand-side management portfolio level – RAP Plus, and preferred plan retirement dates, and optimized future builds using only renewables and storage.

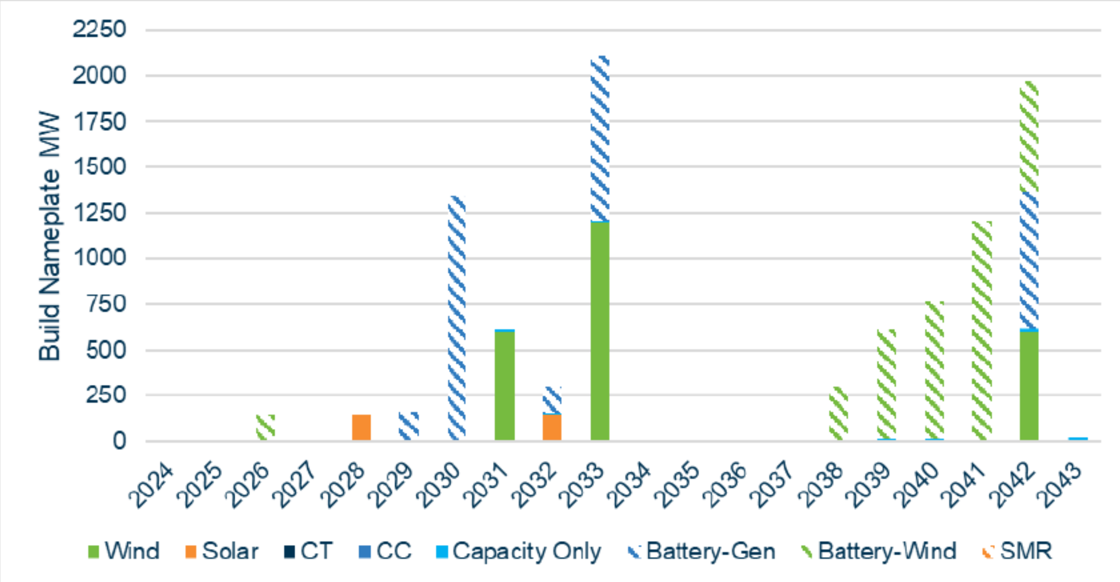
Figure 38: Only Renewable and Storage Additions CAAL



The second, BEAL, included MAP DSM and early retirements of all coal units (Iatan and Jeffrey in 2030) with only renewable and storage builds.

[16] 20 CSR 4240-22.060(3)(A)2

Figure 39: Earliest Retirements, Only Renewable and Storage Additions BEAL



Renewable build alone, and renewable and storage build together cannot meet the summer and winter capacity requirements of Missouri West in every year if capital spend limits are respected. Therefore, CAAL and BEAL resource plans were optimized for lowest cost with relaxed build limits. They would be difficult to implement due to the high volume of additions and would not meet financial metrics. Both plans have significantly higher NPVRR than the preferred plan.

Table 23: NPVRR Comparison of High Renewable Plans

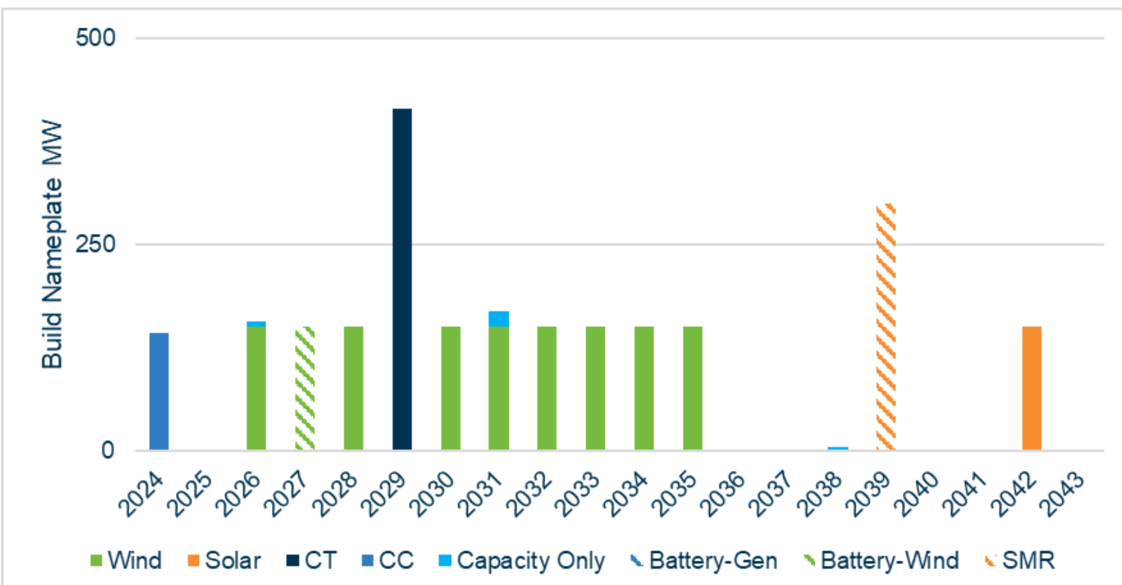
Rank	Plan	NPVRR	Difference	Description
1	CAAA	11,086		RAP Plus; Base builds
2	CAAL	12,883	1,796	RAP Plus; Only renewable/ storage build, relaxed limits
3	BEAL	13,752	2,665	MAP; Retire all Jeffrey and Iatan 2030; Only renewable/ storage build, relaxed limits

Section 7: Analysis of Discrete Scenarios

7.1 GHG Rules

Evergy tested the optimal coal fleet retirement strategy assuming high carbon restrictions and high natural gas prices, at the joint-planning level.[17] A prescriptive compliance plan applying the proposed GHG rule best system of emission reduction (BSER) was also developed and included for comparison with the retirement strategies. The lowest cost ARP had the same retirements as the Preferred Plan. For Evergy Missouri West, this includes Iatan 1 retiring in 2039, Jeffrey 2 and Jeffrey 3 retiring in 2030, and Jeffrey 1 retiring in 2039. Iatan 2 operates throughout the planning period. The plan is the same as the High/High plan discussed in section 6.1.

Figure 40: GHG Rule Optimal Plan CAAF



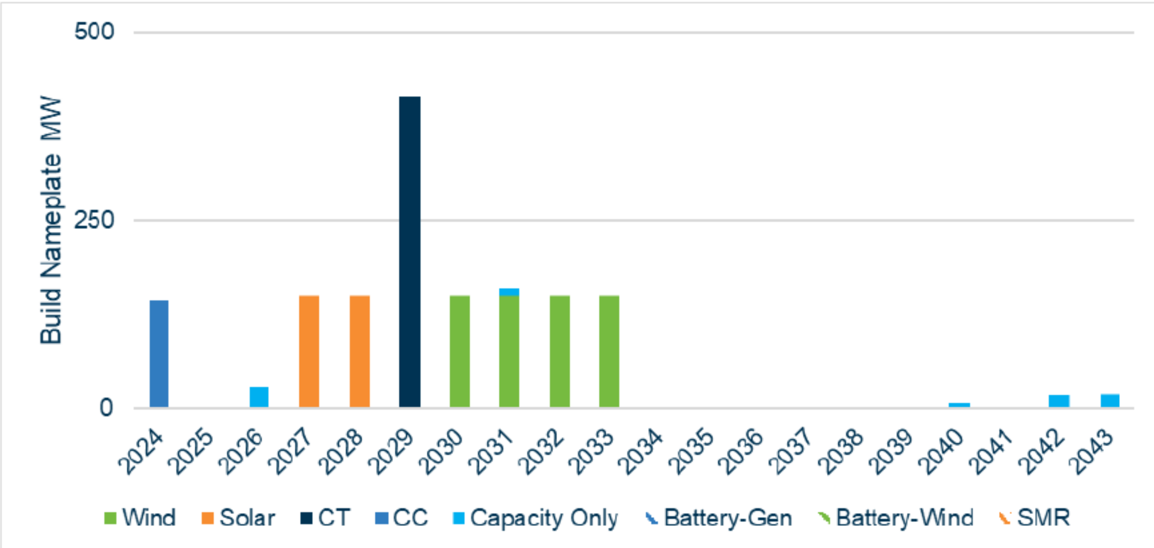
7.2 Low/Low No Retirements

The Low/Low No Retirements ARP was developed by extending the operation of all Evergy Missouri West coal units through the planning horizon and optimizing resource additions for the expectation of a non-CO_2-restricted, low-natural-gas-price future. As compared to the preferred plan, this ARP moves a solar build up to 2028 from the end of

[17] See the Special Contemporary Issue response in Volume 8 for the full analysis. 20 CSR 4240-22.060(3)(A)6

the horizon, moves the wind additions forward one year and adds one less, and moves the CT build forward one year and does not add a ½ CC.

Figure 41: Low/Low No Retirements CGAG



7.3 Expected Costs of Planning for Discrete Scenarios

Both discrete plans are higher cost than the Preferred Plan on a weighted-average risk basis. CGAG is less costly, likely because it is similar to the Preferred Plan, but substitutes an earlier solar build for a ½ CC since it does not need to replace retiring coal capacity.

Table 24: NPVRR Comparison of Discrete Scenarios

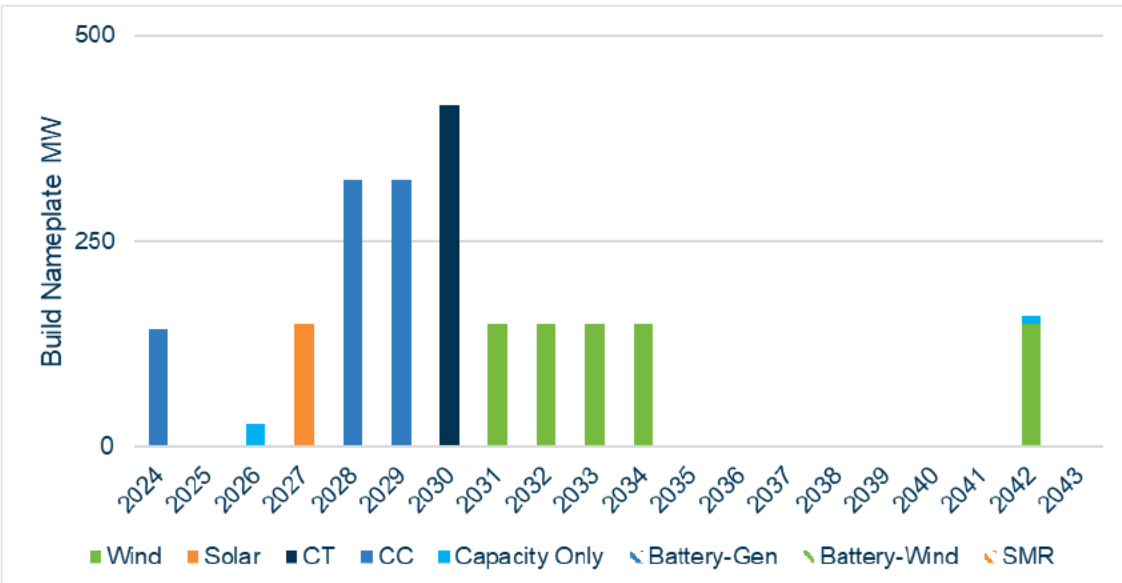
Rank	Plan	NPVRR	Difference	Description
1	CAAA	11,086		Mid/Mid
2	CGAG	11,138	52	Low/Low, No retirements
3	CAAF	11,241	155	High/High, GHG rules

Section 8: Analysis of Contingency Plans

8.1 Potential Crossroads Retirement

The Crossroads facility, with four combustion turbines totaling about 300 MW, is part of the Evergy Missouri West existing portfolio. Because the facility is located in MISO, Evergy Missouri West currently purchases long-term-firm transmission from MISO to SPP to ensure capacity deliverability to its customers. The existing transmission contract expires in 2028, and Evergy Missouri West will be faced with a decision of whether to pursue another long-term contract or retire the units. Since the expected transmission is not currently included in rates, an alternative resource plan was created to evaluate the economics of procuring the transmission versus retiring the resource. The plan CFAA retires the Crossroads units at the end of 2028, saving the future long-term transmission expense and future capital and O&M expenses. The optimal resource plan builds an additional ½ combined cycle to replace the retiring resource. This plan represents the likely contingency plan which would be implemented if the request in the current Missouri West rate case to recover transmission expenses associated with Crossroads is not granted.

Figure 42: Retire Crossroads 2028 CFAA



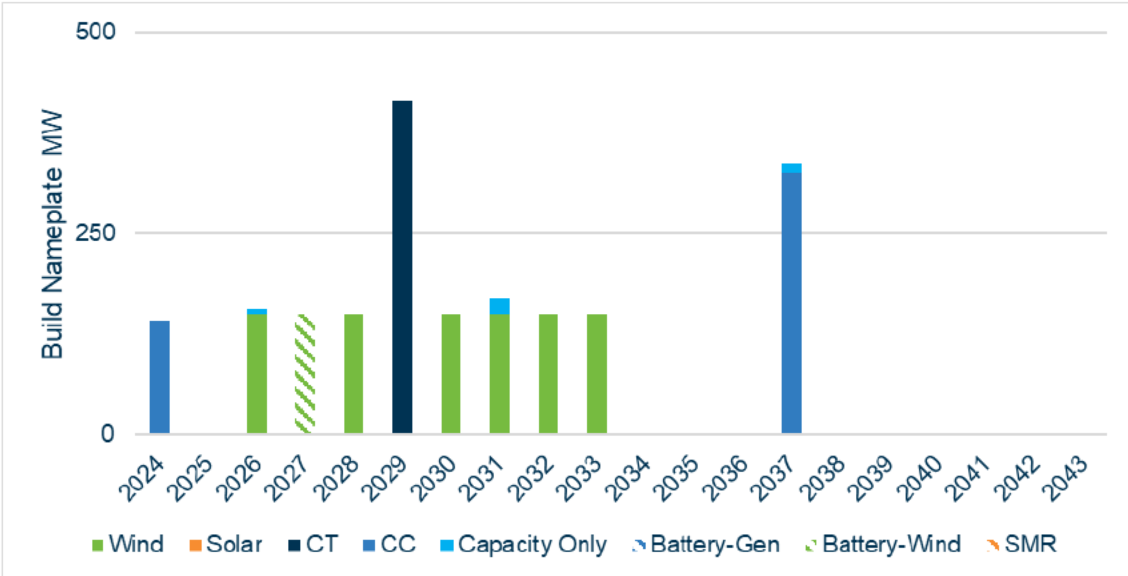
The plan that retires Crossroads is more expensive than the base case which keeps the resource with long-term transmission. This indicates that the replacement cost is expected to be higher than the costs associated with continued operation of Crossroads.

Table 25: NPVRR Comparison Crossroads Early Retirement

Rank	Plan	NPVRR	Difference	Description
1	CAAA	11,086		PP 2023 retirement dates
2	CFAA	11,208	121	Retire Crossroads 2028

8.2 Execution Risk of 2027 Solar

Figure 43: Alternative Plan Without 2027 Solar CAAC



The plan which removes the 2027 solar project as an option for Missouri West is around the same cost on an expected value basis as the base case, but requires replacing the 2027 solar with 2026/2028 wind and a 2027 battery, which introduces additional execution risk associated with these near-term additions.

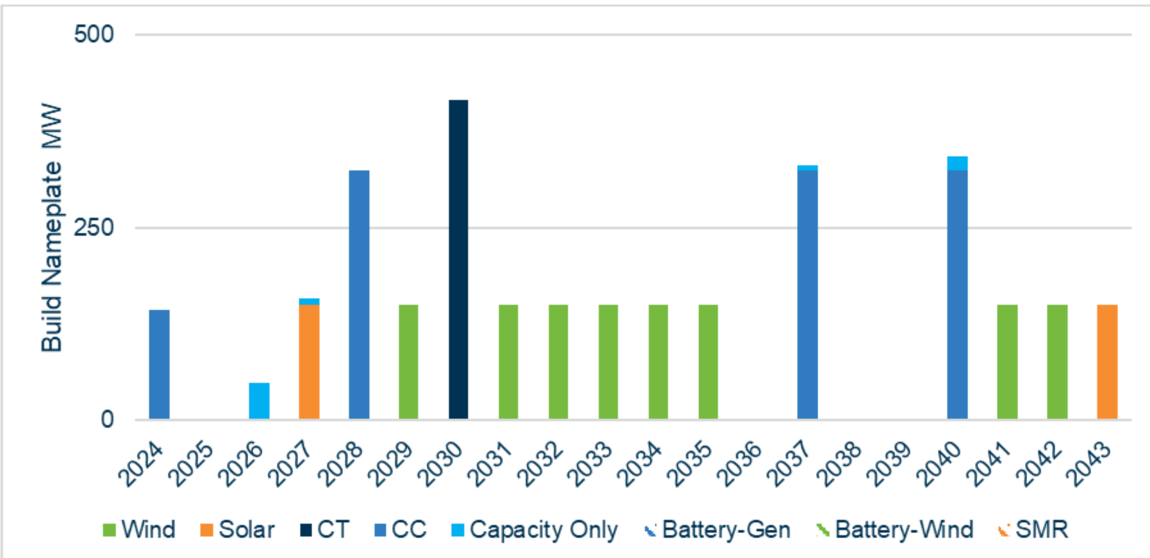
Table 26: NPVRR Comparison Without 2027 Solar

Rank	Plan	NPVRR	Difference	Description
1	CAAA	11,086		Optimal Build
2	CAAC	11,089	2	No 2027 Solar

8.3 High Load Growth

Evergy Missouri West developed an ARP using the high load forecast, which includes high economic growth as well as economy-wide electrification. This forecast requires significant energy and capacity additions as compared to the base load forecast. The ARP pulls forward the half combined-cycle build from 2029 to 2028, adds wind in 2029 and 2035, then adds two additional half combined cycles in 2037 and 2040, and an additional wind at the end of the planning period.

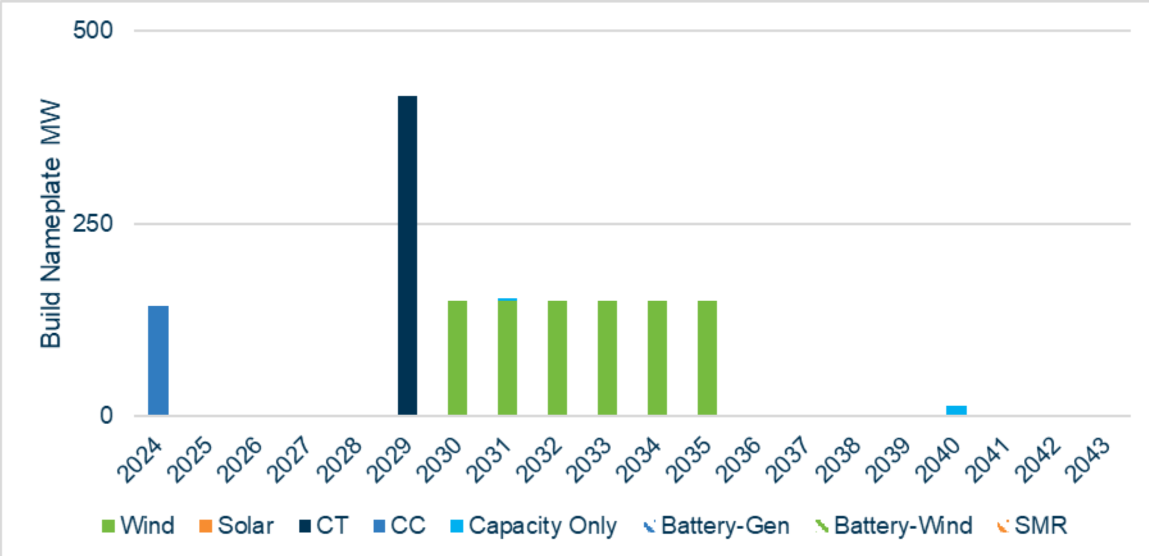
Figure 44: High Load Growth Plan CAAH



8.4 Low Load Growth

Evergy Missouri West also developed an ARP using the low load forecast. The plan includes fewer resource additions than the Preferred Plan. The optimal resource additions no longer include 150 MW of solar in 2027, and a half-combined cycle in 2028. The combustion turbine is pulled forward one year from 2030 to 2029 and additional wind is added in 2030. The end of period wind is moved forward to 2035, and there are no more additions through 2043.

Figure 45: Low Load Growth Plan CAAI



8.5 Capital Budget Constraint

The resource plan CAAD was created to test whether relaxing the capital budget constraint to allow double the amount of solar or battery builds per year would change the optimal build plan. The ARP built the same resources as the plan with Evergy Missouri West's expected capital budget limit.

8.6 Future Carbon Capture and Nuclear SMR Options

Combined cycles with carbon capture were available resource options for the high CO_2/high natural gas future alternative resource plan and GHG rule alternative resource plans.

All plans with combined cycle builds were upgraded to include carbon capture beginning in 2035 for the High CO_2 restriction endpoints (with capital costs and resource modifications included).

Evergy allowed Nuclear SMR as a resource option in the high CO_2/high natural gas future alternative resource plan and in the GHG rule alternative resource plans. The high CO_2/high natural gas resource plan selected an SMR in 2039.

Evergy also tested SMR as a resource option for the preferred plan, CAAA, when optimizing builds for the mid/mid/mid future. No SMRs were selected.[18] This indicates that based on current assumptions of the economics and timing of SMR availability, SMR is not a lower cost option than the resources selected in the plan. However, when the technology becomes more mature and costs and timing are more certain, Evergy Missouri West will have better information to assess if it may be part of the lowest cost future portfolio.

Section 9: Performance Measures

Evergy Missouri West calculated performance measures for all of the ranked ARPs.

9.1 Plan Metrics[19]

Annual performance measures for each ARP include the expected revenue requirement, revenue requirement, levelized annual rates, and annual rate increase. The base planning assumption is that performance incentives are included as part of DSM programs, but each performance measure is also calculated without these incentives.

Annual revenue requirements and rates are determined assuming perfect ratemaking. Revenue requirement differences among ARPs reflect only the differences attributable to the resource plan, with all other company planning and operational decisions held constant across ARPs. The analysis does not take into consideration other factors such as company commitments and determinations from Commission Orders in other dockets that may impact the rate increase depicted each year. As such, rate increase percentages reflected in the various years of analysis should not be interpreted as actual planned rate increase requests anticipated by the company.

[18] Plans CAAM and CAAN have the same resource plan as CAAA, however the models allowed selection of Nuclear SMR beginning in 2039 and 2038 respectively.
[19] 20 CSR 4240-22.060(2)(A)-(B)

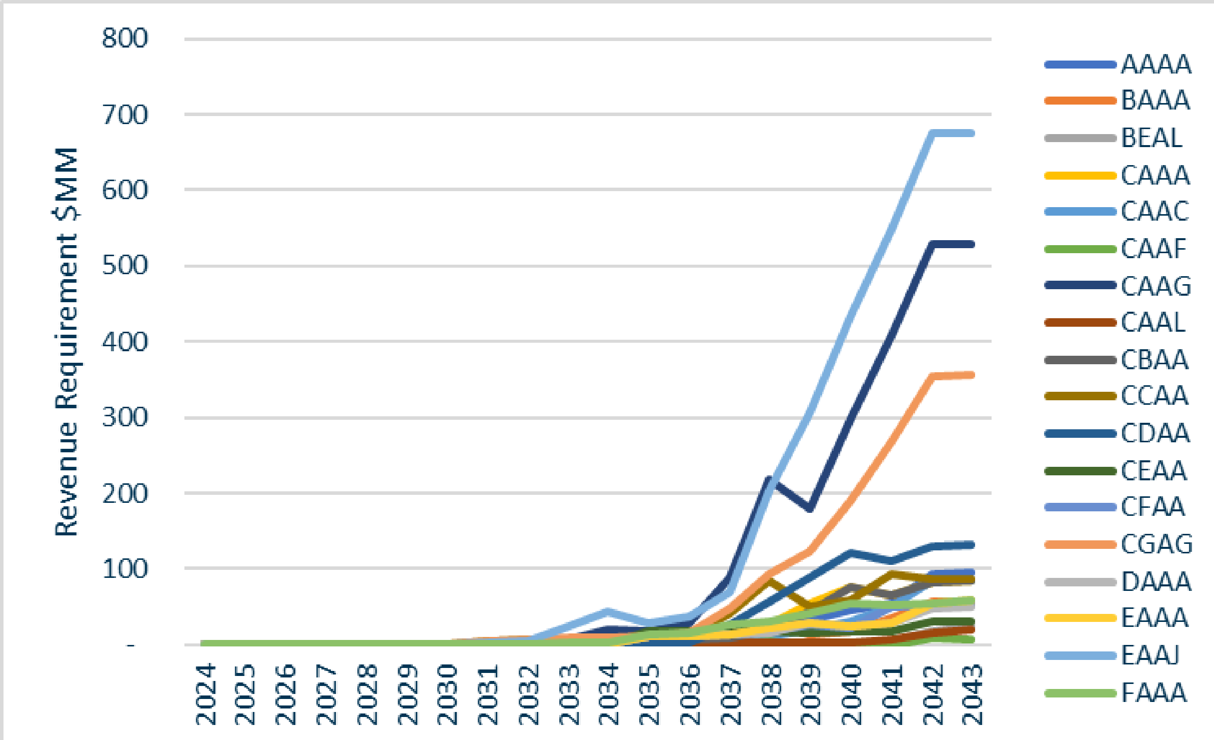
Table 27: Annual Performance Measures for Preferred Plan CAAA[20]

Year	Revenue Requirement ($MM)	Revenue Requirement Without DSM Performance Incentive ($MM)	Levelized Annual Rates ($/kw-hr)	Levelized Annual Rates Without DSM Performance Incentive ($MM)	Rate Increase	Rate Increase Without DSM Performance Incentive	Meets Financial Metrics
2024	746	746	0.08	0.08			YES
2025	792	792	0.08	0.08	2%	2%	YES
2026	813	813	0.08	0.08	0%	0%	YES
2027	853	845	0.08	0.08	3%	2%	YES
2028	867	859	0.09	0.08	1%	1%	YES
2029	947	939	0.09	0.09	9%	9%	YES
2030	1,022	1,014	0.10	0.10	8%	8%	YES
2031	1,103	1,095	0.11	0.10	5%	5%	YES
2032	1,099	1,091	0.11	0.11	2%	2%	YES
2033	1,122	1,113	0.11	0.11	2%	2%	YES
2034	1,147	1,138	0.11	0.11	2%	2%	YES
2035	1,155	1,146	0.11	0.11	0%	0%	YES
2036	1,163	1,154	0.11	0.11	0%	0%	YES
2037	1,186	1,177	0.11	0.11	2%	2%	YES
2038	1,210	1,201	0.11	0.11	2%	2%	YES
2039	1,246	1,238	0.12	0.12	3%	3%	YES
2040	1,426	1,417	0.12	0.12	4%	4%	YES
2041	1,370	1,361	0.13	0.13	6%	6%	YES
2042	1,457	1,449	0.14	0.14	6%	6%	YES
2043	1,625	1,617	0.14	0.14	3%	3%	YES

Annual probable environmental costs were calculated as the difference between the weighted average annual plan costs considering all endpoints and the weighted average annual plan costs at only the low-CO_2 endpoints (which have no CO_2 restrictions), representing the expected incremental value of the costs due to CO_2 restrictions. The ARPs with the highest probable environmental costs were the plan developed to minimally comply with Missouri Renewable Energy Standards (EAAJ) followed by the two developed based on a strategy of planning for a low CO_2, low natural gas price future (CAAG, CGAG). These plans have fewer renewable additions than other plans, making compliance more expensive in endpoints with CO_2 restrictions.

[20] 20 CSR 4240-22.060(4)(C)1A-C. Tables for each plan are in Appendix 6D Rankings and Performance Measures.

Figure 46: Annual Probable Environmental Costs[21]



[21] 20 CSR 4240-22.060(4)(B)8

Table 28: Overall Performance Measures for All Ranked ARPs[22]

Plan	NPV Revenue Requirement ($MM)	NPV Probable Environmental Costs ($MM)	NPV DSM Performance Incentive Costs ($MM)	Average Annual Rates ($/kW-hr)	Maximum Rate Increase	Meets Financial Metrics
AAAA	11,081	109	25	0.11	8%	YES
BAAA	11,272	65	31	0.11	22%	YES
BEAL	13,752	22	31	0.15	2636%	NO
CAAA	11,086	131	68	0.11	9%	YES
CAAC	11,089	87	68	0.11	18%	YES
CAAF	11,241	5	68	0.11	18%	YES
CAAG	11,636	725	68	0.12	11%	YES
CAAL	12,883	20	68	0.14	110%	NO
CBAA	11,067	121	68	0.11	9%	YES
CCAA	11,076	181	68	0.11	14%	YES
CDAA	11,163	209	68	0.11	9%	YES
CEAA	11,271	63	68	0.11	8%	YES
CFAA	11,208	85	68	0.11	41%	YES
CGAG	11,138	463	68	0.11	9%	YES
DAAA	11,090	76	19	0.11	8%	YES
EAAA	11,388	84	0	0.11	18%	YES
EAAJ	12,288	953	0	0.12	23%	YES
FAAA	11,411	117	0	0.11	23%	YES

The expected value of performance measures for all ARPS was summarized using the net present values of the annual measures using the Evergy discount rate of 6.85%. Average annual rates and maximum rate increases over the planning horizon were also calculated.

[22] 20 CSR 4240-22.060(7)(A), 20 CSR 4240-22.060(7)(B)3

Table 29: Standard Deviation Plan Performance Measures[23]

Plan	NPV Revenue Requirement ($MM)	NPV Probable Environmental Costs ($MM)	Average Annual Rates ($/kW-hr)	Maximum Rate Increase
AAAA	465	193	0.0054	0.0028
BAAA	457	138	0.0051	0.0024
BEAL	833	52	0.0107	0.0183
CAAA	468	229	0.0056	0.0020
CAAC	460	161	0.0052	0.0021
CAAF	507	11	0.0057	0.0045
CAAG	576	420	0.0076	0.0057
CAAL	748	47	0.0095	0.0081
CBAA	480	220	0.0056	0.0021
CCAA	492	286	0.0060	0.0031
CDAA	589	421	0.0077	0.0040
CEAA	491	126	0.0054	0.0033
CFAA	445	136	0.0050	0.0008
CGAG	607	469	0.0081	0.0044
DAAA	439	118	0.0048	0.0016
EAAA	460	124	0.0052	0.0023
EAAJ	706	561	0.0098	0.0033
FAAA	456	143	0.0051	0.0018

9.2 Performance Discussion

Most ARPs were developed with capital budget limits to ensure the company continues to meet financial metrics and maintain an investment-grade credit rating. The two ARPs with relaxed budget limits are not expected to be financially viable without changes to cost recovery mechanisms.[24] CAAL includes the RAP-Plus level of demand-side management and preferred plan retirements, with all new additions limited to renewables and storage with relaxed budget constraints. BEAL includes the MAP level of demand-side management and all earliest retirements, with all new additions limited to renewables and storage with relaxed budget constraints. The high volume of resource additions needed to meet SPP reliability requirements and customer needs would require larger cash outlays and additions to rate base. Both ARPs are projected to have the highest

[23] 20 CSR 4240-22.060(7)(B)

[24] 20 CSR 4240-22.060(4)(C)2

rates in the 20-year planning horizon, and highest maximum annual rate increases. CAAL has a 110% maximum annual rate increase, while BEAI reaches over 2,000%, with all other ARPs ranging from 8% - 41%. Neither CAAL nor BEAL was selected as the preferred plan. However, if an all-renewables and storage strategy was pursued, the company would need to coordinate with regulators to manage the balance sheet and rate impacts.

While strategies to only build renewables and storage to meet future load needs and replace retirements are not financially viable, building renewables as part of a diversified future resource plan is cost effective for customers.[25] The plan EAAJ was developed to minimally comply with Missouri Renewable Energy Standards. It ranked 16th in expected overall costs out of the 18 plans ranked. The 15 higher-ranked (lower-cost) plans all had more renewable additions over the planning period.

While there are no legal mandates for energy efficiency and demand response programs, Evergy Missouri West also found that implementation of future demand-side portfolios was more cost effective than no demand-side management. ARPs with each of the four levels of demand-side management (RAP, RAP Plus, RAP Minus, MAP), were all higher ranked (lower cost) than a similar ARP with no demand-side management.[26] Future demand-side portfolios have varying levels of expected out-of-pocket costs, which are costs to participants net of incentives.

[25] 20 CSR 4240-22.060(4)(E)
[26] 20 CSR 4240-22.060(4)(F)

Table 30: Net Present Value Out-of-Pocket Costs[27]

DSM Level	Costs $MM
RAP- Total	**5**
EE	42
DR	(37)
RAP Total	**13**
EE	56
DR	(43)
RAP+ Total	**24**
EE	72
DR	(48)
MAP Total	**(109)**
EE	(62)
DR	(46)

All ARPs were developed to meet the capacity and energy needs of load. The load forecast was a primary input for developing the optimal lowest cost plan taking into consideration future risks. The revenue requirements associated with each ARP were divided by load to determine average rates, assuming perfect ratemaking. As such, the price-elasticity of load was not considered ex-post in calculating rates. Price elasticity is considered in developing the load forecast, as explained in Volume 3.[28]

All ARPs assume expected SPP resource accreditation for new and existing resources and meet or exceed forecasted SPP reserve margin requirements, as detailed in Volume 4. SPP reserve margins are set based on loss of load expectation study results, to plan for a loss of load of one day in ten years. As such, all ARPs are expected to have no more than one day in ten years with unserved energy.[29]

9.3 Impacts and Interrelationships of Critical Uncertain Factors[30]

Each ARP was evaluated based on twenty-seven future endpoints, combining the risks of each critical uncertain factor forecast. The endpoint results were weighted based on

[27] 20 CSR 4240-22.060(2)(A)3
[28] 20 CSR 4240-22.060(4)(D)
[29] 20 CSR 4240-22.060(7)(C)4
[30] 20 CSR 4240-22.060(6)

the combined weightings of the critical uncertain factor scenarios for computation of weighted-average NPVRR and other statistics.

Table 31: Scenario Weighted Endpoint Probabilities

Weighting	Natural Gas Price	CO_2 Restriction	Construction Cost
0.56%	High	High	High
2.25%	High	Mid	High
0.94%	High	Low	High
1.88%	Mid	High	High
7.50%	Mid	Mid	High
3.13%	Mid	Low	High
1.31%	Low	High	High
5.25%	Low	Mid	High
2.19%	Low	Low	High
1.13%	High	High	Mid
4.50%	High	Mid	Mid
1.88%	High	Low	Mid
3.75%	Mid	High	Mid
15.00%	Mid	Mid	Mid
6.25%	Mid	Low	Mid
2.63%	Low	High	Mid
10.50%	Low	Mid	Mid
4.38%	Low	Low	Mid
0.56%	High	High	Low
2.25%	High	Mid	Low
0.94%	High	Low	Low
1.88%	Mid	High	Low
7.50%	Mid	Mid	Low
3.13%	Mid	Low	Low
1.31%	Low	High	Low
5.25%	Low	Mid	Low
2.19%	Low	Low	Low

Evergy Missouri West used regression analysis to assess the risk drivers for ARP cost. Each extreme risk driver (high, low) and combinations of risk drivers (natural gas price with CO_2 restriction) were tested to determine the effects and correlations.

Figure 47: Regression Study Results

Regression Statistics	
Multiple R	0.615266366
R Square	0.378552702
Adjusted R Square	0.368130105
Standard Error	760.5672966
Observations	486

ANOVA

	df	SS	MS	F
Regression	8	168079876.21	21009984.53	36.32
Residual	477	275926666.23	578462.61	
Total	485	444006542.44		

	Coefficients	Standard Error	t Stat	P-value
Intercept	11453.693	114.424	100.099	0.000
High CO_2	381.277	133.618	2.853	0.005
Low CO_2	-166.086	133.618	-1.243	0.214
High Natural Gas	719.251	133.618	5.383	0.000
Low Natural Gas	-192.031	133.618	-1.437	0.151
High Construction Cost	470.827	84.507	5.571	0.000
Low Construction Cost	-446.520	84.507	-5.284	0.000
Natural Gas + CO_2	-0.997	163.648	-0.006	0.995
Natural Gas - CO_2	-14.139	163.648	-0.086	0.931

9.4 Cumulative Probabilities of Performance Measures[31]

Each ranked ARP was valued in all twenty-seven endpoints representing each combination of critical uncertain factor forecast. The cumulative probability of each performance measure represents the cumulative likelihood of each cost based on the endpoint probabilities.

[31] 20 CSR 4240-22.060(7)(C)2

Figure 48: Cumulative Probability NPVRR

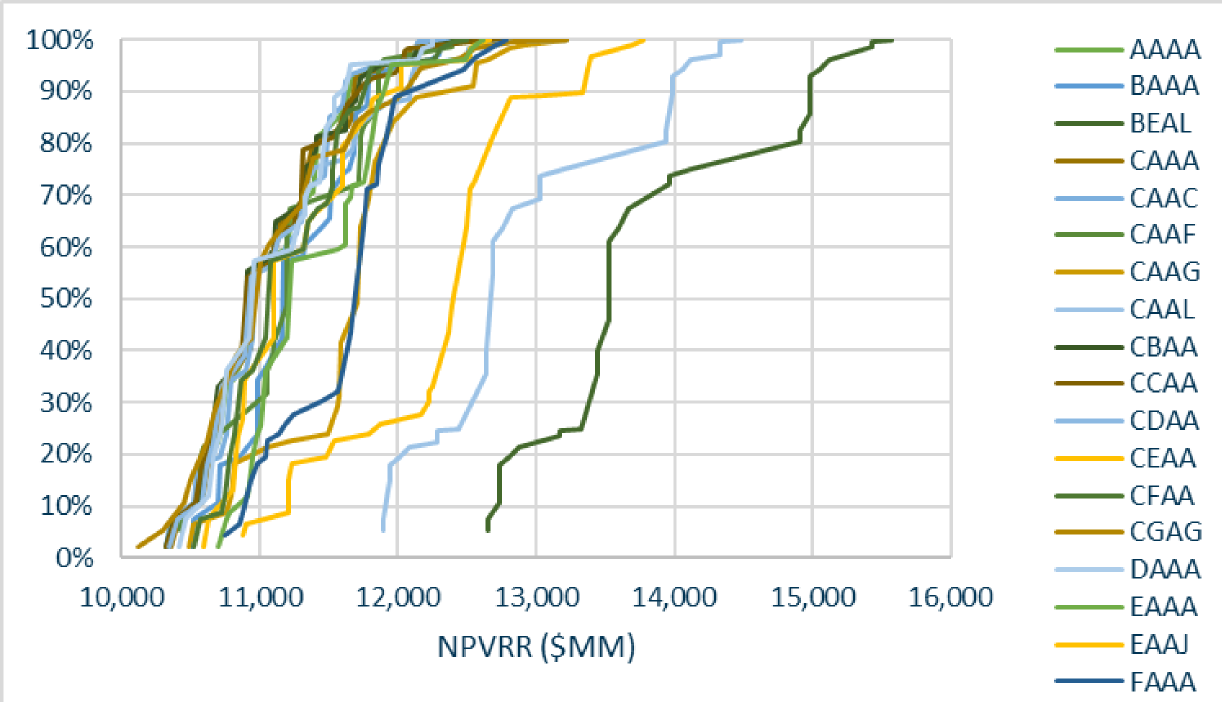


Figure 49: Cumulative Probability Probable Environmental Costs

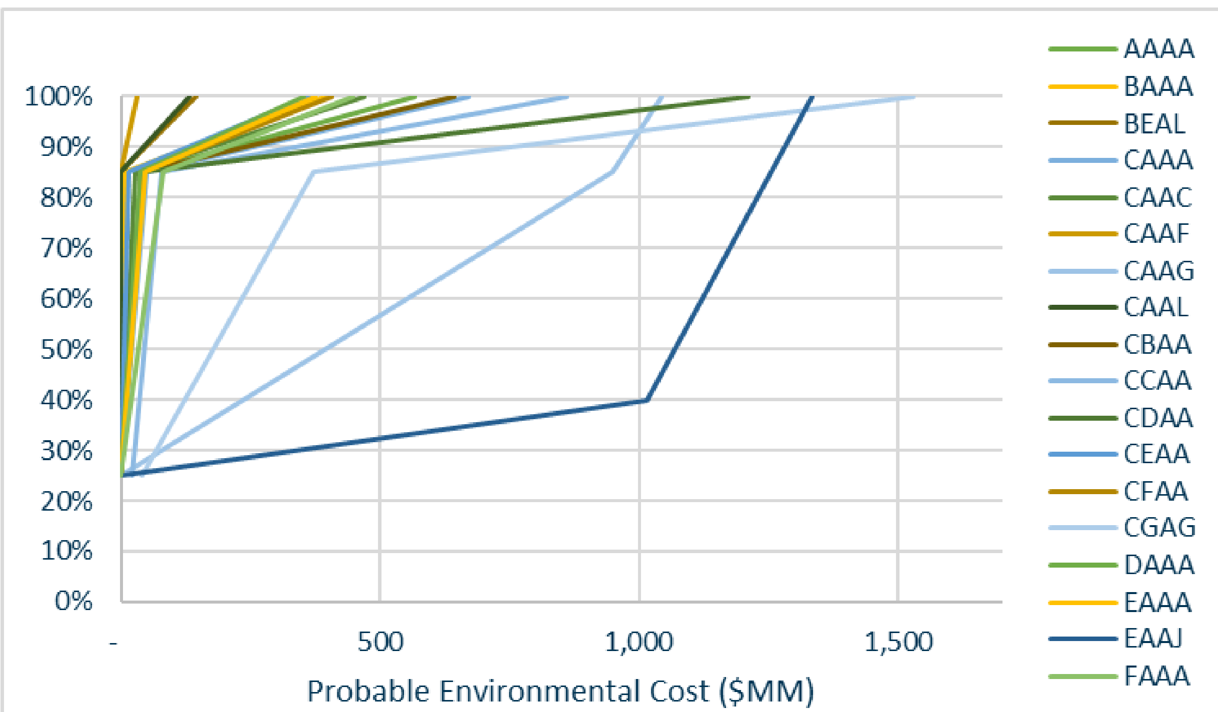


Figure 50: Cumulative Probability Average Rates

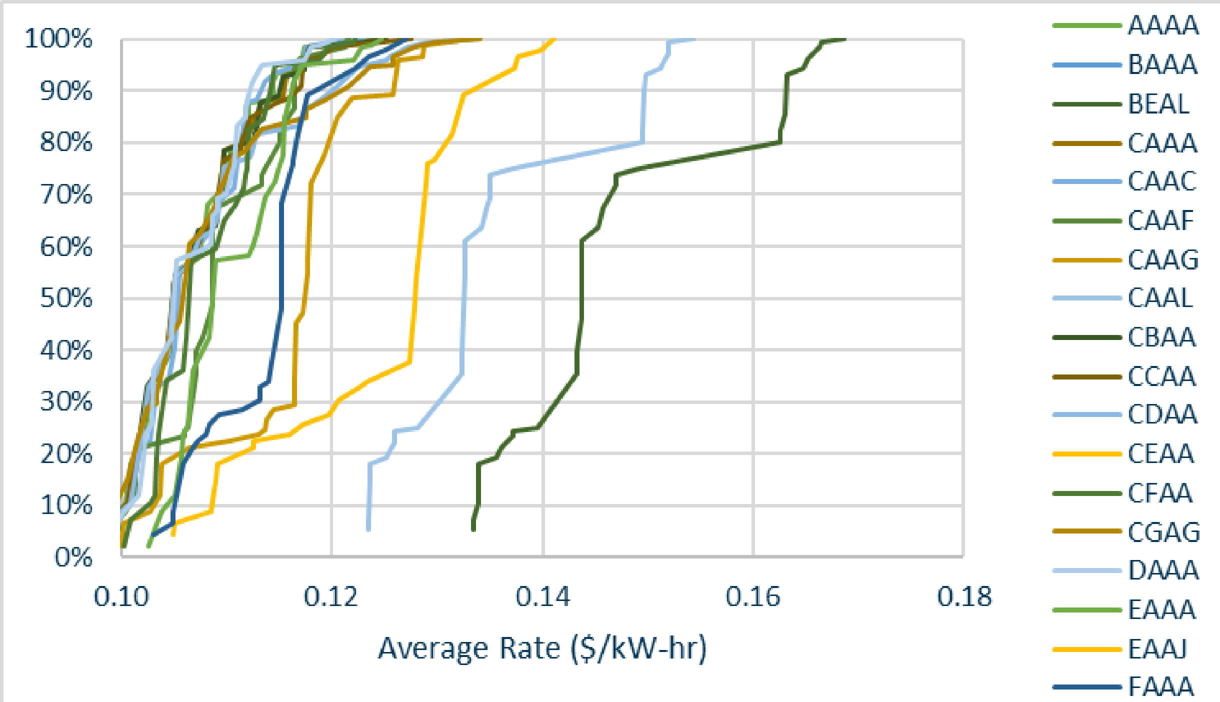
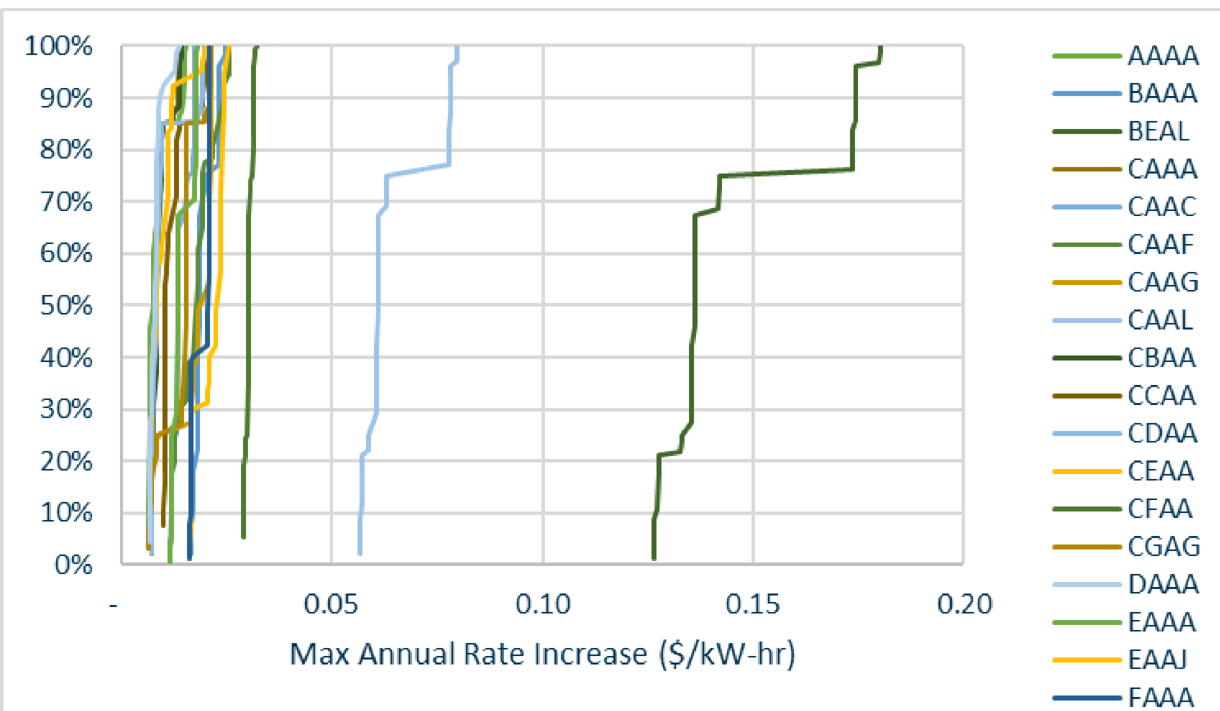


Figure 51: Cumulative Probability Maximum Annual Rate Increase



Section 10: Uncertain Factor Analysis

10.1 Overview of Uncertain Factor Analysis

The company developed a list of potential critical uncertain factors to consider in alternative resource plans.[32] The following factors were found to be critical based on a two-part analysis:

- Load
- CO_2 Restrictions
- Natural Gas Prices
- Total Build Costs

Table 32: Uncertain Factors Evaluated[33]

Uncertain Factor	Evaluated?	Critical?	Comments
Load Growth	✓	✓	
Interest Rate	✓	×	
Legal Mandates	✓	✓	CO_2 restriction
Fuel Prices	✓	×	Natural gas only
New Gen Construction / Permitting	✓	✓	
Purchased Power	N/A	×	Uncertainty assessed using other factors
Emission Allowance Pricing	✓	×	
Gen O&M costs	✓	×	
Forced Outage Rates	✓	×	
DSM Load Impacts	✓	×	
DSM Costs	✓	×	
Other potential uncertain factors	N/A	N/A	None identified

Uncertain factors were identified as critical based on two criteria: (1) whether the uncertain factor significantly changed the base optimal resource build plan, and (2)

[32] Rule 4 CSR 240-22.060(5)

[33] Purchased power was not assessed because Evergy Missouri West plans to meet its customer energy needs as part of its long term resource plan and includes a maximum level of hourly purchases to balance customer energy security with the benefits of participation in SPP. No other potential uncertain factors were identified beyond the categories named in the rules. 20 CSR 4240-22.060(5)(G),(M)

whether it significantly changed the NPVRR rankings of representative plans. Each test was conducted by varying the level of the uncertain factor, keeping all other variables constant.

A base plan and four variations were constructed at the Evergy level (Kansas Central, Metro, and Missouri West) using capacity expansion in PLEXOS with all of the mid-level and base assumptions in the IRP 2023 model. The base plan included the 2023 Preferred Plan retirements, the Preferred Plan Missouri demand response programs, and the Full Kansas demand response program option. Four other plans were also constructed to represent different future strategies that could be employed. These plans included an accelerated retirement, a delayed retirement, high renewable build, and no renewable build.

Table 33: Representative Plans

Plan	Builds Available	DSM Program	Retirement Changes
Base PP	All – Wind, Solar, Battery, Hybrid, CC, CT	RAP+ MO, Full KS	None (2023 PP)
Delayed Retirement	All – Wind, Solar, Battery, Hybrid, CC, CT	RAP+ MO, Full KS	Jeffrey 2 2039
Accelerated Retirement	All – Wind, Solar, Battery, Hybrid, CC, CT	RAP+ MO, Full KS	Iatan 1 2030
High Renewable	Wind, Solar, Battery, Hybrid	MAP MO, Full KS	None (2023 PP)
No Renewable	CC, CT	RAP+ MO, Full KS	None (2023 PP)

10.2 Representative Plan Capacity Expansion Results

Figure 52: EVG Base PP

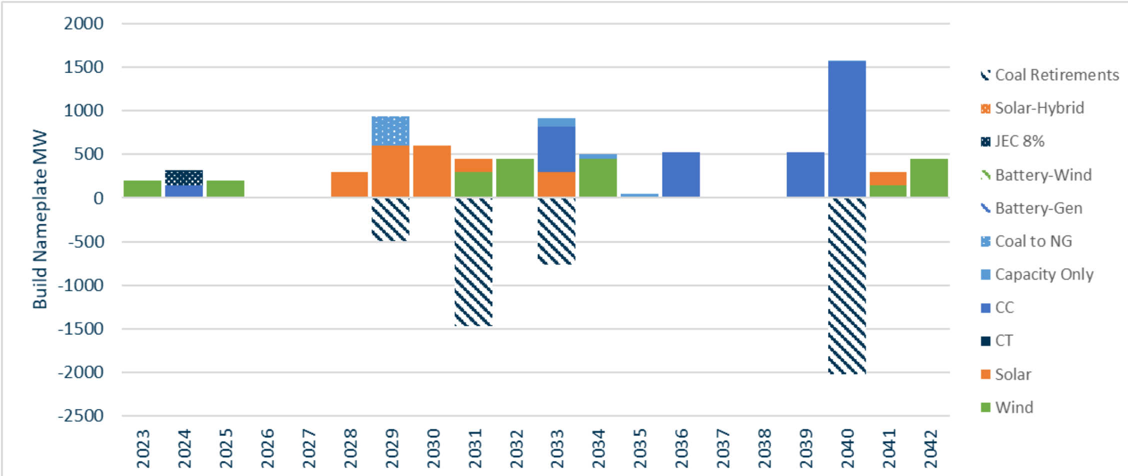


Figure 53: EVG Delayed Retirement Plan

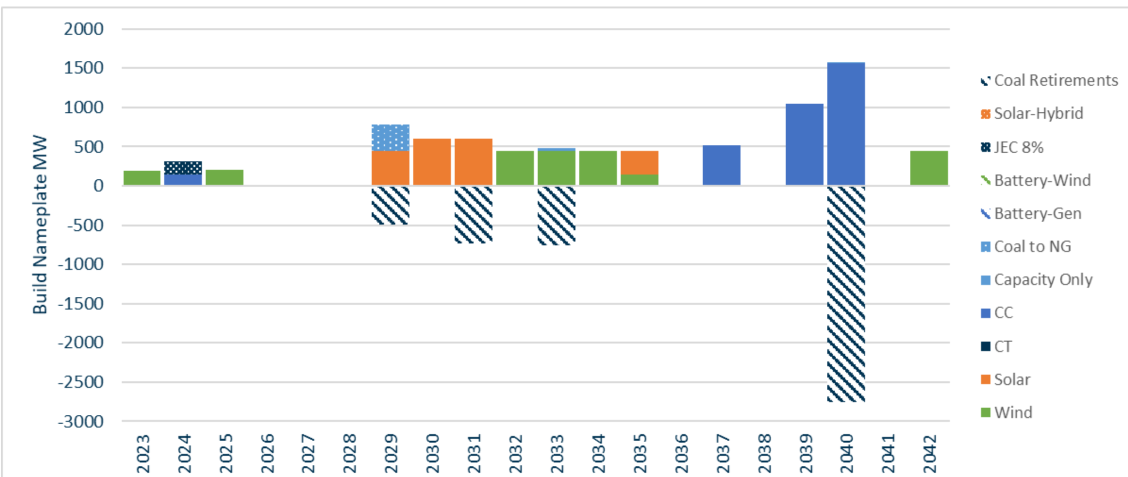


Figure 54: EVG Accelerated Renewable Plan

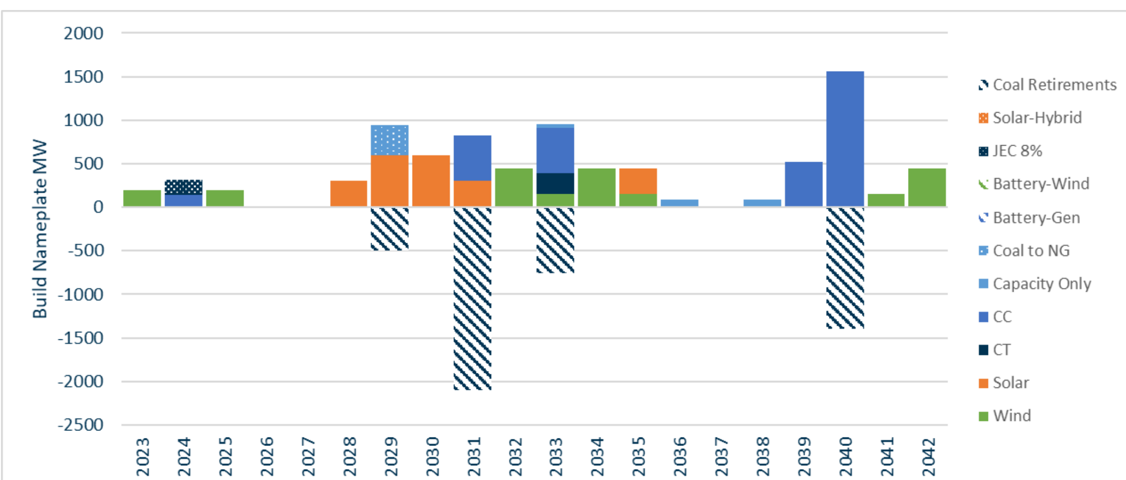


Figure 55: EVG High Renewable Plan

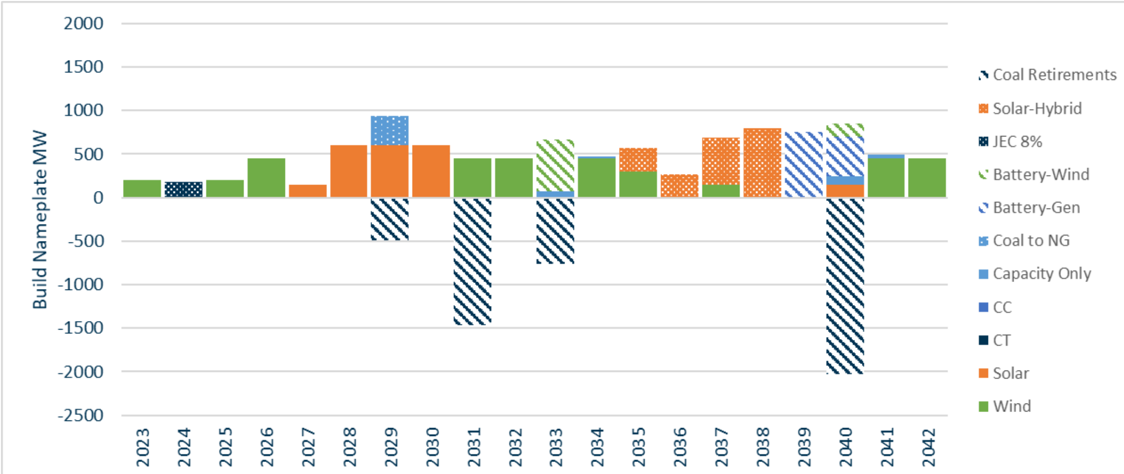
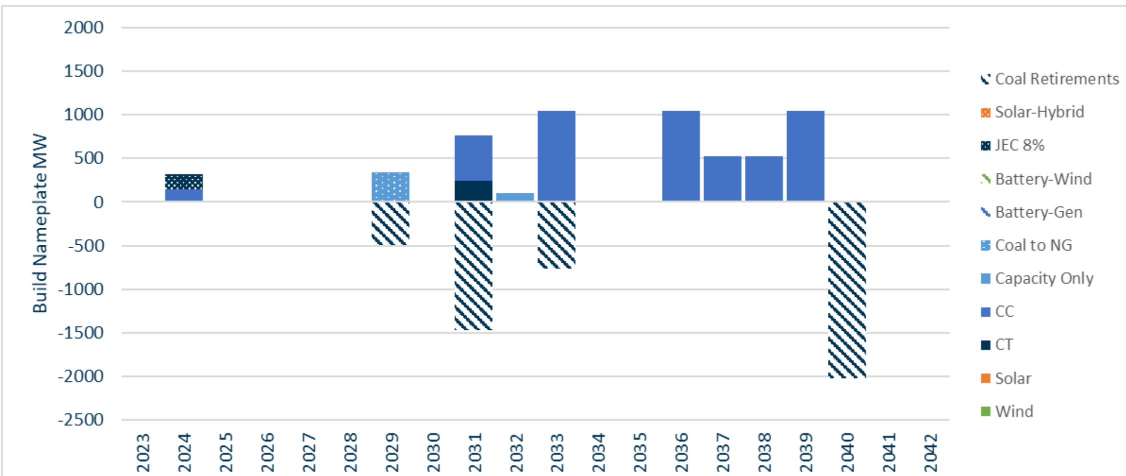


Figure 56: EVG No Renewable Plan



10.3 Uncertain Factor Testing Method

Each uncertain factor was researched, and a low and high sensitivity was developed (if applicable).[34]

For the first test, the base plan was re-run through capacity expansion with a high and low level of each uncertain factor sensitivity listed below. The build decision outcomes were then compared to the base plan.

[34] 20 CSR 4240-22.060(7)(C)1A. See descriptions of each uncertain factor forecast below.

For the second test, all five representative plans were re-run through the production cost model with each uncertain factor sensitivity. Capacity expansion was not used, as the build plans were fixed. Each plan was ranked based on economics using the net present value revenue requirements (NPVRR) metric. The rankings were compared to the original rankings using all mid-level and base assumptions.

Table 34: Summary of Results

Uncertain Factor	Build Test	Rankings Test	Critical?
Load Growth	n/a	n/a	Yes
Interest Rates	Minor Change	Minor Change	No
CO_2 Restrictions	Significant	Significant	Yes
Coal Prices	No Change	No Change	No
Natural Gas Prices	Change	Change	Yes
Interconnection Costs	No Change	No Change	No
Construction Costs	Change	Change	No
Total Build Costs	Significant	Significant	Yes
Emissions Allowances	No Change	No Change	No
Fixed O&M	Minor Change	No Change	No
Outage Rates	No Change	No Change	No
Load Reductions DSM	Minor Changes	No Change	No
Costs DSM	No Change	No Change	No

10.4 Uncertain Factor Sensitivity Discussion

10.4.1 Load Growth[35]

Load is critical in that it determines how much capacity is required, which drives the creation of resource plans. Load has historically been incorporated as an endpoint in evaluating revenue requirements, but evaluated resource plans were not adjusted to reflect more or less required capacity. For the 2024 triennial IRP, Evergy evaluated load as a high and low contingency plan to reflect that different resource decisions could be made if load was higher or lower than the expected base case. These high and low scenarios also capture the range of uncertainty around future SPP resource adequacy requirements that could drive more or less future capacity need. Load growth scenario results are discussed in more detail in sections 2.3.2, 8.3 and 8.4.

[35] 20 CSR 4240-22.060(5)(A)

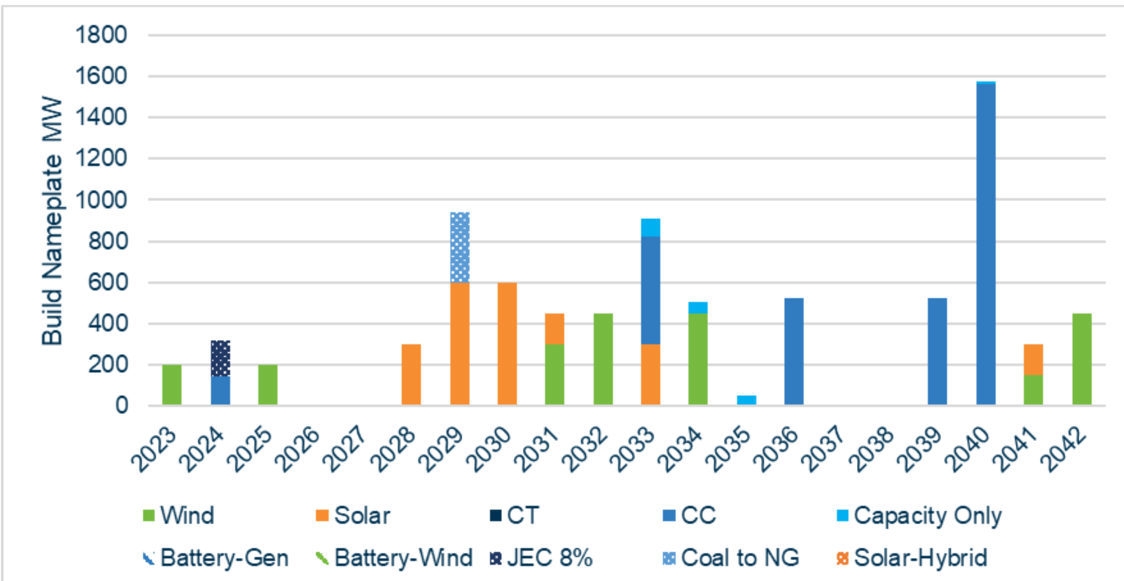
10.4.2 Cost of Capital[36]

Evergy used a 7.13% WACC in its 2023 IRP update, representing the average forward-looking cost of capital across the combined company. For uncertain factor sensitivity testing, the low WACC was 6.5% and high WACC was 9%.

Build Test

The high WACC scenario pushes solar back, includes a solar-hybrid build, and additional combined cycle generation. The low WACC scenario build plan is very similar to the base preferred plan.

Figure 57: EVG Base PP



[36] 20 CSR 4240-22.060(5)(B)

Figure 58: EVG High WACC

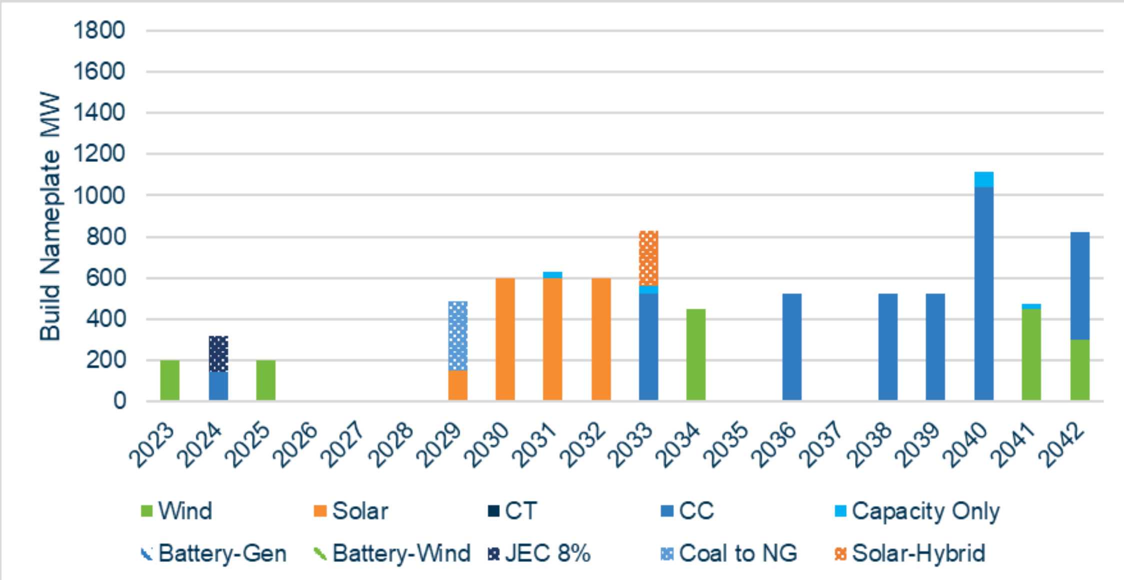
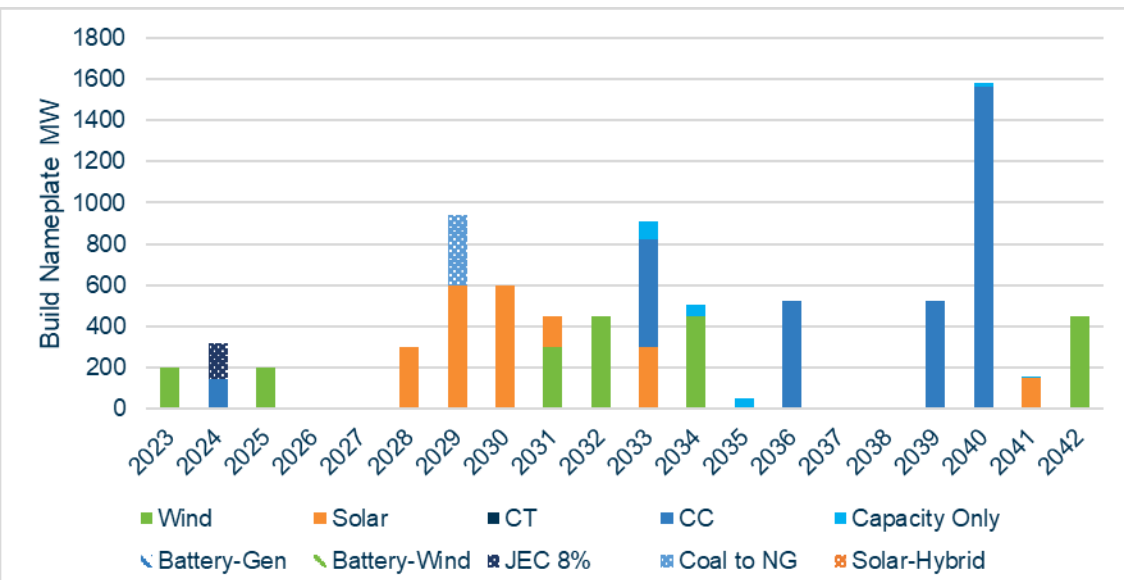


Figure 59: EVG Low WACC



Rankings Test

Plan rankings did not change under the low WACC scenarios. The higher WACC caused the No Renewable plan to rank higher than the Accelerated Retirements and High Renewables plans. These changes, along with the changes to the build plan, were relatively minor compared to the other factors that were deemed critical.

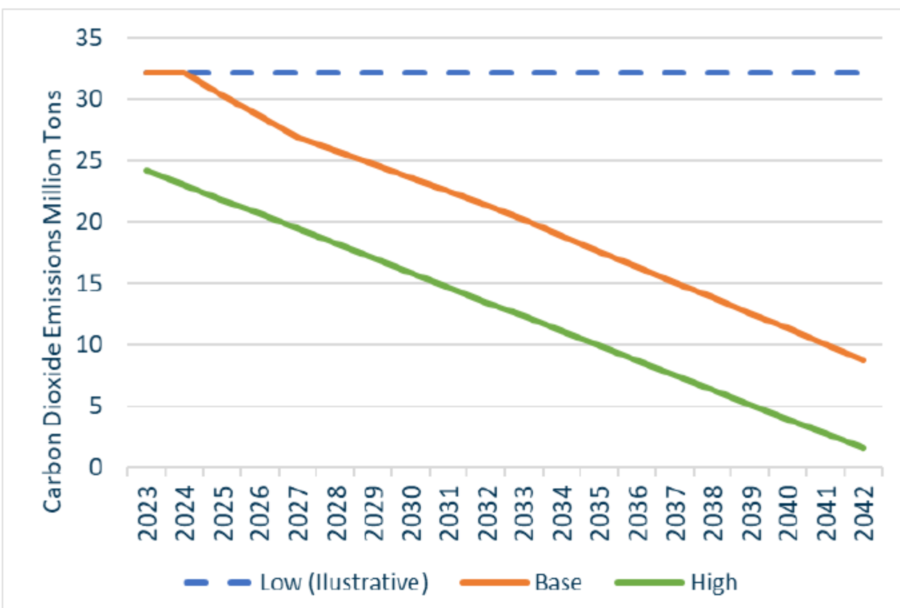
Table 35: WACC Rankings Test

Ranking	Base	High WACC	Low WACC
1	Base PP	Base PP	Base PP
2	Delayed Retirement	Delayed Retirement	Delayed Retirement
3	Accelerated Retirement	Accelerated Retirement	Accelerated Retirement
4	High Renewable	No Renewable	High Renewable
5	No Renewable	High Renewable	No Renewable

10.4.3 Carbon Emissions Restrictions[37]

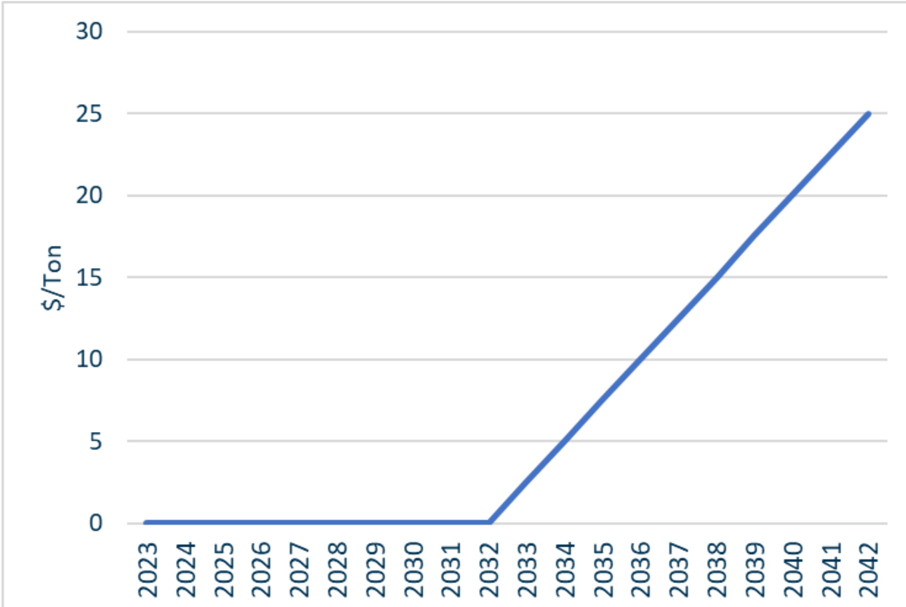
Carbon emissions restriction forecasts developed for the 2023 IRP and corresponding market price endpoints were used for uncertain factor testing. For the low forecast, no emissions restrictions were assumed. For the high forecast, emissions were based on the SPP integrated transmission planning Future 3 model which was engineered with an explicit carbon reduction goal of an approximately 95% reduction in CO_2 production from 2017 levels. Evergy used the same logic to ratably restrict emissions from historic 2017 CO_2 production levels to culminate in 2042 with a 95% reduction. The high forecast also incorporates a carbon tax which ramps to $25/ton by the end of the twenty-year horizon, consistent with Future 3.[38]

Figure 60: Evergy-Level Carbon Emissions Restrictions



[37] 20 CSR 4240-22.060(5)(C) Future changes in legal mandates
[38] Carbon Constraint Values CUF Workpaper.

Figure 61: Carbon-Tax - High Emissions Restriction



Build Test

The build test demonstrates that optimal build decisions would be notably different in the high and low carbon emissions restriction scenarios. The plan for high restrictions includes earlier solar build, significantly more wind build, and other differences. The plan for low (no) restrictions pushes back solar build and includes no wind build.

Figure 62: EVG Base PP

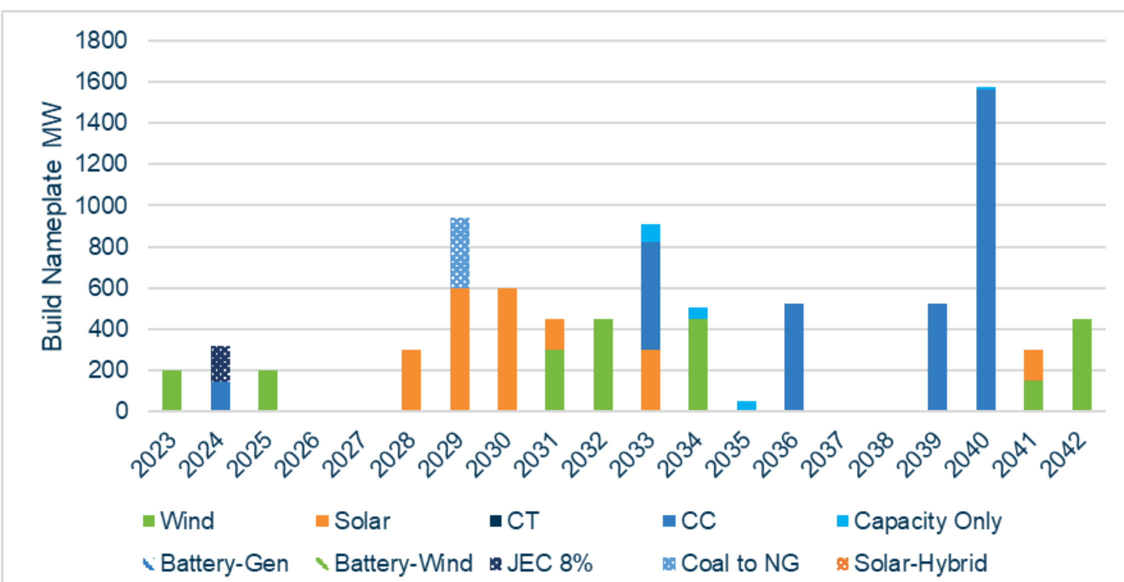


Figure 63: EVG High Emissions Restrictions

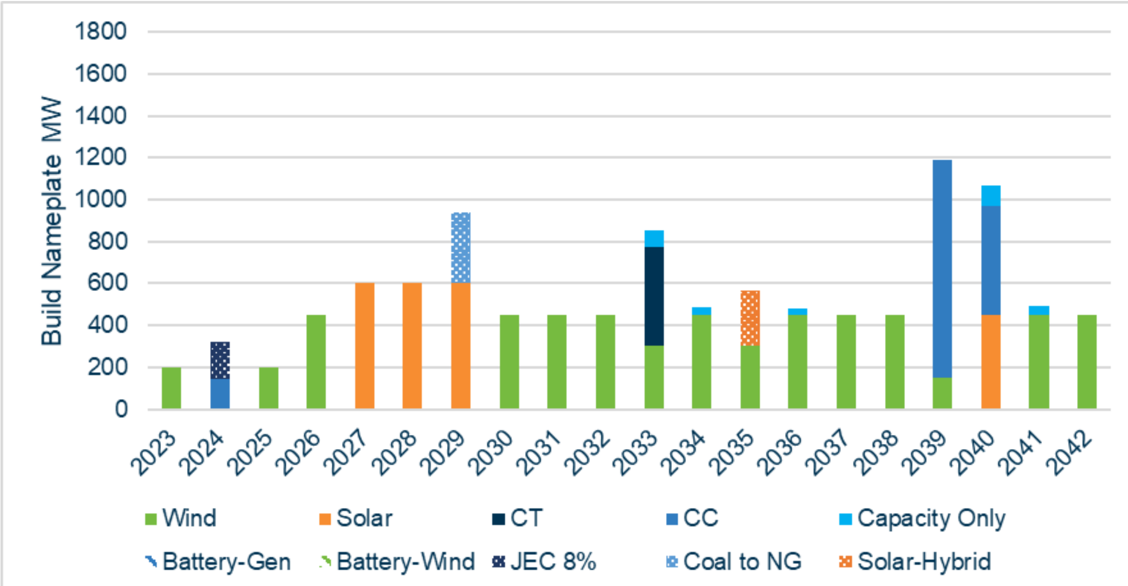
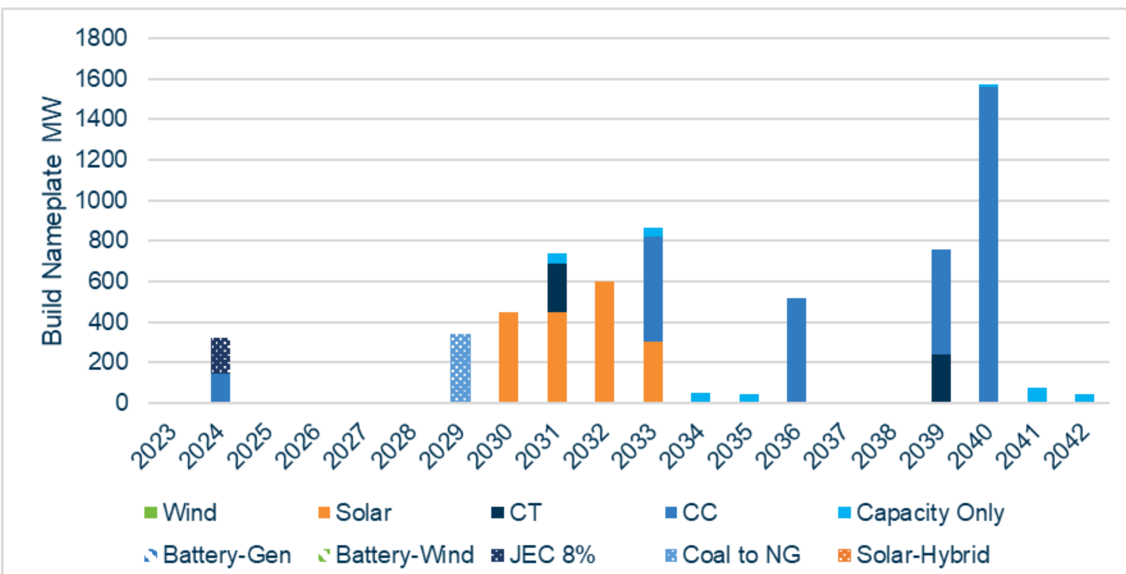


Figure 64: EVG Low Emissions Restrictions



Rankings Test

Plan rankings changed significantly with the High CO_2 restriction forecast. The lowest NPVRR plan was the fourth ranked plan under the base scenario. Rankings also changed in the Low forecast.

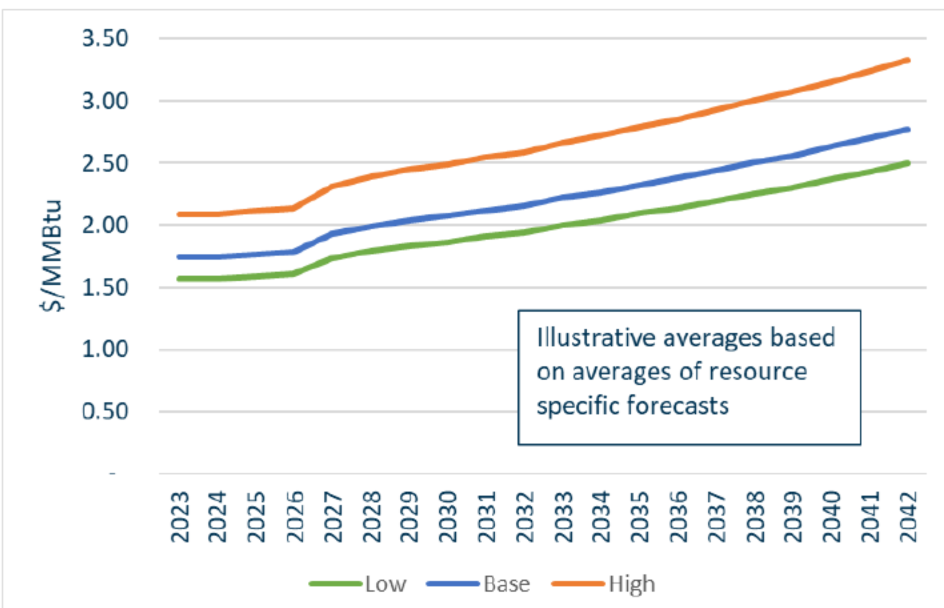
Table 36: Emissions Restriction Rankings Test

Ranking	Base	High CO_2 Restriction	Low CO_2 Restriction
1	Base PP	Accelerated Retirement	Base PP
2	Delayed Retirement	High Renewable	Delayed Retirement
3	Accelerated Retirement	Delayed Retirement	High Renewable
4	High Renewable	Base PP	No Renewable
5	No Renewable	No Renewable	Accelerated Retirement

10.4.4 Coal Prices[39]

Evergy coal resources source fuel from the Powder River Basin, WY. Historically, this fuel source has not experienced much commodity price volatility because it is not exported internationally, and therefore has been insulated from the global market pressure influencing oil, natural gas, and other coal sources (Illinois Basin, Atlantic). Evergy does experience delivery cost risk based on negotiated rates with rail companies, which may be influenced by labor costs, rail traffic, and availability of alternative routes to plant sites. The coal price uncertain factor sensitivity was tested with an increase of 20% (high) and a decrease of 10% (low).[40]

Figure 65: Coal Price Forecast Sensitivities



[39] 20 CSR 4240-22.060(5)(D)
[40] CONF Coal Prices CUF Workpaper.

Build Test

Estimated high and low future coal prices lead to no significant change in the preferred build plan.

Figure 66: EVG Base PP

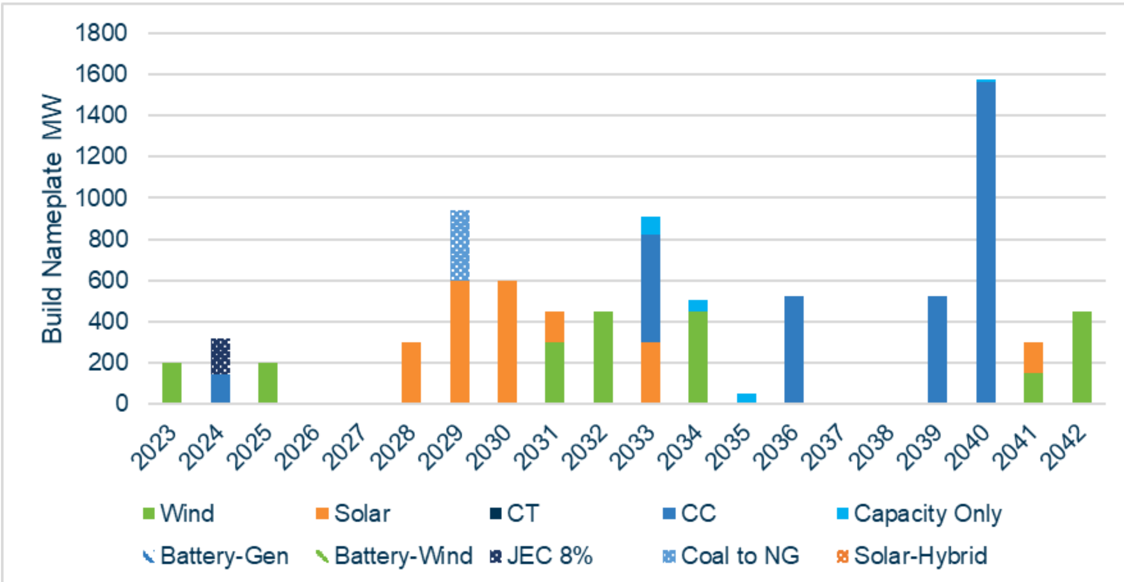


Figure 67: EVG High Coal

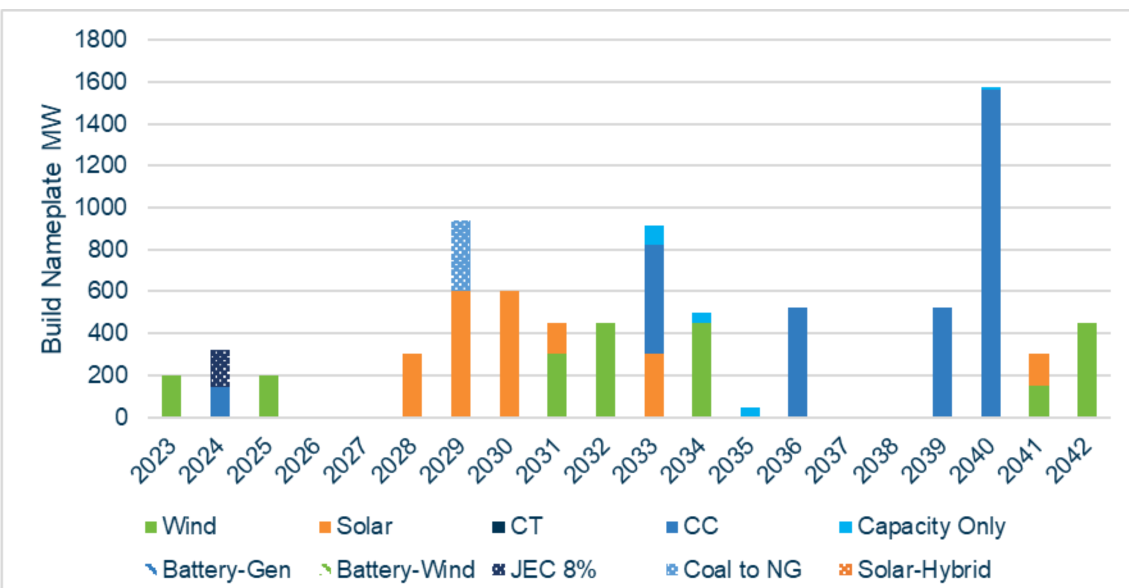
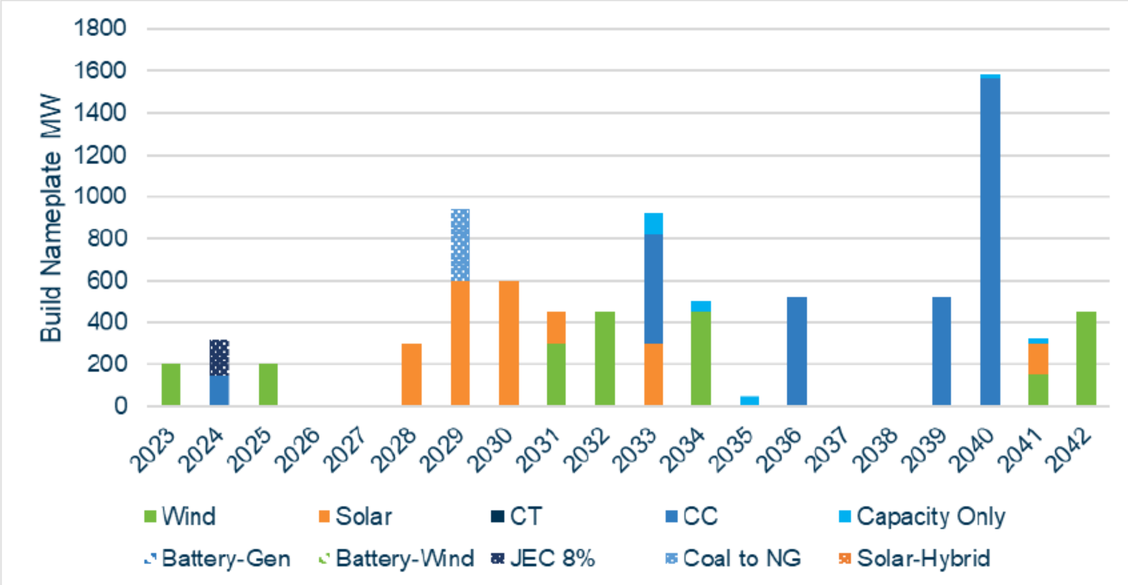


Figure 68: EVG Low Coal



Rankings Test

The plan rankings did not change in high or low coal price scenarios.

Table 37: Coal Prices Rankings Test

Ranking	Base	High Coal	Low Coal
1	Base PP	Base PP	Base PP
2	Delayed Retirement	Delayed Retirement	Delayed Retirement
3	Accelerated Retirement	Accelerated Retirement	Accelerated Retirement
4	High Renewable	High Renewable	High Renewable
5	No Renewable	No Renewable	No Renewable

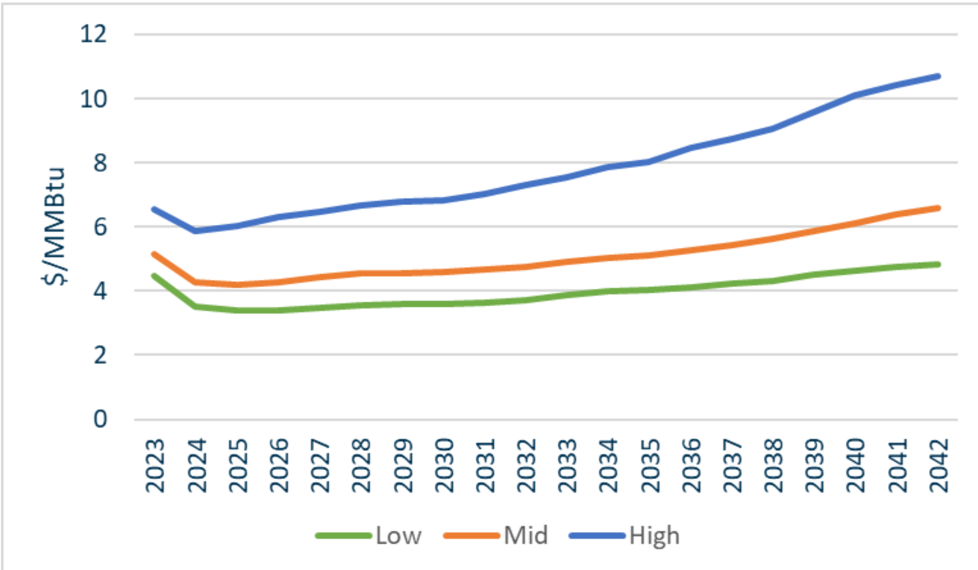
10.4.5 Natural Gas Prices[41]

Natural gas price forecasts for high and low cases were developed for the 2023 IRP. The high and low forecasts were developed by using the mid forecast and scaling it based on the fundamental supply and demand forecasts in the EIA Annual Energy Outlook model. Evergy used the “High Oil and Gas Supply” to calculate the low natural gas price forecast, and the “Low Oil and Gas Supply” for the high natural gas price forecast. These natural

[41] 20 CSR 4240-22.060(5)(D)

gas price forecasts and the corresponding market price forecasts were used to test the high and low uncertain factor sensitivities.[42]

Figure 69: Natural Gas Price Forecasts



Build Test

The high natural gas sensitivity pulled solar build forward, while the low natural gas sensitivity pushed it back in the time horizon. The high also resulted in more wind and CT builds, while the low was similar to the base plan.

[42] Natural Gas Price Forecasts CUF Workpaper

Figure 70: EVG Base PP

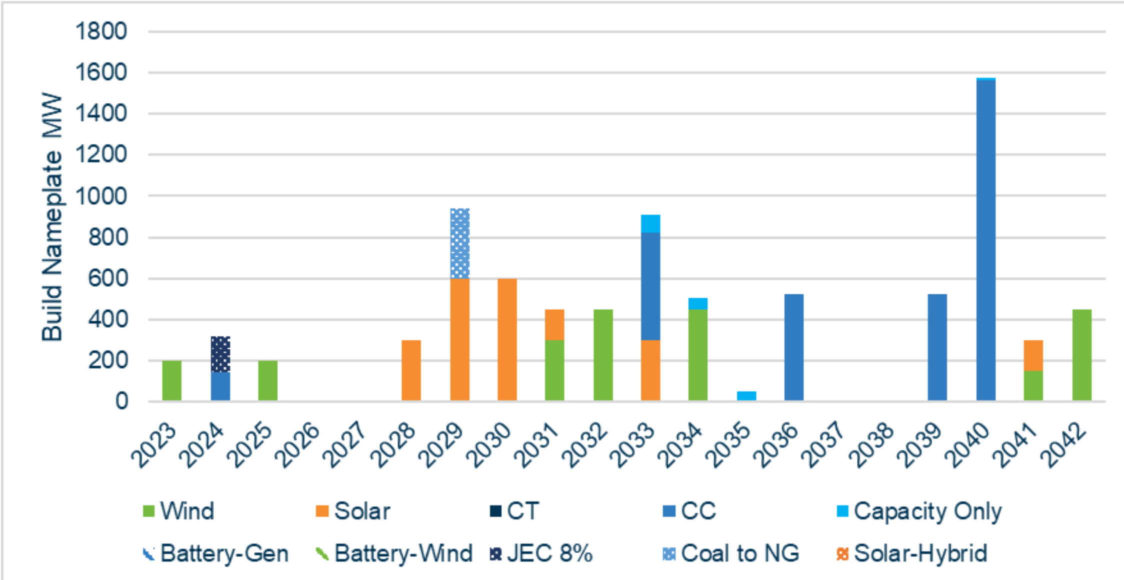


Figure 71: EVG High Natural Gas

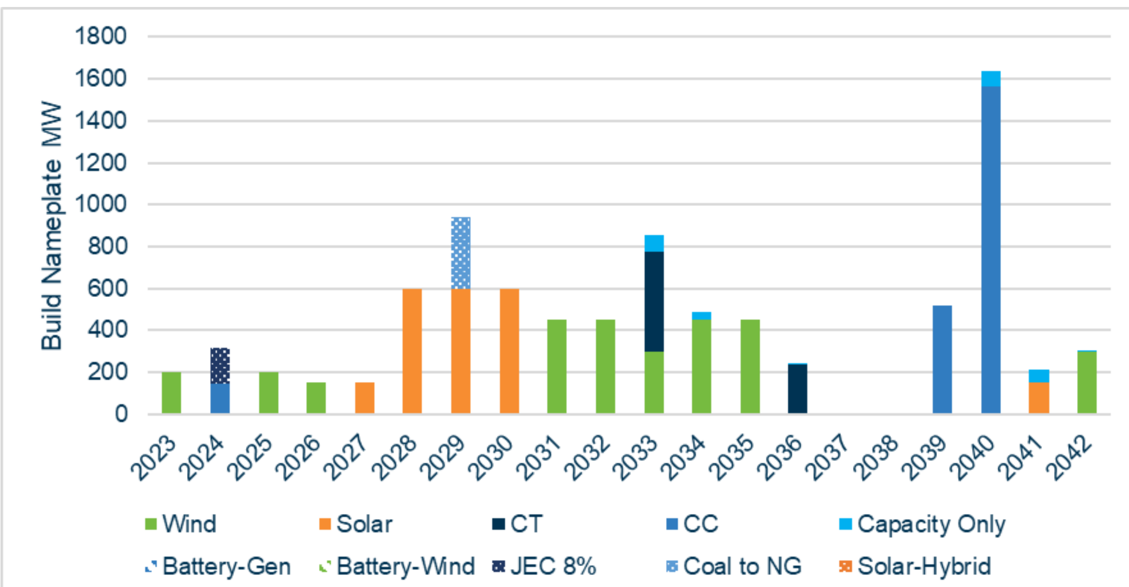
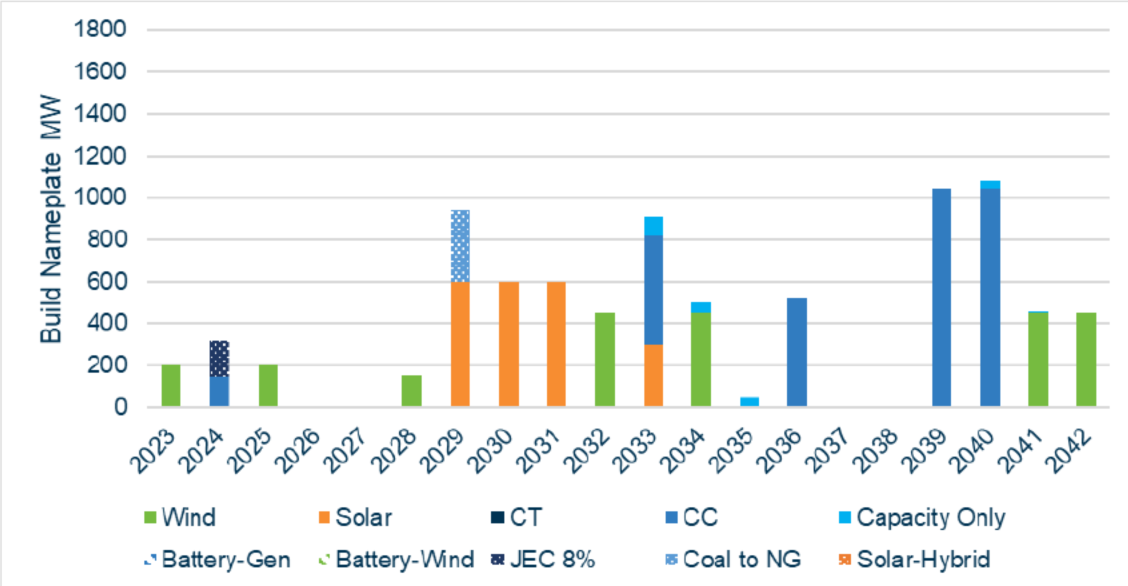


Figure 72: EVG Low Natural Gas



Rankings Test

The plan rankings did not change for the low natural gas price forecast relative to the base forecast. The Delayed Retirement plan was ranked first in the high natural gas price forecast sensitivity, changing the rankings slightly.

Table 38: Natural Gas Prices Rankings Test

Ranking	Base	High NG	Low NG
1	Base PP	Delayed Retirement	Base
2	Delayed Retirement	Base	Delayed Retirement
3	Accelerated Retirement	Accelerated Retirement	Accelerated Retirement
4	High Renewable	High Renewable	High Renewable
5	No Renewable	No Renewable	No Renewable

10.4.6 Interconnection Costs[43]

SPP Interconnection cost data compiled by Berkeley Lab[44] from 2002 to early 2023 was used to assess the impact of interconnection costs. Interconnection cost variation was found to have only a minor impact on Evergy capacity expansion plans and does not change NPVRR plan rankings.

[43] 20 CSR 4240-22.060(5)(E)
[44] https://emp.lbl.gov/publications/generator-interconnection-cost-0

Berkeley Lab's SPP interconnection cost data provides point of interconnection and broader network upgrade costs for individual projects from 2002 to early 2023. The data shows that interconnection costs vary widely by fuel type, year, and location. Renewables and storage projects typically have higher interconnection costs than natural gas plants. Broader transmission system upgrade costs are the primary cost driver and costs have grown over time. Projects that withdraw have significantly higher costs than projects that are completed or still active.

Since the impact of recent cost increases is the primary concern, total interconnection cost data ($/kW) from 2019-2023 for active and completed projects was analyzed to obtain estimates of high and low interconnection costs by fuel type. The smallest and largest 5% of estimates were dropped from the sample due to extreme outliers ($0 interconnection costs, for example). Those estimates were used to assess the impact on the IRP model's capacity expansion plans and NPVRR.

Interconnection costs were included in the 2023 IRP as part of a new build's capital expenditures. CT and CC estimated interconnection costs in the 2023 IRP were slightly higher than the SPP high estimate. Renewables interconnection costs in the 2023 IRP were integrated into the total cost of project estimates obtained from recent RFPs.

The sample median observation for each fuel type was used as the midpoint estimate. The 25th and 75th percentile of each fuel type was used as the high and low estimated costs.

Table 39: 2019-2023 SPP Interconnection Costs

Active and Completed Projects ($/kW)

	Sample Size	Low Estimate	Median	High Estimate
Hybrid	7	$34.50	$41.01	$65.14
Natural Gas	15	$12.99	$48.01	$52.89
Solar	123	$31.57	$60.89	$117.23
Storage	58	$26.61	$72.28	$116.58
Wind	136	$17.57	$43.32	$77.35
		25th Percentile		*75th Percentile*

Build Test

Interconnection costs had a minor impact on the timing of solar and wind builds.

Figure 73: EVG Base PP

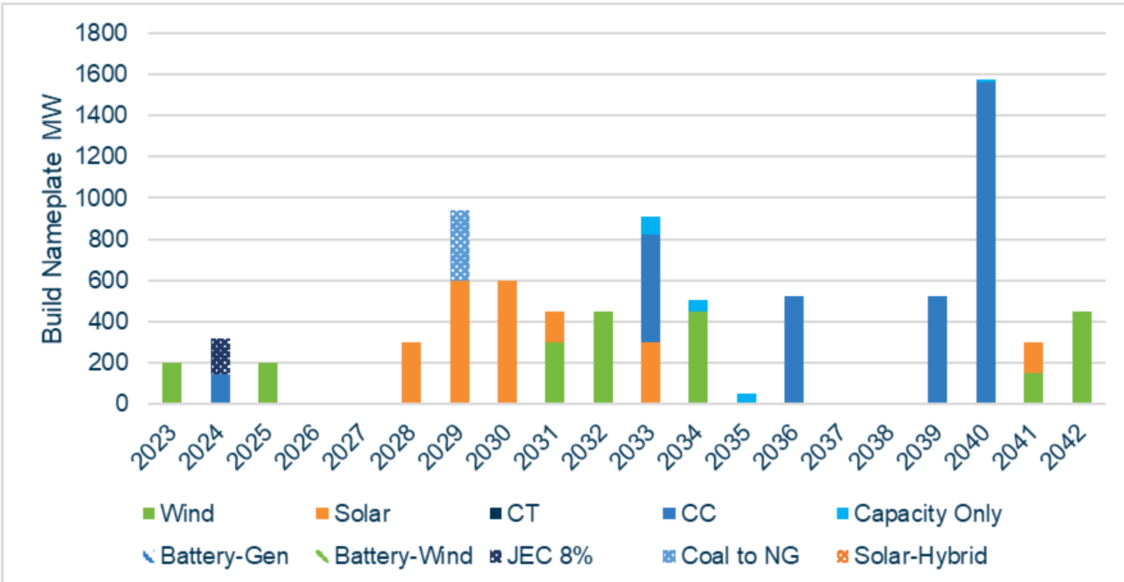


Figure 74: EVG High Interconnection Costs

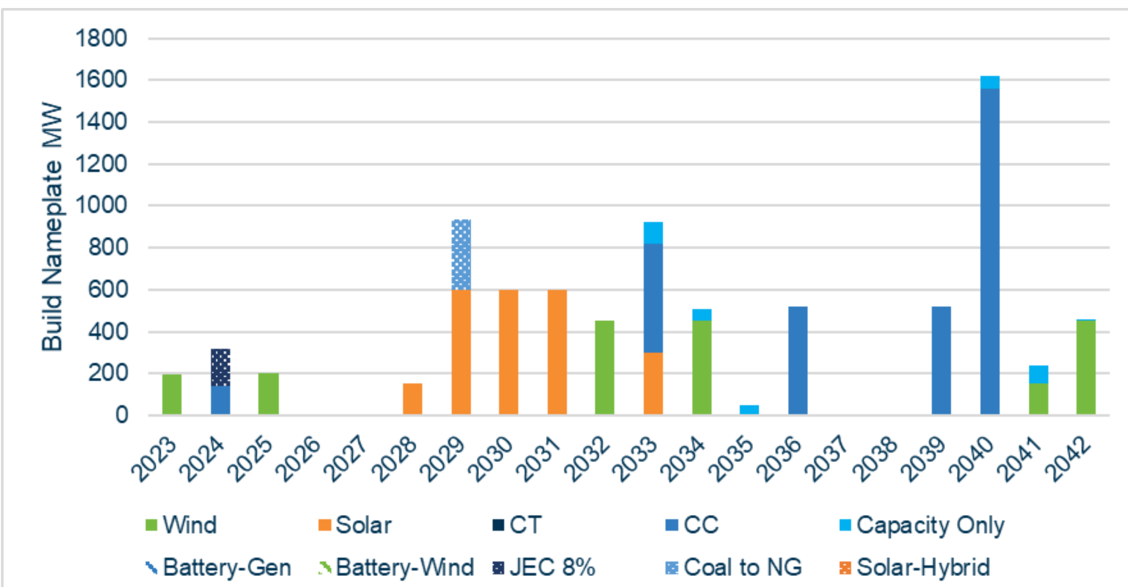
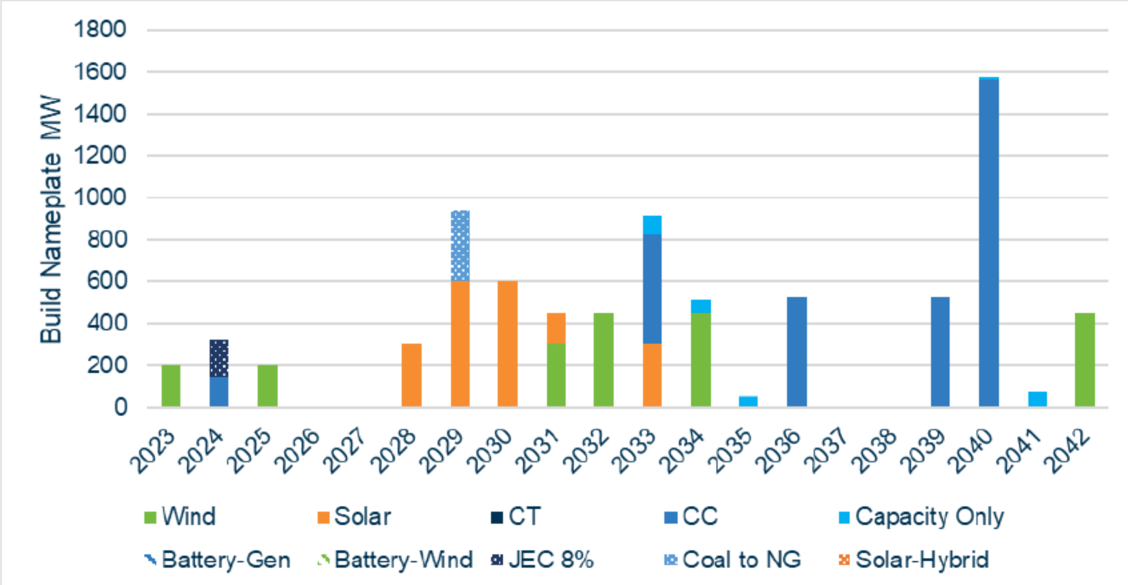


Figure 75: EVG Low Interconnection Costs



Rankings Test

The plan rankings did not change for the high or low interconnection cost scenarios relative to the base forecast.

Table 40: Interconnection Cost Rankings Test

Ranking	Base	High Interconnection Costs	Low Interconnection Costs
1	Base PP	Base PP	Base PP
2	Delayed Retirement	Delayed Retirement	Delayed Retirement
3	Accelerated Retirement	Accelerated Retirement	Accelerated Retirement
4	High Renewable	High Renewable	High Renewable
5	No Renewables	No Renewables	No Renewables

10.4.7 Construction Costs[45]

Construction cost estimates have been fairly volatile over the past few years. Supply chain issues and inflation have increased costs and cost uncertainty. The average year over year cost estimate differences in the past two IRPs were 28% for solar projects and 27% for wind projects. On an absolute value basis, the cost estimate differences were 22% for CTs and 24% for CCs. For this uncertain factor test, construction costs (net of

[45] 20 CSR 4240-22.060(5)(F)

interconnection costs) were increased by 25% for the high sensitivity and decreased 25% for the low sensitivity.

Build Test

Higher construction costs push solar back, reduces wind, and increases combined cycle builds. Lower construction costs push solar forward, increases wind, and builds combustion turbine and solar hybrid resources.

Figure 76: EVG Base PP

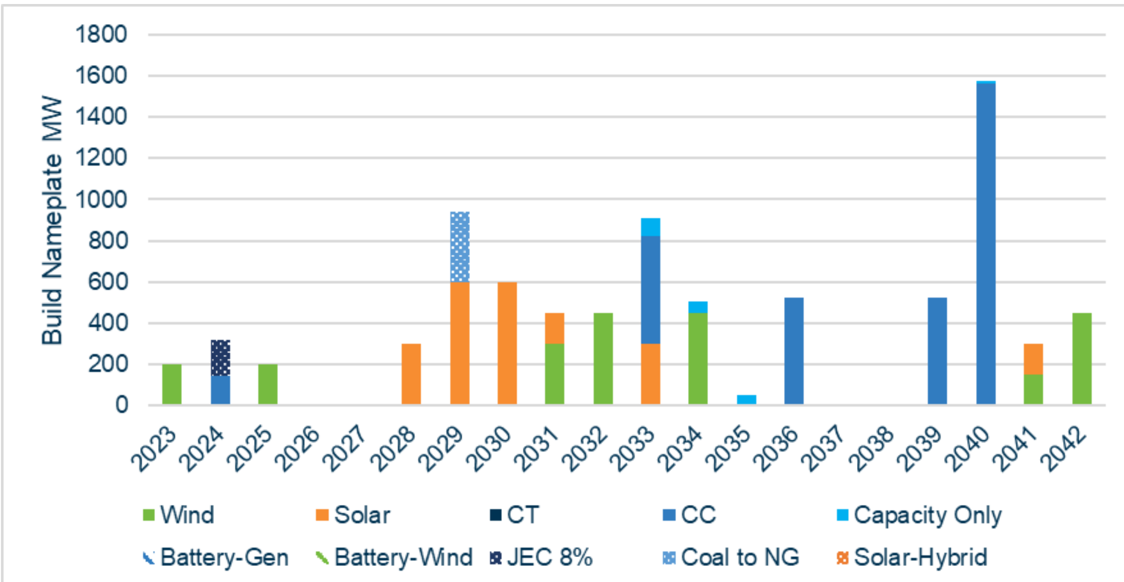


Figure 77: EVG High Construction Costs

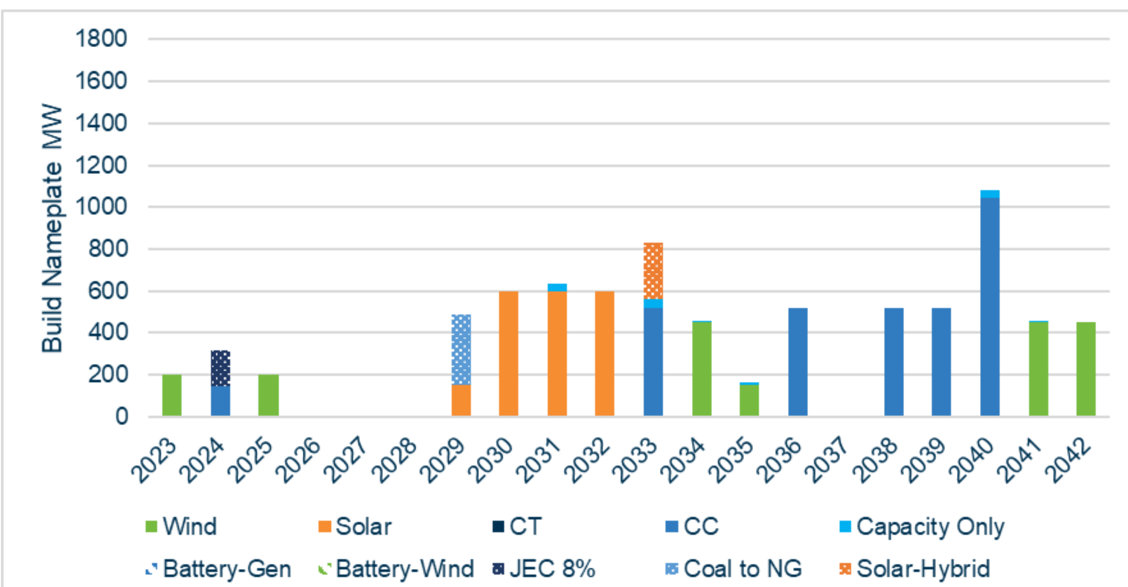
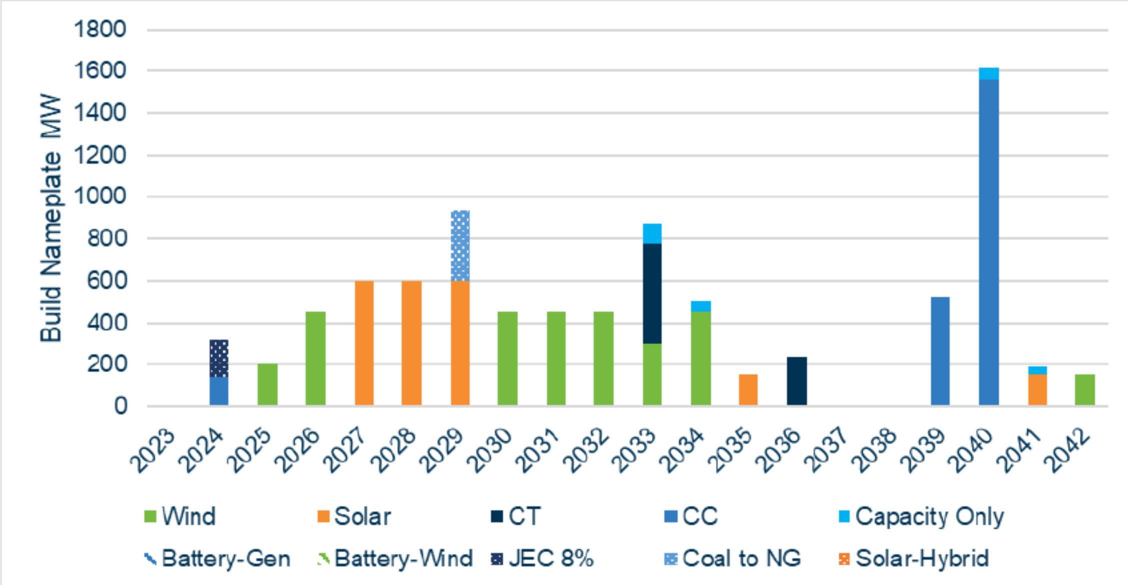


Figure 78: EVG Low Construction Costs



Rankings Test

Construction costs changed the order of the high renewable plan and no retirements plan in the high construction costs scenario.

Table 41: Construction Cost Rankings Test

Ranking	Base	High Construction Costs	Low Construction Costs
1	Base PP	Base PP	Base PP
2	Delayed Retirement	Delayed Retirement	Delayed Retirement
3	Accelerated Retirement	Accelerated Retirement	Accelerated Retirement
4	High Renewable	No Renewables	High Renewable
5	No Renewables	High Renewable	No Renewables

10.4.8 Total Build Costs (Combined Construction & Interconnection)

A combination of construction costs and interconnection costs were created to assess the impact of an increase or decrease of all build costs. Estimates from the high and low construction cost and interconnection cost tests described above were added together to create high and low build cost scenarios.

Build Test

Higher build costs push solar back, reduces wind, and increases combined cycle builds. Lower construction costs push solar forward, increases wind, and builds combustion turbine and solar hybrid resources.

Figure 79: EVG Base PP

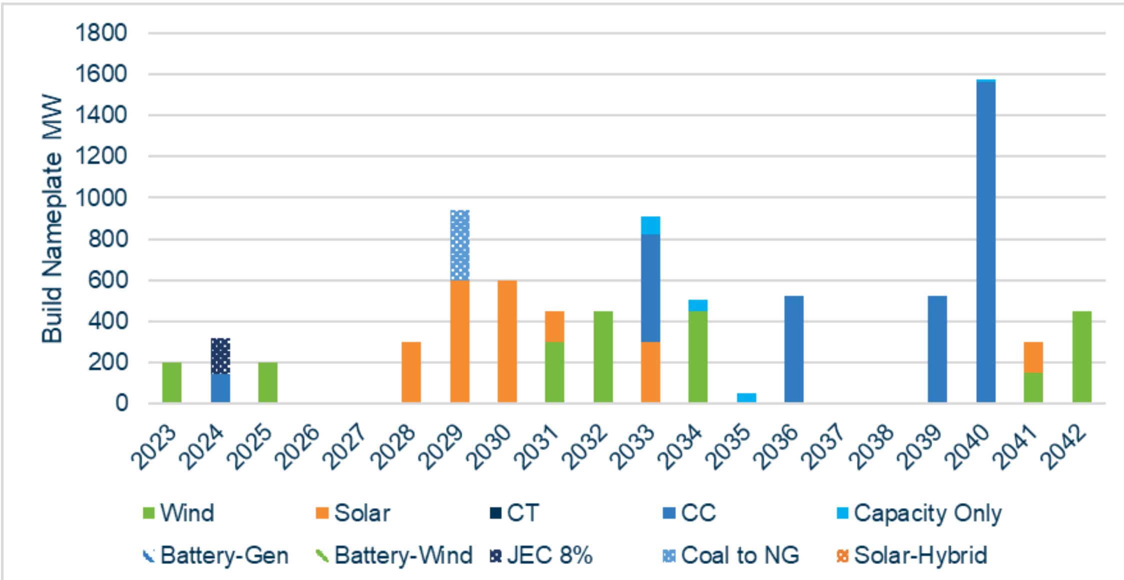


Figure 80: EVG High Total Build Costs

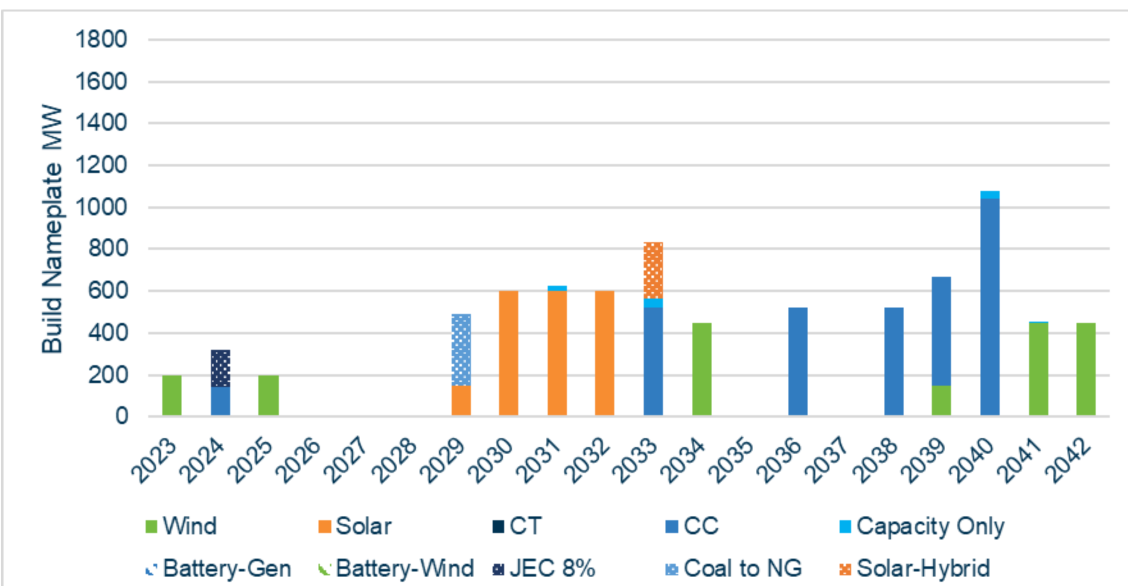
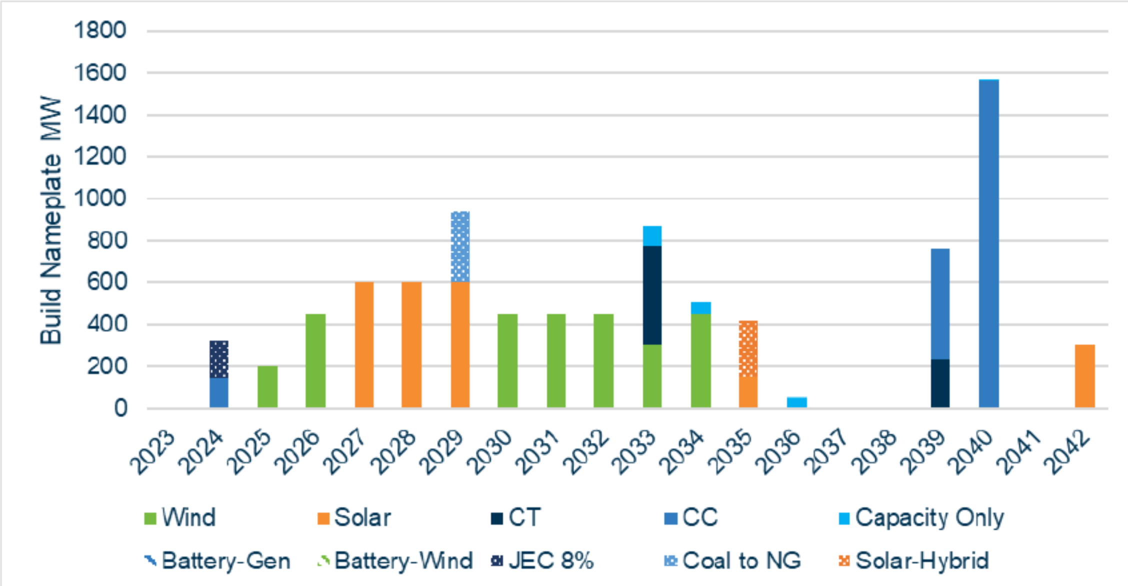


Figure 81: EVG Low Total Build Costs



Rankings Test

Build costs change the order of the high renewable plan and no retirements plan in the high build costs scenario.

Table 42: Total Build Cost Rankings Test

Ranking	Base	High Total Build Cost	Low Total Build Cost
1	Base PP	Base PP	Base PP
2	Delayed Retirement	Delayed Retirement	Delayed Retirement
3	Accelerated Retirement	Accelerated Retirement	Accelerated Retirement
4	High Renewable	No Renewables	High Renewable
5	No Renewables	High Renewable	No Renewables

10.4.9 Prices of Emissions Allowances[46]

Evergy examined the risk that it faces with CO_2, NO_x, and SO_2 allowances. The CO_2 risk is covered in an earlier analysis, based on the "Change in Legal Mandates" uncertain factor. Evergy does not see risks with annual SO_2 or NO_x allowances, and did not create high and low sensitivities.

[46] 20 CSR 4240-22.060(5)(H)

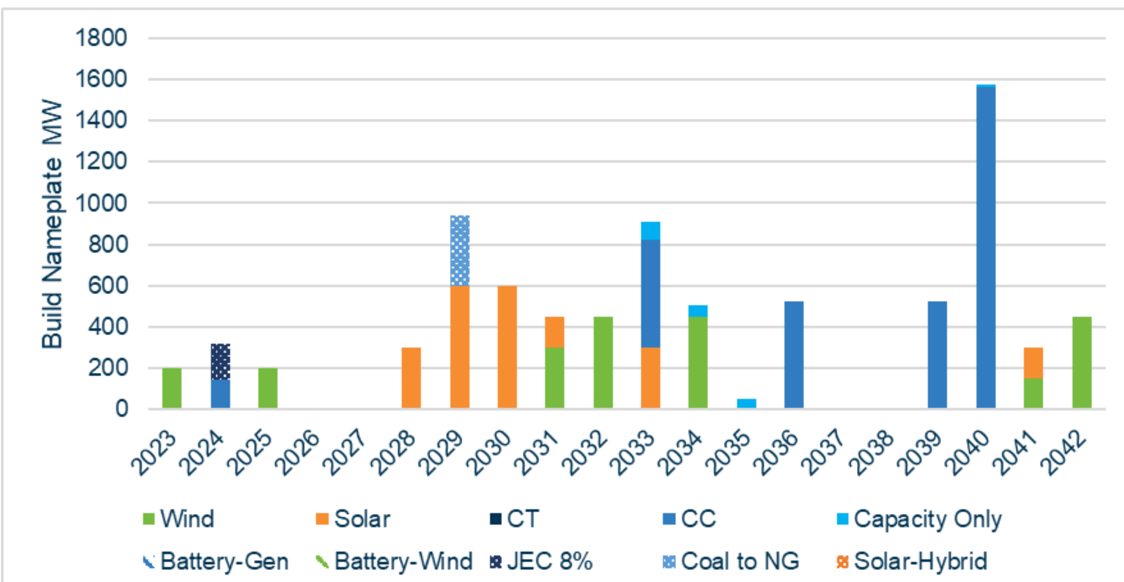
Evergy may have a compliance cost risk affecting Ozone season NO_x allowances associated with potential changes in the Good Neighbor Rule. Currently all Evergy facilities are operating in the Group 2 Ozone region. EPA was moving to place both Missouri and Oklahoma in Group 3, however, the 8th and 10th Federal Circuit Courts of Appeal have stayed EPA from doing so. It is unlikely the judicial process will complete until late 2024 into 2025. Based on current annual allocations from EPA, Evergy will not need to purchase any allowances under the status quo.

For uncertain factor analysis, Evergy created a potential compliance scenario in which it would limit future Ozone season NO_x emissions from Missouri resources.[47]

Build Test

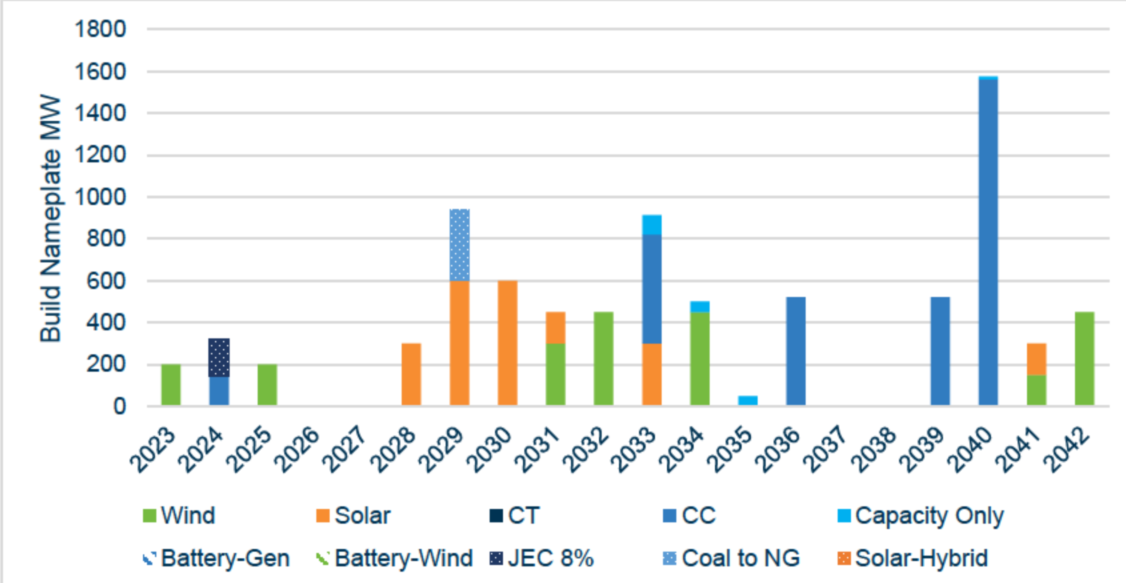
Additional ozone season NO_x emission restrictions for Missouri did not change the preferred build plan.

Figure 82: EVG Base PP



[47] CONF Ozone NO_x CUF Workpaper

Figure 83: EVG NO_x CUF



Rankings Test

Rankings did not change.

Table 43: NO_x Restriction Rankings Test

Ranking	Base	High Ozone NO_x Restriction
1	Base PP	Base PP
2	Delayed Retirement	Delayed Retirement
3	Accelerated Retirement	Accelerated Retirement
4	High Renewable	High Renewable
5	No Renewables	No Renewables

10.4.10 Fixed Operations and Maintenance Costs[48]

To test the sensitivity of the plans to fixed operations and maintenance (FOM) costs, high and low-cost scenarios were created. In the high scenario, costs were 10% higher for all renewable and natural gas options. In the low sensitivity, costs were 10% lower for all renewable and natural gas options. Evergy's coal FOM costs are currently in the lowest quartile of costs in the industry. Coal sensitivities were set to +20% in the high cost and -5% in the low-cost scenario.

[48] 20 CSR 4240-22.060(5)(I)

Build Test

The changes to fixed operations and maintenance costs had a very minor impact on the build plan for both the high and low-cost scenarios.

Figure 84: EVG Base PP

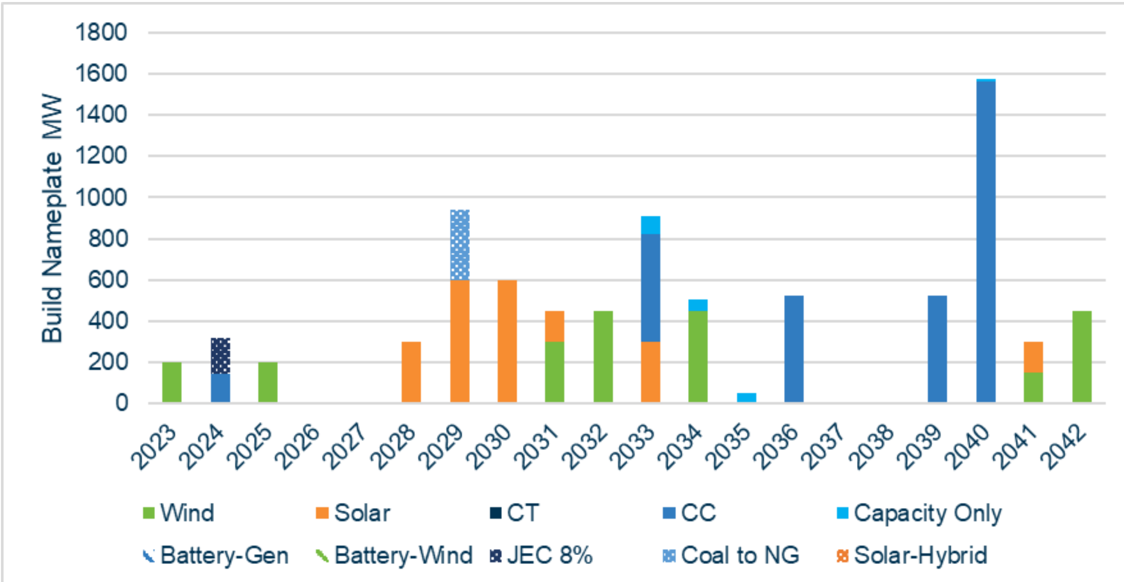


Figure 85: EVG High FOM

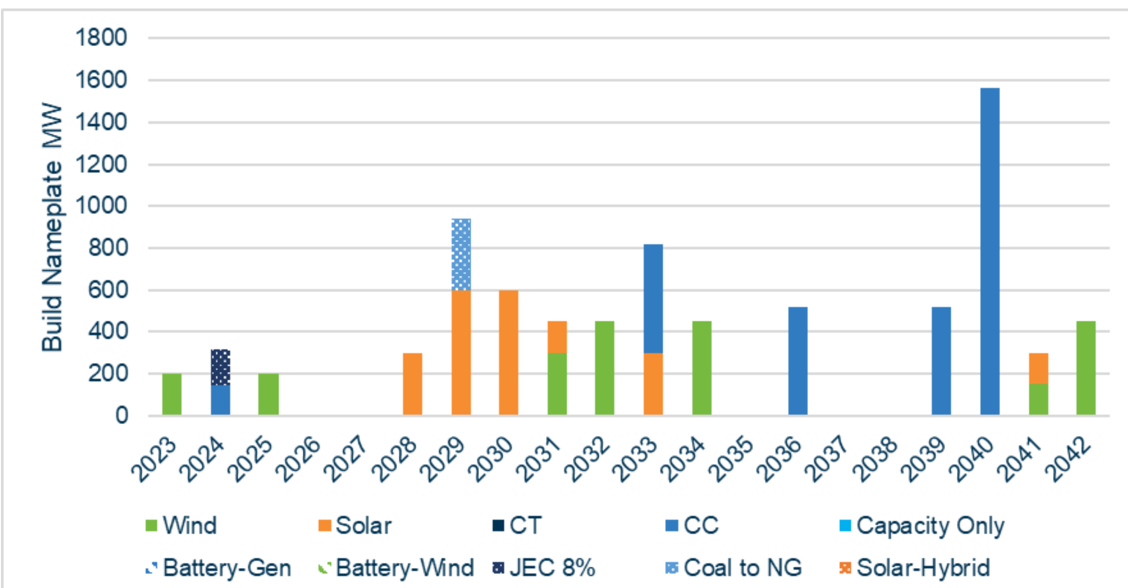
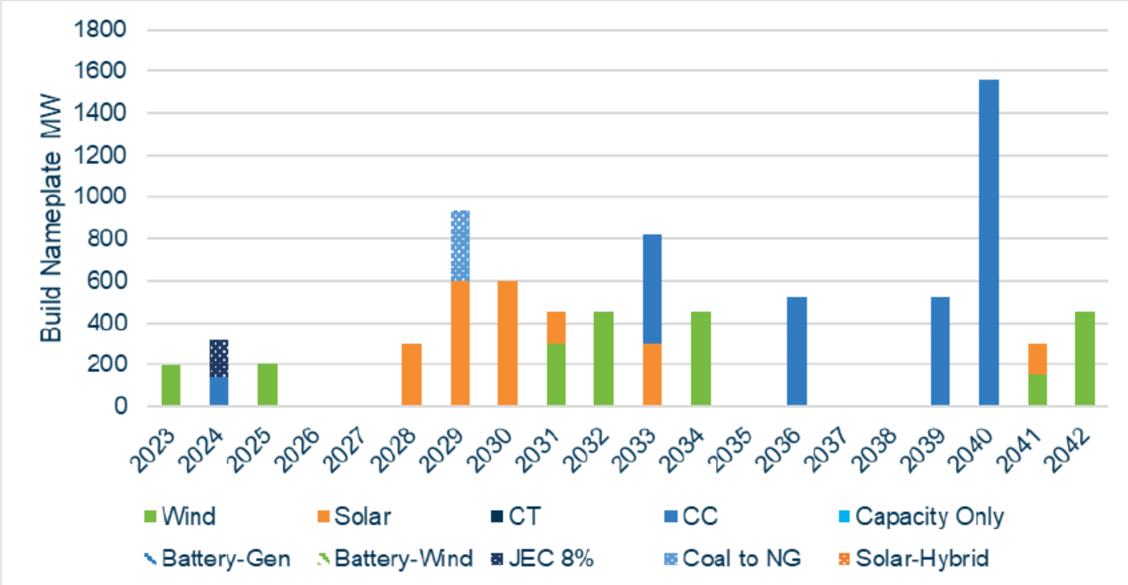


Figure 86: EVG Low FOM



Rankings Test

Changes in fixed operations and maintenance costs did not change the plan rankings.

Table 44: FOM Rankings Test

Ranking	Base	High FOM	Low FOM
1	Base PP	Base PP	Base PP
2	Delayed Retirement	Delayed Retirement	Delayed Retirement
3	Accelerated Retirement	Accelerated Retirement	Accelerated Retirement
4	High Renewable	High Renewable	High Renewable
5	No Renewables	No Renewables	No Renewables

10.4.11 Outage Rates[49]

Outage rates in the 2023 IRP were based on 5-year historical averages. For uncertainty factor analysis, the worst and best year weighted average availability factors were calculated. The low sensitivity decreases outage rates by 3.5%, scaling the fleet to the best availability year, and the high sensitivity increases outage rates by 5.7%, scaling the fleet to the worst availability year.[50]

[49] 20 CSR 4240-22.060(5)(J)
[50] Outage Rates CUF Workpaper

Build Test

The change in outage rates had a minor impact on the build plan for both the high and low outages. Solar and wind builds in 2041 were changed to capacity only.

Figure 87: EVG Base PP

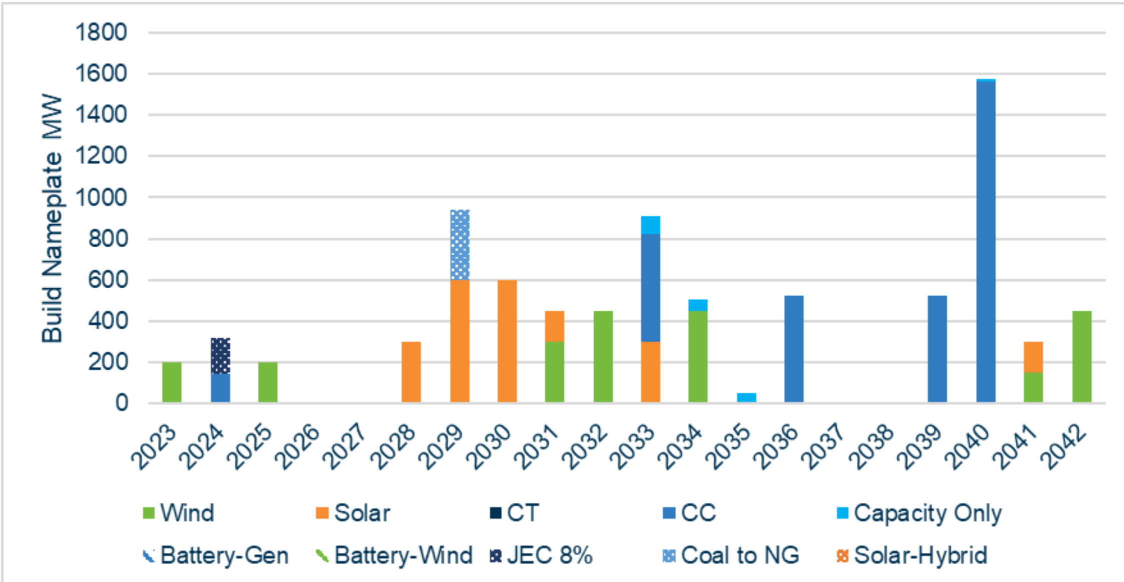


Figure 88: EVG High Outages

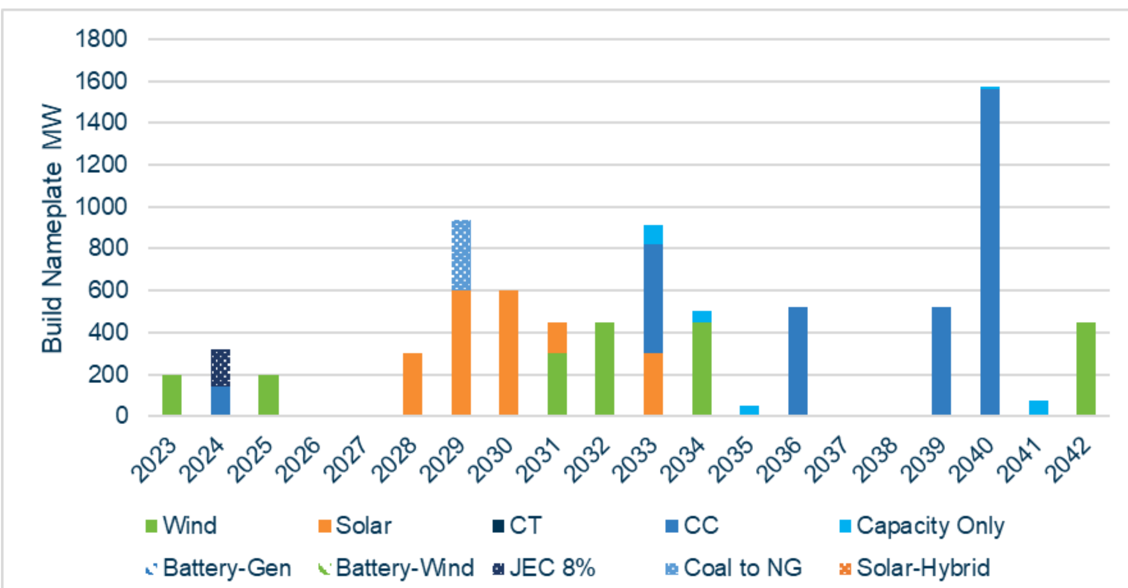
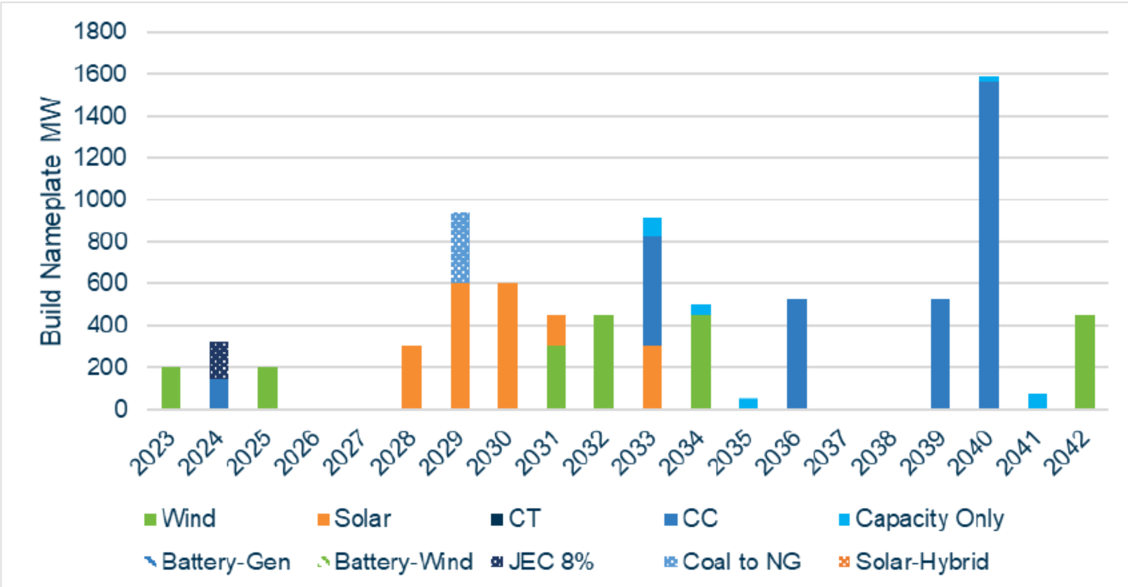


Figure 89: EVG Low Outages



Rankings Test

Changes in outage rates did not change the plan rankings.

Table 45: Outages Rankings Test

Ranking	Base	High Outages	Low Outages
1	Base PP	Base PP	Base PP
2	Delayed Retirement	Delayed Retirement	Delayed Retirement
3	Accelerated Retirement	Accelerated Retirement	Accelerated Retirement
4	High Renewable	High Renewable	High Renewable
5	No Renewables	No Renewables	No Renewables

10.4.12 Load Reductions from Demand-Side Programs[51]

To test the uncertainty of load reduction quantity, sensitivities were created to vary the amount of load reduction achieved by DSM Potential programs. In the high sensitivity, load reductions were 5% higher despite the same program costs, and in the low sensitivity, load reductions were 5% lower.

[51] 20 CSR 4240-22.060(5)(K)

Build Test

Higher load reduction moved new builds further into the future and lower load reduction increased capacity purchases from SPP to meet capacity requirements. While the DSM scenarios did alter the optimal build plans these changes are not significant.

Figure 90: EVG Base PP

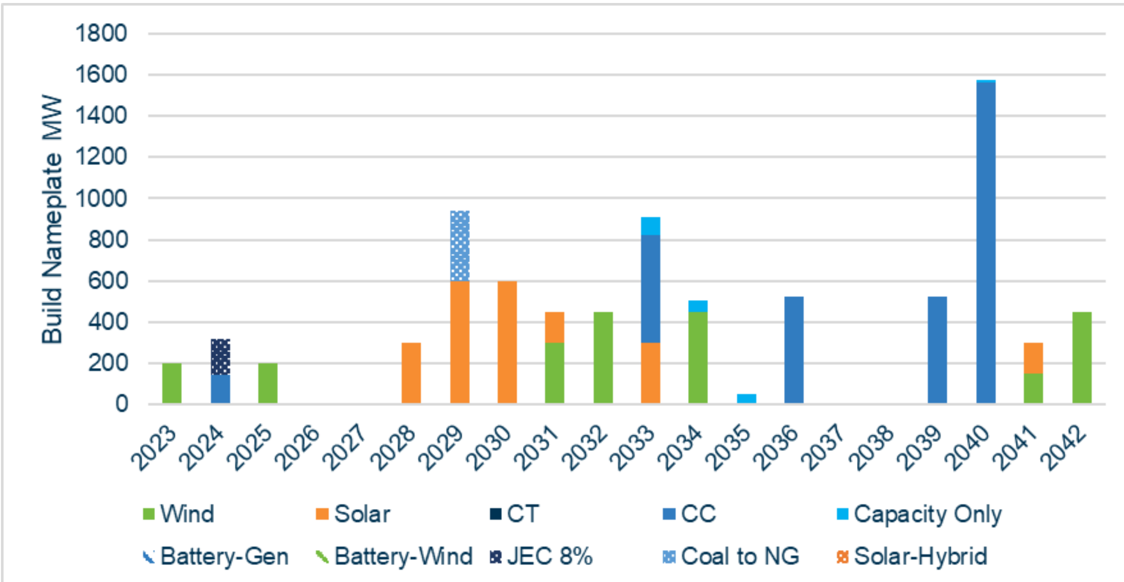


Figure 91: EVG High DSM Load Reduction

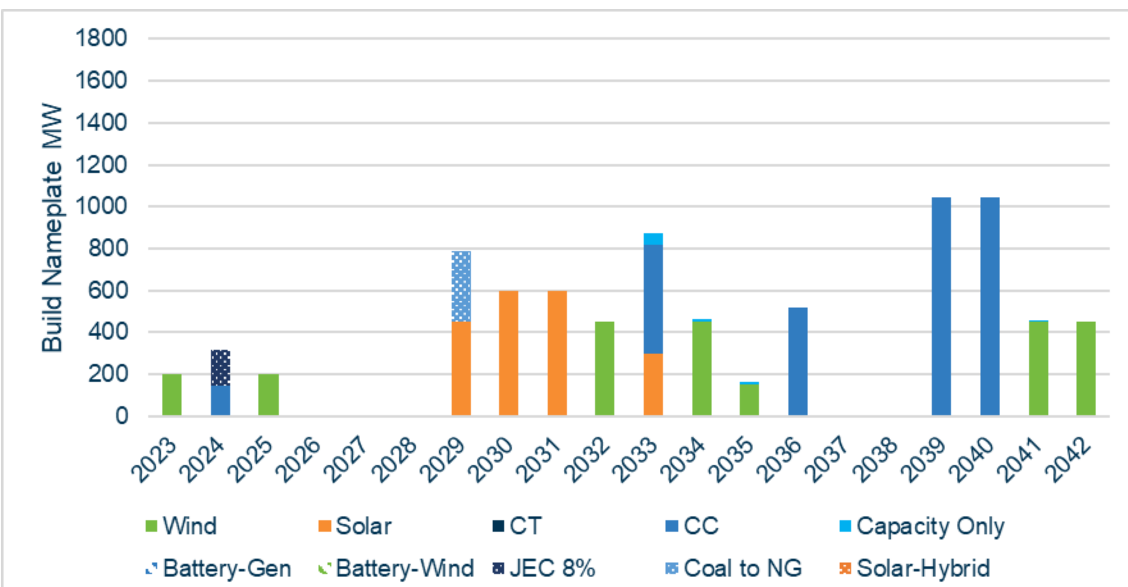
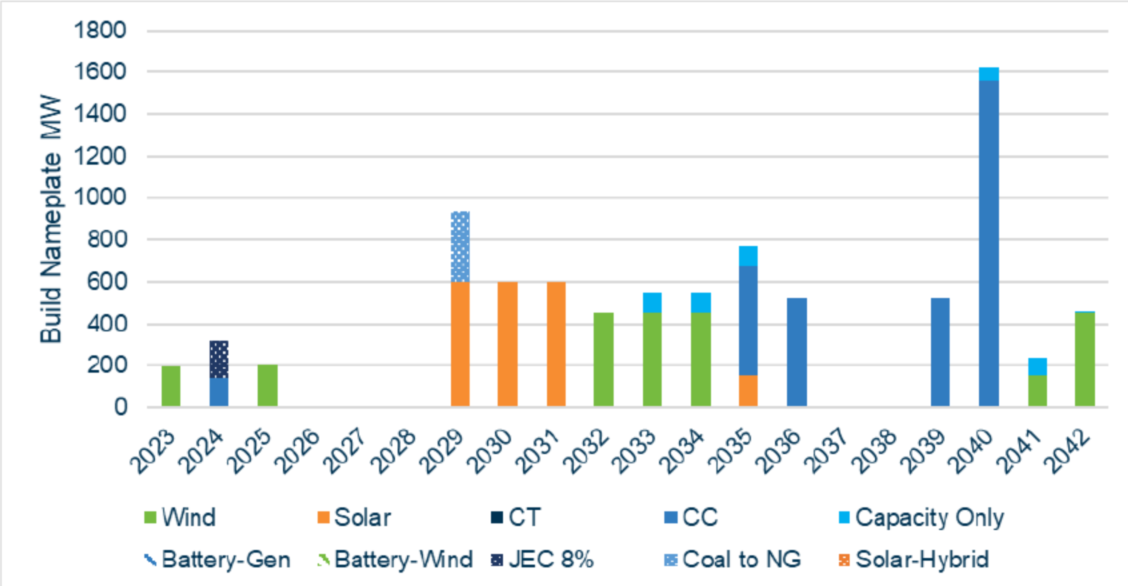


Figure 92: EVG Low DSM Load Reduction



Rankings Test

The plan rankings did not change under high and low load reduction scenarios.

Table 46: DSM Load Reduction Rankings Test

Ranking	Base	High DSM Reduction	Low DSM Reduction
1	Base PP	Base PP	Base PP
2	Delayed Retirement	Delayed Retirement	Delayed Retirement
3	Accelerated Retirement	Accelerated Retirement	Accelerated Retirement
4	High Renewable	High Renewable	High Renewable
5	No Renewables	No Renewables	No Renewables

10.4.13 Costs of Demand-Side Programs[52]

To test the uncertainty of DSM program costs, sensitivities were created to vary the cost of DSM Potential programs. In the high sensitivity, costs were 5% higher despite the same load reduction, and in the low sensitivity, costs were 5% lower.

Build Test

A 5% increase or reduction in DSM program costs did not alter the preferred build plan.

[52] 20 CSR 4240-22.060(5)(L)

Figure 93: EVG Base PP

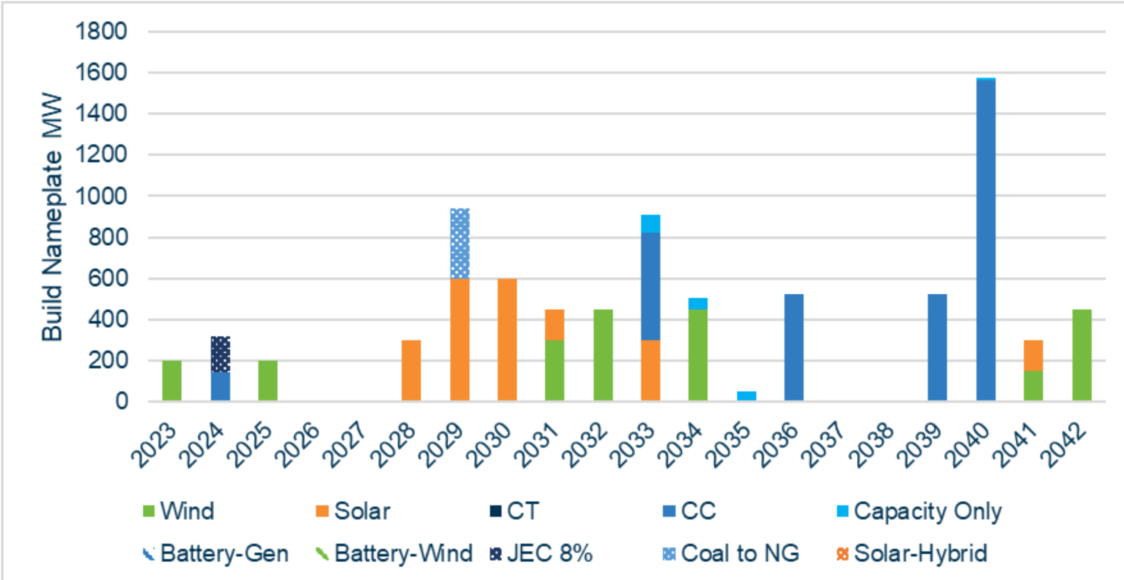


Figure 94: EVG High DSM Costs

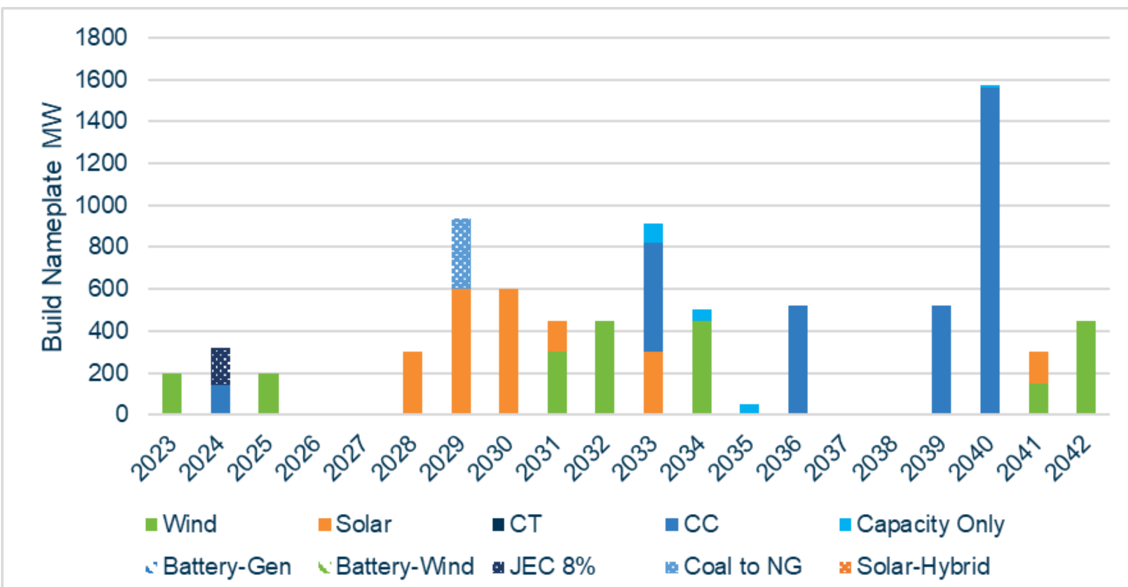
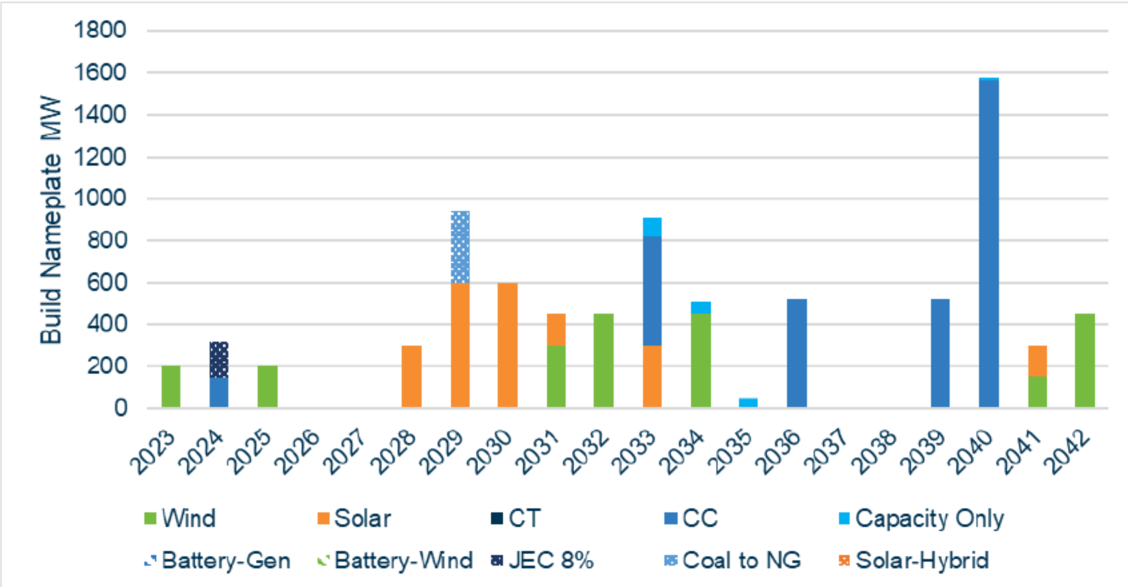


Figure 95: EVG Low DSM Costs



Rankings Test

Plan rankings did not change under high and low DSM cost scenarios.

Table 47: DSM Cost Rankings Test

Ranking	Base	High DSM Costs	Low DSM Costs
1	Base PP	Base PP	Base PP
2	Delayed Retirement	Delayed Retirement	Delayed Retirement
3	Accelerated Retirement	Accelerated Retirement	Accelerated Retirement
4	High Renewable	High Renewable	High Renewable
5	No Renewables	No Renewables	No Renewables