Evergy Missouri West

2025 Annual Update

Integrated Resource Plan

March 2025

Public

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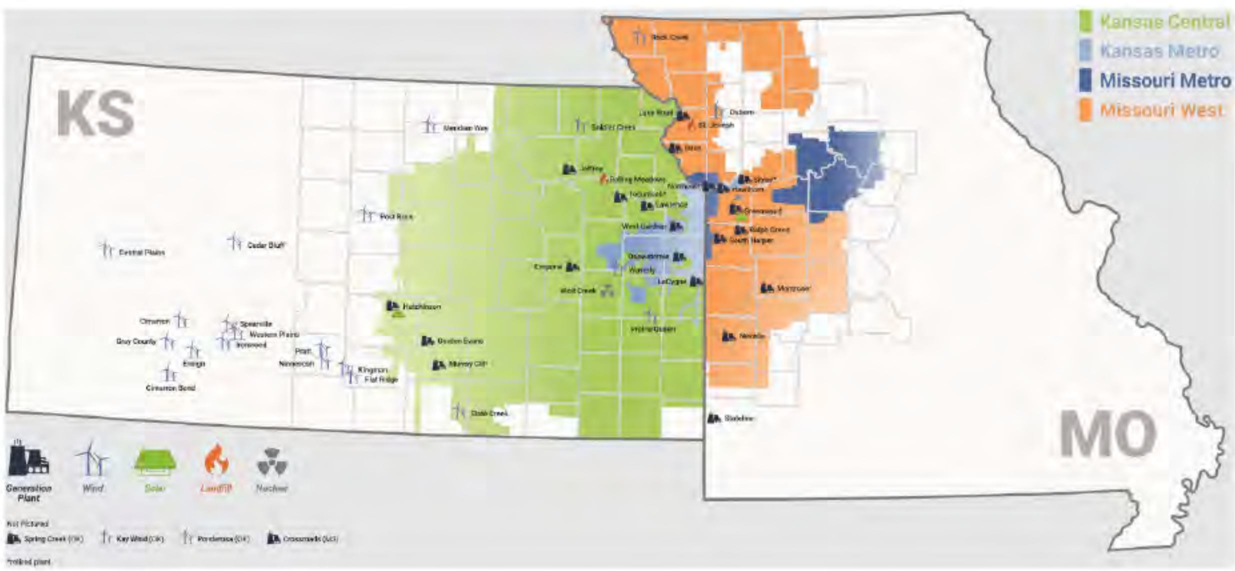
Section 1: Executive Summary

1.1 Utility Introduction

Evergy Missouri West is an integrated, mid-sized electric utility serving portions of Northwest Missouri including St. Joseph and several counties south and east of the Kansas City, Missouri metropolitan area. Evergy Missouri West also provides regulated steam service to certain customers in the St. Joseph, Missouri area. A map of the Evergy service territory which includes Evergy Missouri West is provided in Figure 1 below.

Figure 1: Evergy Service Territory



Evergy Missouri West is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. The Table below provides a snapshot of the number of customers served, retail sales, and peak demand based upon 2024 data.

Table 1: 2024 Customers, Retail Sales, and Peak Demand

Jurisdiction	Number of Retail Customers	Retail Sales (MWh)	Net Peak Demand (MW)
Evergy Missouri West	347,804	775,198	1,968

Evergy Missouri West owns and operates a diverse generating portfolio, including Power Purchase Agreements (PPA) to meet customer energy requirements. The Table below reflects Evergy Missouri West's generation assets including PPAs.

Table 2: Capacity and Energy by Resource Type

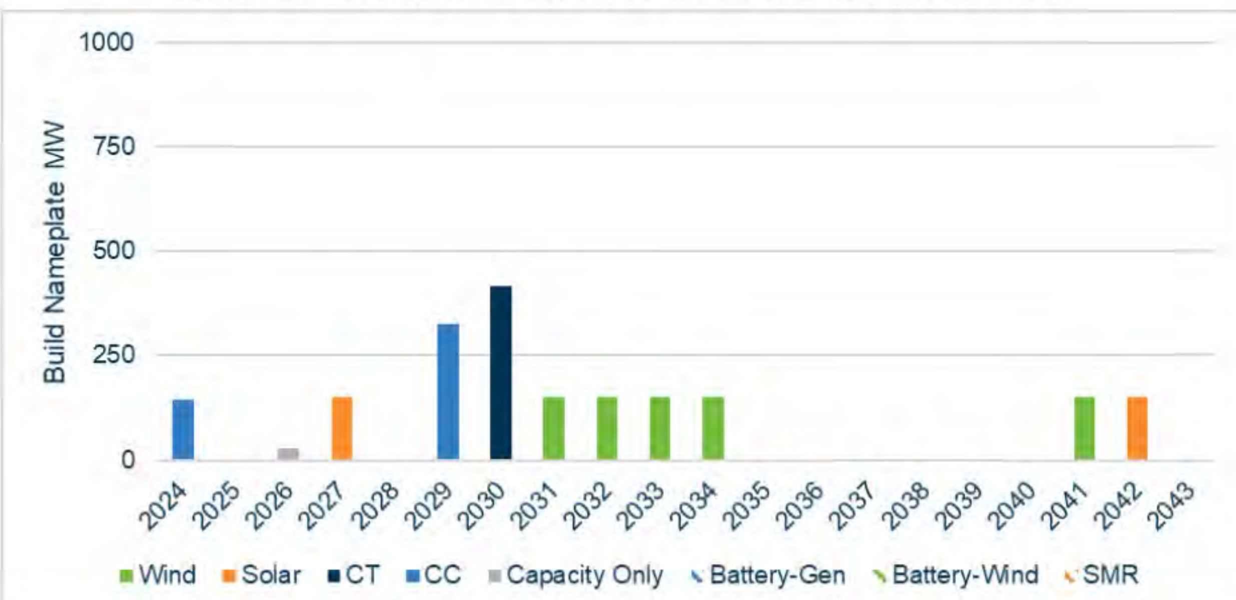
Jurisdiction	Capacity by Fuel Type	Capacity (MW)	Capacity (%)	Energy (MWh)	Energy (%)
Evergy Missouri West	Coal	463	17.9%	1,158,152	24%
	Nuclear	-	-	-	-
	Natural Gas/Oil	1,334	51.6%	1,039,824	21%
	Renewable*	791	30.6%	2,654,187	55%
Total		**2,588**	**100.0%**	**4,852,163**	**100%**

**Nameplate renewables capacity*

1.2 Preferred Plan Filed in the 2024Triennial IRP

Evergy Missouri West submitted its 2024 Triennial IRP filing on April 1, 2024.[1]

Figure 2: Evergy Missouri West 2024 Preferred Plan CAAA



[1] Case No. EO-2024-0154

The Preferred Plan called for Evergy Missouri West to build or acquire new resources including 150 MW of solar in 2027, a 325 MW share of Combined Cycle Gas Turbines in 2029 and a 415 MW Combustion Turbine in 2030 to meet customer needs in the next five years. Evergy Missouri West also selected the RAP+ (Plus) level of future demand-side programs to implement over the planning horizon. Coal generator retirements were anticipated to occur in December 2030 for Jeffrey 2 and Jeffrey 3, and in December 2039 for Iatan 1 and Jeffrey 1.

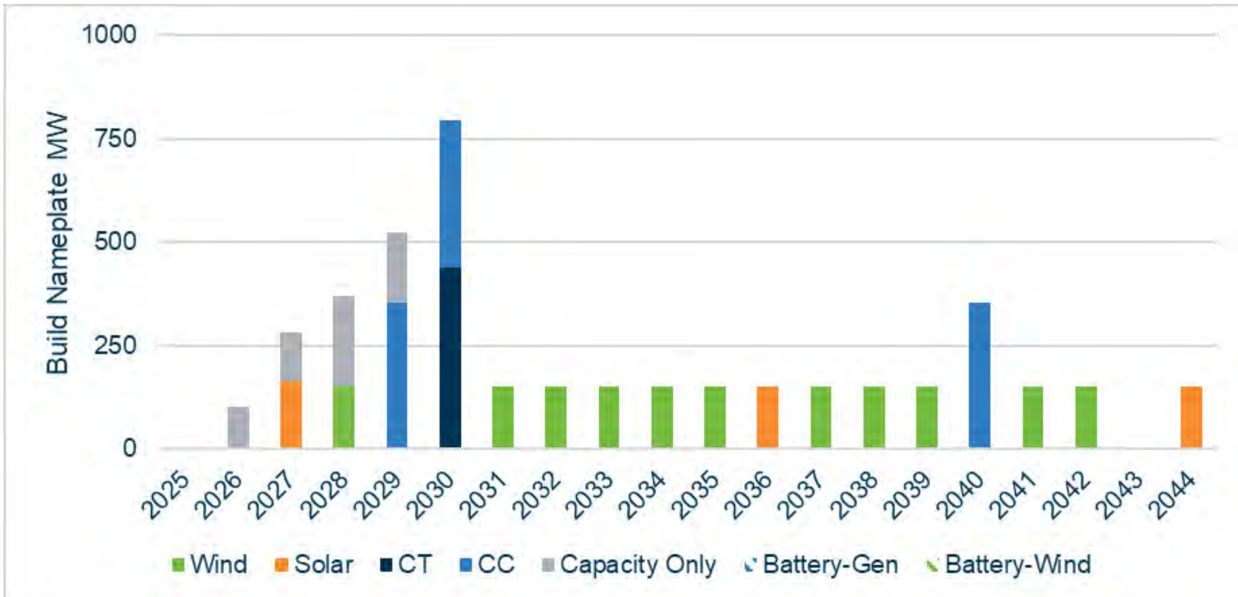
Several months after the IRP filing, Evergy Missouri West finalized execution plans for new resources selected in the Preferred Plan through 2030. The Company contracted for build-transfer or acquired the development of two solar projects, Foxtrot and Sunflower Sky, totaling 165 MW with expected commercial operation by summer 2027. A Certificate of Convenience and Necessity was filed for these projects on October 25, 2024.[2] The Company also finalized site selection for the thermal projects and contracted with turbine vendors. A Certificate of Convenience and Necessity was filed for the Viola Combined Cycle (355 MW) and the Mullin Creek #1 Combustion Turbine (440 MW) projects on November 15, 2024.[3]

1.3 Changes to the Preferred Plan for the 2025 Annual Update

This year's 2025 Annual Update augments the Evergy Missouri West Preferred Plan to include two additional resources in the 5-year near-term horizon. The additions include a 150 MW wind resource in 2028 and a 50% share of a CCGT resource, both of which are primarily needed to meet greater energy and capacity needs due to new large customer load requirements that have become more certain since the 2024 IRP. Evergy Missouri West supplemented its CCN filing on February 19, 2025 to include a 50% share of the McNew CCGT project to meet this planned need.

[2] EA-2024-0292
[3] EA-2025-0075

Figure 3: Evergy Missouri West 2025 Preferred Plan ACAA



The 2025 Preferred Plan also reflects the demand-side programs consistent with the current MEEIA Cycle 4 approved programs, and the Jeffrey 2 coal unit operating on natural gas beginning in 2030, rather than retiring.

Table 3: Evergy Missouri West Preferred Plan Comparison

Note: All retirement dates were assumed to be end of year for 2024 Triennial, but end of winter season for 2025 Annual Update.

	2024 Triennial IRP	2025 IRP Annual Update
Retirements	Lake Road 4/6 in 2030 Jeffrey 3 in 2030 Jeffrey 2 in 2030 Iatan 1 in 2039 Jeffrey 1 in 2039	Lake Road 4/6 in 2030 Jeffrey 3 in 2030 Iatan 1 in 2039 Jeffrey 1 in 2039 Jeffrey 2 to NG in 2030
Wind Additions	150 MW in 2031 150 MW in 2032 150 MW in 2033 150 MW in 2034 150 MW in 2041	150 MW in 2028 150 MW in 2031 150 MW in 2032 150 MW in 2033 150 MW in 2034 150 MW in 2035 150 MW in 2037 150 MW in 2038 150 MW in 2039 150 MW in 2041 150 MW in 2042
Solar Additions	150 MW in 2027 150 MW in 2042	165 MW in 2027 150 MW in 2036 150 MW in 2044
Battery Additions	n/a	n/a
Thermal Additions	325 MW CC in 2029 415 MW CT in 2030	355 MW CC in 2029 440 MW CT in 2030 355 MW CC in 2030 355 MW CC in 2040
New DSM Programs	RAP+	MEEIA Cycle 4 Extended

In addition to load growth, the primary drivers of changes to the needs identified in the resource plan were:

- Alignment with the most recent SPP resource adequacy rules and study results for expected summer and winter reserve margins and capacity accreditation
- Lower demand-side management contributions to capacity needs based on the approved MEEIA Cycle 4 programs compared to RAP+ (Plus) levels selected in the 2024 IRP Preferred Plan (more detail is provided in Section 1.6)

Other changes included in the Annual Update:

- Cost and performance characteristics of new thermal resource options consistent with market availability
- Minor updates to solar, wind, and storage costs based on technology curve updates

1.4 Managing Risk and Growth Opportunities

Evergy Missouri West sees opportunities for high load growth from economic development in the region while it faces the challenges of meeting increasing reliability needs driven by extreme weather and an aging fleet, as well as long lead times and rising costs to build new generation.

Recognizing the uncertainty of future load growth and the need to make commitments to ensure energy and capacity supply at least 3-5 years before it is needed, this annual update examines different load addition scenarios and existing fleet contingencies to determine least-cost alternative plans and to understand the tradeoffs of new resource decisions.

Consistent with the Triennial IRP, future natural gas commodity prices, carbon dioxide emissions policy, and new resource construction costs are assessed as critical uncertain factors which contribute to the economic evaluation of plans.

The Environmental Protection Agency's (EPA) Greenhouse Gas (GHG) Final Rule was issued in May 2024, after the submission of the 2024 Triennial IRP. [4] Evergy Missouri West developed GHG Rule compliance options for its coal fleet, including high-level cost estimates for retrofitting coal resources to co-fire or fully operate with natural gas. The Company also engaged with natural gas pipelines to estimate the costs of adding

[4] New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule. 2024-09233 (89 FR 39798). May 5, 2024.

infrastructure to deliver natural gas to the sites. An analysis of compliance plans is included in this Annual Update Section 11. Because all compliance plans are expected to be more costly than the Preferred Plan, Evergy does not plan to execute a compliance plan until there is more certainty whether the EPA will enforce the GHG Rule, considering the change in presidential administrations.

1.5 Ongoing Commitment to a Responsible Fleet Transition

Evergy Missouri West, along with the rest of the Evergy Companies, is committed to a long-term strategy to reduce CO_2 emissions in a cost-effective and reliable manner. Evergy's coal fleet is aging, and its performance has significant impact on meeting SPP's new resource adequacy requirements. Additionally, the coal fleet is increasingly at risk due to tightening environmental regulations. As a result, each Evergy utility's Integrated Resource Plan (IRP) is built with a goal of responsibly transitioning its fleet away from coal over time, while maintaining a diverse fuel mix and sufficient flexibility to adjust plans as policy and technology change. A responsible transition means one that focuses on maintaining reliability and affordability while also reducing environmental impact over time.

Evergy Missouri West's plan continues to include the measured retirement of coal plants over time and the replacement of this capacity and energy with a mix of new dispatchable resources, renewable resources, and demand-side management programs. In addition to replacing capacity, these additions also allow Missouri West to meet increasing requirements driven by higher resource adequacy requirements and load growth from economic development. This resource plan, through the risk analysis performed in compliance with the Chapter 22 IRP rules, is designed to be robust across a variety of uncertainties and to include a diverse mix of resources that reduce the risk to both system reliability and customer affordability which can result from "putting all of your eggs in one basket." Despite the robustness of the risk analysis performed, however, the future remains inherently uncertain and, as a result, maintaining flexibility and continuing to adjust plans over time is imperative.

The goal of this Preferred Plan is to outline the Company's current long-term strategy to meet customer energy needs, but also to focus particularly on the robustness of near-term decisions which must be made to begin executing on that strategy. Given the increasing capacity and energy requirements described throughout this filing, there is significant urgency to continue to execute both the supply- and demand-side additions outlined in the first three-to-five years of this Preferred Plan. The analysis performed in this IRP will be used to support separate regulatory filings related to these resource additions. These filings must be supported by the IRP, as a whole, and not only by resource-specific evaluations because the evaluation of resource decisions cannot be performed in a vacuum. The integrated analysis of risks and resource options, along with customer needs for energy and capacity, is required to reflect the trade-offs inherent in any resource decision. Any resource added (or not added) today has an impact on future resource decisions in the same way that past resource decisions impact future decisions. An tntegrated analysis of these trade-offs is performed in triennial IRP filings and updated annually in order to make necessary adjustments to the Company's long-term resource plan when conditions change. The latest analysis performed through this IRP is summarized below and outlined in detail throughout this filing.

1.6 Demand-Side Management

After the 2024 Triennial IRP filing, Evergy Missouri West filed its proposal for future demand-side programs in its Missouri Energy Efficiency Investment Act (MEEIA) Cycle 4 application on April 29, 2024.[5] The parties to the case reached a joint agreement and the Commission issued its order approving the agreement and tariffs on December 11, 2024, with an effective date of January 1, 2025.

EMW's approved MEEIA Cycle 4 programs will deliver a lower capacity accreditation as compared to the RAP+ (realistic achievable potential plus) demand-side management ("DSM") profile that was selected in EMW's 2024 IRP and subsequently filed in EMW's MEEIA Cycle 4 proposed plan in Case No. EO-2023-0369/0370. Additionally, the

[5] EO-2023-0369/0370

approved MEEIA Cycle 4 programs were shorter in duration than the proposed programs in Case No. EO-2023-0369/0370. EMW had filed and proposed a 4-year cycle for its energy efficiency programs concurrent with a 4-year cycle for its demand response programs. However, the Stipulation and Agreement approved in Case No. EO-2023-0369/0370 included reduced energy efficiency programs for two years (2025-2026) and demand response programs for three years (2025-2027). These changes result in a lower total cost-effective capacity reduction than what could be achieved through the demand-side programs modeled in EMW's 2024 IRP.

As a result, EMW modified its 2025 IRP DSM planning profile to reflect (1) the lower, approved MEEIA Cycle 4 portfolio (budget, energy, demand and cycle duration) and (2) the uncertainty of future MEEIA programs given the tenor of Staff, OPC and Commission comments during the filing, as well as the terms of the Stipulation and Agreement. Therefore, EMW did not model any additional energy efficiency programs after the approved cycle ends in 2026. It also modeled a continuation of the approved MEEIA Cycle 4 level of demand response programs through the end of the IRP planning horizon.

Evergy also includes the estimated impacts of the Commission's time-of-use (TOU) rates from Case No. ER-2022-0129/0130 based on its 2023 DSM potential study by Applied Energy Group (AEG) (see Appendix 8). Following the Commission's order to transition to default TOU rates, the Company modified its potential study TOU impact estimates to better align with the Commission's final order that approved the peak adjustment charge rate as the default TOU rate. Because this rate reflects a much lower price differential than the modeled TOU rates in the potential study, Evergy adjusted the TOU impact downward by 70% (as determined in the potential study for use in its 2024 IRP), which resulted in only 30% of the study's forecasted impact.

Section 2: Load Analysis and Load Forecasting Update

2.1 Changes from the 2024 Triennial IRP

Several inputs to the load forecasting models were updated for this filing compared to the 2024 Triennial IRP:

- Historical data for customers, kWh and $/kWh: ending June 2024 vs ending June 2023.
- DOE forecasts of appliance and equipment saturations and kWh/unit are unchanged. Both the 2024 IRP and the 2025 utilize the 2023 Annual Energy Outlook. See below for additional descriptions.
- Economic forecasts from Moody's Analytics: June 2024 vs June 2023.
- Class models in the 2025 Evergy Missouri West Update filing are the same as the 2024 Triennial filing: residential, small commercial, big commercial (medium, large, large power) and industrial. However, Nucor Steel was separated from the rest of the Industrial class and forecasted separately.
- The Company also re-evaluated the output elasticity used in the commercial and industrial models and the elasticity used in the residential model. Adjustments were made to improve the model fit.
- The Company utilized an EPRI (Electric Power Research Institute) electric vehicle study within its modeling for 2025 Update filing.
- The Company utilized Google Mobility Reports data through October of 2022 (Google stopped reporting the mobility data publicly October 15, 2022) to account for load pattern changes resulting from geolocation behaviors induced by the COVID19 pandemic.

Table 4, Figure 4, and Figure 5 below show a higher forecast for both peak and energy for the 2025 Update compared to the 2024 Triennial IRP. Below are the primary reasons for the change in forecast:

- The Energy Information Administration (EIA) did not produce an Annual Energy Outlook (AEO) for 2024 and recommended stakeholders to continue using the 2023 AEO. The EIA chose to invest in making updates to their modeling process during 2024. Evergy's 2025 IRP update utilizes end-use forecasts from the 2023 AEO, the same as was used in the 2024 triennial IRP.

- There are some changes from the Moody's Analytics Economic forecasts from 2023 to 2024. Economic forecasts for Population, Households, Employment (both Manufacturing and Non-Manufacturing) and Gross Product (both Manufacturing and Non-Manufacturing) all show slightly higher growth trajectories in the 2024 forecast compared to the 2023 forecast. The higher growth trajectory in the Economic forecast contributes to a higher growth trajectory in the load forecast.
- The growth trajectory of Evergy Missouri West Commercial load since the 2024 Triennial IRP forecast contributes to a higher forecast trajectory, while Industrial load since the 2024 Triennial IRP forecast contributes to a lower forecast trajectory. Additionally, Figures 6 and 7 show how new large load customers heavily influence load growth trajectory 2025-2032.

Table 4: Evergy MO West Mid-Case Annual Forecast **Confidential**

[redacted]

Figure 4: Peak Forecasts - 2025 Annual Update vs. 2024 Triennial IRP

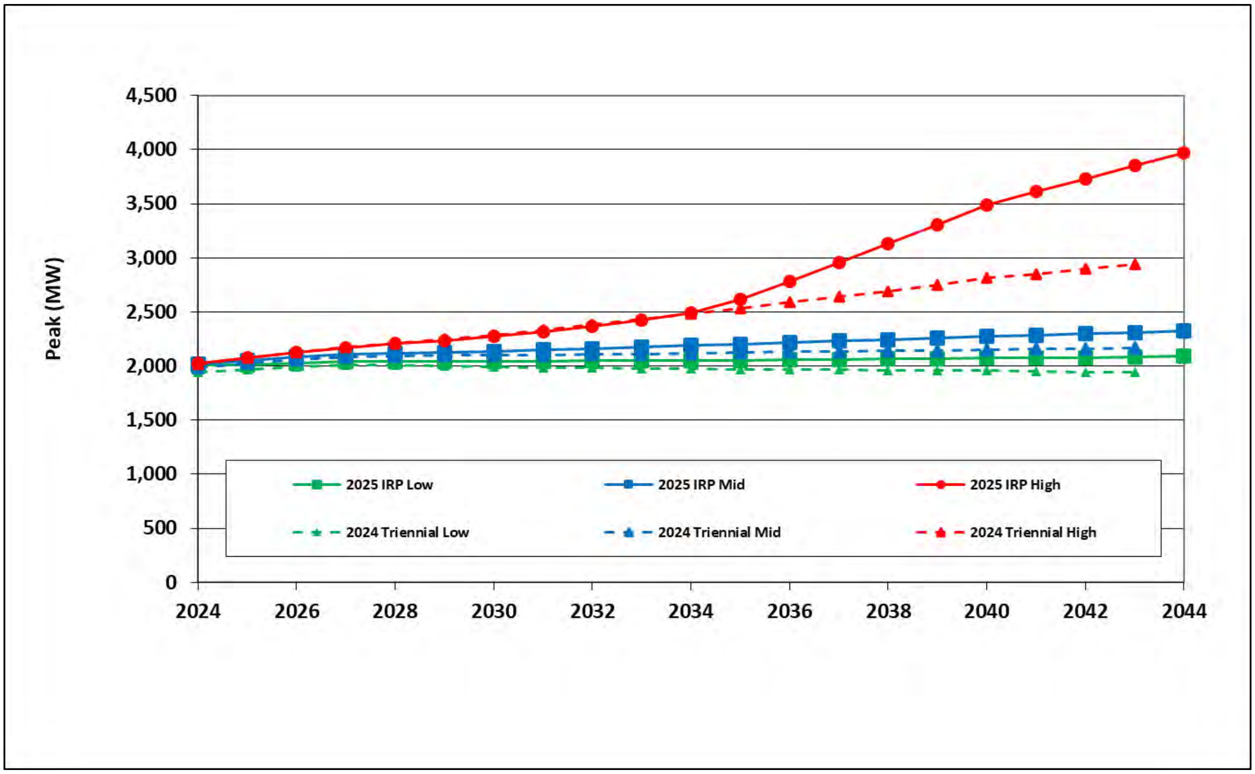
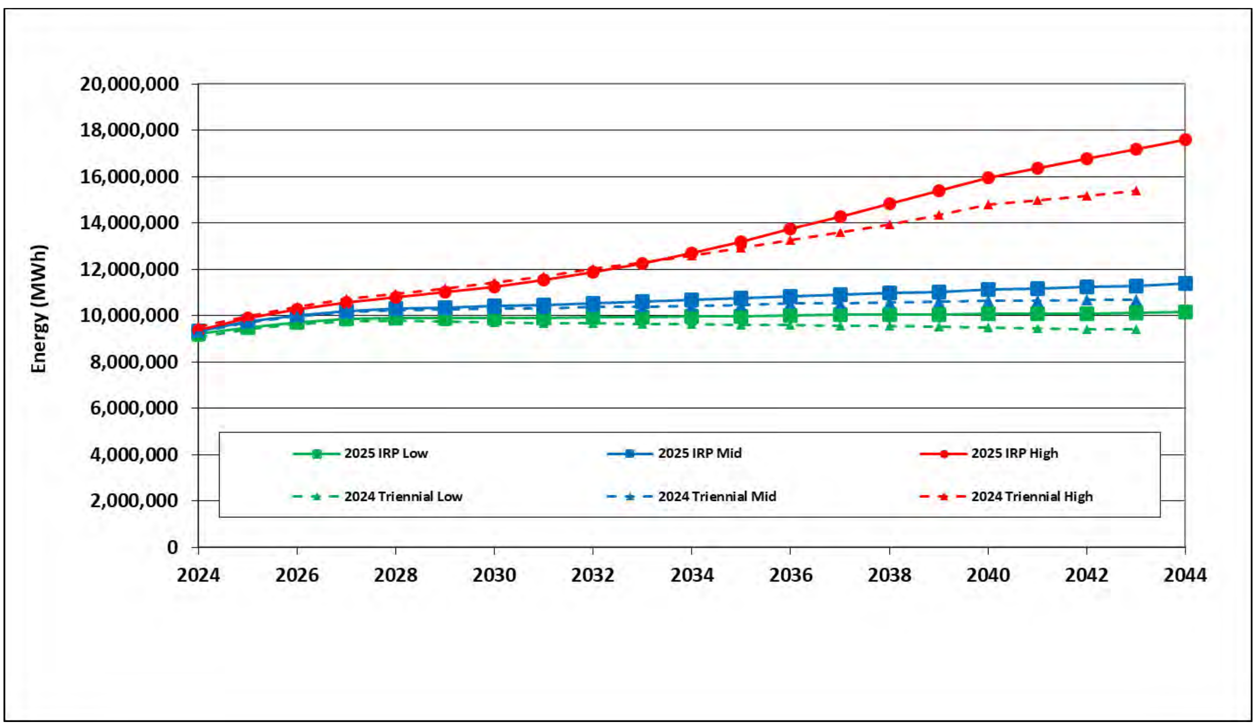


Figure 5: Energy Forecasts - 2025 Annual Update vs. 2024 Triennial IRP



In addition to the higher load forecasts shown in Table 4, Figure 4, and Figure 5 and described above, Evergy Missouri West has included a new large load customer profile in its base load forecast for this IRP starting in 2026.

In recent months, the customer completed Evergy's internal review process that allows the Company to complete due diligence on large load customer requests, sets forth numerous data points to vet the feasibility of the customer locating in Evergy's service territory, and requires a sizeable deposit to support analysis to study the viability of the customer's project. In January 2025, Evergy submitted an Attachment AQ study to the SPP to study the transmission upgrade requirements of adding the new large load. Additionally, Evergy Missouri West and the new large load customer continue to progress negotiations and expect to have Construction and Service Agreements fully executed in the second quarter of 2025 with an expected project announcement in the second half of 2025.

Evergy has a large pipeline of prospective new large load customers, but not all are included in base load planning until certain progress on Evergy's internal review process has been met to avoid exposing our Preferred Plan to unnecessary risks.

The new large load was not included in the typical load forecast data shown in Table 4, Figure 4, and Figure 5 due to the timing of when Evergy completed its annual load forecast update and the subsequent timing of gaining more certainty of the new large load customer locating in Evergy Missouri West's service territory. In order to plan for the new load. an adjustment was made after the load forecast process was complete. Figures 6 and 7 show the peak MW and MWh impact over the next decade of adding the new large load profile to the native demand in the 2025 IRP Mid forecast. Each of the base planning scenarios studied in this 2025 IRP include the new large load starting its ramp in 2026, reaching its peak in 2032, and continuing at the peak load in the early-2030s through the end of the 20-year planning period.

Figure 6: EMW Peak MW Load Forecast Including New Large Load

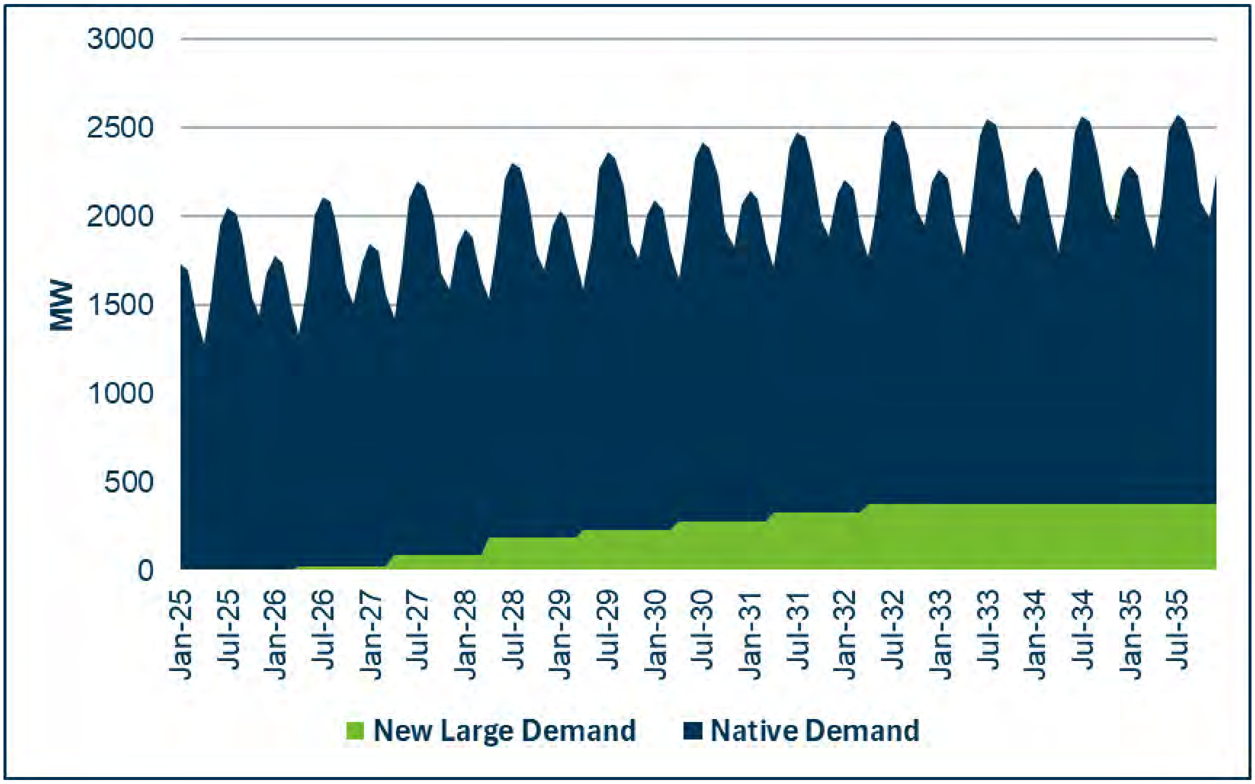
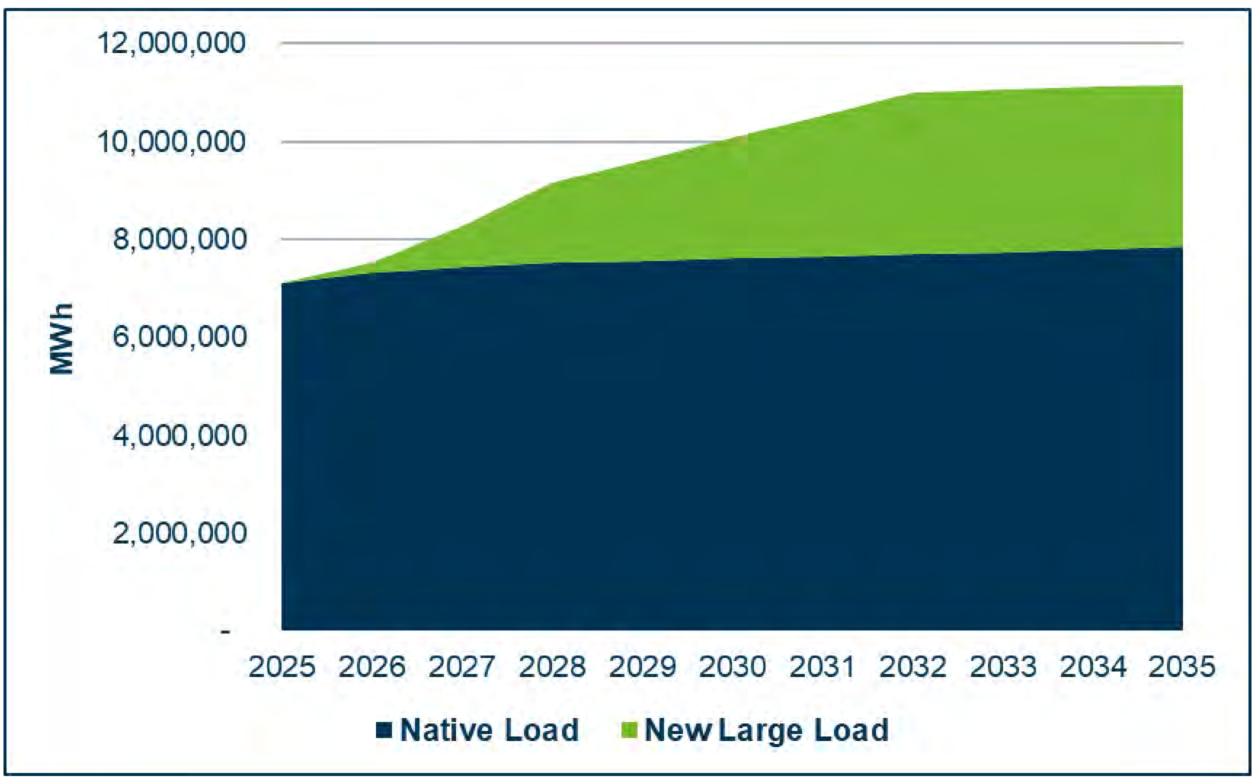


Figure 7: EMW Peak MWh Load Forecast Including New Large Load



Section 3: Market Fundamentals Update

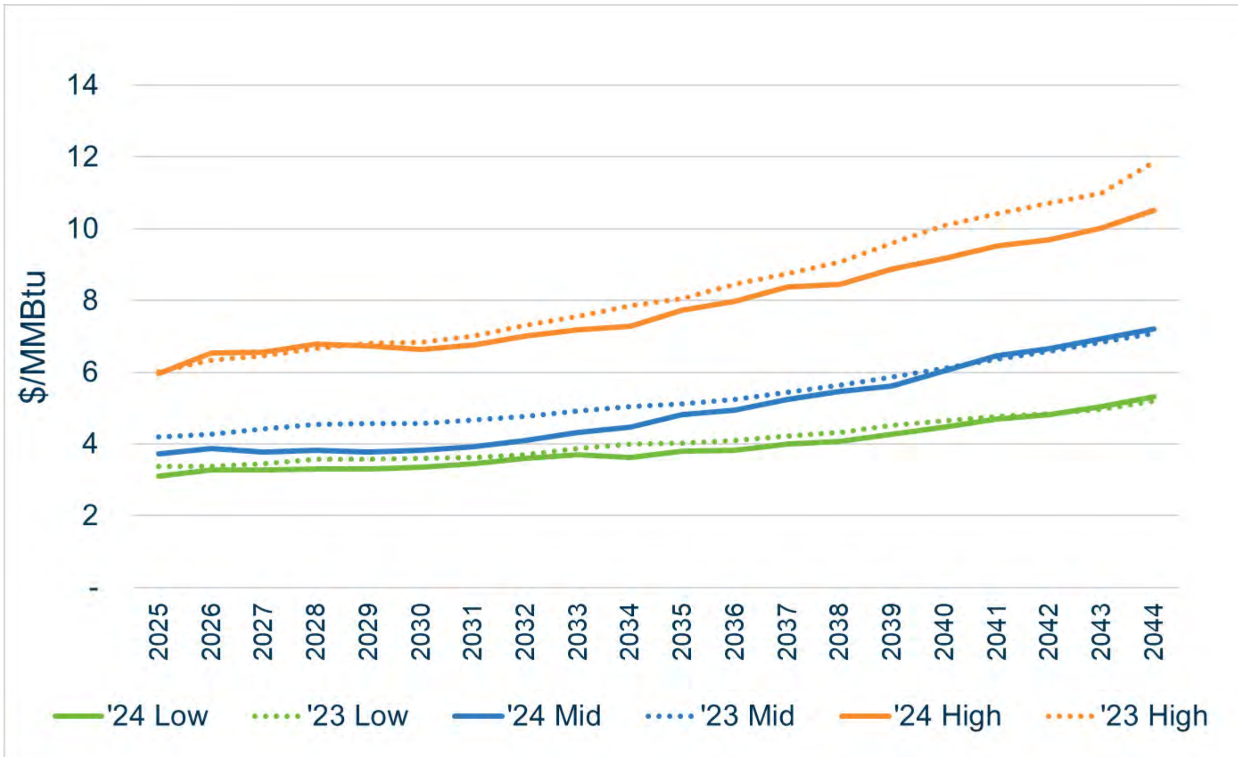
3.1 Fuel Price Forecasts [6]

3.1.1 Natural Gas

Evergy updates the IRP natural gas forecast annually based on the forecast used for internal budgeting, which is developed from vendor forecasts and forward markets.[7] The internal forecast is then scaled by EIA's fundamental supply and demand forecasts to produce high and low estimates. However, EIA did not release new fundamental forecasts for 2024. Without updated fundamentals there was no significant change in the fuels forecast so the 2025 IRP used the 2024 forecast. Natural Gas prices were identified as a critical uncertain factor, consistent with the 2024 Triennial. High, mid (base) and low forecasts are used in the development of resource plans and evaluation of plan economics.

[6] 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(A)
[7] Third party sources include IHS Markit, Energy Information Administration, S&P Global Platts, Energy Ventures Analysis, CME Futures, and ICE.

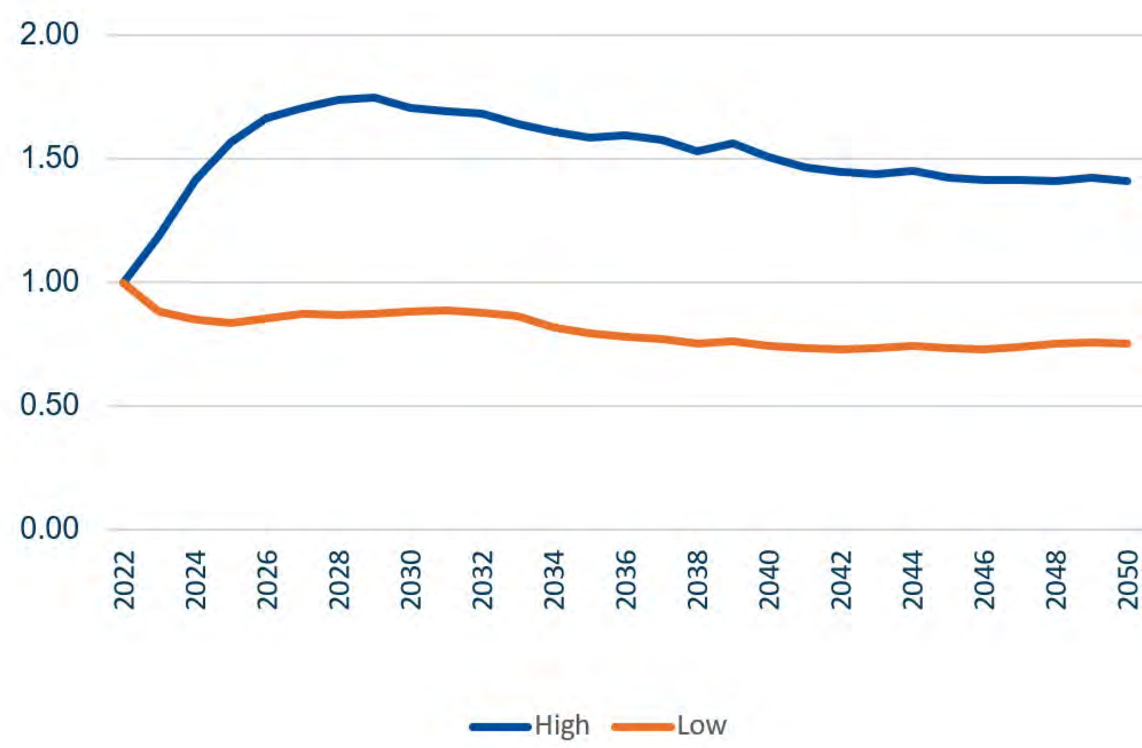
Figure 8: Natural Gas Price Forecasts 2024 IRP and 2023 IRP



The high and low forecasts were developed by scaling the mid forecast based on the fundamental supply and demand forecasts in the EIA Annual Energy Outlook model. The EIA did not release a 2024 update as they prepare a more exhaustive 2025 update, so data from the 2023 Outlook was used. The EIA builds its forecasts considering a variety of factors, including current laws and regulations, current assessments of economic and demographic trends, technology improvements, compounded annual economic growth, oil and natural gas supply and demand, and renewable energy cost cases. Key drivers for US natural gas production volumes include EIA's outlook on international prices and US LNG exports, as well as technology assumptions. 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.[8]

[8] *See* 2023 EIA Annual Energy Outlook, Table 13. Natural Gas Supply, Disposition, and Prices.

Figure 9: Henry Hub Natural Gas Scalar



This method was used beginning in the 2022 IRP to derive a wider range of prices based on changes in fundamental assumptions.

3.1.2 Coal

Evergy negotiates coal and rail delivery contracts with suppliers. The coal price forecast was developed using contract prices for the duration that they are in place. Prices for contracted coal volumes were supplemented with prices from Coaldesk's latest available forward market valuation for all uncontracted coal volumes in that timeframe. For forecasted prices beyond contract terms, a composite coal price forecast was created by combining the forecasts from IHS Markit, S&P Global Platts, Energy Ventures Analysis, and JD Energy. The forecasts are combined and weighted equally to create a composite price forecast that represents the base case consensus of the major forecast sources.

Figure 10: IRP 2025 Missouri West Coal Price Forecast **Confidential**

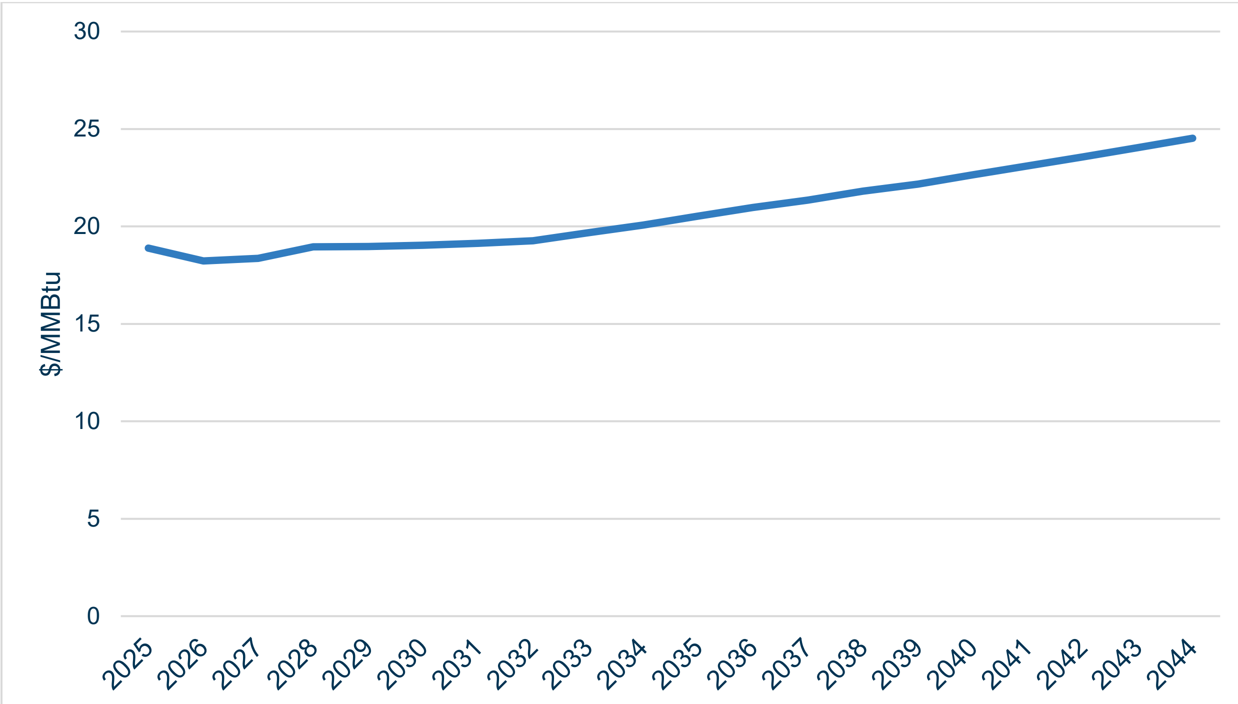
[redacted]

Evergy sources coal from the Powder River Basin. Historically there has been low price volatility in coal commodity prices for Powder River Basin coal because it is not exported, and thus is not subject to the international supply and demand pressures that other coal types, natural gas, and oil experience.

3.1.3 Fuel Oil

A composite crude oil price forecast was created by combining forecasts from IHS Markit, Energy Information Administration, S&P Global Platts, and Energy Ventures Analysis.

Figure 11: IRP 2025 Fuel Oil Price Forecast



3.2 Market Price Forecasts

Evergy considers current and future market conditions in developing its 20-year forward looking forecasts for the IRP. Starting with the 2022 IRP Annual Update, Evergy contracted with 1898&Co. to produce 20-year market price forecasts using SPP's transmission planning models as a baseline. Evergy has not changed its market price forecast from the 2024 IRP.

The 2024 IRP pricing models, based on the finalized 2023 SPP ITP models, reflect current transmission topology and near-term transmission upgrades, including those approved by the SPP Board of Directors to resolve new constraints identified in the 2023 ITP process. The models use economic dispatch, considering transmission limits, to calculate nodal pricing. Pricing was reported at the following locations:

- Load zones for each utility: used for load and DSM
- Coal resource locations for each coal site
- Wind location: used for all new and existing wind and wind PPAs

- Generation zones for each utility: used for existing generators; Metro location used for all non-wind new resources

The market price forecasts reflect the negative pricing that has been observed in SPP and predict that the number of negative-priced hours in SPP will continue to grow. Please see the 2024 Triennial IRP for a more holistic discussion of market price forecasts.

3.3 Carbon Restrictions

Carbon emissions policy was identified as a critical uncertain factor, consistent with the 2024 Triennial IRP. Evergy has modeled three levels of potential future carbon emissions policies. Evergy has not changed its assumptions from the 2024 Triennial IRP.

The low forecast for the 2025 IRP has no emissions restrictions. The mid forecast employs a carbon emissions restriction consistent with the dispatch solution of the pricing model. The CO_2 production constraint mirrors Evergy's anticipated emission levels within the SPP market (e.g., if the dispatch in the pricing model produced a 70% reduction in Evergy's carbon emissions in 2042, the carbon restriction applied in the IRP dispatch model for 2042 is 70%). The high forecast is consistent with the assumptions in the SPP 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 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.

Figure 12: Missouri West CO_2 Emission Constraint

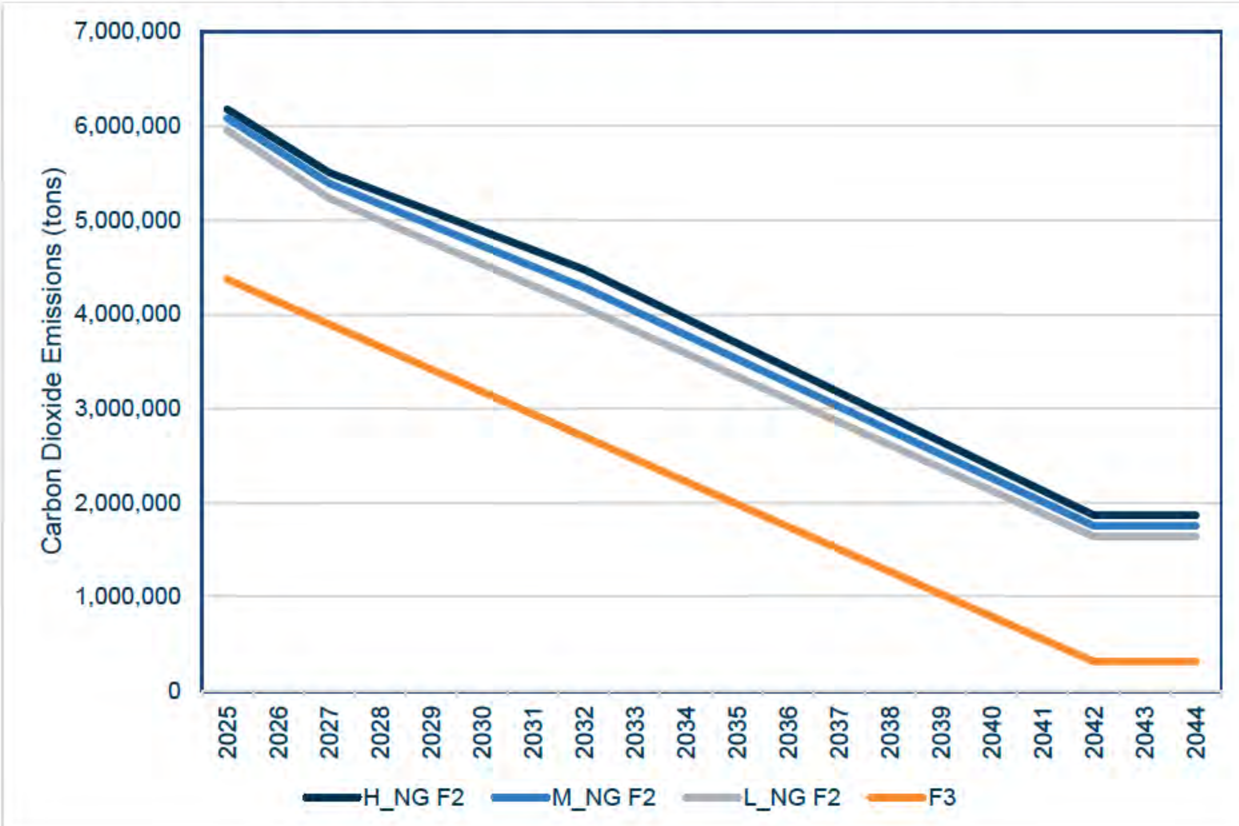


Table 5: Future 3 CO_2 Emission Tax ($/ton)

Year(s)	Price
2025-2032	0
2033	2.5
2034	5
2035	7.5
2036	10
2037	12.5
2038	15
2039	17.5
2040	20
2041	22.5
2042-2044	25

In order to achieve SPP Future 3 emissions goals, breakthroughs would be needed in dispatchable carbon-emissions-free technology. Newer combined cycles and combustion turbines are engineered to burn cleaner fuels including hydrogen or ammonia blends. However, production and transport of these fuels is still cost prohibitive. Improvements in carbon capture and sequestration technologies are another option for reducing or eliminating emissions. US government subsidies are encouraging innovation in these areas. In the 2025 IRP, costs associated with carbon capture and storage were applied to new combined cycles beginning in 2035 in Future 3, reflecting an assumed cost associated with mitigating carbon emissions from these new resources. Additionally, carbon-free energy was assumed to be available in all models for $300/MWh in case the fleet was unable to generate enough energy, or carbon-free energy to serve load. This price point is based on the current typical price of fuel oil-fired peaking units which, although clearly not representative of actual carbon-free energy, provides a “scarcity price” proxy for the cases when Evergy is unable to meet its own load.

3.3.1 Other Emissions Costs or Restrictions

Evergy does not expect to incur costs for emissions allowances for SO_2 and NO_x, and does not expect future restrictions to be limiting on operations.

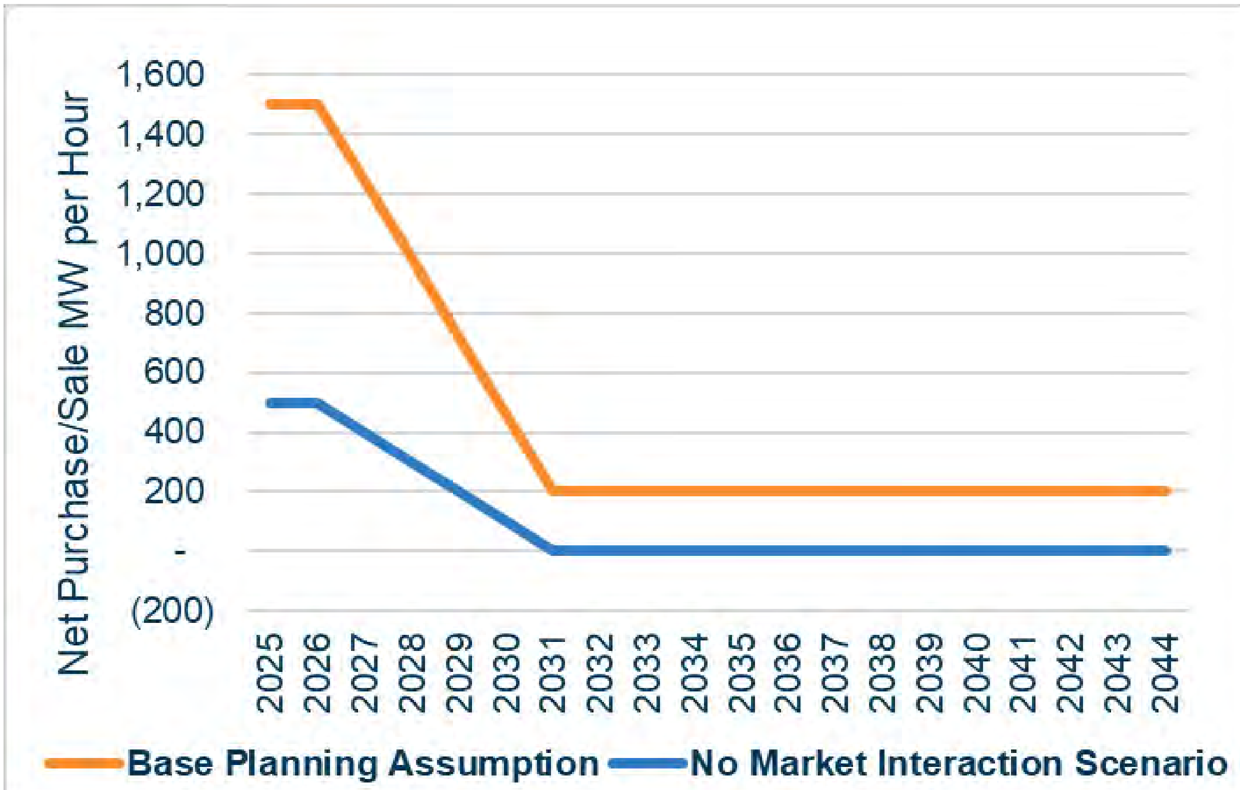
3.4 Market Dependence

Evergy benefits from participation in the SPP energy markets because it can sell energy when prices are higher than production costs and buy energy when prices are lower than production costs. Currently, aggregated Evergy supply and demand (including Evergy Metro, Missouri West, and Kansas Central) is well-matched in SPP. Historically, Missouri West has been a net buyer.

With high load growth expected over the next few years, planned retirements, and expiration of wind PPA contracts, Evergy does not expect other utilities in SPP to build generation to serve the needs of Evergy customers. In addition to meeting SPP Resource Adequacy Requirements, Evergy aligns its future plans with meeting hourly customer energy needs in the lowest cost manner, by limiting net sales and purchases from the market to design a future portfolio that provides an economic and reliability hedge.

Consistent with the 2024 Triennial IRP, beginning in 2031, the allowed level of market purchases/sales is set at approximately 10% of each utility's peak load and 15% of its average load. Allowing market purchases does not mean that a utility (e.g., Missouri West) is physically incapable of meeting 100% of customer energy needs. Resource Adequacy Requirements are established to outline the amount of physical capability (i.e., accredited capacity) necessary to meet customer energy needs. These market purchase constraints simply mean that, when an optimal resource mix is selected, it is selected not only because it is the lowest-cost way to meet these Resource Adequacy Requirements, but also because it is the lowest-cost way to produce energy which aligns closely (within 10-15%) with the utility's customers' hourly energy needs. On the market sale side, it also means that an optimal plan will not be developed solely because of the revenues it could generate from selling energy in excess of customer needs. In short, this constraint ensures that a resource portfolio is developed based on specific customer energy needs and not just forecasted energy market prices. This constraint is phased in over time because it is most relevant in the second decade of the planning horizon when expected fossil retirements across the SPP and within Evergy's fleet, combined with the expiration of Evergy's wind PPAs, are expected to significantly change Evergy's net position in the SPP energy market.

Figure 13: Limit on Market Dependence in Resource Planning (Missouri West)



Based on stakeholder feedback, Evergy also developed an alternative resource plan assuming (for modeling purposes) no market energy purchases or sales, to understand how SPP energy market assumptions affect the new resource build decisions. This plan assumes market dependence is reduced to zero in 2031, rather than 200 MW.

Section 4: Resource Adequacy Requirements Update

SPP requires all load-serving entities to meet Resource Adequacy Requirements based on forecasted peak load plus planning reserve margins. SPP conducts a LOLE (loss of load expectation) study at least every two years, setting the planning reserve margin based on a LOLE of less than one day in ten years.[9] Evergy plans to have sufficient capacity to meet SPP requirements in every planning year. Evergy submits planning data, including load forecasts and resource accreditation to SPP annually to confirm it has met the requirements prior to the summer and winter seasons respectively.

Significant changes to Resource Adequacy Requirements have occurred over the last year. SPP has filed tariff changes to implement Winter Resource Adequacy Requirements, Performance-Based Accreditation (PBA), and effective Load Carrying Capability (ELCC), all of which have been provisionally approved by FERC effective January 1, 2025. However, there are many interrelated issues to work through which could influence future requirements – including LOLE study assumptions and variations on accreditation calculations.

4.1 Winter Reserve Margin Requirement

The Federal Energy Regulatory Commission (FERC) accepted SPP's tariff change to implement a Winter Resource Adequacy Requirement effective January 1, 2025. The Winter Resource Adequacy Requirement will be identical to the Summer Season Resource Adequacy Requirement, only with the dates being six months apart. SPP also proposed to add language stating that a resource can only be used to meet the Resource Adequacy Requirement if the LRE "expects [it] will be available for the duration of the [season]" and has "no knowledge [that the resource] will become unavailable," with an exception for Authorized Outages.[10]

[9] SPP OATT Attachment AA, Section 4.0 Planning Reserve Margin
[10] Sw. Power Pool, Inc., 189 FERC ¶ 61,094, at P 4 (2024).

In addition to the Winter Season Resource Adequacy Requirement, the deficiency payment structure will now account for potential LRE deficiencies in both Summer and Winter. Since the CONE value is based on annual cost, SPP proposed to assess such deficient LREs with an annual deficiency payment equal to the higher of the deficiency payment amounts the LRE has for either the Summer Season or Winter Season. The annual charge for a capacity deficiency in either season would avoid being punitive to LREs by ensuring that an LRE will not be double charged for the same deficient capacity and ensure LREs proactively procure and maintain sufficient capacity for the Winter Season.

The initial winter reserve margin for winter 2025/2026 is expected to be 15%, however SPP studies have indicated potential dramatic increases in future winter requirements. There is still uncertainty in predicting what the winter reserve margins will be as stakeholders need to work through LOLE study assumptions that may show greater risks in winter such as higher forced outage rates in extreme cold weather, balance of when loss-of-load events occur between summer and winter in modeling, and planned outages scheduled in winter months.

4.2 LOLE Study Results and Reserve Margin Expectations

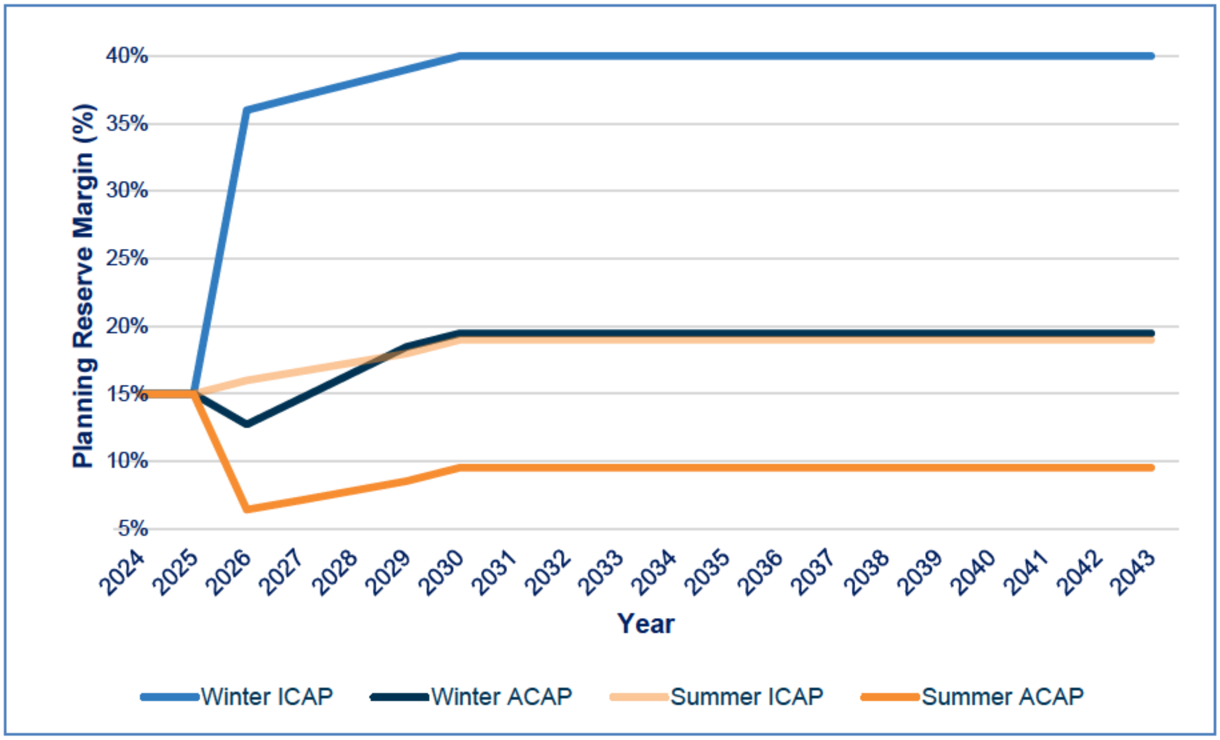
Evergy incorporated a 12% summer reserve margin in its resource plans for the 2021 and 2022 IRPs, consistent with SPP requirements. In July 2022, the SPP board approved an increase in the summer reserve margin to 15% beginning in summer 2023, and Evergy's 2023 IRP met that minimum value for the 20-year planning horizon. The required reserve margin for summers 2024 and 2025 have been set at 15%, and a winter requirement of 15% is in effect for winter 2025/2026. However, SPP's draft LOLE study results anticipate higher reserve margins in future years.

Based on the 2024 submitted forecast for the Resource and Load mix using the 2023 LOLE study assumptions, the 2026 planning year shows a 16% summer reserve margin and a 36% winter reserve margin. For planning year 2029, the summer reserve margin rises to 17%, and the winter reserve margin rises to 38% which includes 50% of cold weather correlated outages assumed. The rise in reserve margins from 2026 to 2029 in the study results is attributed to changes in SPP’s resource mix, planned outage scheduling overlaps with high need hours in winter, increase in load, and shift in risk hours, with additional allocation of LOLE risk to winter.

Based on these results, Evergy has revised its planning assumptions to anticipate a higher initial winter reserve margin and higher reserve margins for both summer and winter over the planned horizon. The summer base assumption is that the reserve margin of 15% in 2025 will increase by approximately 1% per year through 2030 and then remain the same for the remainder of the horizon. The winter base assumption is that the same amount of capacity is needed in both seasons, despite the lower winter load. The winter reserve margin is 15% in 2025, steeply increasing to 36% beginning in 2026 and increasing by 1% every year until hitting 40% in 2030 and remaining stable for the rest of the horizon. Evergy believes the assumed levels of reserve margins adequately plan for SPP’s future planning reserve margin requirement while also including an appropriate buffer to account for annual fluctuations in unit performance which impact the fleet’s overall accredited capacity to meet load obligation (see Section 4.3 Performance Based Accreditation).

SPP is transitioning its Planning Reserve Margin (PRM) calculation from Installed Capacity (ICAP) to Accredited Capacity (ACAP) starting in 2026 with the implementation of Performance Based Accreditation (PBA). Under the ICAP PRM approach, the reserve margin is based on the total installed capacity of all generating units, assuming they are available at maximum capacity, without accounting for potential outages or performance variations and the overall PRM includes buffer to cover the risk of outages. In contrast, the ACAP PRM method calculates the reserve margin based on each unit's accredited capacity, reflecting actual performance and reliability. This approach uses historical performance data, including forced outages and deratings, to determine reliable capacity during peak demand. By shifting to an ACAP PRM, performance risk moves from the overall system to individual units, accrediting them based on demonstrated performance. Units with higher reliability receive higher accreditation, while those with frequent outages receive lower accreditation. Consequently, the overall PRM is reduced, because the buffer that was previously included in the ICAP PRM to cover outages and performance variation is now distributed across individual units.

Figure 14: 2025 IRP Planning Reserve Margin Assumptions



The 2023 SPP LOLE report results and future LOLE study assumptions are still being vetted in the stakeholder process. Some of the primary focus areas for refinement may be:

- **Future Weather Expectations:** The 2023 LOLE study uses 43 years of historical weather data to model load, wind, and solar patterns. The Monte Carlo approach runs thousands of models with these weather-patterned loads, and varying resource availability based on historical outage distributions. The summer 2026 LOLE events occurred in 10 different weather years, with the most events, 33%, in the 1980 models. The winter 2026 LOLE events occurred in only four different weather years, with 72% of events in the 2021 model which had the winter storm Uri. Stakeholders may consider whether a Uri-type event is likely to occur again and how much weight it should carry in the modeling.

- **Cold-Weather Correlated Outages:** Historical analysis shows a large increase in forced outages when temperatures are below zero in SPP. When the LOLE study considers historical cold-weather outage correlation, more LOLE events occur in winter, increasing the reserve margin needed to lower the number of events back to the “1-in-10 years” standard. Stakeholders may consider whether cold weather issues are expected to persist in the future or may have been remedied by better practices in the natural gas industry, winterization, and incorporation of lessons learned.
- **Seasonal Balance of Risk:** The allocation of events to summer and winter changes the reserve margin for each season. For example, allowing more events to occur in winter raises the summer reserve margin and lowers the winter reserve margin. This may affect utilities that are summer and winter peaking differently.
- **Scheduling of Maintenance Outages:** The modeling accounts for some scheduled outages in winter, consistent with historical scheduling practices. The presence of scheduled outages in winter increases the need for other resources to be available, raising the winter reserve margin.

4.3 Performance-Based Accreditation

Performance-based accreditation (PBA) is a metric to redistribute accreditation based on historical availability at peak times. SPP currently accredits thermal resources based on their tested summer capacity, through 1-hour capability tests every five years, supplemented by 1-hour operational tests annually. The new PBA method that has been provisionally accepted by FERC reduces accreditation based on each resource’s seasonal (winter or summer) forced outage rate and forced outage factor (winter only). Seven-year average seasonal forced outage rates will be used. However, until SPP collects seven years of data, class average outage rates will substitute for resource-specific forced outage rates as part of the calculation. All resources lose accreditation under PBA; however, the SPP reserve margin will also decrease to reflect the system need for unforced capacity. Therefore, resource portfolios with higher outages than average will get less relative accreditation and will need more capacity to meet requirements, and portfolios with lower outages than average will get more relative accreditation and will need less capacity. For the 2025 IRP, Evergy has incorporated the expected change in accreditation in its resource planning beginning summer 2026. Key differences in PBA calculation methodology in the 2025 IRP include a forced outage factor (EFOF) applied in winter is to account for Fuel Assurance and Cold Weather Outage Impacts, which was recently finalized in the SPP stakeholder process this year and has made a large impact on our winter capacity position for the 2025 IRP as compared to our 2024 IRP assumption. In addition, PBA was estimated on a fleetwide basis in the 2024 IRP but has been refined with more data for the 2025 IRP.

4.4 Effective Load Carrying Capability (ELCC)

ELCC is a method to measure the contribution a resource makes to meeting load, taking into account fuel supply and duration limitations (for example, solar resources cannot serve load at night). SPP is working toward implementing ELCC for renewable and storage resources, recently coupling ELCC with performance-based accreditation and fuel assurance for thermal resources in a filing to address stakeholder concerns regarding whether renewables and storage would be unfairly accredited more stringently than thermal resources. The filing has been provisionally accepted. For the 2025 IRP, Evergy is factoring in expected ELCC values for renewable and battery resources in its resource planning beginning in summer 2026.

4.5 Accredited Capacity (ACAP) Reserve Margin

As SPP moves to performance-based accreditation and ELCC it will be measuring the unforced capacity of resources rather than the installed capacity. ACAP reserve margins will reflect the need for resource capacity that has already been adjusted for ELCC and performance-based accreditation. In the 2025 IRP, Evergy includes this beginning in summer 2026 as part of the adjustment to the capacity need for performance-based accreditation.

4.6 Demand Response Accreditation

Demand response resources are currently netted against peak load based on their tested capabilities. SPP Stakeholders have discussed whether these resources should be accredited using an ELCC construct to reflect their availability limitations – such as number and duration of events. The 2025 IRP incorporates an assumption that demand response receives accreditation up to its expected tested capacity. This is lower than the past IRP assumption that demand response would continue to be treated as a net to load, which gave it a capacity value equivalent to its tested capacity plus the reserve margin. Updated SPP policy related to Demand Resource is still in very early stages of development, but this change in assumption allows for a slightly more conservative assessment of accreditation in expectation of potential future changes.

4.7 Resource Adequacy Requirement Uncertainty

Evergy is not specifically treating Resource Adequacy Requirements as a Critical Uncertain Factor in the 2025 IRP. While uncertainty in Resource Adequacy Requirements can certainly impact the amount of capacity Evergy must procure to meet requirements, it does not specifically impact the relative performance of different resource plans (i.e., if requirements increase, more capacity is necessary; if requirements decrease, less capacity is necessary). In this way, Resource Adequacy Requirements are very similar to Load because they both define the amount of capacity each Evergy utility must maintain to meet customer needs. As a result, for the 2025 IRP, Evergy is considering the load and contingency alternative resource plans sufficient to capture both Load and Resource Adequacy Requirement uncertainty. The High Electrification Load scenario includes a very large amount of load growth based on an assumption of policy changes that support economy-wide electrification. Multiple economic development contingency scenarios capture the impact of a more moderate level of load growth combined with even larger increased in Resource Adequacy Requirements. Generator contingency alternative resource plans ACAE and ACAF specifically assess the loss of a resource or increases in resource adequacy requirements. These various higher load scenarios, along with the Low Load and No Market Energy scenarios, have been assessed to develop contingency plans which would reflect either higher or lower Load/Resource Adequacy Requirements for each utility compared to its base.

Section 5: Supply-Side Resource Options

In the 2025 IRP, Evergy updated costs and resource characteristics for combined cycles and combustion turbines based on its recent development experience. Slight modifications were made to battery, wind, and solar resource costs based on updated technology curves. Production tax credits were also updated based on recent published guidance. Resource availability was also updated based on expected lead time.

Table 6: Primary Resource Options **Confidential**

[redacted]

Evergy continuous to consider construction costs a critical uncertain factor in resource planning. Evergy modeled installed cost increases of 25% for the high construction cost scenarios, and cost decreases of 25% for the low construction cost scenarios.

Table 7: Primary Resource Costs in First Year of Operation **Confidential**

[redacted]

Table 8: New Resource Emissions Rates (lb/MWh)

Resource Type	NO_x	SO_2	CO_2
Solar	-	-	-
Wind	-	-	-
Battery	-	-	-
Combustion Turbine	0.045	0.009	1,064
Combined Cycle	0.026	0.006	754
Half Combined Cycle	0.026	0.006	754

Evergy also considered Combined Cycles with Carbon Capture as a resource that could be deployed to enable future emissions reductions. While the technology is not currently operating, and cost data is more speculative, it may assist in the analysis of tradeoffs in a low-carbon future.

Table 9: Future Low Emissions Option **Confidential**

[redacted]

Table 10: Future Low Emissions Costs in First Year of Operation **Confidential**

[redacted]

Table 11: Future Low Emissions Resource Emissions Rates (lb/MWh)

Resource Type	NO_x	SO_2	CO_2
Combined Cycle CCS	0.0267	0.0073	42.7

5.1 Renewable and Storage Resources

Renewable and storage resource costs and characteristics continue to be informed by the results of Evergy's 2023 Request for Proposals. Evergy has found solar costs to be similar to 2024 IRP estimates through experience negotiating solar agreements with developers and self-developing a solar project in the months after the 2024 IRP was filed. While the near-term solar construction costs are generally aligned with the 2024 IRP solar costs, changes in the technology curve resulted in lower expected solar costs starting in 2030. Evergy is also not revising expectations for wind and battery costs and characteristics. The updated technology curves for wind shifted costs slightly higher, while the updated technology curve for battery had minimal impact. Evergy does not have refreshed wind project offer prices. Although it has been reported that battery costs have decreased over the past year, there is considerable uncertainty around how US tariffs may affect the market which relies heavily on Chinese imports. Evergy expects to issue another Request for Proposals in 2025.

Figure 15: Annual Solar Build Costs ($/kW) **<u>Confidential</u>**

[redacted]

Figure 16: Annual Wind Build Costs ($/kW) **<u>Confidential</u>**

[redacted]

Figure 17: Battery Build Costs (Excluding ITC) ($/kW) **Confidential**

[redacted]

5.2 Tax Incentives

Consistent with the 2024 IRP, Evergy assumes that new wind and solar will receive PTC and new battery resources will receive ITC. Evergy updated the PTC values per the most recent annual IRS guidance, and used the same assumptions about PTC and ITC eligibility and election as used in the 2024 IRP.

New wind and solar resources can select either the PTC or ITC. New wind resources are expected to have high capacity factors, making the PTC advantageous. Solar resources have lower capacity factors; however, the PTC is still expected to be the most economic option for Evergy customers, because of the expected capacity factor and the requirement for utilities to amortize the ITC over the life of the asset. New battery resources are only able to use the ITC and utilities are able to take the credit upfront (rather than amortizing it) as part of the IRA guidelines.

Evergy expects new wind and solar projects to meet the eligibility criteria for 100% PTC, with a PTC earned for every MWh of production for the first 10-years of operation. Consistent with IRA provisions, production tax credit eligibility for new projects phases out as the US meets its GHG emissions reduction goals. Projects beginning operation in

2034 and 2035 are eligible for 75% PTC and 50% PTC, respectively, before the credit ceases for projects after 2035.

Evergy expects new battery projects to meet the eligibility criteria for 30% ITC, with the benefit received upfront in the first year of operation. The IRA allows additional bonus credit eligibility for projects located in "energy communities".[11] Evergy is modeling additional bonus credit eligibility for a total of 40% ITC beginning in 2029. As the credit phases out, projects beginning operation in 2034 and 2035 are eligible for 75% and 50% of the expected credits, respectively, before the credit ceases for projects after 2035.

5.3 ELCC

Evergy expects new renewable and battery resources to be subject to SPP's ELCC capacity accreditation rules beginning in summer 2026. ELCC measures the effectiveness of the resource to produce energy at times needed to meet load. Generally, as the saturation of the resource type increases in the market, each resource is less effective at meeting load requirements. Evergy has not changed ELCC assumptions from the 2024 IRP. ELCC accreditation is not fixed because it is based on outputs from SPP's LOLE models. ELCC can change based on changes to other modeling assumptions (load, addition and retirement of other resources, etc.). Evergy's assumptions are based on SPP studies which estimate the relationship between increasing amounts of resources and ELCC value.

5.4 Thermal Resources

5.4.1 Cost and Availability

The need for firm dispatchable generation beginning in the late 2020's to early 2030's was identified in the 2023 and 2024 IRPs. Evergy did not receive any offers for thermal resources in its 2023 RFP and developers are not pursuing speculative thermal resource projects in SPP. Evergy expects to self-develop these resources.

[11] IRS. Energy Community Bonus Credit Amounts under the Inflation Reduction Act of 2022 Notice 2023-29. https://www.irs.gov/irb/2023-29_IRB#NOT-2023-29.

Cost estimates used in the 2024 IRP were based on engineering studies and publicly available information. In the past year, Evergy's development team has taken steps to execute on the resource plan, and has received updated cost estimates from suppliers. Costs have risen significantly from 2024 IRP estimates. This is partly attributable to broad inflation in the economy, but also likely the result of the strong supply and demand forces for natural gas-fired generation. Utilities across the US are forecasting unprecedented load growth from economic development, datacenters and other large-load customers and many utilities have announced intentions to build new natural gas projects to meet their growing needs. The high demand for project development is also resulting in higher contracting costs as these firms have limited capacity.[12]

Costs for future years were estimated by scaling the 2029 and 2030 cost estimates by inflation and the average of the NREL and EIA technology curves. Inflation exceeds technological innovation, resulting in higher nominal costs each year.

Figure 18: Combined Cycle Build Costs ($/kW) **<u>Confidential</u>**

[redacted]

[12] Evergy testimony from Kyle Olson and Jason Humphrey in EA-2025-0075 provide more detail on construction cost estimates for planned CCGT and SCGT resources.

Figure 19: Combustion Turbine Build Costs ($/kW) **<u>Confidential</u>**

[redacted]

Evergy estimates that the earliest available natural gas-fired generation not currently in development would be for commercial operation by summer 2031.

5.4.2 PBA Assumptions

New thermal generation will be subject to performance-based accreditation like the rest of the Evergy thermal fleet. The expectation is that initial PBA would be calculated based on design specifications. Since these resources are designed to be highly available and will have firm fuel supply, a 3% outage rate was applied for accreditation purposes.

5.5 Low-Emission Future Resources

5.5.1 Combined Cycle with CCS

Evergy modeled retrofitting new combined cycle builds with CCS, beginning in 2035 as an option for compliance with the strict (high) CO_2 emissions reductions scenarios. Carbon capture facilities have high capital costs, similar to the costs of building the generator. The operation of carbon capture increases fixed and variable costs, and decreases the efficiency (i.e., increases the heat rate) and the net output of the underlying resource. However, the net CO_2 emissions are also reduced by 95%. Plant capital and operating costs were modeled using NREL estimates from the 2023 Annual Technology Baseline (ATB),[13] while the cost of CO_2 transportation and storage was estimated from a 2022 report by the National Energy Technology Laboratory (NETL).[14]

Table 12: Unit Characteristics of Combined Cycle with and without CCS

****Confidential****

[redacted]

5.6 Market Capacity

Evergy has been actively pursuing market capacity purchases to meet short term reliability needs and enable large customer load ramp prior to thermal resource construction. Based on ongoing negotiations with counterparties, Evergy believes it can secure some market capacity in the 2026 – 2031 time horizon.

Because SPP is in the process of significantly tightening resource adequacy requirements, including raising reserve margins, reducing capacity accreditation, and imposing penalties for failing to meet winter requirements, Evergy expects that some utilities will be short capacity beginning in 2026 when new rules are forecasted to be in effect. Evergy expects market capacity to be expensive and scarce relative to recent history of market capacity in SPP, limiting potential purchases beyond its current assumptions. Evergy will continue to look for offers in the market to mitigate the risks associated with the lead time in bringing new resources to commercial operation and changes to capacity needs.

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[13] https://atb.nrel.gov/electricity/2023/data

[14] https://netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf

Table 13: Market Capacity Available Missouri West

Year	Summer Market Capacity	Winter Market Capacity
2026-2029	250 MW	500 MW
2030	250 MW	250 MW
2031+	20 MW	20 MW

Section 6: Environmental Regulation Update

6.1 Air Emission Impacts

6.1.1 Particulate Matter National Ambient Air Quality Standards

In March 2024, the EPA published in the Federal Register the final rule which strengthens the primary annual PM2.5(particulate matter less than 2.5 microns in diameter) NAAQS. The EPA lowered the primary annual PM2.5 NAAQS from 12.0 µg/m3 (micrograms per cubic meter) to 9.0 µg/m3. The final rule took effect in May 2024. In August 2024, the EPA released the PM2.5 ambient monitor design values for calendar years 2021 through 2023. These design values will be used by each state governor for recommending to the EPA attainment designations for their states. The EPA will issue final designations for all states, including Kansas and Missouri, by February 2026. Future non-attainment designation for these revised standards could require additional reduction technologies on existing fossil-fueled units.

6.1.2 Cross-State Air Pollution Rule

Ozone Interstate Transport State Implementation Plans (ITSIP)

In 2015, the EPA lowered the Ozone National Ambient Air Quality Standards (NAAQS) from 75 ppb to 70 ppb. States were required to submit ITSIPs in 2018 to comply with the "Good Neighbor Provision" of the Clean Air Act (CAA) as it applies to the revised NAAQS. The EPA did not act on these ITSIP submissions by the deadline established in the CAA and entered consent decrees establishing deadlines to take final action on various ITSIPs. In February 2022, the EPA published a proposed rule to disapprove the ITSIPs submitted by nineteen states including Missouri and Oklahoma. In April 2022, the EPA published an approval of the Kansas ITSIP in the Federal Register. The Missouri Department of Natural Resources (MDNR) submitted a supplemental ITSIP to the EPA in November 2022. In February 2023, the EPA published a final rule disapproving the ITSIPs submitted by nineteen states, including the final disapproval of the Missouri and Oklahoma ITSIPs. In April 2023, the Attorneys General of Missouri and Oklahoma filed Petitions for Review in the U.S. Court of Appeals for the Eighth Circuit (Eighth Circuit) and the U.S. Court of Appeals for the Tenth Circuit (Tenth Circuit), respectively, challenging the EPA's disapproval. In May 2023, the Eighth Circuit granted a stay of the

EPA's disapproval of the Missouri ITSIP. Similarly, in July 2023, the Tenth Circuit granted a stay of the EPA's disapproval of the Oklahoma ITSIP. In August 2024, the EPA published in the Federal Register a proposed rule to disapprove the supplemental ITSIP that Missouri submitted in November 2022. In January 2024, the EPA proposed to disapprove the ITSIP for Kansas and four other states. The Kansas ITSIP was previously approved in April 2022.

Ozone Interstate Transport Federal Implementation Plans (ITFIP)

In April 2022, the EPA published in the Federal Register the proposed ITFIP to resolve outstanding "Good Neighbor" obligations with respect to the 2015 Ozone NAAQS for twenty-six states including Missouri and Oklahoma. This ITFIP would establish a revised Cross-State Air Pollution Rule (CSAPR) ozone season nitrogen oxide (NO_x) emissions trading program for EGUs beginning in 2023 and would limit ozone season NO_x emissions from certain industrial stationary sources beginning in 2026. The proposed rule would also establish a new daily backstop NO_x emissions rate limit for applicable coal-fired units larger than 100 MW, as well as unit-specific NO_x emission rate limits for certain industrial emission units and would feature "dynamic" adjustments of emission budgets for EGUs beginning with ozone season 2025. The proposed ITFIP included reductions to the state ozone season NO_x budgets for Missouri and Oklahoma beginning in 2023 with additional reductions in future years. Evergy Missouri West provided formal comments as part of the rulemaking process. In March 2023, the EPA issued the final ITFIPs for twenty-three states, including Missouri and Oklahoma, which included reduced ozone season NO_x budgets for EGUs in Missouri, Oklahoma and other states, and included other features and requirements that were in the proposed version of the rule. Because the EPA's authority to impose an ITFIP for a state is triggered by the state's failure to submit an ITSIP addressing NAAQS by the statutory deadline or disapproval of an ITSIP, the EPA lacks authority under the Clean Air Act to impose an ITFIP on a state for which state implementation plan (SIP) disapprovals have been stayed by the courts. Accordingly, the EPA issued interim final rules staying the effectiveness of the ITFIP in both Missouri and Oklahoma while the stays issued by the Eighth and Tenth Circuits in the ITSIP disapproval cases remain in place. During this time, both states will continue to operate under the existing CSAPR program. While Kansas was not originally included in the ITFIP, in January 2024, the EPA issued a proposal to include Kansas in the ITFIP. If finalized, the ITFIP for Kansas would become effective for the 2025 ozone season beginning in May 2025. In June 2024, the U.S. Supreme Court issued an order granting emergency motions for stay filed by state and industry petitioners of the final ITFIP pending further review of the ITFIP by the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit).

Evergy Missouri West currently complies with the existing CSAPR rule through a combination of trading allowances within or outside its system in addition to changes in operations as necessary. Future, strengthened ozone, PM, or SO_2 standards could result in additional CSAPR updates requiring additional procurement of allowances, emission reduction technologies or reduced generation on fossil-fueled units.

6.1.3 Regional Haze

In 1999, the EPA finalized the Regional Haze Rule which aims to restore national parks and wilderness areas to pristine conditions. The rule requires states in coordination with the EPA, the National Park Service, the U.S. Fish and Wildlife Service, the U.S. Forest Service, and other interested parties to develop and implement air quality protection plans to reduce the pollution that causes visibility impairment. There are 156 "Class I" areas across the U.S. that must be restored to pristine conditions by the year 2064. There are no Class I areas in Kansas, whereas Missouri has two: the Hercules-Glades Wilderness Area and the Mingo Wilderness Area. States must submit revisions to their Regional Haze Rule SIPs every ten years and the first round was due in 2007. For the second ten-year implementation period, the EPA issued a final rule revision in 2017 that allowed states to submit their SIP revisions by July 2021.

The Missouri SIP revision does not require any additional reductions from the Evergy Companies' generating units in the state. MDNR submitted the Missouri SIP revision to the EPA in August 2022, however, they failed to do so by the EPA's revised submittal deadline in August 2022. As a result, in August 2022, the EPA published "finding of failure" with respect to Missouri and fourteen other states for failing to submit their

Regional Haze SIP revisions by the applicable deadline. This finding of failure established a two-year deadline for the EPA to issue a Regional Haze federal implementation plan (FIP) for each state unless the state submits, and the EPA approves a revised SIP that meets all applicable requirements before the EPA issues the FIP. In July 2024, the EPA published in the Federal Register a proposal to partially approve and partially disapprove Missouri's Regional Haze SIP revision.

The Kansas SIP revision did not include any additional emission reductions by electric utilities based on the significant reductions that were achieved during the first implementation period. The Kansas Department of Health and Environment (KDHE) submitted the Kansas SIP revision in July 2021. In August 2024, the EPA issued the final disapproval of the Kansas SIP revision for failing to conduct a four-factor analysis for at least two emission sources in Kansas. If a Kansas generating unit of the Evergy Missouri West is selected for analysis, the possibility exists that the state or the EPA, through a revised SIP or a FIP, could determine that additional operational or physical modifications are required on the generating unit to further reduce emissions.

Evergy Missouri West’s existing emission controls at its Jeffrey and Iatan Generating Stations maintain compliance with the current Regional Haze Rule requirements. Future visibility progress goals will likely result in additional SO_2, NO_x and PM controls or reduction technologies on fossil-fired units. This assumption led to the inclusion of selective catalytic reduction (SCR) systems in the future capital plan for Jeffrey unit 2 and unit 3. Jeffrey unit 1 already has an SCR installed and in service. The timeline selected for these projects is based on EPA’s next Regional Haze planning period which will occur in 2028. It is assumed that a compliance timeline would be agreed upon at that time which would allow the SCRs to be online by the end of 2032 for one unit and 2033 for the other.

6.1.4 Greenhouse Gases

In April 2024, the EPA finalized the Greenhouse Gas (GHG) regulations and GHG guidelines that apply to new and existing fossil fuel fired EGUs. The final GHG regulation establishes CO_2 limitations on emissions from new and reconstructed stationary combustion turbines. The GHG guidelines set CO_2 emission limitations for existing coal, oil and gas-fired steam generating units. For new and reconstructed stationary combustion turbines, the emission limitations were developed by applying the Best System of Emission Reduction (BSER) to three distinct subcategories (low load, intermediate load and base load) taking into consideration the annual capacity factor of the stationary combustion turbine. For intermediate and base load stationary combustion turbines, BSER is assumed to be the utilization of highly efficient combustion turbine technology. Base load stationary combustion turbines are also required to consider the emissions reduction associated with the application of carbon capture and sequestration (CCS) beginning in 2032. For existing coal-fired EGUs, the emission limitations were established by applying the BSER to two subcategories (medium and long-term). For medium-term existing coal-fired units, which are units retiring between 2032 and 2038, the BSER established emission limitation is based on co-firing natural gas beginning in 2030. For units operating in 2039 and after, BSER is the application of CCS starting in 2032. In July 2024, the D.C. Circuit denied motions of stay filed by various states, industry and trade organizations; however, the D.C. Circuit has ordered expedited review of the challenges to the final regulations and guidelines. In December 2024, a three-judge panel of the D.C. Circuit heard oral arguments on challenges to the merits of the rule. In February 2025, EPA filed an unopposed motion to ask the D.C. Circuit to hold the case in abeyance while the new Administration determines their next steps regarding the future of these regulations.

6.1.5 Mercury and Air Toxics Standards

In April 2024, the EPA finalized a rule to tighten certain aspects of the Mercury and Air Toxics Standards (MATS) rule. The EPA is lowering the emission limit for particulate matter (PM) and requiring the use of PM continuous emissions monitors (CEMS). It is anticipated that Evergy Missouri West will be able to comply with the current PM standard on rule effective date of July 2027. However, further strengthening of the PM standard could require Evergy Missouri West to consider additional PM controls at the Jeffrey Energy Center.

6.2 Water Emission Impacts

6.2.1 Effluent Limitation Guidelines (ELG)

The Evergy Companies discharge some of the water used in generation and other operations containing substances deemed to be pollutants. In April 2024, the EPA finalized an update to the Effluent Limitation Guidelines (ELG) for steam electric power generating facilities to address the vacated limitations and prior reviews of the existing rule. Flue Gas Desulfurization (FGD) wastewater, bottom ash transport wastewater (BATW), coal residual leachate (CRL), and legacy wastewater are addressed in the rulemaking. FGD, BATW and CRL at operating facilities are required to achieve zero liquid discharge as soon as feasible and no later than December 2029. The Evergy Companies have reviewed the modifications to limitations on FGD wastewater and bottom ash transport water and the Evergy Companies do not believe the impact to be material. The Evergy Companies are reviewing the limitations on CRL, its impact on their operations and financial results and believe the cost to comply will not be material. In June 2024, multiple legal challenges to the ELG were consolidated in the Eighth Circuit. In October 2024, the Eighth Circuit denied a motion to stay the ELG. Additional litigation is ongoing that could impact the timing or cost to comply.

6.2.2 Clean Water Act Section 316(A)

Evergy's river plants comply with the calculated limits defined in the current permits. Hawthorn and Iatan Generating Stations' water discharge permits issued February 1, 2022 and April 1, 2023, respectively, contain future thermal discharge limits that become effective no later than February 1, 2032. The compliance period will be utilized by Evergy to study both discharge conditions and conditions of the receiving river to finalize compliance plans. Application of these future limitations or future regulations that could be issued that restrict the thermal discharges may require alternative cooling technologies to be installed at coal-fired units using once through cooling, a reduction or shutdown of certain plants during periods of high river water temperature, or application of a thermal variance process.

6.2.3 Clean Water Act Section 316(B)

In May 2014, the EPA finalized standards to reduce the injury and death of fish and other aquatic life caused by cooling water intake structures at power plants and factories. The rule could require modifications to cooling water inlet screens and fish return systems. Intake structures at applicable facilities are evaluated and any modifications permitted through site specific wastewater discharge permits with state agencies.

6.2.4 Zebra Mussel Infestation

Evergy monitors for zebra mussels at generation facilities, and a significant infestation could cause operational changes to the stations.

6.2.5 Total Maximum Daily Loads

A Total Maximum Daily Load (TMDL) is a calculation of the maximum amount of a given pollutant that a body of water can absorb before its quality is impacted. A stream is considered impaired if it fails to meet Water Quality Standards established by the Clean Water Commission. Future TMDL standards could restrict discharges and require equipment to be installed to minimize or control the discharge.

6.3 Waste Material Impact

6.3.1 Coal Combustion Residuals (CCR's)

In the course of operating their coal generation plants, the Evergy Companies produce CCRs, including fly ash, gypsum and bottom ash. The EPA published a rule to regulate CCRs in April 2015 that required additional CCR handling, processing and storage equipment and closure of certain ash disposal units.

In April 2024, the EPA finalized an expansion to the CCR regulations focused on legacy surface impoundments and historic placements of CCR. This regulation expands the applicability of the 2015 CCR regulation to inactive landfills and beneficial use sites not previously regulated. On August 2, 2024, East Kentucky Power Cooperative (EKPC) filed a petition for review of the Legacy/CCRMU Rule in the D.C. Circuit, which was subsequently consolidated with other petitions for review filed by industry groups and members, a coalition of states, and City Utilities of Springfield. On November 1, 2024, the D.C. Circuit denied EKPC's motion to stay the Legacy/CCRMU Rule and EPKC subsequently filed an application for immediate stay with the United States Supreme Court. In December 2024, the Supreme Court denied the stay application. Additional litigation could impact the timing or cost to comply.

Section 7: Transmission and Distribution Update

7.1 Changes from the 2024 Triennial IRP

Transmission and Distribution-related changes and updates are provided below:

7.1.1 RTO Expansion Planning

Evergy Missouri West assessment of RTO expansion plans is an ongoing process that occurs through the various regional planning processes conducted by SPP. These assessments include review and approval of plan scope documents, review and approval of plan input assumptions, review of plan study analysis and results with feedback from Evergy Missouri West staff, and review and approval of final plan reports. All transmission projects identified by SPP for the Evergy Missouri West service territory are included in SPP's annual Transmission Expansion Plan Report and Project List. By meeting the performance standards established for transmission planning the assessment ensures that adequate transmission is available in the near term and long term to meet the firm load and transmission service requirements included in the SPP Regional Plan for Evergy Missouri West. These documents are attached as Appendix 7A 2024 SPP Transmission Expansion Plan Report.pdf and Appendix 7B 2024 SPP Transmission Expansion Plan Project List.xlsx.

7.1.2 Advanced Distribution Technologies

Evergy's ongoing grid modernization efforts are focused on the need to ensure the grid is reliable and flexible to meet our customers' needs. Out of that initiative, Evergy is focusing on the advanced distribution technologies below to support those needs:

- Advanced Distribution Management Systems (ADMS)
- Communicating Faulted Circuit Indicators (CFCIs)
- Reclosers with communication
- Regulators and Capacitors with Communication
- Load Tap Changers with Communication

Advanced Distribution Management Systems

Evergy has started the process of implementing ADMS functionality beginning with Fault Location, Isolation and Service Restoration (FLISR). When fully deployed, ADMS can provide the following functions for system operators to manage the grid in a safe, intelligent, and efficient manner:

- Fault Location Isolation and Service Restoration (FLISR)
- Advanced Fault Location functionality utilization (FLA)
- Distribution Supervisory Control and Data Acquisition (D-SCADA)
- Power Flow Optimization
- Volt/Var Optimization (VVO)
- State Estimation

Fault Location Isolation and Service Restoration

Evergy is actively deploying FLISR that uses a central application to communicate with and control smart switching with reclosers and communicating fault indicators.

A centralized FLISR engine will be used to drive the primary functions of our Intelligent End Devices (IEDs). These functions include Supervisory Control and Data Acquisition (SCADA) commands, automated FLISR actions, circuit/substation parameters and safety needs such as hold cards. In order to enable a hybrid (partially centralized, partially decentralized) approach, the IED will consume remote data while taking on some of the responsibility to adjust circuit protection settings, trip cycles and switching functions. This allows IEDs to have a subset of safe operational capabilities should communications be interrupted.

Centralized systems require little operator interaction during FLISR events. This allows the FLISR system to run quickly and effectively based on engineered algorithms. Operators will have ultimate authority over the system and will be able to disable and enable FLISR as needed.

Fault Location Analysis Functionality (FLA)

To enable automated fault location prediction, an advanced application is needed which requires accurate and persistently maintained circuit source impedance profiles, primary conductor impedance profiles, and communicating field equipment sensor data. This sensor data allows the application to model and calculate sections of a feeder where a fault is likely or unlikely to be physically located. Further improved fault location accuracy is attainable by installing additional fault sensors (such as communicating faulted circuit indicators or communicating switches) on the circuit to compliment the model with more physical and logical sensor data points in coordination with smart meter integration.

The Company's current fault location solution is an internally engineered application for circuit and data modeling that exists alongside the Company's Outage Management System (OMS), granting capability to leverage system integrations and data which do not necessarily exist or need to exist within the OMS platform itself. This independent application models and calculates fault location using similar methods and equations to an advanced vendor supplied engineering distribution system modeling platform which is leveraged by several engineering departments for various routine system load flow analyses and ad-hoc system studies such as arc-flash. The internally created FLA application has been validated in producing actionable solutions for actual outage events to aid crew and operators in reduction of outage duration.

Benefits anticipated from Fault Location prediction are mainly reduced patrol time for field crews in event location identification during outage events, and the ability to identify and trend momentary faulting events enabling the Company to remedy emergent issues prior to their severity producing a sustained outage event. With a near real-time FLA solution produced for an outage event, dispatchers can immediately direct field crews to focus on specific predicted sections of circuit as opposed to crews needing to patrol an entire circuit to identify the specific location of a system fault.

No specific timeline has been established, but the Company intends to further expand FLA solutions beyond the current state by fully configuring the system impedance model within the OMS application and aggregating in the required field data as a parallel FLA effort, which will enable further validation and model calibration of the two FLA systems in contrast to one another. Success of this planned effort is dependent on OMS system capability plus successful integration and testing of model comparisons and prescribed event solutions.

Communicating Faulted Circuit Indicators (CFCI)

Evergy is perpetually evaluating emerging CFCI technologies and installing where enhancements benefit grid resiliency and reliability.

Dispatchers now have the ability to receive CFCI alarms and activity in OMS. Using the OMS One-line diagram, Operators use CFCIs while troubleshooting an outage. This greatly enhances the “visibility” and usefulness of CFCIs to dispatchers.

CFCIs are also anticipated to be a cost-effective way to enhance the Fault Location functionality discussed previously. Although CFCIs cannot perform switching operations, they can enhance the effectiveness of dispatching and manual switching. To date, over 8,100 CFCIs have been installed in the Evergy service territory.

Reclosers with Communication

Evergy is currently deploying reclosers configured to support FLISR. These devices function like a traditional reclosers with the benefit of being able to communicate with a centralized FLISR application for coordination and action. Additionally, these devices can be used by an operator in our dispatch center.

Regulators and Capacitors with Communication

Evergy is working to upgrade as needed our Regulators and Capacitors with communication to support our VVO by enabling control of system voltage. Evergy currently has these assets deployed however they currently can only react to pre-planned events at the time the asset is deployed. This change will allow us to us automation and intelligence to manage the system to a greater degree.

Load Tap Changers with Communication

Similar to Regulators and Capacitors Evergy is upgrading Load Tap Changers (LTCs) as needed to add communications and controls for these devices. They will support VVO. Evergy currently has these assets deployed however they currently can only react to pre-planned events at the time the asset is deployed. This change will allow us to use automation and intelligence to manage the system to a greater degree.

7.1.3 Advanced Transmission Technologies Discussion

In the Evergy Missouri West area, Evergy is using advanced assessment methods to evaluate new technologies to support the transmission system. This effort is focused around maintaining a robust transmission system as customer end-uses and generation resources change, in addition to the continued adoption of behind-the-meter and other distributed energy resources.

Advanced Assessment Methods

Evergy uses end-use load models developed by the North American Electric Reliability Corporation (NERC) in association with the US Department of Energy (DoE) and Electric Power Research Institute (EPRI) to locate areas within the Evergy Missouri West footprint that may be susceptible to phenomena such as Fault-Induced Delayed Voltage Recovery (FIDVR). FIDVR and other fast-acting phenomena can be mitigated by means of new transmission technologies.

New Transmission Technologies

Static synchronous compensators (STATCOMs), enhanced STATCOMs (E-STATCOMs), and synchronous condensers (SynCons) are advanced transmission technologies currently being evaluated by Evergy.

STATCOM – a sub-division of a group of devices known as Flexible Alternating Current Transmission System (FACTS) devices. A STATCOM uses a voltage source converter (VSC) to match or produce a voltage wave and can react to large changes nearly instantaneously.

E-STATCOM – a STATCOM with added super-capacitor to enable primary frequency response and enhance grid-support capability.

SynCon – a synchronous generator connected to a motor. SynCons provide nearly identical system support characteristics in terms of voltage and frequency as a traditional synchronous generator. However, since they are connected via a motor to the transmission system, they are unable to produce real-power output (i.e., Megawatts).

Section 8: Demand-Side Resource Analysis Update

8.1 Changes from the 2024 Triennial IRP

Evergy has not conducted a new DSM Market Potential Study since 2023. Therefore, no new DSM potential forecast is included in this 2025 IRP Annual Update. However, Evergy's base case includes impacts of MEEIA Cycle 4 energy efficiency and demand response programs as approved by the Commission in EO-2023-0369/0370.

Evergy also includes estimated impacts of the Commission-ordered time-of-use (TOU) rates from ER-2022-0129/0130 based on its 2023 DSM potential study. However, the estimated impact is adjusted downward because the default TOU rate (i.e., peak adjustment charge rate) that was approved by the Commission reflects a much lower price differential than the modeled TOU rates in the potential study.

8.2 2023 Demand-Side Rate Analysis

The 2023 Demand-Side Management (DSM) Market Potential Study was conducted by Applied Energy Group (AEG). The DSM Market Potential Study included the Evergy Missouri Metro and Evergy Missouri West service territories and was delivered to Evergy in May 2023. The Potential Study included a RAP and a MAP level of DSM, as defined in the IRP Rules. This Potential Study included energy efficiency programs, demand response programs and demand-side rate potential savings analyses.

During the Potential Study and in ER-2022-0129/0130, the Commission ordered default time-of-use (TOU) rates. The Commission ordered that Evergy would transition all residential customers to default TOU rates by October 1, 2023, with the default rate being the two-period TOU rate. AEG analyzed the two-period TOU rate in the Maximum Achievable Potential (MAP) scenario with high, medium and low retention rates. AEG assumed a conservative retention rate of 50% to estimate MAP and then tested the sensitivity of impacts and program costs to changes in the TOU retention rate as shown in Table 14.

Table 14: MAP Sensitivity Analysis

Sensitivity	(1) TOU Standard	(2) TOU for EV Owners	(3) TOU Peak Adjustment Rate	(4) TOU 3-Period
MAP	**50% of all residential customers**	**20% of EV owners who opt out of TOU Standard**	**95% of remaining TOU Standard opt-outs**	**All other TOU Standard opt-outs**
MAP Medium-Retention	70% of all residential customers	50% of EV owners who opt out of TOU Standard	95% of remaining TOU Standard opt-outs	All other TOU Standard opt-outs
MAP High - Retention	85% of all residential customers	100% of EV owners who opt out of TOU standard	95% of remaining TOU Standard opt-outs	All other TOU Standard opt-outs

The expected demand savings in MW for Summer and Winter peak are presented in Table 15 and Table 16.

Table 15: Cumulative Annualized Demand Savings (MW) from TOU – Summer

Year	MAP(High)	MAP(Low)	MAP (Medium)	RAP	RAP (-)	RAP (+)
2025	67	43	57	11	9	11
2026	58	37	49	19	16	19
2027	58	37	49	28	25	28
2028	58	37	49	37	33	37
2029	58	37	49	37	33	37
2030	58	37	49	37	33	37
2031	58	37	49	37	33	37
2032	57	37	49	37	33	37
2033	59	38	50	38	34	38
2034	57	37	48	37	33	37
2035	57	36	48	37	33	37
2036	57	36	48	37	33	37
2037	57	36	48	37	33	37
2038	58	37	49	38	34	38
2039	57	36	48	37	33	37
2040	57	36	48	37	33	37
2041	57	36	48	37	33	37
2042	57	36	48	37	33	37
2043	57	36	48	37	33	37
2044	57	36	48	37	33	37

Table 16: Cumulative Annualized Demand Savings (MW) from TOU – Winter

Year	MAP(High)	MAP(Low)	MAP (Medium)	RAP	RAP (-)	RAP (+)
2025	55	35	47	9	8	9
2026	48	31	41	15	14	15
2027	48	31	41	23	20	23
2028	48	31	41	31	27	31
2029	48	31	41	31	27	31
2030	48	31	41	31	28	31
2031	48	31	41	31	28	31
2032	48	31	41	31	28	31
2033	48	31	41	32	28	32
2034	48	31	41	32	28	32
2035	48	31	41	32	28	32
2036	49	31	41	32	28	32
2037	48	31	41	32	28	32
2038	49	31	41	32	28	32
2039	49	31	41	32	28	32
2040	49	31	41	32	28	32
2041	49	31	41	32	28	32
2042	48	31	41	32	28	32
2043	48	31	41	32	28	32
2044	48	31	41	32	28	32

However, at the end of 2023, the Commission revised its order, changing the default rate for Missouri residential customers to the Peak Adjustment Charge Rate. Because the revised order was received after the DSM Market Potential Study had been completed and because the Peak Adjustment Charge Rate reflects a much lower price differential than the modeled TOU rates in the potential study, it was determined that a lower demand impact would likely result. Therefore, Evergy adjusted the TOU impact downward determined in the potential study for use in its 2024 IRP by 70%, or resulting in 30% of the potential study forecast. The savings modeled in IRP 2025 annual update for TOU are shown in Table 17 and Table 18.

Table 17: IRP Modeled Cumulative Annualized Demand Savings (MW) from TOU – Summer

Year	Time-of-Use (TOU) Rate	Electric Vehicle (EV) TOU Rate	Total
2025	3.19	0.00	3
2026	5.60	0.01	6
2027	8.39	0.02	8
2028	11.18	0.02	11
2029	11.18	0.03	11
2030	11.17	0.03	11
2031	11.16	0.03	11
2032	11.15	0.03	11
2033	11.44	0.04	11
2034	11.14	0.04	11
2035	11.12	0.04	11
2036	11.12	0.04	11
2037	11.14	0.05	11
2038	11.42	0.05	11
2039	11.13	0.05	11
2040	11.12	0.06	11
2041	11.12	0.06	11
2042	11.08	0.07	11
2043	11.09	0.07	11
2044	11.10	0.07	11

Table 18: IRP Modeled Cumulative Annualized Demand Savings (MW) from TOU – Winter

Year	Time-of-Use (TOU) Rate	Electric Vehicle (EV) TOU Rate	Total
2025	2.62	0.00	3
2026	4.63	0.01	5
2027	6.97	0.01	7
2028	9.32	0.02	9
2029	9.34	0.02	9
2030	9.38	0.02	9
2031	9.40	0.03	9
2032	9.41	0.03	9
2033	9.42	0.03	9
2034	9.44	0.03	9
2035	9.45	0.03	9
2036	9.47	0.04	10
2037	9.47	0.04	10
2038	9.49	0.04	10
2039	9.51	0.05	10
2040	9.51	0.05	10
2041	9.52	0.05	10
2042	9.48	0.06	10
2043	9.49	0.06	10
2044	9.50	0.06	10

Section 9: Resource Plan Analysis

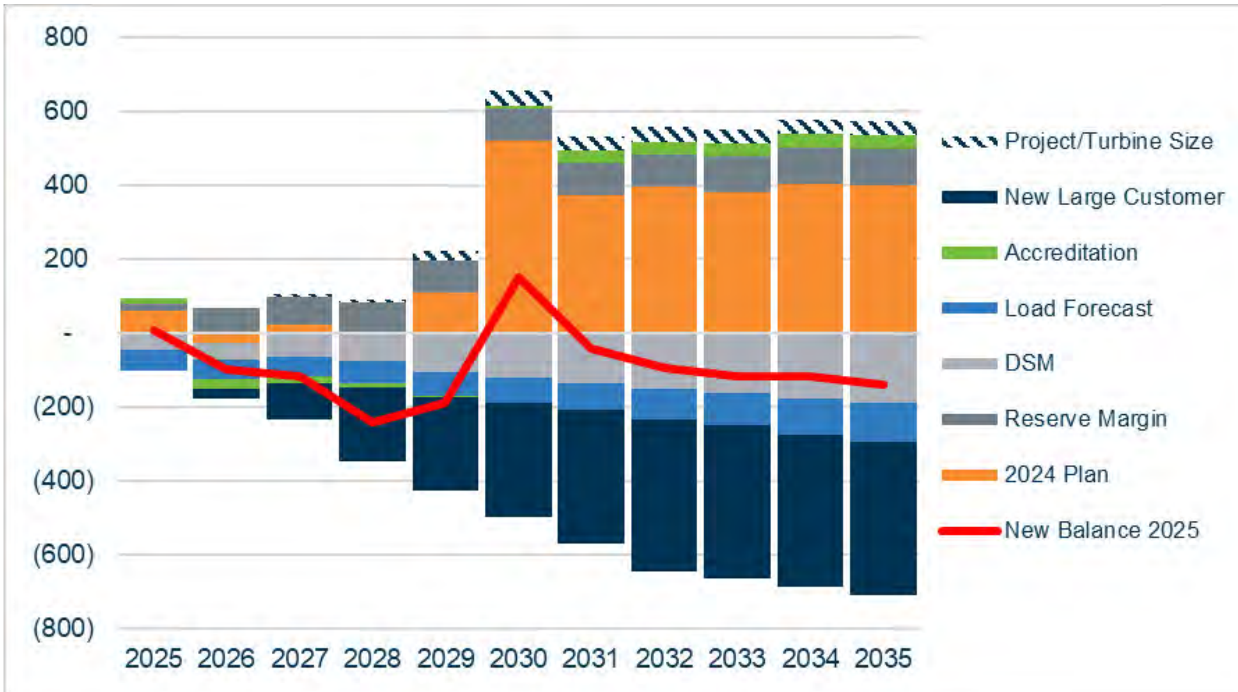
9.1 Changes to Expected Capacity Needs

Evergy Missouri West's 2024 Preferred Plan forecasted a small summer capacity surplus in 2025, with a need to purchase market capacity in 2026. In 2027, with the selected solar addition, the plan was again slightly long summer capacity. In 2029, with the ½ CCGT addition, the plan was 100 MW long capacity and then with the SCGT addition in 2030, maintained summer capacity length of about 400 MW through 2035.

Evergy Missouri West's current forecast for the 2025 IRP leaves it short in most years with the 2024 Preferred Plan. Forecast changes reducing the capacity balance include lower levels of demand-side programs, higher base load forecast, and addition of a large customer. Evergy Missouri West has also recalculated needs based on updated reserve margin assumptions, which were lower than the 2024 IRP and reduced capacity needs. Accreditation assumptions for performance-based accreditation changed slightly causing small losses in capacity in the early years and gains in capacity in the later years of the planning horizon. Additionally, changes to project size between the 2024 IRP and the expected execution (larger solar, CCGT and SCGT projects) increased projected capacity.

The result of these changes is a net short summer capacity position through 2029, averaging around 150 MW. The capacity balance becomes positive in 2030 after the addition of the ½ CCGT in 2029 and SCGT in 2030. However, after 2030, the plan becomes short summer capacity again.

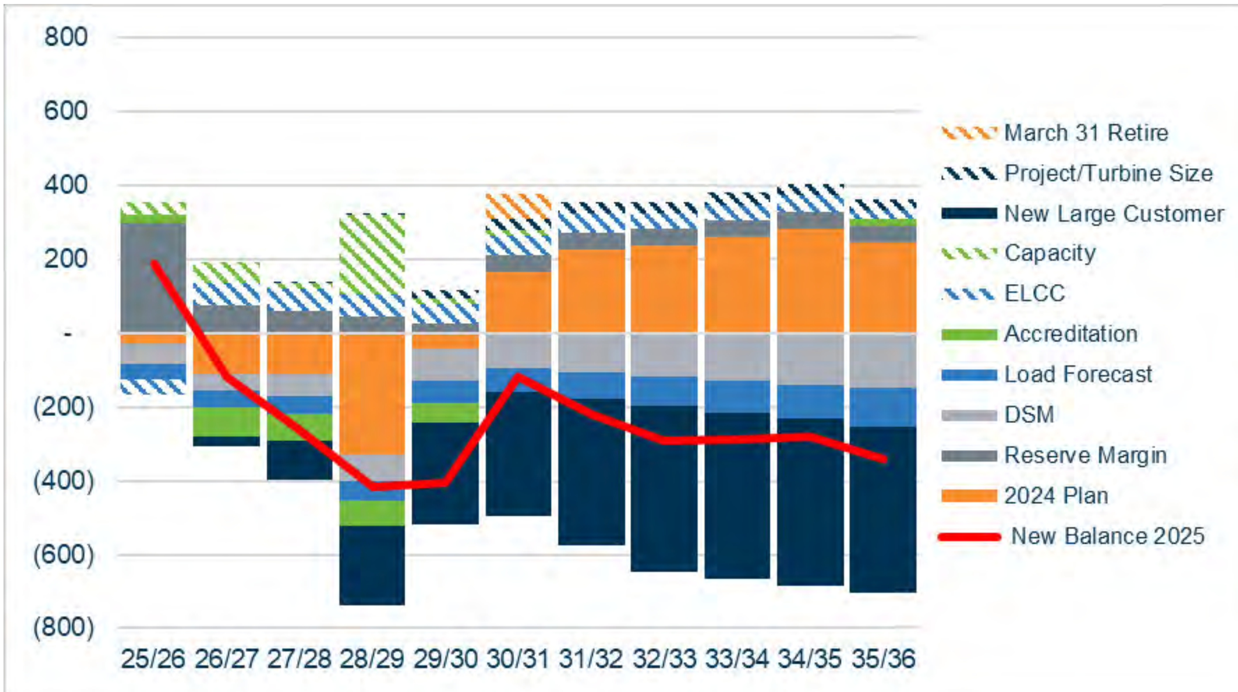
Figure 20: Changes to Summer Capacity Balance



Evergy Missouri West forecasted a winter capacity short position through winter 2029/2030 in its 2024 Preferred Plan. Evergy Kansas Central was forecasted to have a surplus of winter capacity during this time horizon, so Evergy believed that winter market capacity would be available for purchase by Evergy Missouri West to bridge this short until thermal resources could be built. Beginning in winter 2030/2031, after the ½ CCGT and SCGT commercial operation, Evergy Missouri West was forecast to have about 200 MW surplus winter capacity.

Updates to forecasts since the 2024 IRP make Every Missouri West much shorter winter capacity. Drivers of increased capacity need include lower demand-side programs forecast, higher base load forecast, large new customer load, and decrease in expected resource accreditation from fuel assurance/ performance-based accreditation provisions. Helping the capacity position were changes to reserve margins, turbine/project size of projects in execution, and higher ELCC accreditation. Evergy Missouri West also better accounted for a capacity contract ending winter 2028/2029, and assumed in this IRP that retirements would be concluded after the winter season to ensure continuity of retirement-new build capacity across seasons.

Figure 21: Changes to Winter Capacity Balance



9.2 Base Planning Options

9.2.1 Resource Availability

All resource plans developed include the 2027 solar projects, Foxtrot and Sunflower Sky, and the Viola ½ CCGT in 2029. These resources were retested for the CCN filings, inclusive of updated cost estimates and specific resource characteristics known at the time, and determined to be needed by Evergy Missouri West, consistent with the 2024 Triennial Preferred Plan. Since these filings, in addition to the changes in expected needs for Missouri West, cost information has been updated for Mullin Creek, the 2030 CT selected in the Preferred Plan. The need for this resource is tested in this 2025 Annual Update by allowing the capacity expansion software to select Mullin Creek or other possible alternatives. The McNew ½ CCGT was unallocated in the CCN filings, and is also a possible resource build.

Evergy Missouri West's base planning assumptions include limiting the number of project additions each year to ensure the company continues to meet financial metrics and maintain an investment-grade credit rating. The project limit assumption is one new resource per year. The base-planning ARPs also allow the McNew ½ CCGT to be selected in 2030 when it is expected to be commercially available.

Table 19: Base Build Limit Assumptions

Year	Solar	Wind	Battery	CC	CT
2027	Foxtrot, Sunflower Sky	n/a	n/a	n/a	n/a
2028	150 MW	150 MW	150 MW	n/a	n/a
2029	n/a	n/a	n/a	Viola	n/a
2030	n/a	n/a	n/a	McNew	Mullin Creek
2031+	150 MW	150 MW	150 MW	355 MW	440 MW

Consistent with stakeholder feedback, alternative resource plans were developed to determine other options to meeting customer needs. Evergy Missouri West does not expect to have options to develop thermal resources that can be operational in the next five years other than the named units. To understand the options to meet customer needs without these resources, or to meet additional near-term load growth, ARPs were developed with higher build limits for solar and storage through 2031 when the next thermal resource would be available. The higher early solar/storage limit allows up to 450 MW of these resources per year.

Table 20: Higher Early Solar/Storage Build Limits

Year	Solar	Wind	Battery	CC	CT
2027	Foxtrot, Sunflower Sky	n/a	n/a	n/a	n/a
2028	450 MW	150 MW	450 MW	n/a	n/a
2029	450 MW	n/a	450 MW	Viola	n/a
2030	450 MW	n/a	450 MW	McNew	Mullin Creek
2031	450 MW	150 MW	450 MW	355 MW	440 MW
2032+	150 MW	150 MW	150 MW	355 MW	440 MW

Evergy Missouri West also tested a plan with higher wind build limits beginning in 2035, which may allow the Company to replace wind energy and capacity from power purchase agreements that end during the planning period.

Table 21: Higher Wind Build Limits 2035+

Year	Solar	Wind	Battery	CC	CT
2027	Foxtrot, Sunflower Sky	n/a	n/a	n/a	n/a
2028	150 MW	150 MW	150 MW	n/a	n/a
2029	n/a	n/a	n/a	Viola	n/a
2030	n/a	n/a	n/a	McNew	Mullin Creek
2031-2034	150 MW	150 MW	150 MW	355 MW	440 MW
2035+	150 MW	300 MW	150 MW	355 MW	440 MW

Evergy Missouri West does not expect to be able to procure or develop additional thermal resources earlier than 2031. A plan was developed to test whether full combined cycles or higher amounts of other resources would be cost-effective if build limits were loosened.

Table 22: Higher Build Limits 2031+

Year	Solar	Wind	Battery	CC	CT
2027	Foxtrot, Sunflower Sky	n/a	n/a	n/a	n/a
2028	150 MW	150 MW	150 MW	n/a	n/a
2029	n/a	n/a	n/a	Viola	n/a
2030	n/a	n/a	n/a	McNew	Mullin Creek
2031+	450 MW	300 MW	450 MW	710 MW	440 MW

Finally, in order to develop plans that could not select new thermal resources beyond the CCN resources, Evergy Missouri West tested relaxed build limits equivalent to 10 projects/year each for solar, wind and storage.

Table 23: High Renewables and Storage Build Limits

Year	Solar	Wind	Battery	CC	CT
2027	Foxtrot, Sunflower Sky	n/a	n/a	n/a	n/a
2028	1500 MW	1500 MW	1500 MW	n/a	n/a
2029	1500 MW	1500 MW	1500 MW	Viola	n/a
2030	1500 MW	1500 MW	1500 MW	n/a	Mullin Creek
2031+	1500 MW	1500 MW	1500 MW	n/a	n/a

9.2.2 Retirements

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

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.

The 2024 Preferred 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.

Evergy Missouri West expects Jeffrey 2 to convert to natural gas operation in 2030, a difference from the 2024 plan. This will enable the resource to avoid SCR and continue operation. The 2025 IRP continues to plan for a Jeffrey Unit 3 retirement in 2030, consistent with the 2024 IRP. Retaining Jeffrey 2 on natural gas and fully retiring Jeffery 3 allows for a diversified approach to planning for the multiple issues that make each unit a retirement candidate in the near-term. With this plan, both Jeffrey 2 and Jeffrey 3 will be able to avoid the expected costly SCR investment. The Jeffrey units will be roughly 50 years old in 2030 and approaching the expected end of their useful life. Continuing to plan for a retirement at Jeffrey 3 is a balanced approach of responsibly transitioning the fleet, while lowering the overall risk of continuing to operate aged coal generation. Additionally, retirement at Jeffrey 3 will open valuable interconnection to the transmission grid that will allow for newer, more efficient, and more reliable generation to come online faster and cheaper than developing at a greenfield site.

The 2025 IRP has ARPs reflecting this change as well as other possible retirement scenarios:

- Jeffrey 2 retires 2030
- Jeffrey 2 retires 2039
- Iatan 1 retires 2030

9.3 Alternative Resource Plan Testing

Evergy Missouri West developed various scenarios to test the most cost-effective future resource mix to meet customer needs, using capacity expansion modeling:

- Additional resources needed considering expected new builds from CCN proceedings
- Including the expected continued operation of Jeffrey 2 on natural gas beginning in 2030, per Kansas Central’s resource plan
- Testing if the unallocated McNew ½ CCGT resource would be an economic addition to the resource plan
- Testing if the Mullin Creek CT is still desirable in the resource plan given the increased costs from the 2024 IRP and CCN estimates
- Testing the economics of plans without McNew and/or Mullin Creek, and with other resources instead
- Testing alternative coal retirement/conversion scenarios
- Testing plans with different future critical uncertain factor expectations
- Testing how varying capital spend/number of projects per year would influence the resource plan decisions and economics
- Testing a plan that only meets the minimum requirements for Missouri Renewable Energy Standards (RES)

Table 24: Plan Key for Base Plans

DSM	Coal (Changes from PP 2024)	Builds	Load & Contingencies
A - MEEIA Extends	A – 2024 PP Retirements	A - Base capital + CCN Builds + McNew Allowed	A - Base load
B – MEEIA Ends	B - Extend JEC 2 2039	B - McNew in Plan	P - High NG, High CO_2 Restriction
	C - JEC 2 NG 2030	C - Allow higher early solar/storage	Q - Low NG, Low CO_2 Restriction
	D - Ret IAT 1 2030	D - Allow higher wind 2035+	R - High NG, Mid CO_2 Restriction
		E - Allow higher builds 2031+	T – Minimum Compliance with RES
		F - Only renewables/storage; No Build Limit	
		G - No McNew	
		H- No McNew, allow higher early solar/storage	
		I - No McNew, No 2031 Thermal, allow higher early solar/storage	
		J - No Mullin Creek	
		K- No Mullin Creek, No McNew, No 2031 Thermal, allow higher early solar/storage	

Table 25: Base Plan Descriptions

Plan Name	Description
AAAA	Base Load, MEEIA Extends, CCN Resources, Build Limits, 2024 PP Retirements
ABAA	Extend JEC 2 2039
ACAA	JEC 2 NG 2030
ACAP	High NG/High CO_2
ACAQ	Low NG/Low CO_2
ACAR	High NG/Mid CO_2
ACFA	Only renewables/storage; No Build Limit
ACFP	High NG/High CO_2, Only renewables/storage no build limit
ACGA	No McNew
ACHA	No McNew, No 2031 CCGT, allow higher early solar/storage
ACIA	No McNew, No 2031 Thermal, allow higher early solar/storage
ACJA	No Mullin Creek
ACKA	No Mullin Creek, No McNew, or 2031 Thermal, higher early solar/storage
ADAA	Retire IAT 1 2030

The alternative resource plans generated through this process were tested in each endpoint (future with varied critical uncertain factors) and rankings were developed based on the probability-weighted average net present value revenue requirement (NPVRR), consistent with the 2024 Triennial IRP and the Missouri IRP process.

Table 26: Critical Uncertain Factor Probabilities

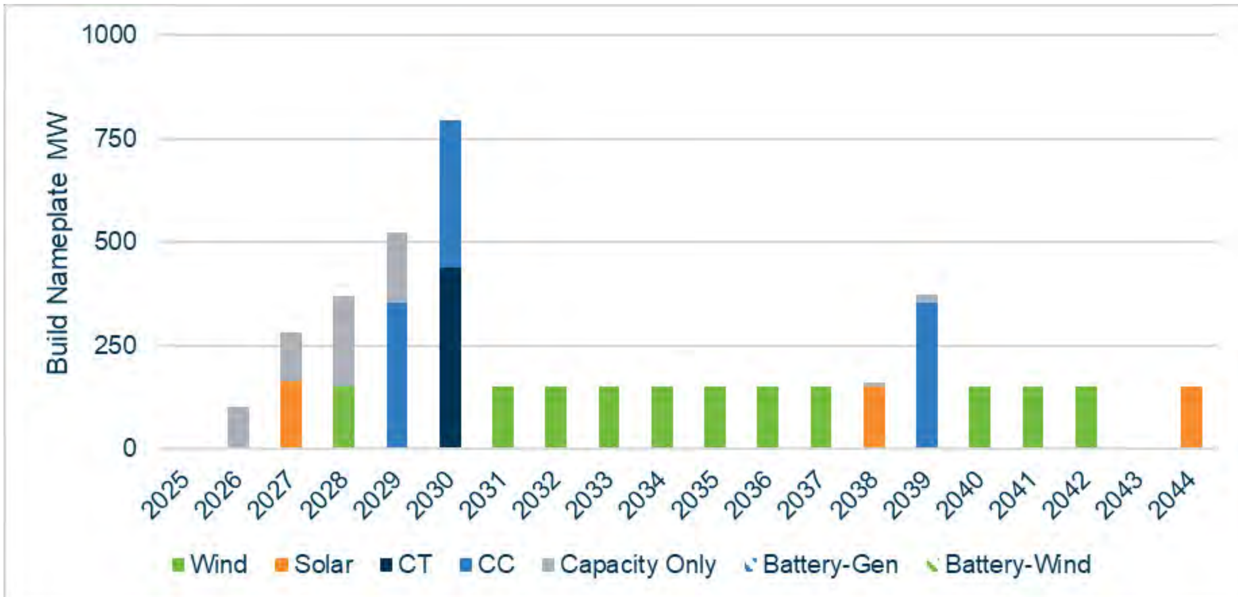
	Natural Gas Price	CO_2 Emissions Restrictions	Construction Cost
Low	35%	25%	25%
Mid	50%	60%	50%
High	15%	15%	25%

9.4 Base Plans

The AAAA plan uses capacity expansion and base planning assumptions, including the updated load and resource adequacy forecasts, retirements identified in the 2024 IRP, the MEEIA level of demand-side programs, and the resources that Evergy is developing with pending CCN filings: Foxtrot, Sunflower Sky, Viola, and Mullin Creek.

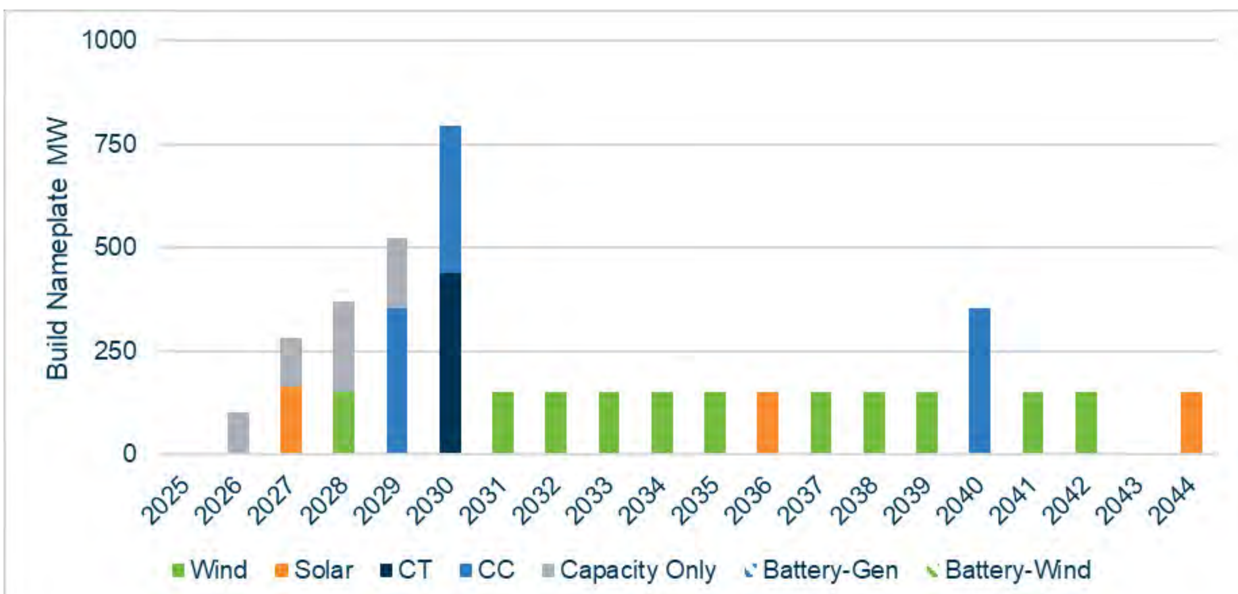
The alternative resource plan selects a wind project in 2028 and the McNew ½ CCGT in 2030. The plan also selects wind projects in 2031-2037, with the next additional thermal build in 2039. Market capacity is purchased in 2026-2029.

Figure 22: Base Planning Assumptions Including CCN Plan AAAA



Plan ACAA uses same base planning assumptions, but instead of Jeffrey 2 retiring 2030, it is operated on natural gas for the remaining time horizon. The resources selected are very similar; however, the first thermal build after the 2030 McNew and Mullin Creek projects is pushed back one year to 2040.

Figure 23: Jeffrey 2 NG 2030 Plan ACAA



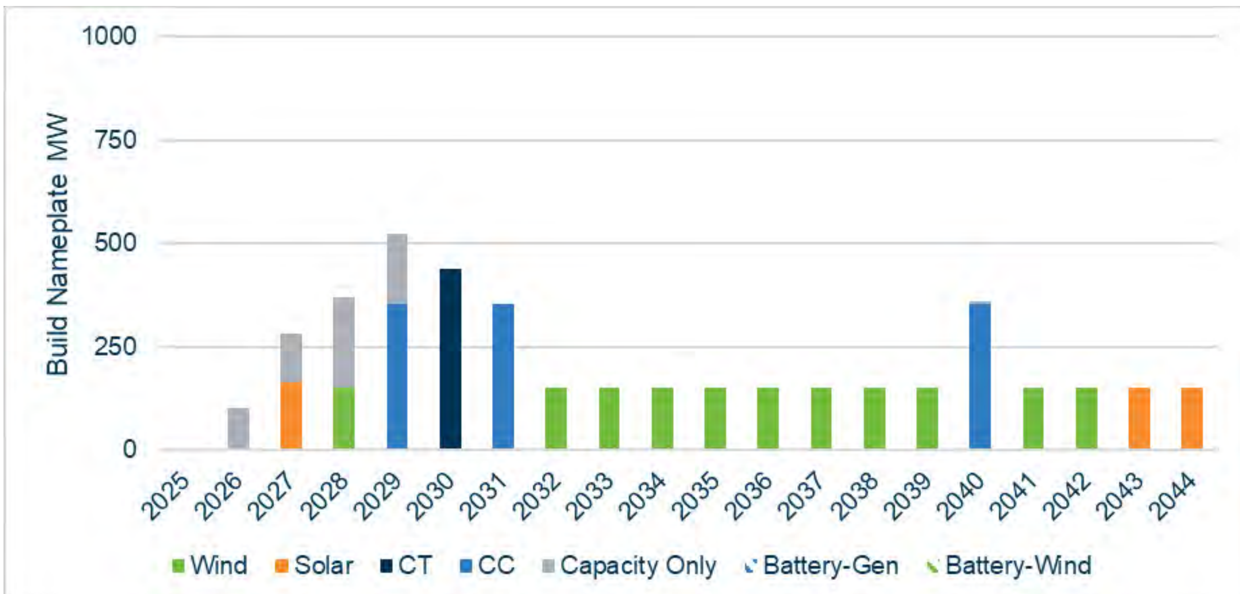
9.5 Plans Testing Near-Term Options

9.5.1 Plans without McNew as an Option

Alternative resource plans ACGA, ACHA, and ACIA test what resources would be built if the ½ McNew CCGT was not a build option in 2030. Jeffrey 2 converts to natural gas in 2030 in the three plans.

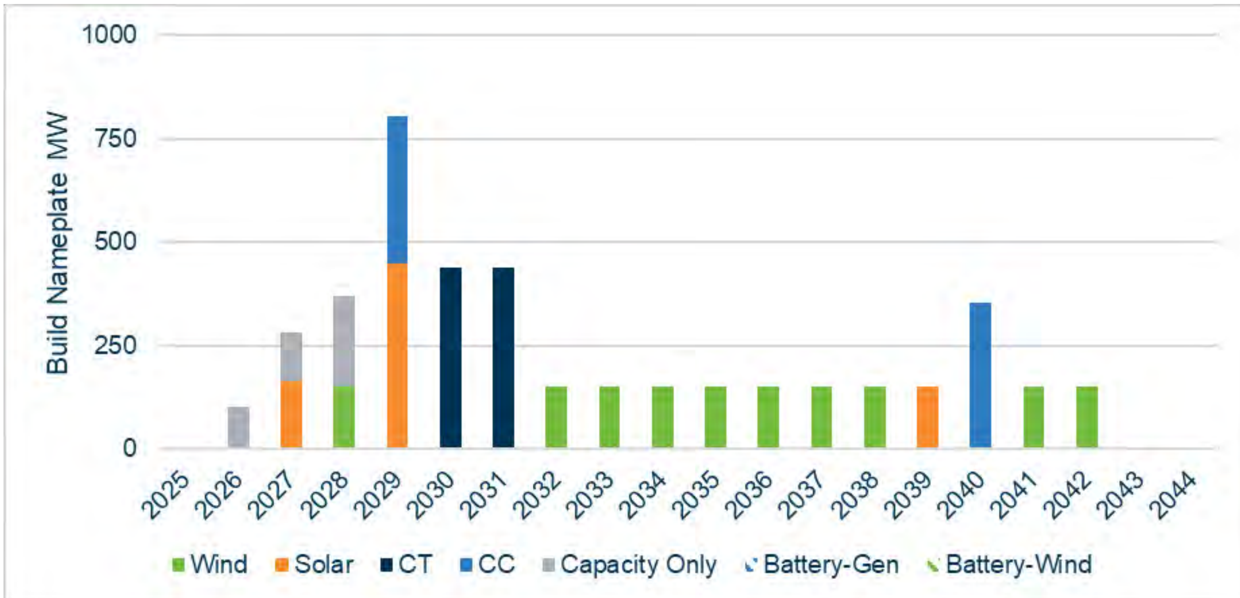
The resource plan ACGA builds a ½ CCGT in 2031 without McNew in 2030. Market capacity is also purchased in 2026-2029.

Figure 24: No McNew Plan ACGA



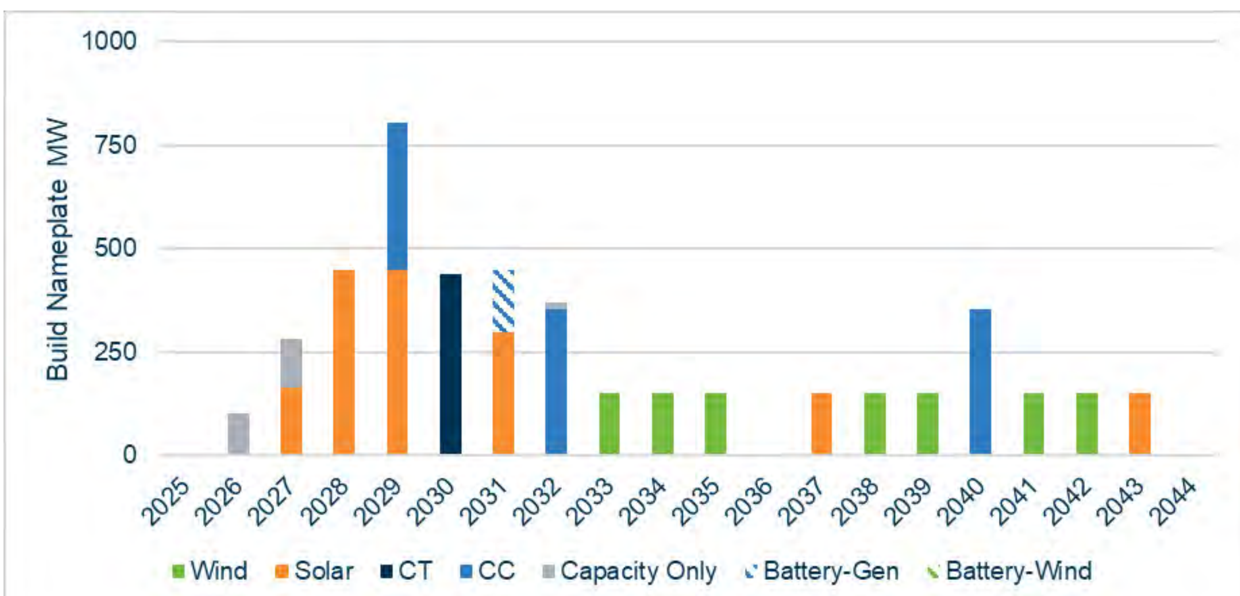
Plan ACHA relaxes early build constraints for solar and storage and does not allow the ½ McNew nor any CCGT build through 2031. The resource plan ACHA builds 450 MW of solar in 2029 before building a full SCGT in 2031. Market capacity is purchased in 2026-2028.

Figure 25: No McNew, Higher Early Solar/Storage, No 2031 CCGT Plan ACHA



Plan ACIA relaxes early build constraints for solar and storage and does not allow the ½ McNew build nor any thermal resource (CCGT or SCGT) through 2031. The resource plan builds 1,200 MW of solar between 2028-2031 plus 150 MW of storage in 2031 before building a ½ CCGT in 2032. Market capacity is purchased in 2026, 2027, and 2032.

Figure 26: No McNew, Higher Early Solar/Storage, No 2031 Thermal Plan ACIA



The resource plans selected without the ½ share of McNew available include a 2031 ½ CCGT, or a 2031 SCGT, or large amounts of solar and storage followed by a 2032 ½ CCGT. These alternative resource plans demonstrate the need for firm dispatchable generation incremental to the 2024 IRP Preferred Plan to serve Missouri West customers. Practically, Evergy Missouri West does not expect to achieve cost savings from postponing a thermal resource build by 1-2 years when it has customer needs, a site selected, and materials and labor in the contracting process at a time of high demand in the industry. However, the economic analysis also shows the ½ McNew share has the lowest risk-weighted NPVRR.

Table 27: Rankings for McNew Testing

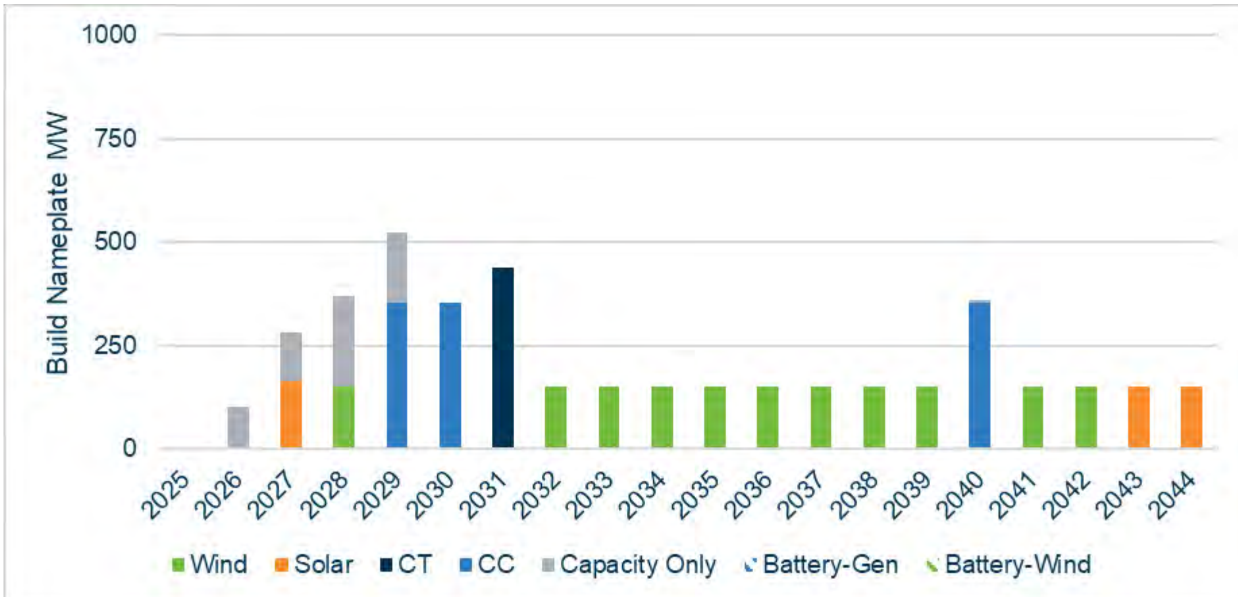
Rank	Plan	NPVRR	Difference	Description
1	ACAA	14,124		McNew selected
2	ACIA	14,244	120	No McNew, No 2031 Thermal, allow higher early solar/storage
3	ACGA	14,278	154	No McNew
4	ACHA	14,377	253	No McNew, No 2031 CCGT, allow higher early solar/storage

9.5.2 Plans without Mullin Creek

Alternative resource plans ACJA and ACKA test what would be built if the Mullin Creek CT was not available as a thermal build option in 2030. Jeffrey 2 converts to natural gas in 2030 in both plans.

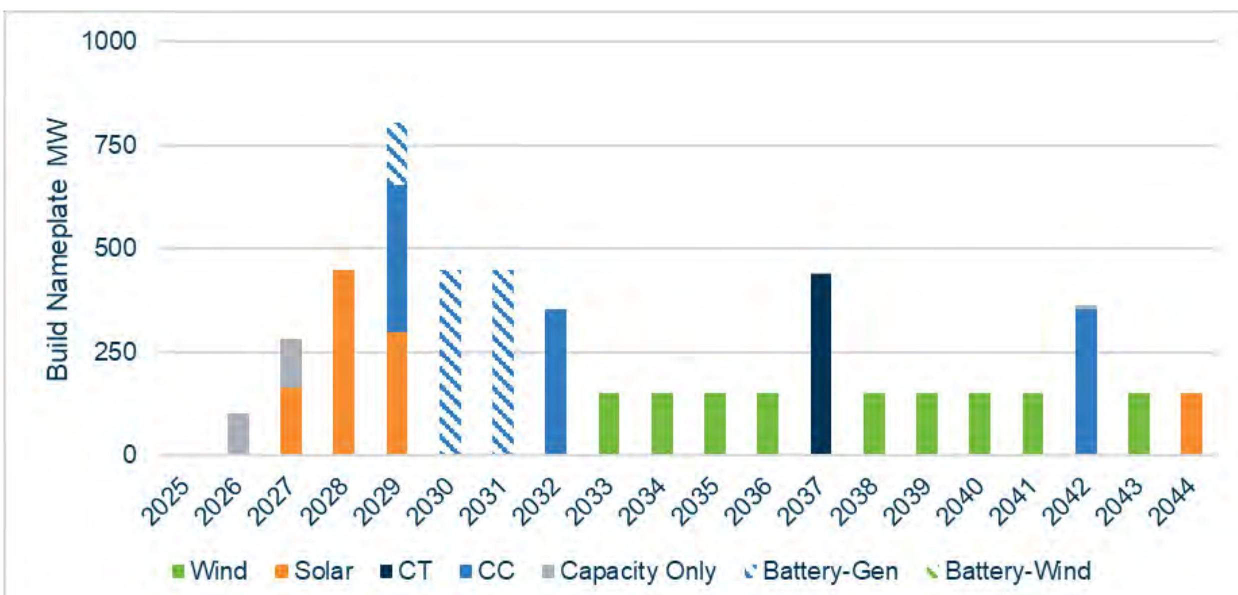
The resource plan ACJA builds the ½ CCGT McNew and wind in 2030, and a SGCT in 2031. Market capacity is purchased in 2026-2029.

Figure 27: No Mullin Creek Plan ACJA



Plan ACKA uses higher early solar/storage build limits and cannot select McNew nor any additional thermal resource through 2031. The resource plan builds 750 MW of solar in 2028-2029, and 1,050 MW of storage in 2029-2031 before building a ½ CCGT in 2032. Market capacity is purchased in 2026 and 2027.

Figure 28: No McNew, No Mullin Creek, Higher Early Solar/Storage Plan ACKA



The alternative resource plan selected if Mullin Creek is not available includes a SCGT in the next available year, 2031. This plan is slightly more expensive than the plan including Mullin Creek in 2030. Again, Evergy Missouri West does not expect to be able to achieve measurable cost differences from postponing the project one year since market demand is high for materials and labor and there are a long lead times in the development process. Replacing the Mullin Creek resource with solar and storage and postponing the ½ CCGT build to avoid the 2030 timing is also substantially more expensive.

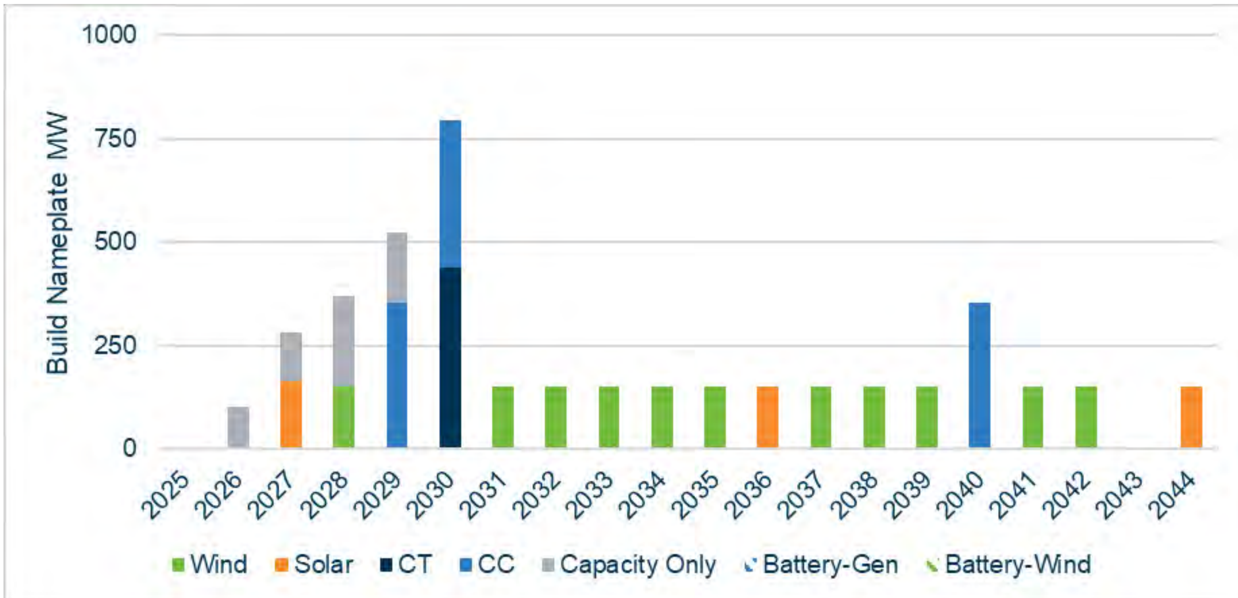
Table 28: Rankings Testing Mullin Creek

Rank	Plan	NPVRR	Difference	Description
1	ACAA	14,124		Mullin Creek, McNew selected
2	ACJA	14,267	142	No Mullin Creek
3	ACKA	14,786	662	No Mullin Creek, No McNew, or 2031 Thermal, allow higher early solar/storage

9.6 Plans Testing Retirements

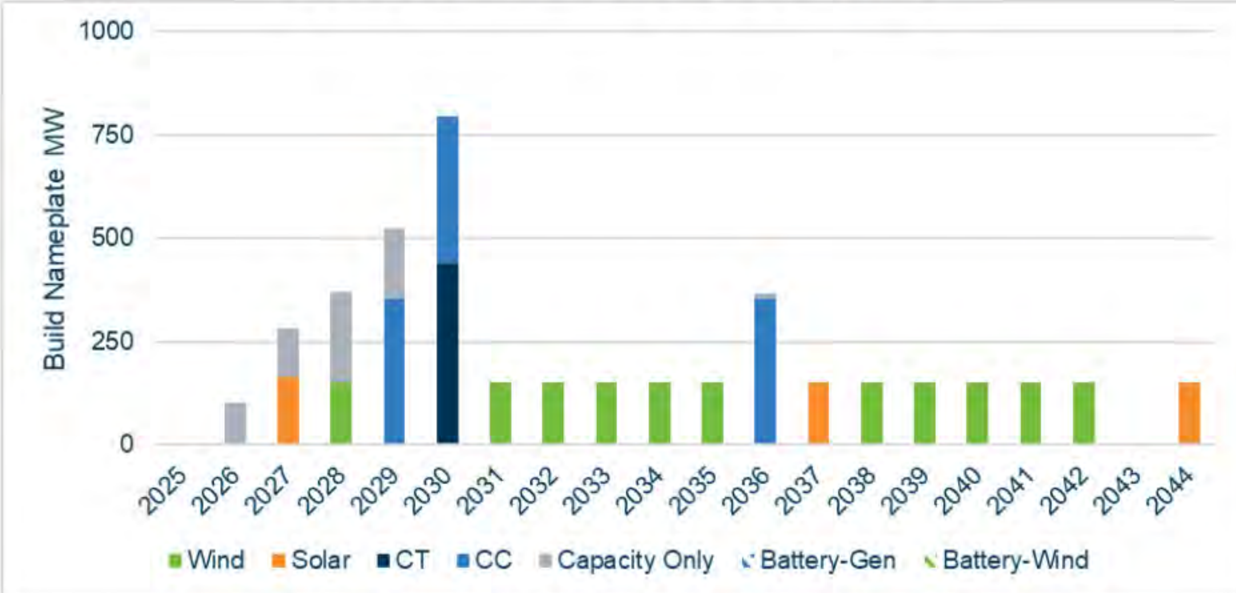
Alternative resource plans ABAA and ADAA test additional coal plant retirement options. Base build limits are used and the ½ CCGT McNew is available as a build option. Plan ABAA extends Jeffrey 2 to run on coal until 2039. The resource plan builds the ½ CCGT McNew in 2030, 1350 MW of wind in 2031-2039, and a ½ CCGT in 2040 and 2043. Market capacity is purchased in 2026-2029. This plan is similar to AAAA (Jeffrey 2 retires in 2030) and ACAA (Jeffrey 2 converts to NG 2030), due to the small contribution Jeffrey 2 makes to the Evergy Missouri West capacity balance.

Figure 29: Extend Jeffrey 2 Retirement to 2039 Plan ABAA



Plan ADAA retires Iatan 1 in 2030. The resource plan builds the ½ CCGT McNew, and the next thermal resource addition is brought forward to 2036.

Figure 30: Retire Iatan 1 in 2030 Plan ADAA



There are small differences in the alternative plans with different Jeffrey 2 scenarios. The plan with the 2030 retirement is higher ranked than the extension on natural gas in 2030 and the 2039 retirement. However, the earlier retirement of Iatan 1 is more expensive because it pulls up the next thermal resource to 2036.

Table 29: Coal Retirement Plan Rankings

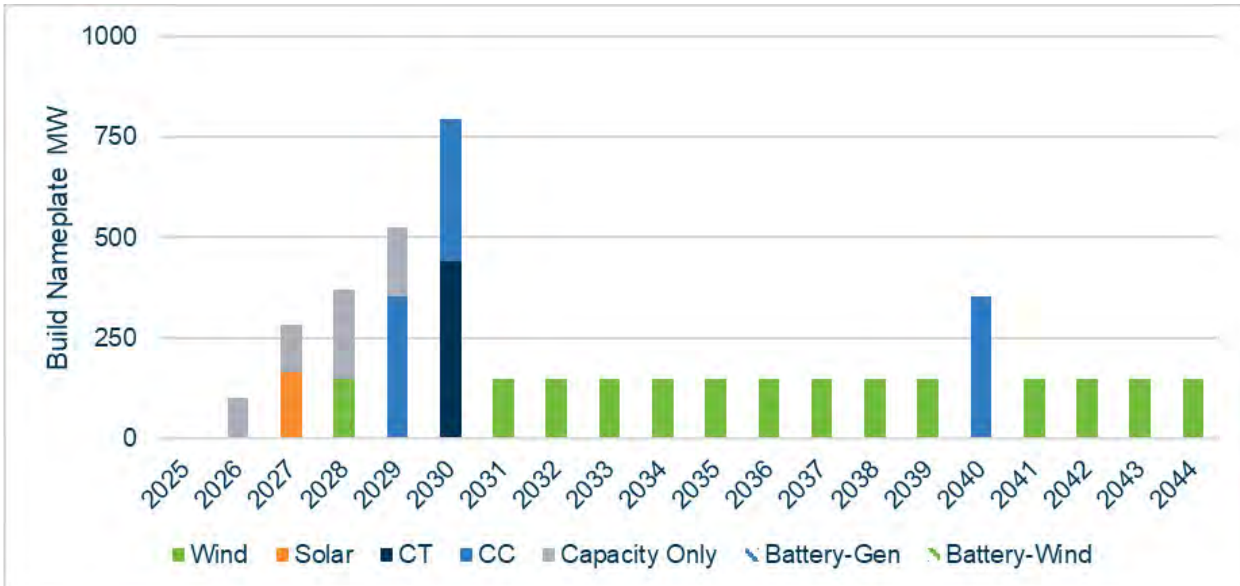
Rank	Plan	NPVRR	Difference	Description
1	AAAA	14,086		2024 PP Retirements
2	ABAA	14,093	7	Extend JEC 2 2039
3	ACAA	14,124	38	JEC 2 NG 2030
4	ADAA	14,171	85	Ret IAT 1 2030

9.7 Plans Testing Optimal Builds for Varying Futures

Alternative resource plans ACAP, ACAQ, ACAR, and ACFP test optimal build decisions for varying natural gas and CO_2 futures. Jeffrey 2 converts to natural gas in 2030 in all four plans, and base build assumptions with the option of the ½ CCGT McNew are used in all but ACFP.

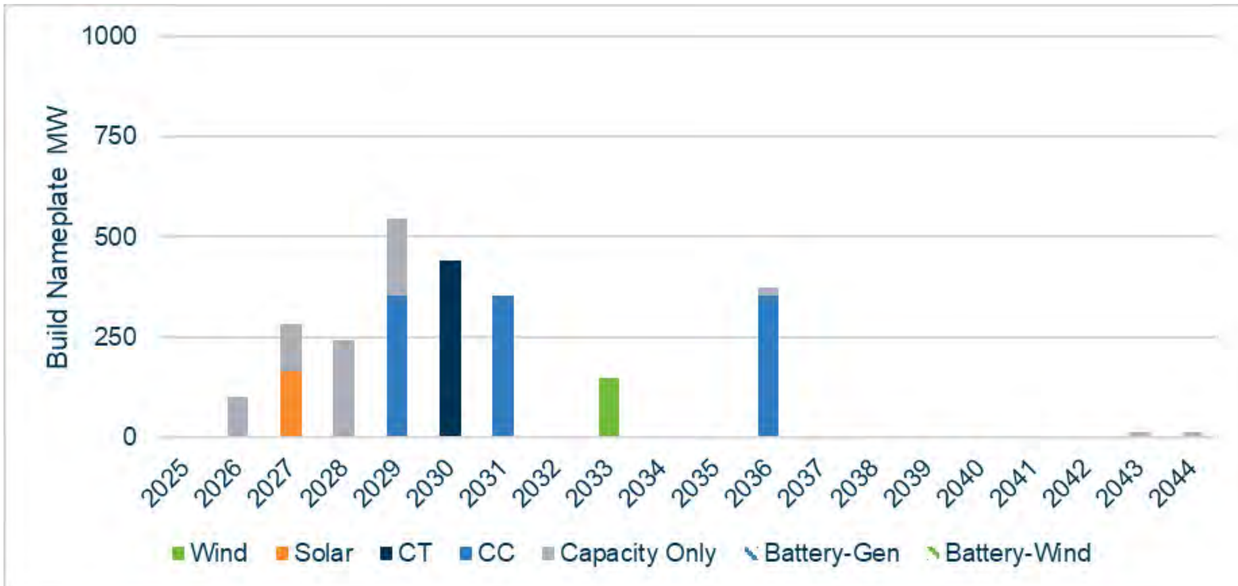
The resource plan ACAP uses a high natural gas and high CO_2 future and builds the ½ CCGT McNew. The plan also selects 1,350 MW of wind projects in 2031-2039, with the next additional thermal build in 2040. Market capacity is purchased in 2026-2029.

Figure 31: High NG/High CO_2 Future Plan ACAP



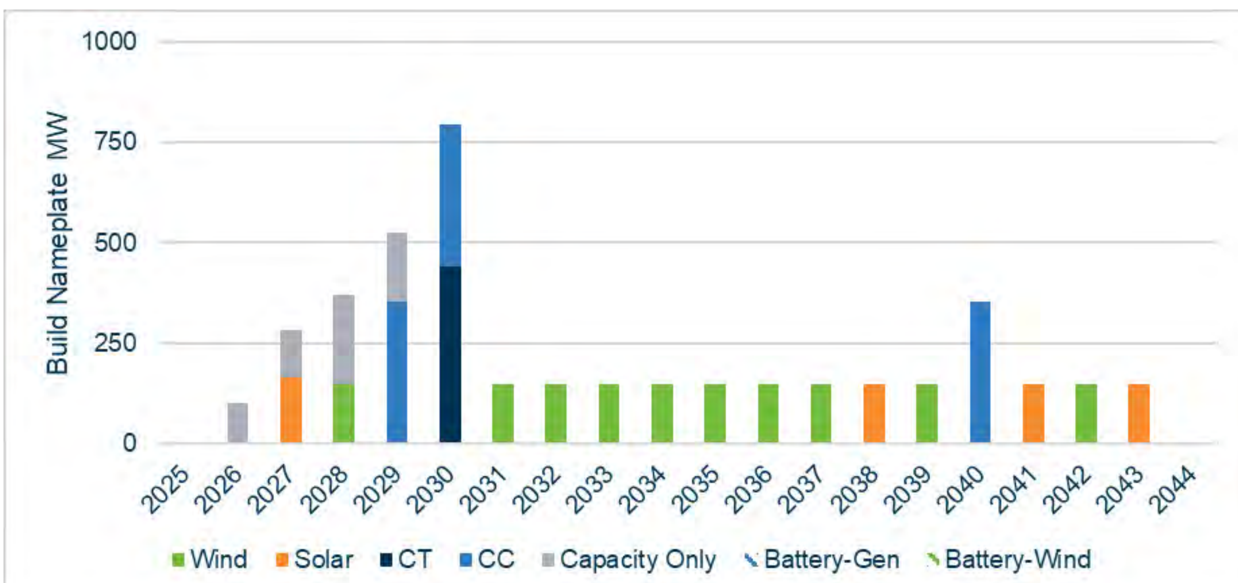
Plan ACAQ uses a low natural gas and low CO_2 future. The resource plan does not select the ½ CCGT McNew, but builds a ½ CCGT in 2031. No wind is built in 2028 and only one wind resource is added in 2033. A ½ CCGT is added in 2036.

Figure 32: Low NG/Low CO_2 Future Plan ACAQ



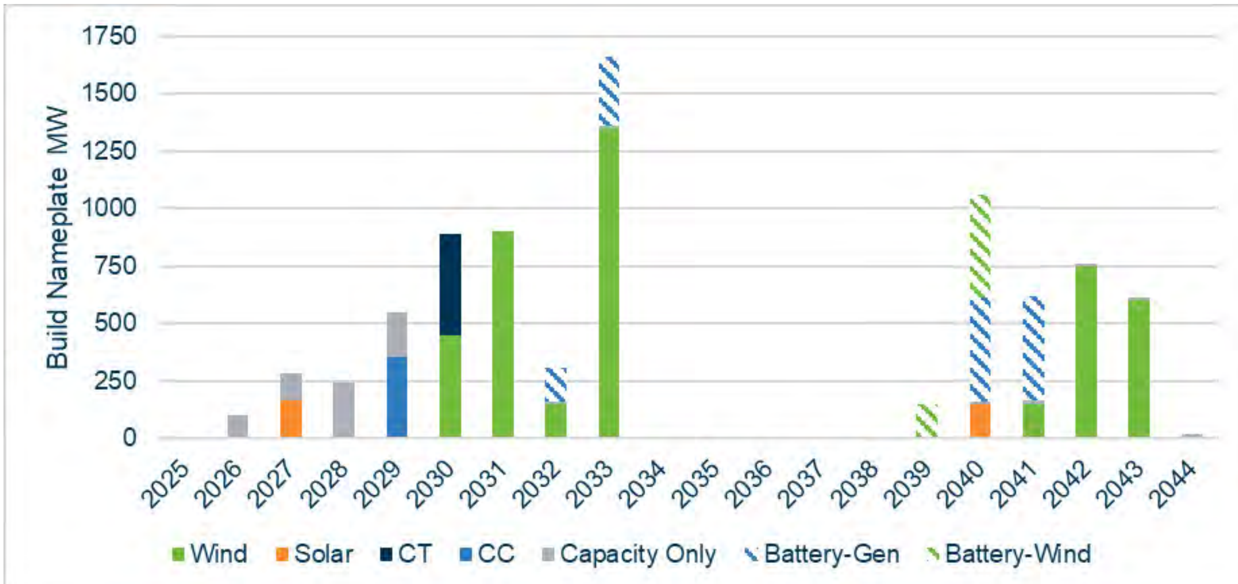
Plan ACAR uses a high natural gas and mid CO_2 future. The resource plan builds the ½ CCGT McNew and wind resources in 2031-2037, before adding solar and more wind in the last few years of the plan. The next thermal resource is built in 2040.

Figure 33: High NG/Mid CO_2 Future Plan ACAR



Plan ACFP uses a high natural gas/high CO_2 future, similar to ACAP, but only allows renewables and storage resources to be built after Viola and Mullin Creek additions, with a greatly relaxed build limit. The resource plan builds 4,350 MW of wind and 1,950 MW of storage plus 150 MW of solar (in addition to the 2027 CCN projects).

Figure 34: High NG/High CO_2 Renewables & Storage Only Plan ACFP



These optimal plans assuming different futures for natural gas prices and carbon dioxide restrictions show that there is variability in the resources that would be selected based on different future forecasts. The low NG/low (no) carbon restriction future relies on CCGTs for future energy needs with little wind. Higher NG and carbon restrictions are associated with more wind over solar and SCGTs over CCGTs. Even with a high carbon restriction, thermal build would still be needed because using only carbon-free additions after 2030 would be difficult with the existing technologies available to meet capacity needs. The Low/Low optimal plan is the worst plan when considering the risk-weighted NPVRR.

Table 30: Rankings of Plans Optimized for Different Futures

Rank	Plan	NPVRR	Difference	Description
1	ACAA	14,124		Mid NG/Mid CO_2
2	ACAR	14,135	10	High NG/Mid CO_2
3	ACFP	14,449	324	High NG/High CO_2, Only renewables/storage, relaxed build limit
4	ACAP	15,914	1,790	High NG/High CO_2
5	ACAQ	16,865	2,741	Low NG/Low CO_2

9.8 Rankings of Base Plans

9.8.1 Risk-Weighted Rankings

Table 31: Overall Plan Rankings

Rank	Plan	NPVRR	Difference	Description
1	AAAA	14,086		Base Load, MEEIA Extends, CCN Resources, Build Limits, 2024 PP Retirements
2	ABAA	14,093	7	Extend JEC 2 2039
3	ACAA	14,124	38	JEC 2 NG 2030
4	ACAR	14,135	48	High NG/Mid CO_2
5	ADAA	14,171	85	Retire IAT 1 2030
6	ACIA	14,244	158	No McNew, No 2031 Thermal, allow higher early solar/storage
7	ACJA	14,267	180	No Mullin Creek
8	ACGA	14,278	192	No McNew
9	ACHA	14,377	291	No McNew, No 2031 CCGT, allow higher early solar/storage
10	ACFA	14,420	334	Only renewables/storage; relaxed build limit
11	ACFP	14,449	362	High NG/High CO_2, Only renewables/storage, relaxed build limit
12	ACKA	14,786	700	No Mullin Creek, No McNew, or 2031 Thermal, allow higher early solar/storage
13	ACAP	15,914	1,828	High NG/High CO_2
14	ACAQ	16,865	2,779	Low NG/Low CO_2

9.8.2 Carbon Restriction Rankings

Table 32: Rankings for High Carbon Restriction Future

Rank	Plan	NPVRR	Difference	Description
1	ACFA	14,553		Only renewables/storage; relaxed build limit
2	ACFP	14,557	4	High NG/High CO_2, Only renewables/storage, relaxed build limit
3	ACIA	14,867	314	No McNew, No 2031 Thermal, allow higher early solar/storage
4	AAAA	14,962	409	Base Load, MEEIA Extends, CCN Resources, Build Limits, 2024 PP Retirements
5	ABAA	15,007	454	Extend JEC 2 2039
6	ACAR	15,010	457	High NG/Mid CO_2
7	ACAA	15,022	469	JEC 2 NG 2030
8	ADAA	15,051	498	Retire IAT 1 2030
9	ACJA	15,511	958	No Mullin Creek
10	ACGA	15,528	975	No McNew
11	ACHA	15,696	1,143	No McNew, No 2031 CCGT, allow higher early solar/storage
12	ACKA	16,009	1,456	No Mullin Creek, No McNew, or 2031 Thermal, allow higher early solar/storage
13	ACAQ	18,685	4,132	Low NG/Low CO_2
14	ACAP	26,733	12,179	High NG/High CO_2

Table 33: Rankings for Mid Carbon Restriction Future

Rank	Plan	NPVRR	Difference	Description
1	AAAA	13,978		Base Load, MEEIA Extends, CCN Resources, Build Limits, 2024 PP Retirements
2	ABAA	13,985	6	Extend JEC 2 2039
3	ACAA	14,013	34	JEC 2 NG 2030
4	ACAP	14,031	53	High NG/High CO_2
5	ACAR	14,037	59	High NG/Mid CO_2
6	ADAA	14,061	83	Retire IAT 1 2030
7	ACJA	14,123	144	No Mullin Creek
8	ACGA	14,133	155	No McNew
9	ACIA	14,177	198	No McNew, No 2031 Thermal, allow higher early solar/storage
10	ACHA	14,191	213	No McNew, No 2031 CCGT, allow higher early solar/storage
11	ACFA	14,398	420	Only renewables/storage; relaxed build limit
12	ACFP	14,430	451	High NG/High CO_2, Only renewables/storage, relaxed build limit
13	ACKA	14,644	665	No Mullin Creek, No McNew, or 2031 Thermal, allow higher early solar/storage
14	ACAQ	17,787	3,809	Low NG/Low CO_2

Table 34: Rankings for Low (No) Carbon Restriction Future

Rank	Plan	NPVRR	Difference	Description
1	ACAQ	13,560		Low NG/Low CO_2
2	ABAA	13,804	244	Extend JEC 2 2039
3	AAAA	13,820	260	Base Load, MEEIA Extends, CCN Resources, Build Limits, 2024 PP Retirements
4	ACAR	13,843	283	High NG/Mid CO_2
5	ACAA	13,853	293	JEC 2 NG 2030
6	ACJA	13,865	305	No Mullin Creek
7	ACGA	13,875	315	No McNew
8	ADAA	13,908	348	Retire IAT 1 2030
9	ACAP	13,943	383	High NG/High CO_2
10	ACHA	14,033	473	No McNew, No 2031 CCGT, allow higher early solar/storage
11	ACIA	14,033	473	No McNew, No 2031 Thermal, allow higher early solar/storage
12	ACFA	14,393	833	Only renewables/storage; relaxed build limit
13	ACKA	14,393	833	No Mullin Creek, No McNew, or 2031 Thermal, allow higher early solar/storage
14	ACFP	14,429	869	High NG/High CO_2, Only renewables/storage, relaxed build limit

9.8.3 Natural Gas Price Rankings

Table 35: Rankings for High Natural Gas Price Future

Rank	Plan	NPVRR	Difference	Description
1	ACFP	14,978		High NG/High CO_2, Only renewables/storage, relaxed build limit
2	ACFA	15,016	38	Only renewables/storage; relaxed build limit
3	ABAA	15,158	181	Extend JEC 2 2039
4	AAAA	15,162	185	Base Load, MEEIA Extends, CCN Resources, Build Limits, 2024 PP Retirements
5	ACAR	15,200	223	High NG/Mid CO_2
6	ACAA	15,206	229	JEC 2 NG 2030
7	ACIA	15,233	255	No McNew, No 2031 Thermal, allow higher early solar/storage
8	ADAA	15,287	309	Retire IAT 1 2030
9	ACJA	15,388	410	No Mullin Creek
10	ACGA	15,401	423	No McNew
11	ACHA	15,418	440	No McNew, No 2031 CCGT, allow higher early solar/storage
12	ACKA	15,829	851	No Mullin Creek, No McNew, or 2031 Thermal, allow higher early solar/storage
13	ACAP	17,011	2,033	High NG/High CO_2
14	ACAQ	18,150	3,172	Low NG/Low CO_2

Table 36: Rankings for Mid Natural Gas Price Future

Rank	Plan	NPVRR	Difference	Description
1	AAAA	14,019		Base Load, MEEIA Extends, CCN Resources, Build Limits, 2024 PP Retirements
2	ABAA	14,027	8	Extend JEC 2 2039
3	ACAA	14,057	38	JEC 2 NG 2030
4	ACAR	14,069	50	High NG/Mid CO_2
5	ADAA	14,102	83	Retire IAT 1 2030
6	ACIA	14,183	164	No McNew, No 2031 Thermal, allow higher early solar/storage
7	ACJA	14,194	175	No Mullin Creek
8	ACGA	14,205	186	No McNew
9	ACHA	14,314	295	No McNew, No 2031 CCGT, allow higher early solar/storage
10	ACFA	14,373	354	Only renewables/storage; relaxed build limit
11	ACFP	14,406	387	High NG/High CO_2, Only renewables/storage, relaxed build limit
12	ACKA	14,714	695	No Mullin Creek, No McNew, or 2031 Thermal, allow higher early solar/storage
13	ACAP	15,856	1,837	High NG/High CO_2
14	ACAQ	16,744	2,725	Low NG/Low CO_2

Table 37: Rankings for Low Natural Gas Price Future

Rank	Plan	NPVRR	Difference	Description
1	AAAA	13,721		Base Load, MEEIA Extends, CCN Resources, Build Limits, 2024 PP Retirements
2	ABAA	13,731	10	Extend JEC 2 2039
3	ACAA	13,756	35	JEC 2 NG 2030
4	ACAR	13,772	51	High NG/Mid CO_2
5	ADAA	13,792	71	Retire IAT 1 2030
6	ACJA	13,890	169	No Mullin Creek
7	ACGA	13,901	180	No McNew
8	ACIA	13,908	187	No McNew, No 2031 Thermal, allow higher early solar/storage
9	ACHA	14,022	301	No McNew, No 2031 CCGT, allow higher early solar/storage
10	ACFA	14,232	511	Only renewables/storage; relaxed build limit
11	ACFP	14,282	561	High NG/High CO_2, Only renewables/storage, relaxed build limit
12	ACKA	14,442	720	No Mullin Creek, No McNew, or 2031 Thermal, allow higher early solar/storage
13	ACAP	15,528	1,807	High NG/High CO_2
14	ACAQ	16,487	2,766	Low NG/Low CO_2

9.8.4 Construction Cost Rankings

Table 38: Rankings for High Construction Cost Future

Rank	Plan	NPVRR	Difference	Description
1	AAAA	15,019		Base Load, MEEIA Extends, CCN Resources, Build Limits, 2024 PP Retirements
2	ABAA	15,020	1	Extend JEC 2 2039
3	ACAA	15,051	32	JEC 2 NG 2030
4	ACAR	15,060	41	High NG/Mid CO_2
5	ADAA	15,110	91	Retire IAT 1 2030
6	ACJA	15,140	121	No Mullin Creek
7	ACGA	15,152	133	No McNew
8	ACIA	15,335	316	No McNew, No 2031 Thermal, allow higher early solar/storage
9	ACHA	15,406	387	No McNew, No 2031 CCGT, allow higher early solar/storage
10	ACKA	15,829	810	No Mullin Creek, No McNew, or 2031 Thermal, allow higher early solar/storage
11	ACFA	16,047	1,028	Only renewables/storage; relaxed build limit
12	ACFP	16,155	1,136	High NG/High CO_2, Only renewables/storage, relaxed build limit
13	ACAP	17,262	2,243	High NG/High CO_2
14	ACAQ	17,367	2,348	Low NG/Low CO_2

Table 39: Rankings for Mid Construction Cost Future

Rank	Plan	NPVRR	Difference	Description
1	AAAA	14,124		Base Load, MEEIA Extends, CCN Resources, Build Limits, 2024 PP Retirements
2	ABAA	14,129	5	Extend JEC 2 2039
3	ACAA	14,160	36	JEC 2 NG 2030
4	ACAR	14,170	46	High NG/Mid CO_2
5	ADAA	14,215	91	Retire IAT 1 2030
6	ACIA	14,271	147	No McNew, No 2031 Thermal, allow higher early solar/storage
7	ACJA	14,303	179	No Mullin Creek
8	ACGA	14,315	191	No McNew
9	ACFA	14,376	252	Only renewables/storage; relaxed build limit
10	ACHA	14,396	272	No McNew, No 2031 CCGT, allow higher early solar/storage
11	ACFP	14,410	286	High NG/High CO_2, Only renewables/storage, relaxed build limit
12	ACKA	14,772	648	No Mullin Creek, No McNew, or 2031 Thermal, allow higher early solar/storage
13	ACAP	15,557	1,433	High NG/High CO_2
14	ACAQ	16,912	2,788	Low NG/Low CO_2

Table 40: Rankings for Low Construction Cost Future

Rank	Plan	NPVRR	Difference	Description
1	ACFP	12,820		High NG/High CO_2, Only renewables/storage, relaxed build limit
2	ACFA	12,881	61	Only renewables/storage; relaxed build limit
3	AAAA	13,078	258	Base Load, MEEIA Extends, CCN Resources, Build Limits, 2024 PP Retirements
4	ABAA	13,095	275	Extend JEC 2 2039
5	ACIA	13,101	280	No McNew, No 2031 Thermal, allow higher early solar/storage
6	ACAA	13,126	306	JEC 2 NG 2030
7	ACAR	13,138	318	High NG/Mid CO_2
8	ADAA	13,145	325	Retire IAT 1 2030
9	ACHA	13,311	491	No McNew, No 2031 CCGT, allow higher early solar/storage
10	ACJA	13,321	501	No Mullin Creek
11	ACGA	13,330	510	No McNew
12	ACKA	13,771	951	No Mullin Creek, No McNew, or 2031 Thermal, allow higher early solar/storage
13	ACAP	15,282	2,462	High NG/High CO_2
14	ACAQ	16,270	3,450	Low NG/Low CO_2

9.9 Plans Testing Build Limits and Restrictions

9.9.1 Higher Build Limits

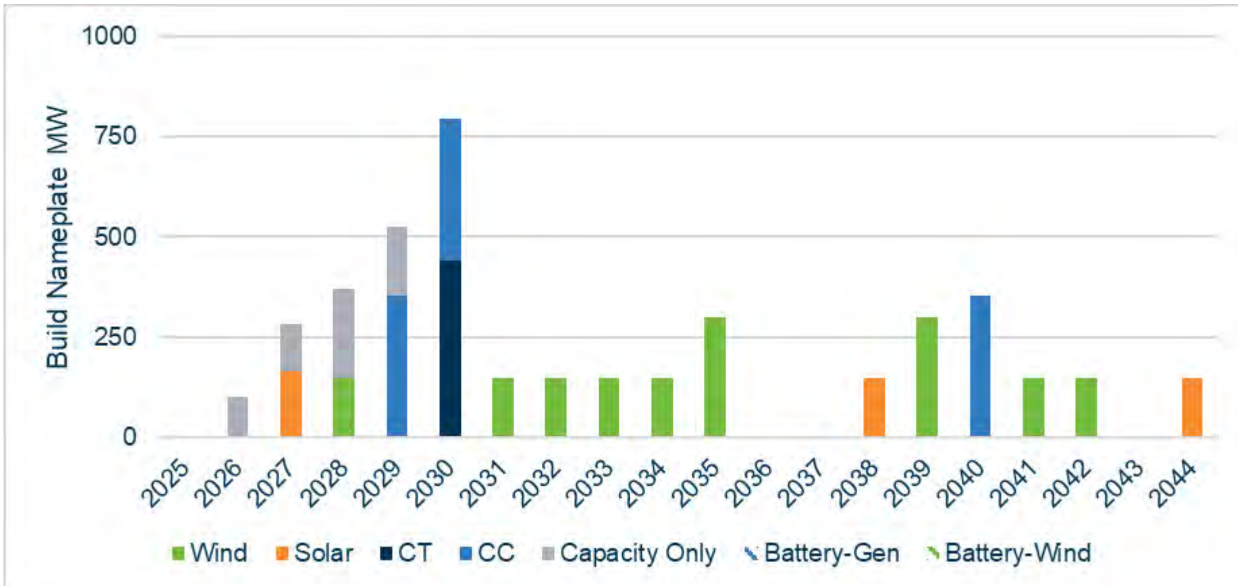
Alternative resource plans ACDA, ACEA, and ACFA test increasing build limits. Jeffrey 2 converts to natural gas in 2030 in all plans.

Table 41: Plans Testing Build Limits

Plan Name	Description
ACDA	Allow higher wind 2035+
ACEA	Allow higher builds all 2031+
ACFA	Only renewables/storage; relaxed build limit

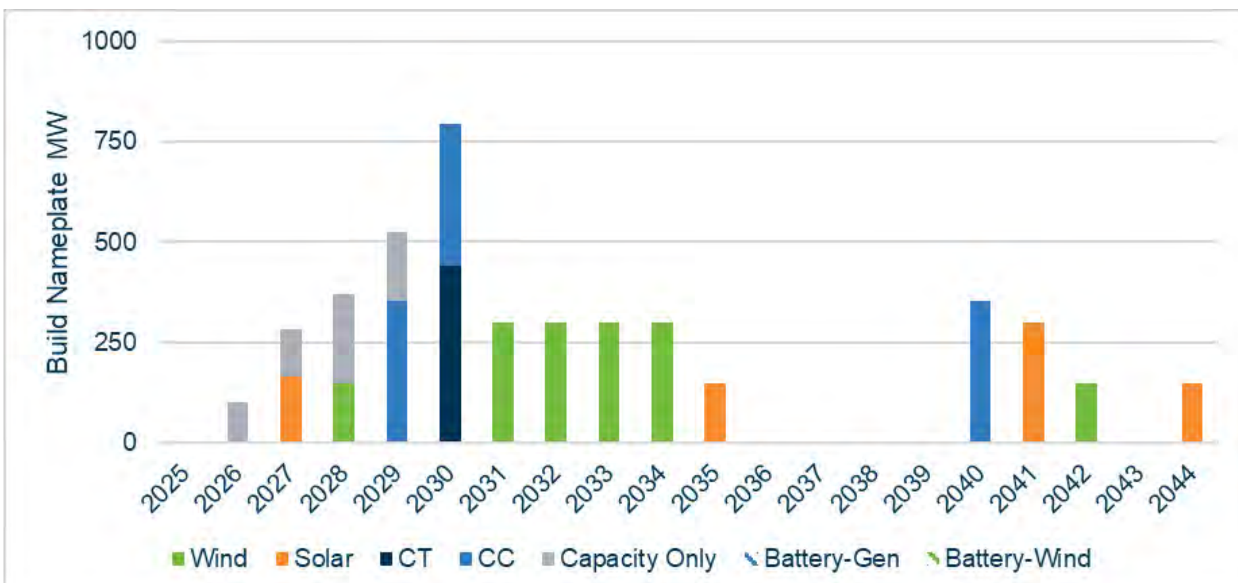
Plan ACDA allows a higher amount of wind to be built in years 2035+. The primary changes in the resource plan are higher wind builds in 2035 and 2039.

Figure 35: Higher Wind Build Allowed 2035+ Plan ACDA



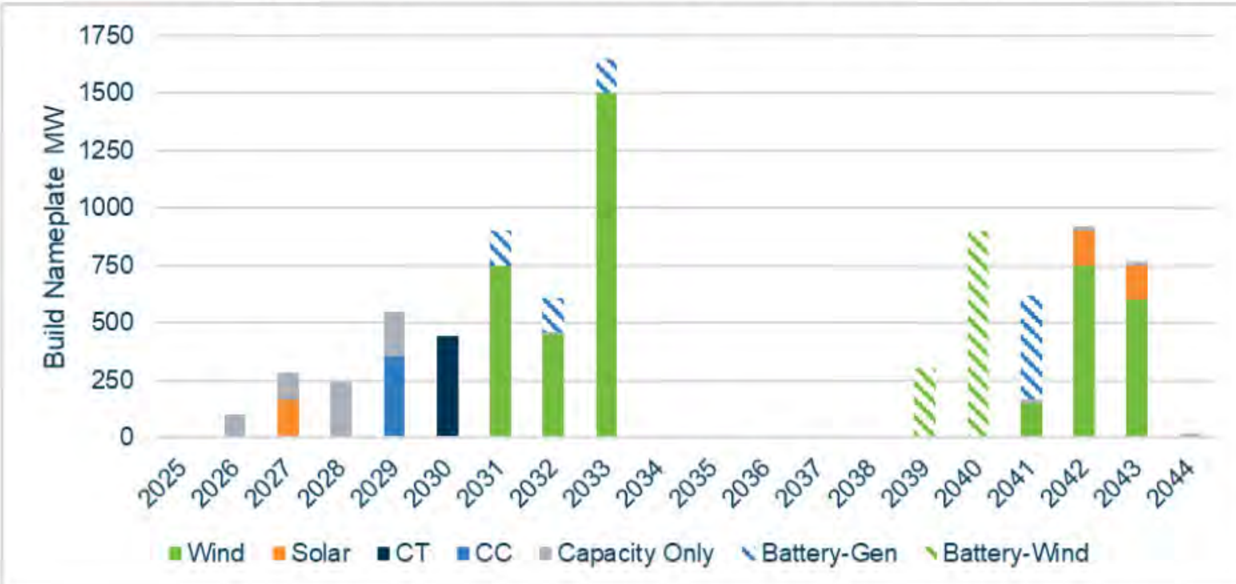
Plan ACEA allows higher build amounts for all resources in 2031+. The plan selects more wind in the early 2030s and more solar in the 2040s.

Figure 36: Allow Higher Resource Builds 2031+ Plan ACEA



Plan ACFA could not select new thermal resources beyond the CCN resources, and greatly relaxed the renewables build limit. The resource plan builds 4,200 MW of wind, 300 MW solar, and 2,100 MW of storage after 2030.

Figure 37: Only Allow Renewables & Storage with No Build Limit Plan ACFA



Relaxing build limits allows the resource plan to select more wind resources earlier in the planning horizon. The extra wind resources help with meeting future carbon restrictions and providing low-cost energy. Evergy Missouri West will continue to monitor the availability of wind projects and congestion in SPP to determine if owning/contracting more deliverable wind energy can reduce costs as part of the future resource plan.

Table 42: Rankings with Varied Build Limits

Rank	Plan	NPVRR	Difference	Description
1	ACEA	13,727		Allow higher builds all 2031+
2	ACDA	14,082	356	Allow higher wind 2035+
3	ACAA	14,124	398	Base build limits
4	ACFA	14,420	693	Only renewables/storage; relaxed build limit

9.9.2 Minimally Compliant RES Plan

All Alternative Resource Plans comply with the Missouri renewable energy mandates (Missouri Renewable Energy Standard). The RES requirements include 14.7% of retail sales to be served by non-solar renewables and 0.3% by solar renewables. Evergy Missouri West's expected compliance need is 8 MW of solar in 2034.

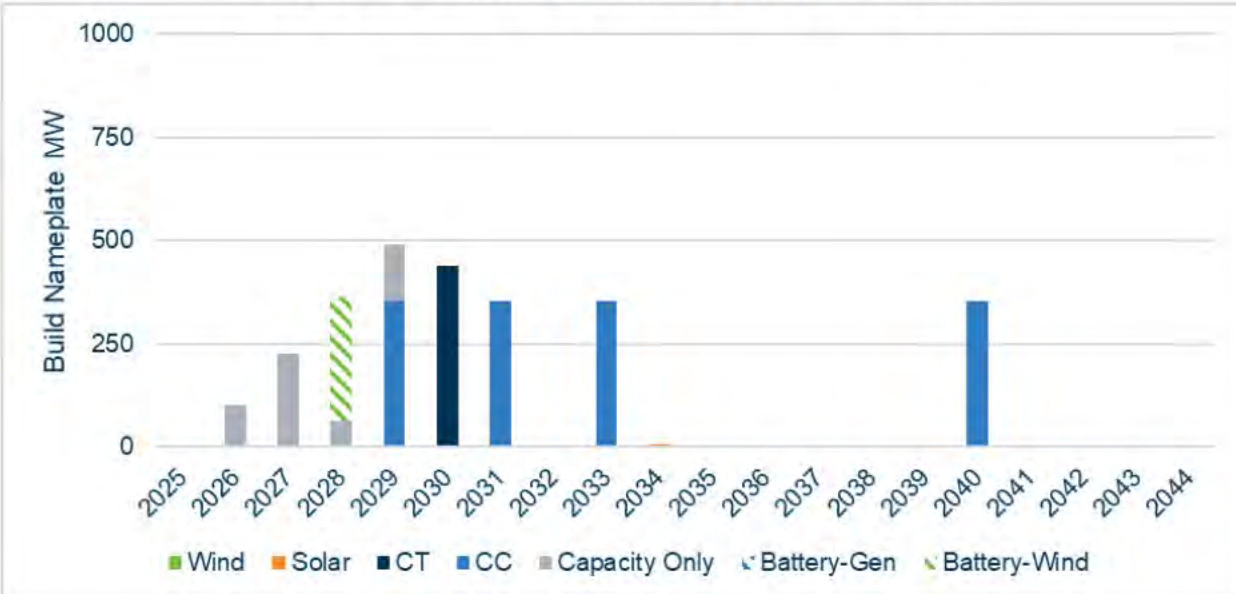
Table 43: Missouri West RES Requirements

Year	Retail Electric Sales (MWh)	Missouri RES Non-Solar Requirement	Non-Solar RES Requirement (MWh)	Missouri RES Solar Requirement	Solar RES Requirement (MWh)
2025	9,014,382	14.7%	1,325,114	0.3%	27,043
2026	9,281,810	14.7%	1,364,426	0.3%	27,845
2027	9,459,744	14.7%	1,390,582	0.3%	28,379
2028	9,545,594	14.7%	1,403,202	0.3%	28,637
2029	9,598,646	14.7%	1,411,001	0.3%	28,796
2030	9,654,031	14.7%	1,419,143	0.3%	28,962
2031	9,707,914	14.7%	1,427,063	0.3%	29,124
2032	9,781,667	14.7%	1,437,905	0.3%	29,345
2033	9,833,269	14.7%	1,445,491	0.3%	29,500
2034	9,900,311	14.7%	1,455,346	0.3%	29,701
2035	9,970,058	14.7%	1,465,598	0.3%	29,910
2036	10,056,699	14.7%	1,478,335	0.3%	30,170
2037	10,109,342	14.7%	1,486,073	0.3%	30,328
2038	10,175,901	14.7%	1,495,858	0.3%	30,528
2039	10,236,491	14.7%	1,504,764	0.3%	30,709
2040	10,316,261	14.7%	1,516,490	0.3%	30,949
2041	10,358,186	14.7%	1,522,653	0.3%	31,075
2042	10,416,024	14.7%	1,531,156	0.3%	31,248
2043	10,477,636	14.7%	1,540,212	0.3%	31,433
2044	10,558,271	14.7%	1,552,066	0.3%	31,675

Plan, BCAT limits solar additions to the 8 MW of solar capacity in 2034 that is expected to be needed to meet solar RES requirements. Evergy is currently expected to be compliant with non-solar RES requirements through 2044.

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 4 approved programs.

Figure 38: Minimally Compliant RES Plan BCAT



The minimally compliant RES plan meets capacity and energy needs at the lowest cost by buying market capacity in 2026-2029, building 300 MW of battery storage in 2028 and building two ½ CCGTs and an SCGT in 2029-2031. The next thermal build is a ½ CCGT in 2033 and then another ½ CCGT is built in 2040.

A resource plan that meets customer needs without new renewables is significantly more costly. The NPVRR for the plan that only meets minimum RES requirements is $4 billion higher than Plan ACAA.

Table 44: Minimally Compliant RES Plan

Rank	Plan	NPVRR	Difference	Description
1	ACAA	14,124		Mid NG/Mid CO_2
2	BCAT	18,180	4,056	RES Plan

Section 10: Resource Plan Contingency Analysis

Evergy Missouri West also developed several contingency plans given the uncertainties in the planning process. These include:

- Load variances
    - More load growth early in the plan representing potential new customers of different sizes
    - More load growth later (2031+) in the plan representing potential new customers of different sizes
    - Addition of a very large customer in the queue
- MEEIA demand-side programs not renewed
- Loss of Crossroads

Table 45: Plan Key for Contingency Analysis

DSM	Coal (Changes from PP)	Builds	Load & Contingencies
A - MEEIA Extends	C - JEC 2 NG 2030	A - Base capital + CCN Builds + McNew Allowed	A - Base load
B - MEEIA Ends		B - McNew in Plan	B - No Crossroads
		C - Allow higher early solar/storage	G – No market energy purchases or sales
		E - Allow higher builds 2031+	H - Base load, 50 MW Eco Devo Early
		L - Allow higher early solar/storage and higher builds 2031+	I - Base load, 150 MW Eco Devo Early
			J - Base load, 250 MW Eco Devo Early
			K - Base load, 50 MW Eco Devo Late
			L - Base load, 150 MW Eco Devo Late
			M - Base load, 250 MW Eco Devo Late
			N - High load growth and electrification
			O - Low load growth
			S - Base load, very large customer

Table 46: Contingency Plan Descriptions

Plan	Description
ACAG	No market energy purchases or sales
ACAK	Additional 50 MW large load 2031+
ACAL	Additional 150 MW large load 2031+
ACAM	Additional 250 MW large load 2031+
ACCB	Crossroads retires, Allow higher early solar/storage
ACCH	Additional 50 MW large load early, Allow higher early solar/storage
ACCI	Additional 150 MW large load early, Allow higher early solar/storage
ACCJ	Additional 250 MW large load early, Allow higher early solar/storage
ACLS	Additional very large customer, Allow higher early solar/storage and higher build 2031+
BCAA	MEEIA Ends

10.1 Load Contingencies

10.1.1 Large Customer Growth

Evergy Missouri West developed alternative resource plans to determine how additional large customers could be served.

Table 47: New Large Customer Load Ramp Scenarios (MW)

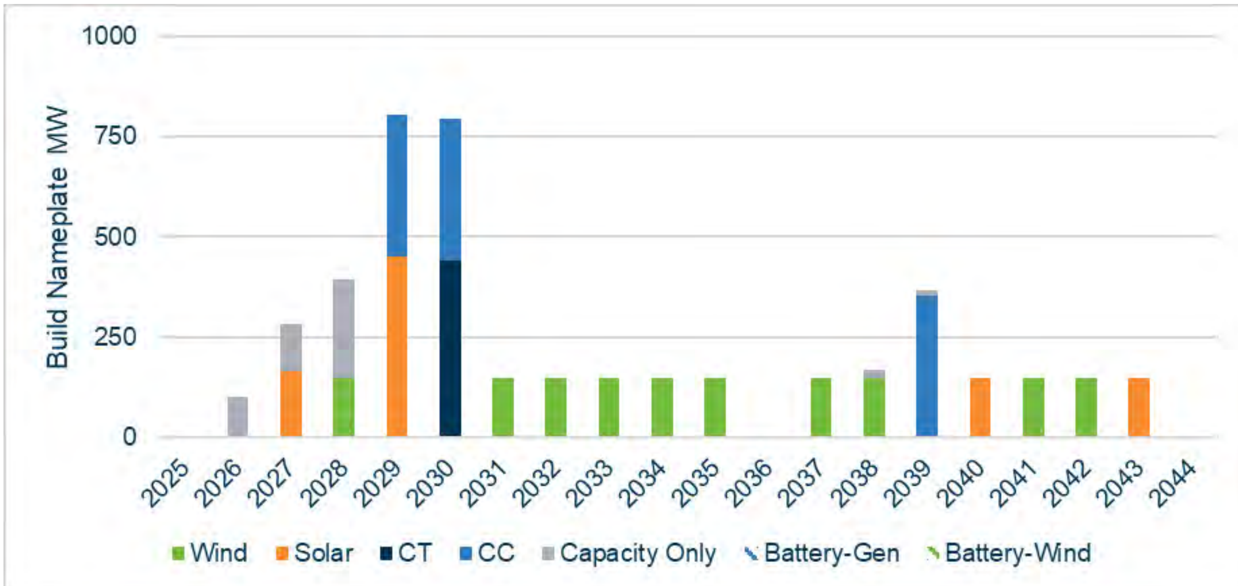
New Load Scenario	2028	2029	2030	2031	2032	2033+
50 MW Early	20	30	50	50	50	50
150 MW Early	50	100	150	150	150	150
250 MW Early	70	150	250	250	250	250
50 MW Late	0	0	0	20	30	50
150 MW Late	0	0	0	50	100	150
250 MW Late	0	0	0	70	150	250
Very Large Customer	115	340	570	810	940	940

For customers desiring to ramp prior to 2031, Evergy Missouri West would have to increase its renewable or storage builds, or work with new customers who may have their own resources under contract, because no additional thermal resources are expected to be available before 2031. For customers beginning ramp in 2031, Evergy Missouri West has more options to add thermal resources in addition to renewables and storage.

Alternative resource plans ACCH, ACCI, and ACCJ evaluate additional early load ramp, allowing higher early build amounts of solar and storage.

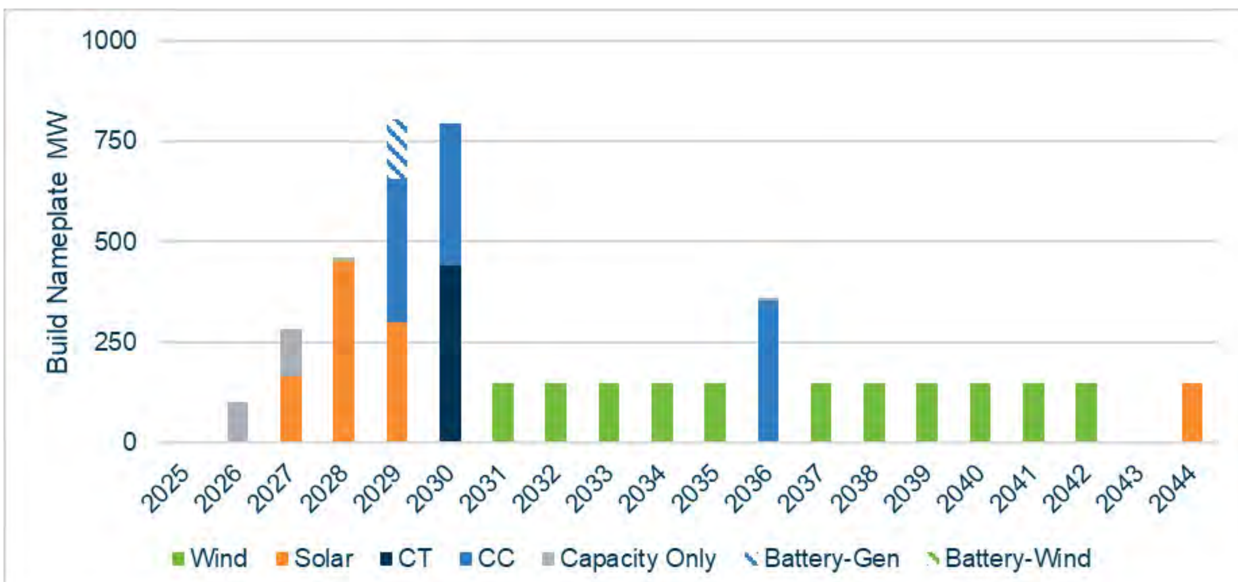
Plan ACCH accommodates an additional 50 MW load by building an additional 450 MW solar in 2029 in addition to purchasing market capacity. The plan would also need more winter market capacity before the thermal additions.

Figure 39: Early 50 MW Load, Higher Early Solar/Storage Plan ACCH



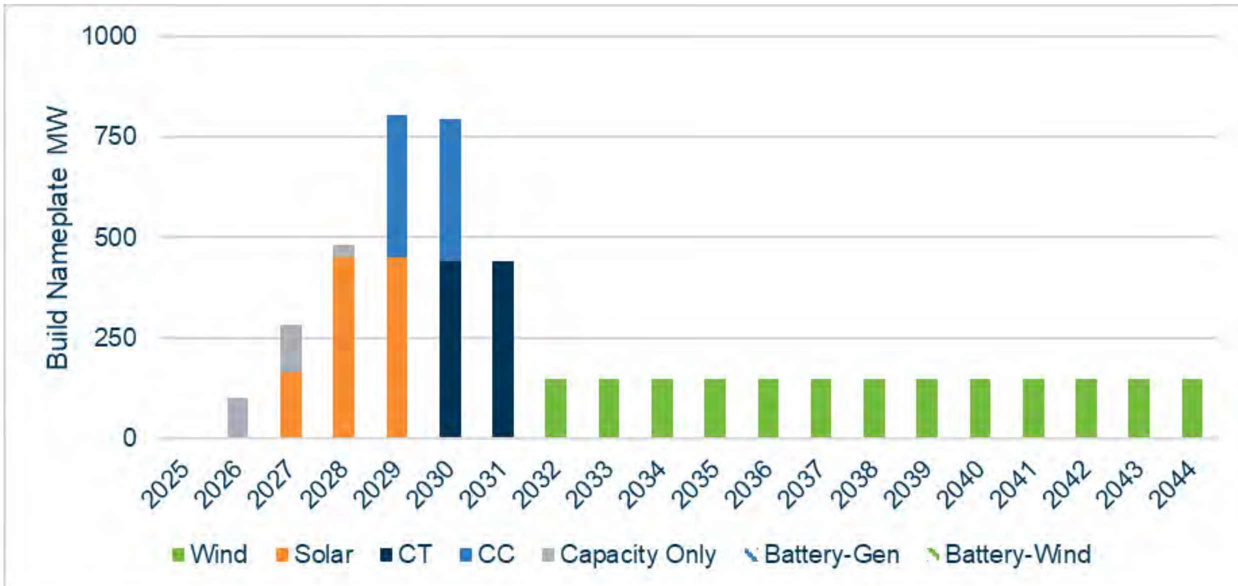
Plan ACCI accommodates an additional 150 MW of load with 750 MW solar in 2028-2029, and 150 MW storage in 2029. The plan also pulls forward the next thermal build with a 2036 CCGT.

Figure 40: Early 150 MW Load, Higher Early Solar/Storage Plan ACCI



Plan ACCJ accommodates an additional 250 MW load with 900 MW solar in 2028-2029, and pulls forward the next thermal build to 2031.

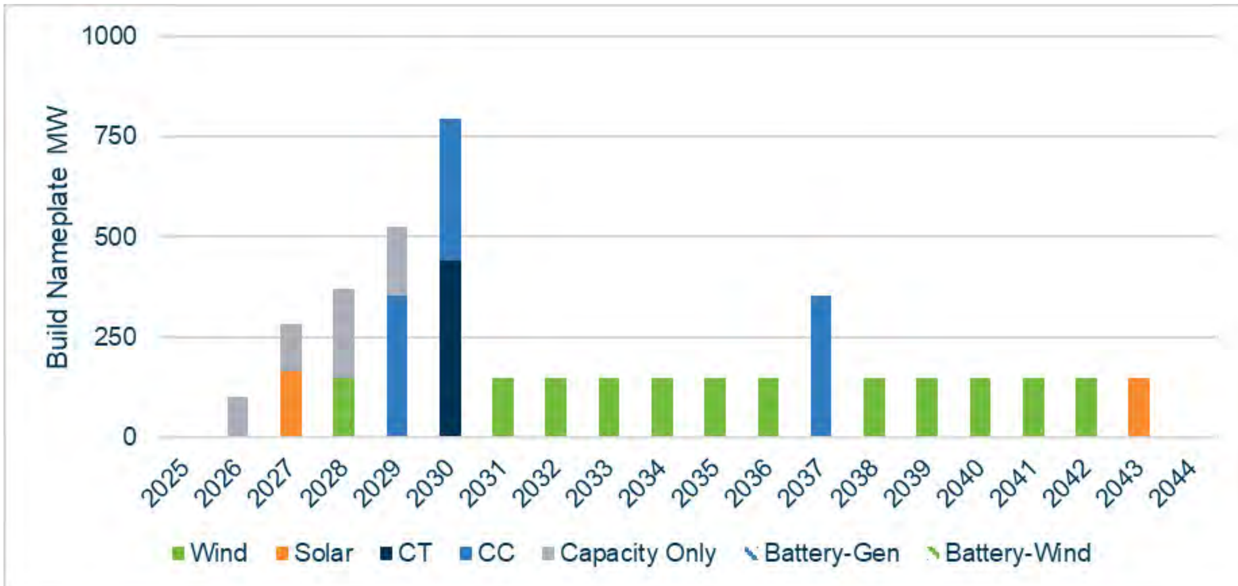
Figure 41: Early 250 MW Load, Higher Early Solar/Storage Plan ACCJ



Alternative resource plans ACAK, ACAL, and ACAM evaluate later load ramps, allowing more flexibility for Evergy Missouri West to consider all resource types and remain within capital planning limits.

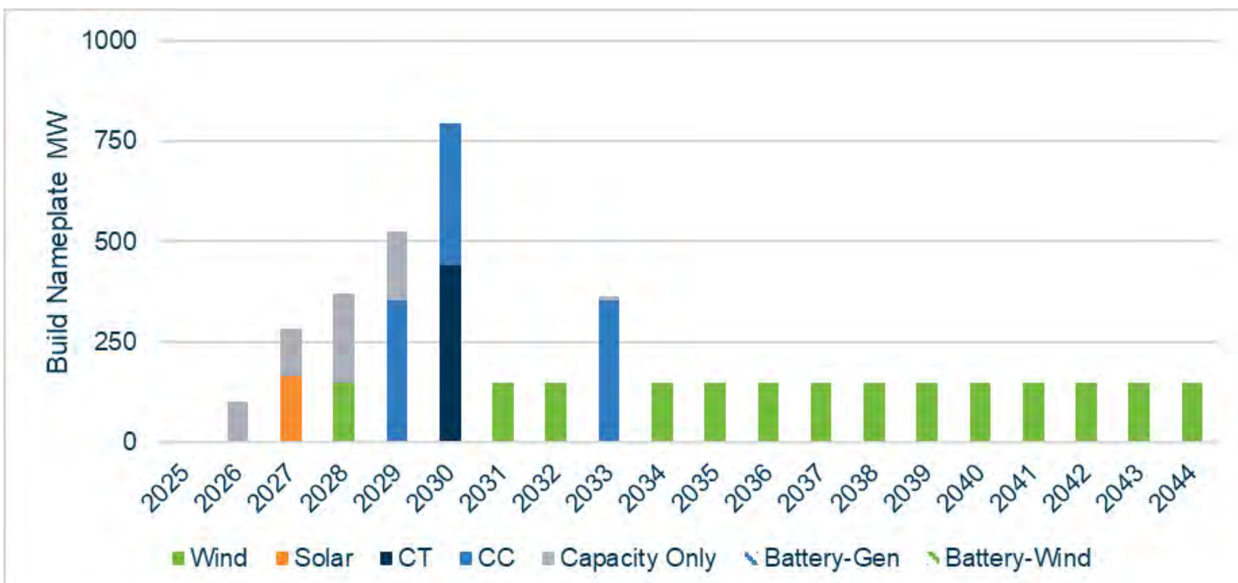
Plan ACAK accommodates an additional 50 MW load ramping in 2031+ by accelerating the next thermal resource to 2037.

Figure 42: Late 50 MW Load Plan ACAK



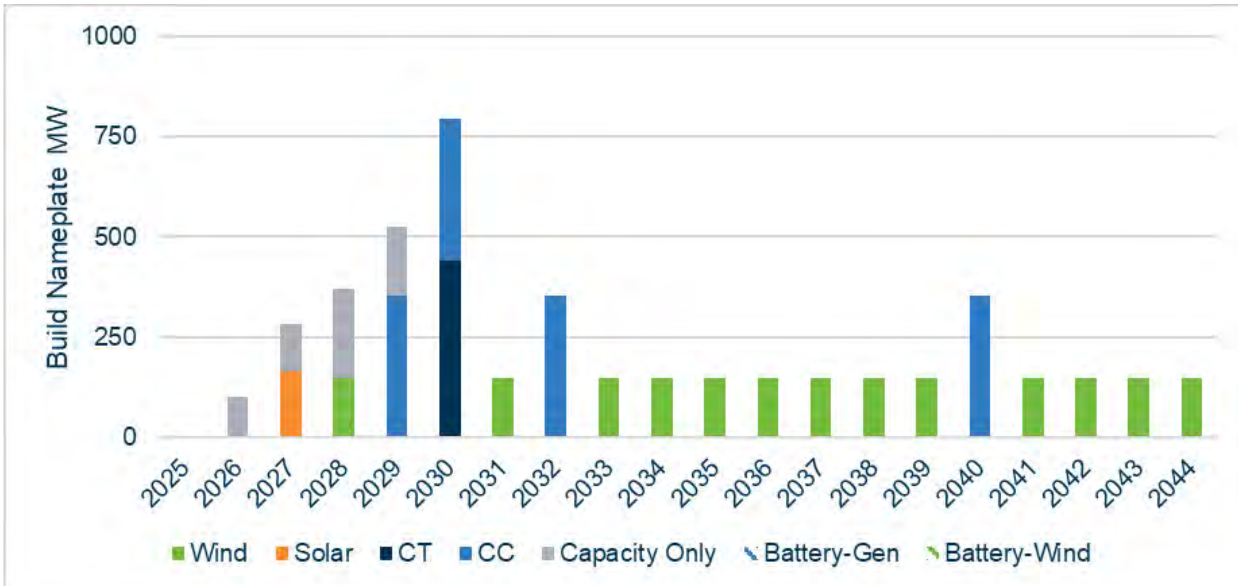
Plan ACAL accommodates a 150 MW large load ramping in 2031+ by pulling forward a thermal build to 2033.

Figure 43: Late 150 MW Load Plan ACAL



Plan ACAM accommodates a 250 MW large load ramping in 2031+ by pulling forward a thermal build to 2032.

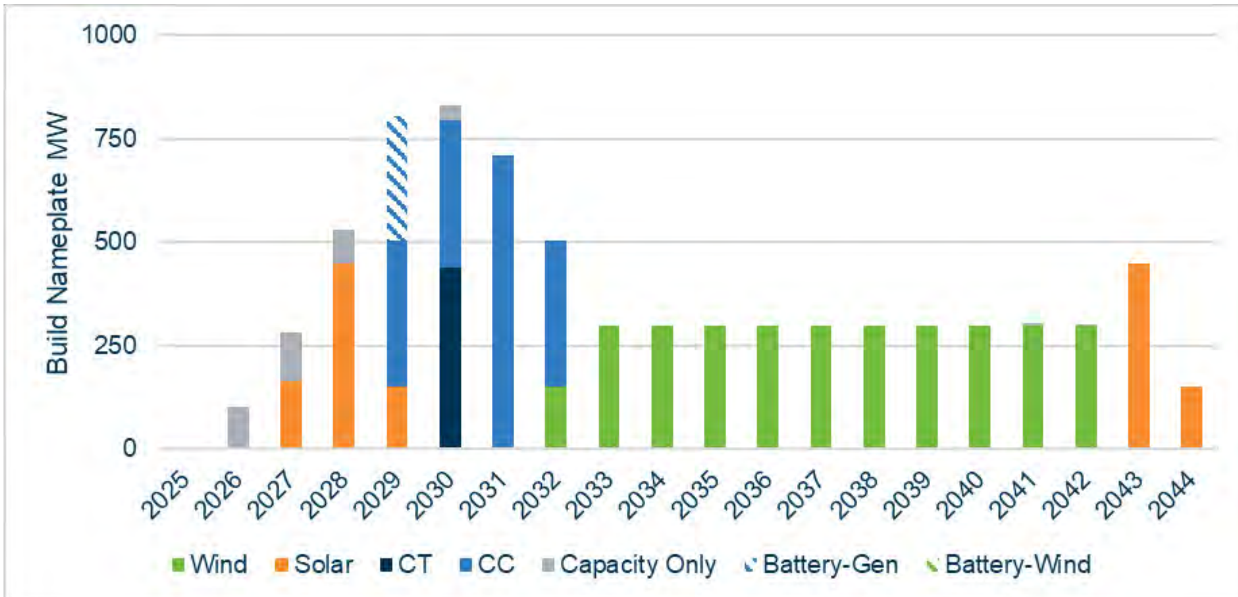
Figure 44: Late 250 MW Load ACAM



Evergy Missouri West could accommodate additional large loads ramping in 2031+ without changing its execution strategy through 2031. Load growth of 250 MW triggers the need for a ½ CCGT in 2032, while 150 MW would need the ½ CCGT in 2033.

Evergy Missouri West has a very large customer in its queue. Since this customer has both an early ramp beginning in 2028 and a large total need for energy and capacity, Plan ACLS analyzes using early solar/storage for the early ramp and higher build limits after 2031. A plan that could meet this customer need as part of the Evergy Missouri West system includes 600 MW additional solar in 2028-2029, 300 MW storage in 2029 and three additional ½ CCGTs in 2031-2032, as well as increased wind resources in future years.

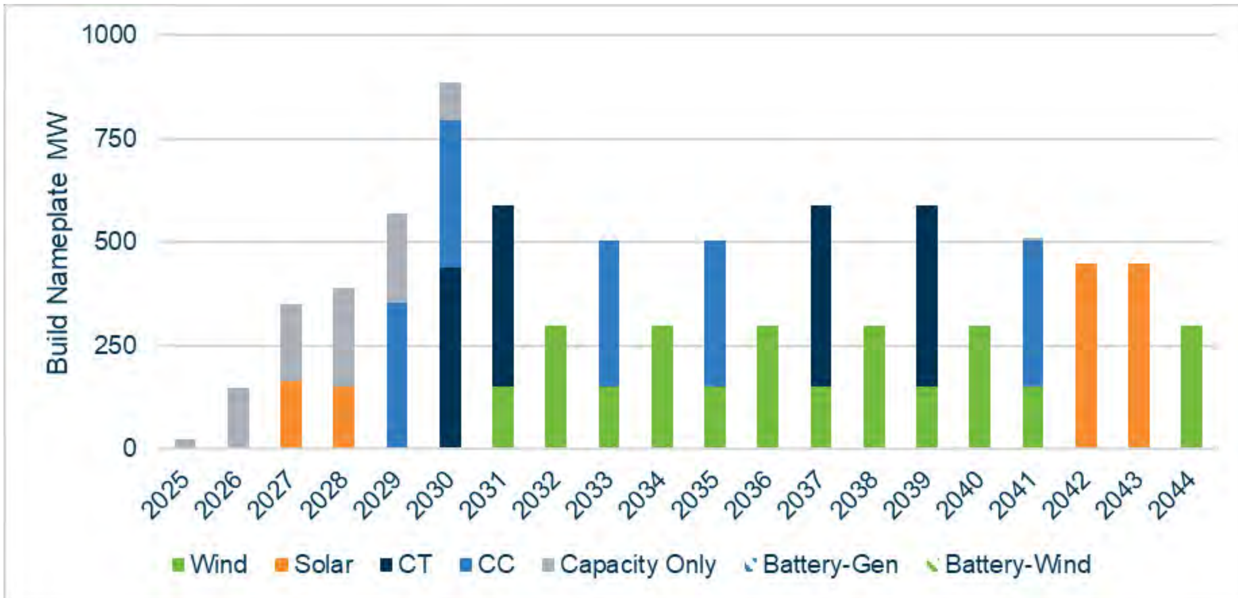
Figure 45: Very Large Customer Plan ACLS



10.1.2 High Electrification and Low Load Growth Scenarios

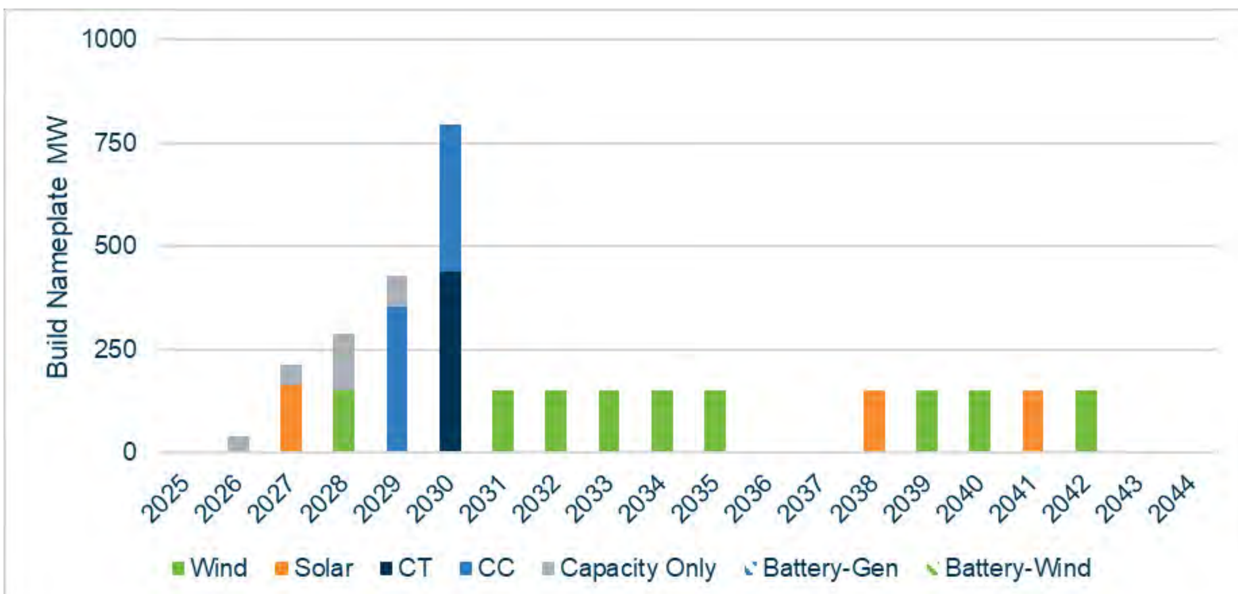
Evergy Missouri West's high load growth and economy-wide electrification forecast includes the highest load growth over the planning horizon of the scenarios modeled, but has a slower ramp than the largest customer scenarios. The Plan ACEN shows that to meet this growth, more thermal generation will be needed beginning in 2031, as well as additional wind and solar.

Figure 46: High Electrification Plan ACEN



The low load growth scenario also resembles the early years of the Preferred Plan but substitutes some solar resources for wind in later years. Additional thermal resources are not needed.

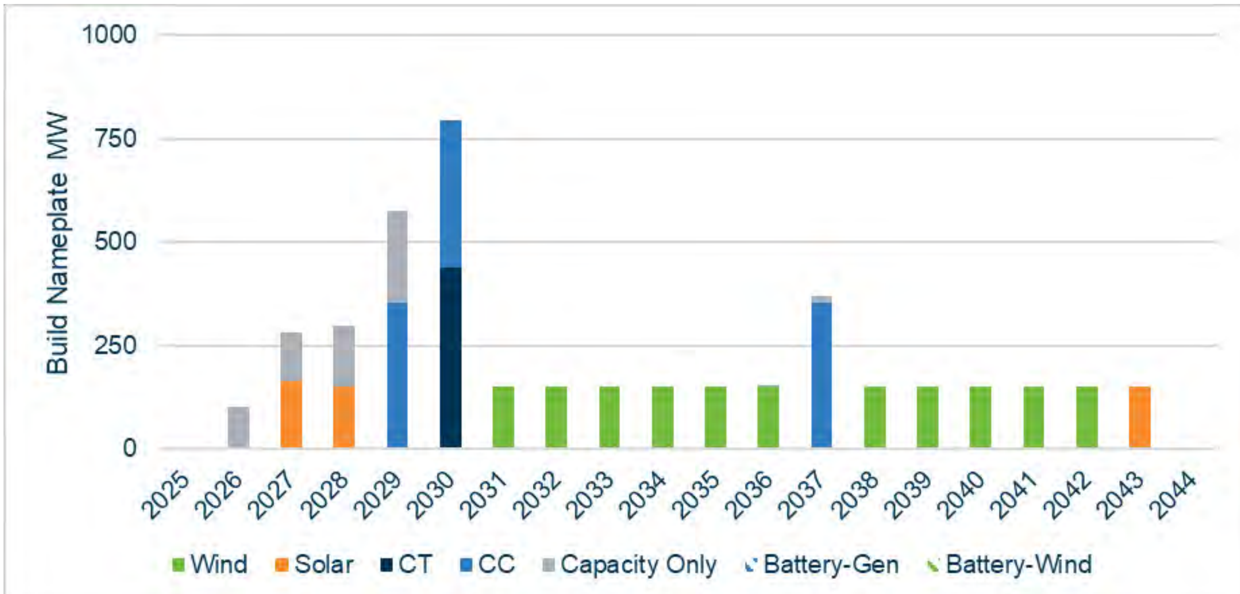
Figure 47: Low Load Growth Plan ACAO



10.2 Demand-Side Contingencies

Evergy Missouri West's current demand-side programs have been approved through 2027. If programs are not approved going forward the utility will lose the energy and capacity value assumed in the resource plan. Alternative resource Plan BCAA tests MEEIA ending after the current approved time frame. The plan substitutes 150 MW of solar for wind in 2028, maintains the ½ McNew CCGT build, and pulls forward the next ½ CCGT to 2037.

Figure 48: MEEIA Ends, Plan BCAA

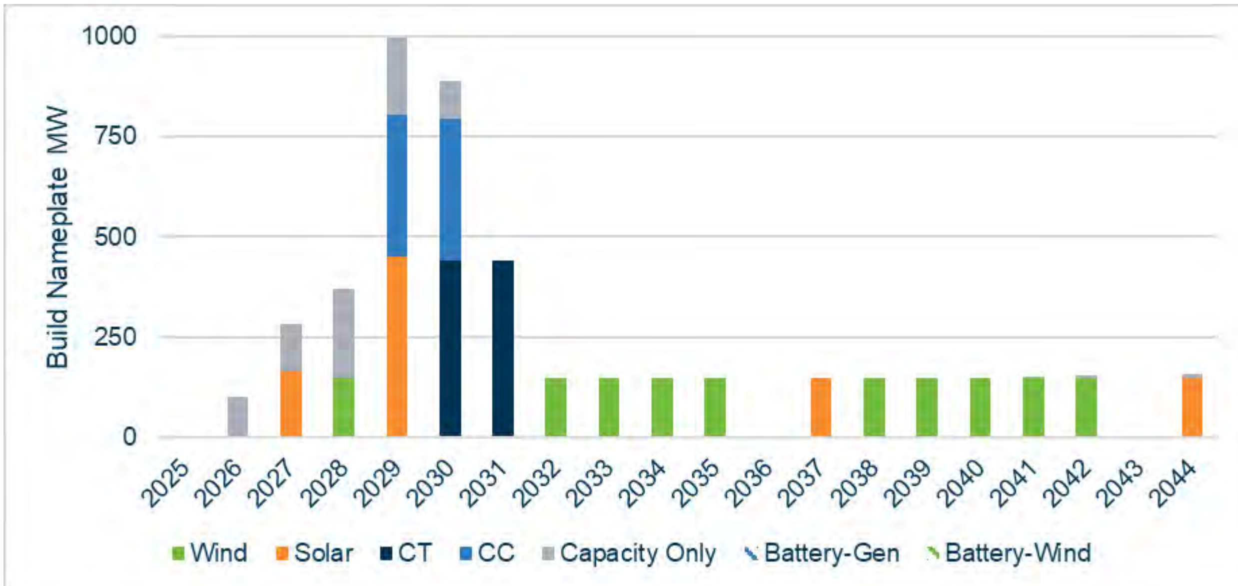


10.3 Crossroads

Alternative resource plan ACCB evaluates the retirement of Evergy Missouri West's Crossroads units. Evergy Missouri West cannot replace the Crossroads resources within capital plan limits. Plan ACCB allows more, early solar/storage to enable Evergy Missouri West to meet its customer needs if Crossroads is retired at the end of 2028.

The plan includes an additional 450 MW of solar in 2029, as well as four thermal resources in 2029-2031 (adding a SCGT in 2031).

Figure 49: Crossroads Retires, Allow Higher Early Solar & Storage Plan ACCB

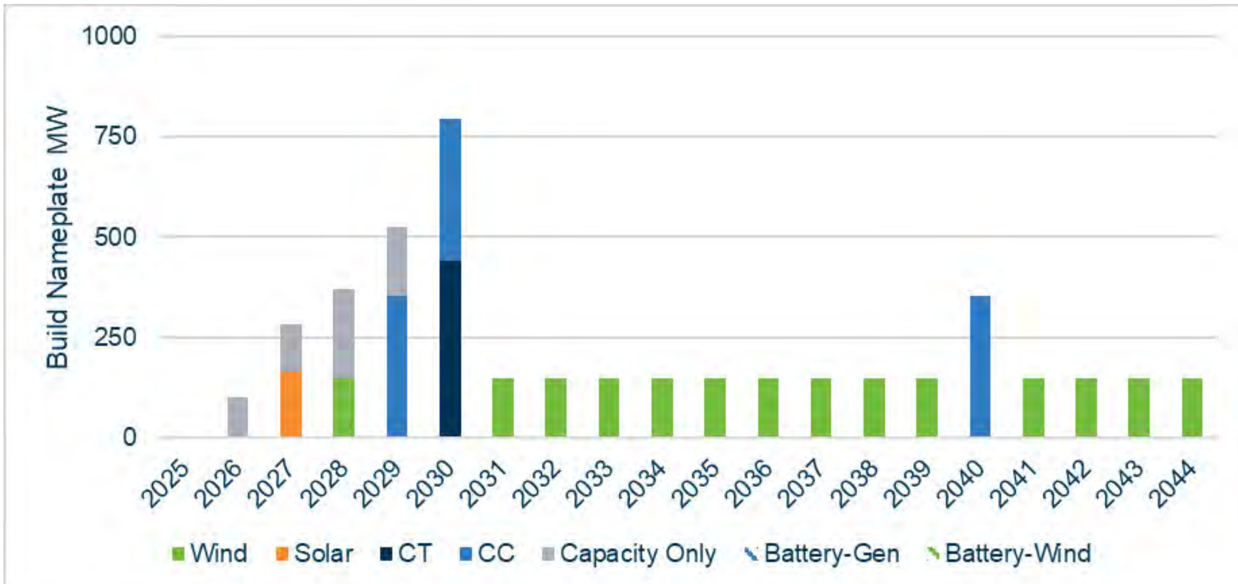


10.4 Capacity Expansion Plan with No Market Energy Purchases or Sales

Evergy Missouri West is currently a net buyer in the SPP market. As discussed in Section 3.4 Evergy Missouri West does not expect other utilities to build for its customer needs in a time of rapid load growth, increasing reliability needs, and rising costs. The resource planning process is aligned to develop a future resource mix that meets Evergy Missouri West's energy and capacity needs at lowest cost. The base planning assumption is that Evergy Missouri West will have a future fleet that hedges its production costs to serve load. This is modeled with a parameter that limits future market purchases and sales to 200 MW per hour beginning in 2031 (approximately 10% of Evergy Missouri West's peak load, and 15% of average load).

Evergy Missouri West tested the Preferred Plan with a lower limit on market purchases and sales that tapered to zero beginning in 2031 to understand whether the optimal build decisions would differ. Plan ACAG has the Preferred Plan assumptions (load, demand-side programs, retirements) but incorporates the restriction of no market purchases and sales beginning in 2031. It builds more wind, to avoid market energy purchases to meet the carbon constraint.

Figure 50: Preferred Plan with No Market Dependence Plan ACAG



Section 11: GHG Compliance Plans

11.1 GHG Rule Background

On April 25, 2024, the U.S. Environmental Protection Agency (EPA) announced final Clean Air Act performance standards for carbon dioxide (CO_2) emissions from existing coal-fired power plants and new gas power plants. These rules, referred to collectively herein as the GHG Rule, aim to significantly reduce greenhouse gas (GHG) emissions from existing coal-fired power plants and from new natural gas turbines.

According to the GHG Rule, the new source performance standards (NSPS) and emission guidelines reflect what is achievable through implementation of the best system of emission reduction (BSER) that, taking into account costs, energy requirements, and other statutory factors, is adequately demonstrated for the purpose of improving the emissions performance of covered electric generating units (EGUs).

EPA has determined that the BSER for the longest-running existing coal units and for new base load combustion turbines is carbon capture and sequestration/storage (CCS) that can be applied directly to power plants that use fossil fuels to generate electricity. For other types of new gas-fired combustion turbines and existing fossil fuel-fired steam generating units, these rules prescribe standards based on other technologies, including co-firing with natural gas and efficient generating practices.

For existing steam electric generating units, compliance deadlines range from 2030 to 2032 depending upon the type of unit and the applicable standard. For new combustion turbines, efficiency-based requirements apply as soon as the unit starts operation. New base load combustion turbines will have until January 1, 2032, to meet an emission standard based on 90% capture of CO_2 emissions.

For existing coal-fired EGUs, the final rule establishes subcategories based on how far into the future the plant intends to operate.

- Units that demonstrate that they plan to permanently cease operation prior to January 1, 2032, will have no emission reduction obligations under the rule.

- Units that have committed to cease operations by January 1, 2039 (i.e., “medium-term” units) will have a numeric emission rate limit based on 40% natural gas co-firing that they must meet on January 1, 2030.
- Units that intend to operate on or after January 1, 2039 (i.e., “long-term” units) will have a numeric emission rate limit based on application of CCS with 90% capture, which they must meet on January 1, 2032.

For new combustion turbines, the final rule establishes three subcategories based on how intensively they are operated.

- New base load turbines (defined as units that are generating at least 40% of their maximum annual capacity, i.e., greater than 40% capacity factor) are subject to an initial "phase one" standard based on efficient design and operation of combined cycle turbines; and a "phase two" standard based on 90% capture of CO_2 with a compliance deadline of Jan. 1, 2032.
- New intermediate load turbines (defined as units that are generating between 20 and 40% of their maximum annual capacity, i.e., 20-40% capacity factor) are subject to a standard based on efficient design and operation of simple cycle turbines.
- New low load turbines (defined as units that are generating less than 20% of their maximum annual capacity, i.e., less than 20% capacity factor) are subject to a standard based on low-emitting fuel.

11.2 Evergy Missouri West GHG Rule Compliance

The electric industry has challenged CCS as BSER for a host of reasons delineated in the Edison Electric Institute’s August 2023 comments on the proposed rule. While the final rule includes CCS as BSER, Evergy remains concerned about the ability to implement the technology. In summary, the concerns with CCS center on the current limited deployment and adequate demonstration of the technologies, the unlikely availability at the required scale according to the proposed compliance date, and the lack of documented integration of the individual components (capture, transportation, and storage).

Further, on February 5, 2025, EPA submitted an unopposed motion asking the U.S. Circuit Court for the District of Columbia (DC Circuit Court) to hold in abeyance for 60 days the current case challenging the GHG Rule. This delay will give the new presidential administration time to review the GHG Rule and determine their next steps regarding the future of the Rule. On February 19, 2025, the DC Circuit Court granted EPA's motion. The Court ordered EPA to file motions governing further proceedings by April 21, 2025.

In light of these ongoing concerns regarding CCS deployment, the change in presidential administration, and favorable judicial challenges, Evergy conducted an analysis to comply with the GHG Rule without employing CCS. For Evergy Missouri West, the evaluation included natural gas (NG) conversion and co-firing options for existing coal units and a capacity factor limitation on new combustion turbines (including Viola CC, McNew CC, and Mullin Creek 1 CT). The effective date for compliance is January 1, 2030, for coal units and January 1, 2032, for combustion turbines (including combined cycle).

Table 48: GHG Rule Compliance Options

Generating Unit	GHG Compliance Pathway	Retirement Date
Coal	Retirement	Prior to January 1, 2032
Coal	40% NG Co-Firing (2030)	By January 1, 2039
Coal	100% NG Conversion (2030)	None
Viola CC	40% Capacity Factor Limit (2032)	None
McNew CC	40% Capacity Factor Limit (2032)	None
Mullin Creek 1 CT	40% Capacity Factor Limit (2032)	None
New Combined Cycle	40% Capacity Factor Limit (2032)	None
New Combustion Turbine	40% Capacity Factor Limit (2032)	None

11.3 GHG Rule Cost Estimates and Planning Assumptions

For existing coal units, the natural gas co-firing and conversion compliance options require significant capital investment and ongoing operating expense. In 2030, the cost estimates include the following for plant modifications to burn natural gas, gas pipeline extensions, and annual firm gas transport cost.

Table 49: GHG Rule Cost Estimates[15] **Confidential**

[redacted]

For capacity expansion and production cost modeling, Evergy used high natural gas prices with a mid-point carbon dioxide restriction. The Company assumed that the GHG Rule would increase demand for natural gas and exert upward pressure on prices, and while the GHG Rule is intended to address carbon dioxide limits, Evergy chose to place a restriction on emissions to account for uncertainty in the long-term modeling forecasts.

11.4 GHG Rule Compliance vs. Preferred Plan

Using the above assumptions, Evergy modeled a range of compliance scenarios. Table 50 summarizes the scenarios with the estimated cost of GHG compliance relative to the 2025 IRP Preferred Plan ACAA. The comparison is based on the H2C modeling endpoint, which was used to develop the GHG estimates. As measured by NPVRR, the GHG compliance cost ranges from $385 million to $615 million.

[15] These cost estimates, which are based on preliminary engagement with the pipeline companies, are classified as Class V construction estimates which have a tolerance of -50% to +100%. Evergy contracted for a more detailed study at Jeffrey which should narrow the tolerance to +/-20%, but has not yet received results.

Table 50: GHG Rule Cost Comparisons

Plan	ACAA	AQAR	ARAR	ASAR	ATAR	AUAR	AVAR
Iatan 1	Ret 2039	Co-Fire	Co-Fire	Co-Fire	Co-Fire	Co-Fire	Co-Fire
Iatan 2	No Ret	Conv	**Co-Fire**	Conv	Conv	**Co-Fire**	Conv
Jeffrey 1	Ret 2039	Co-Fire	Co-Fire	Co-Fire	Co-Fire	Co-Fire	Co-Fire
Jeffrey 2	Conv	Conv	Conv	**Co-Fire**	Conv	**Co-Fire**	**Ret 2030**
Jeffrey 3	Ret 2030	Ret 2030	Ret 2030	Ret 2030	**Conv**	Ret 2030	Ret 2030
H2C NPVRR ($ mil)	**15,070**	**15,684**	**15,484**	**15,642**	**15,685**	**15,455**	**15,608**
GHG vs ACAA ($ mil)	**-**	**614**	**414**	**572**	**615**	**385**	**538**

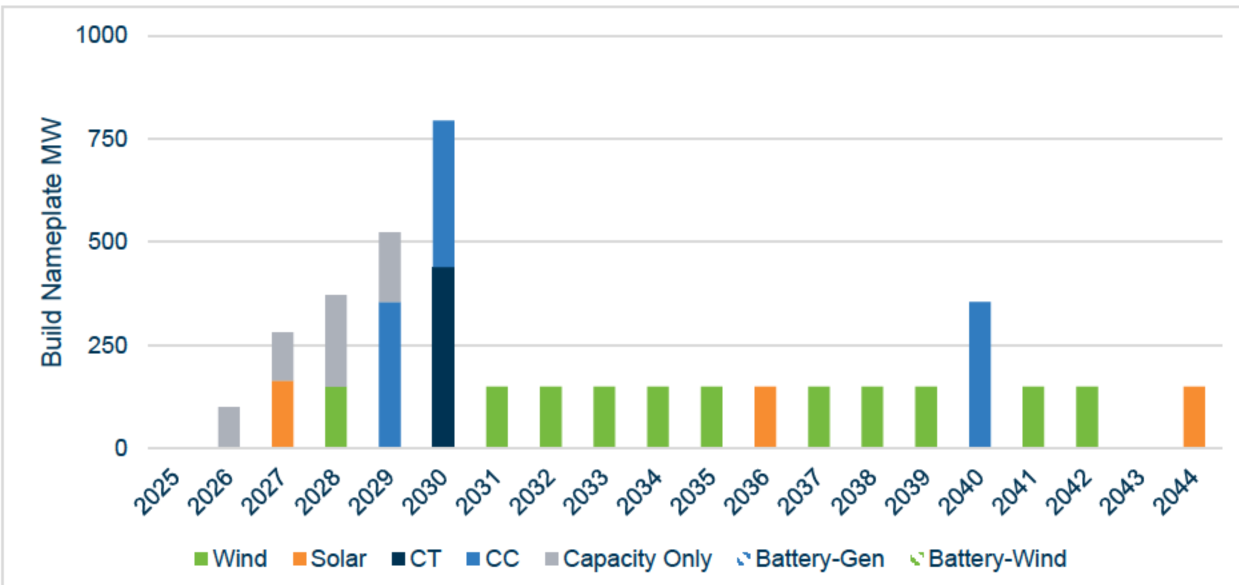
In summary, the GHG compliance plans require significant cost to implement with little impact on capacity expansion. The GHG expansion plans were all identical with the exception of some minor differences in capacity purchases. When compared to the Preferred Plan, the GHG plans accelerate the retirement of certain coal-fired resources by one year from 2039 to 2038, which pulls a 355 MW combined cycle resource forward from 2040 to 2038. Additionally, there are some timing differences for wind and solar resources beginning in 2036, with the GHG plans substituting an additional 150 MW solar resource for a 150 MW wind resource. In total, the GHG plans include 1,500 MW of wind, 615 MW of solar, 1,065 MW of combined cycle, and 440 MW of combustion turbine. Table 51 summarizes the capacity expansion plans, while Figure 51 presents a comparison of the Preferred Plan with the GHG plans.

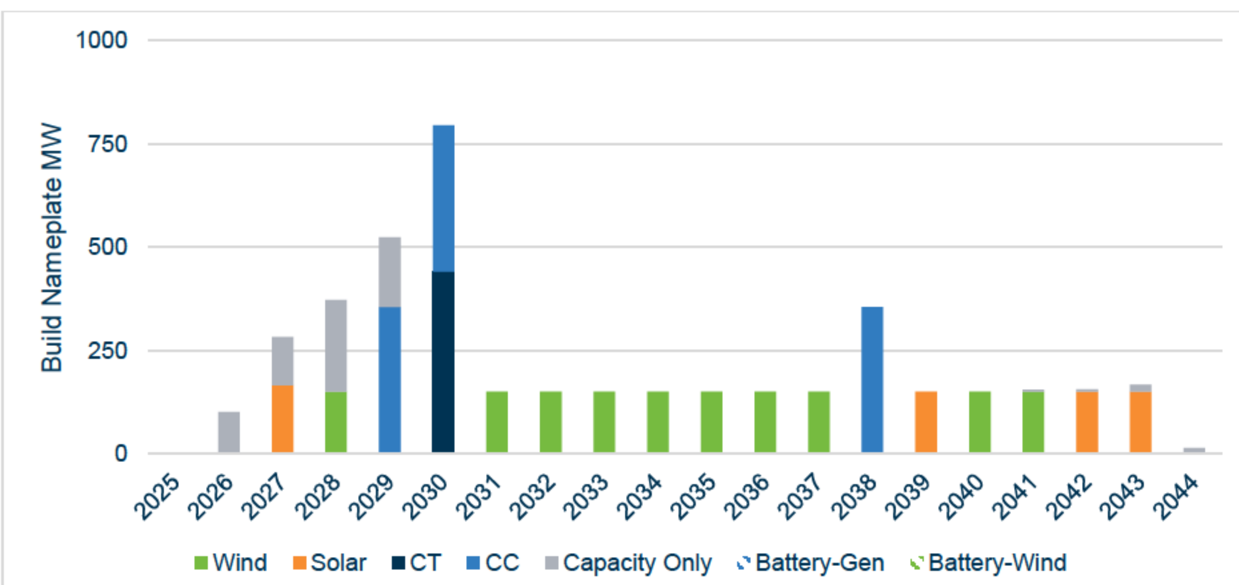
As the GHG Rule progresses through the courts, Evergy will adapt its plans to maintain compliance with the law.

Table 51: GHG Capacity Expansion Summary

Plan	ACAA	AQAR	ARAR	ASAR	ATAR	AUAR	AVAR
Wind (MW)	1650	1500	1500	1500	1500	1500	1500
Solar (MW)	465	615	615	615	615	615	615
CT (MW)	440	440	440	440	440	440	440
CC (MW)	1065	1065	1065	1065	1065	1065	1065
Capacity (MW)	609	609	609	609	609	649	621

Figure 51: Evergy Missouri West 2025 Preferred Plan ACAA (Top) vs. GHG Compliance Plan AUAR (Bottom)





Section 12: Resource Acquisition Strategy Update

12.1 2025 Annual Update Preferred Plan

The Alternative Resource Plans (ARP) developed and analyzed under the requirements of 20 CSR 4240-22.060 were designed to meet the objectives of 20 CSR 4240-22.010(2).

Evergy Missouri West has selected ACAA as its Preferred Plan. This plan continues to select the resources that Evergy Missouri West had in the early years of the 2024 Preferred Plan, including 2027 solar, a 2029 ½ CCGT and a 2030 SCGT. These resources are in the development process and included in ongoing CCN proceedings.

Evergy Missouri West has identified the need for additional resources in the short term based on changes to the forecasts for load growth, reliability needs and expected accreditation, and demand-side programs.

Due to the increased needs Evergy Missouri West is seeing in this update, more resources are included in this plan in the execution window. 150 MW of wind was selected in 2028 and the ½ share of McNew CCGT was selected in 2030. Additionally, market capacity is needed to meet summer and winter SPP reserve margin requirements before the thermal buildout in 2029-2030 is complete. Evergy Missouri West has also changed its expected retirement schedule, with the expected conversion of Jeffrey 2 to natural gas in 2030, rather than retiring. Evergy Missouri West continues to expect retirements of Jeffrey 3 in 2030, Jeffrey 1 in 2039, and Iatan 1 in 2039. Evergy Missouri West is a minority owner in each of these units.

The Evergy Missouri West Preferred Plan ACAA for the 20-year planning period is shown in Table 52.

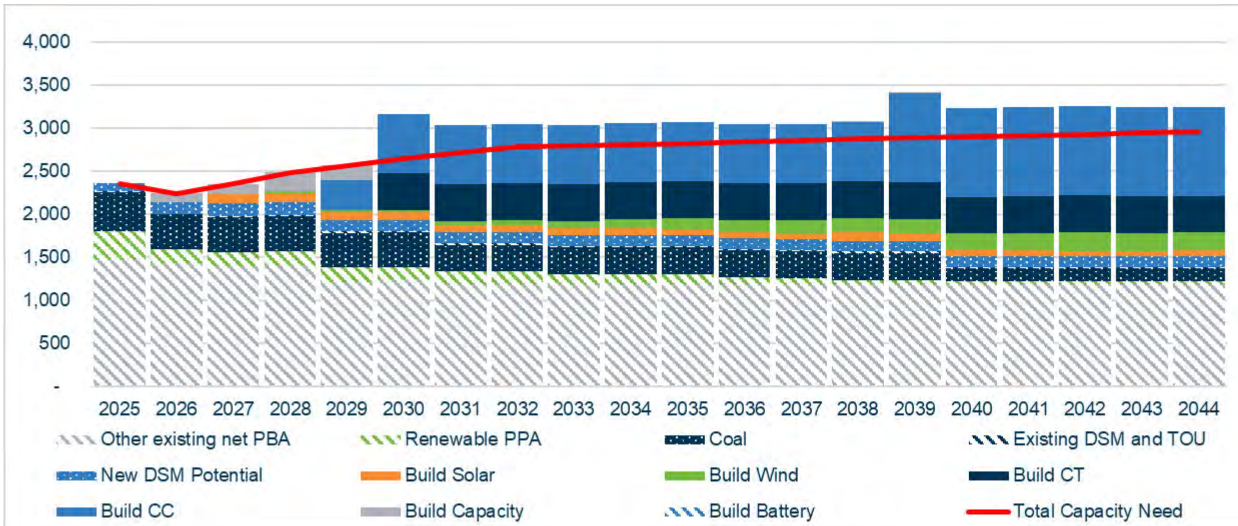
Table 52: Evergy Missouri West Preferred Plan ACAA

Year	Wind (MW)	Solar (MW)	Battery (MW)	Thermal (MW)	Capacity (Summer MW)	DSM (Summer MW)	Retirements (MW)
2025	0	0	0	0	0	97	0
2026	0	0	0	0	101	136	0
2027	0	165	0	0	117	147	0
2028	150	0	0	0	222	145	0
2029	0	0	0	355	169	128	0
2030	0	0	0	795	0	128	0
2031	150	0	0	0	0	128	155
2032	150	0	0	0	0	127	0
2033	150	0	0	0	0	127	0
2034	150	0	0	0	0	127	0
2035	150	0	0	0	0	127	0
2036	0	150	0	0	0	126	0
2037	150	0	0	0	0	126	0
2038	150	0	0	0	0	126	0
2039	150	0	0	0	0	126	0
2040	0	0	0	355	0	125	187
2041	150	0	0	0	0	125	0
2042	150	0	0	0	0	124	0
2043	0	0	0	0	0	124	0
2044	0	150	0	0	0	125	0

As the detailed above, resource needs for Evergy Missouri West include execution window builds of 165 MW solar in 2027, 150 MW wind in 2028, 355 MW CCGT in 2029, 355 MW CCGT and 440 MW SCGT in 2030, and market capacity purchases. Beyond 2030, the Preferred Plan includes an additional 1,500 MW wind, 300 MW solar, and 355 MW CCGT.

12.1.1 Preferred Plan Composition

Figure 52: Preferred Plan Summer Capacity Composition (MW)



12.2 Implementation Plan

12.2.1 Supply-Side Implementation Schedules

Combine Cycle Additions – Viola and McNew Plants

The Preferred Plan includes the construction of two advanced class 710 MW combined cycle gas turbine ("CCGT") generating facilities known as the Viola Generating Station and the McNew Generating Station. The configuration and equipment for the two CCGT facilities will be substantially the same. These combined cycle plants are slated to be shared 50/50 between Evergy Missouri West and Evergy Kansas Central. The Viola facility has a planned commercial operation date of Summer 2029. The McNew facility has a planned commercial operation date of Summer 2030. A schedule of the major milestones for the CCGT plants is detailed in Table 53.

Table 53: Combined Cycle Implementation Milestones

Illustrative Milestone Schedule (By Developer or Evergy)	CCGT #1 (Viola) Expected Completion	CCGT#2 (McNew) Expected Completion
Site Control Complete	December 2023	October 2024
SPP Large Generator Interconnection Application	October 2024	October 2024
Environmental and Land Permitting Complete	February 2026	2026
Design Spec & Engineering, Procurement, and Construction Award	First Half 2025	First Half 2026
State Utility Regulatory Approvals	Q3 2025	Q3 2025
Detailed Design and Engineering	Second Half 2025	Second Half 2026
Construction Begins	2026	2027
Major Equipment Delivery	2026	2027
Construction Complete	2028	2029
Testing and Commissioning Complete	2028	2029
Commercial Operation	Summer 2029	Summer 2030

Simple Cycle Addition – Mullin Creek #1

The Preferred Plan also includes the construction of one advanced class 440 MW simple cycle gas turbine ("SCGT") generating facility known as the Mullin Creek #1 Generating Station (Mullin Creek #1). The Mullin Creek #1 facility has a planned commercial operation date of January 1, 2030. This plant, along with the two CCGT's will satisfy the 1,150 MW need for thermal resources identified in the 2025 Preferred Plan. An application to the Missouri Public Service Commission for a Certificate of Convenience and Necessity that authorizes Evergy Missouri West to construct, install, own, operate, and control these plants was filed in November of 2024. The Mullin Creek #1 facility has a planned commercial operation date of Summer 2030. A schedule of the major milestones for the Mullin Creek #1 plant is detailed in Table 54.

Table 54: Mullin Creek #1 Implementation Milestones

Milestone Description	Expected Completion
Site Control Complete	October 2024
SPP Large Generator Interconnection Application	October 2024
Environmental and Land Permitting Complete	2026
Design Spec & Engineering, Procurement, and Construction Award	First Half 2026
State Utility Regulatory Approvals	Q3 2025
Detailed Design and Engineering	Second Half 2026
Construction Begins	2027
Major Equipment Delivery	2027
Construction Complete	2029
Testing and Commissioning Complete	2029
Commercial Operation	Summer 2030

2026 Solar Additions

The 2026 solar additions are modeled from responses to Evergy's 2023 All-Source RFP. Evergy plans to move forward with the acquisition process out of the RFP offered projects. A regulatory application was filed in October of 2024 by Evergy Missouri West seeking permission and approval of Certificates of Convenience and Necessity authorizing it to construct, install, own, operate, manage, maintain, and control two solar generating facilities. These facilities are known as the Sunflower Sky Solar Project, and Foxtrot Solar Energy LLC. Details of the projects are provided below.

Sunflower Sky Solar

Sunflower Sky Solar is an 88 MWdc/65 MWac single axis tracking photovoltaic solar facility located in Wilson County, Kansas. The project is being developed by a third-party developer and is projected to go commercial in December of 2026. This project is being acquired through a development asset sale, which means the developer will complete the early phase project due diligence and Evergy will be responsible for project construction. A schedule of the major milestones for the Sunflower Sky project are detailed in Table 55.

Table 55: Sunflower Sky Solar Implementation Milestones

Milestone Description	Expected Completion
Term Sheet Executed	December 2023
PSA Agreement Signed	August 2024
MPT on Order	December 2024
EPC Limited to Proceed	Q2 2025
State Utility Regulatory Approvals	Q3 2025
Closing on Development Assets	Q3 2025
EPC Full Notice to Proceed	Q3 2025
Mechanical Completion	Q3 2026
Substantial Completion/Commercial Operation	December 2026

Foxtrot Solar

Foxtrot Solar is a 130 MWdc/100 MWac single axis tracking photovoltaic solar facility located in Jasper County, Missouri. The project is being developed by a third-party developer and is projected to go commercial in December of 2026. Evergy is purchasing this project through a build transfer agreement, which has both acquisition agreement and construction contract portions. The developer is responsible for securing land rights, permits, interconnection rights, approval from local jurisdictions, and required engineering, land, and water studies of the site. Once the development work and a contract have been finalized, the project goes into the construction phase. The developer (or its contractor) will then procure all necessary material, design and build the project. In the case of Foxtrot, the developer will hire a contractor to provide these services. A schedule of the major milestones for the Sunflower Sky project are detailed in Table 56 below:

Table 56: Foxtrot Solar Implementation Milestones

Milestone Description	Expected Completion
Term Sheet Executed	April 2024
Build Transfer Agreement Signed	September 2024
State Utility Regulatory Approvals	Q3 2025
Notice to Proceed Given to Developer	Q3 2025
Mechanical Completion	Q3 2026
Substantial Completion/Commercial Operation	December 2026

In addition to the planned resources detail above, the IRP has identified a need for 150 MW of wind resources in each year from 2031 through 2039 as well as 150 MW of wind in 2041 and 2042. An additional need for 150 MW of solar is identified in 2044, along with 440 MW of thermal resource additions in both 2040 and 2043. It is expected that these needs will be filled through a combination of projects offered in the upcoming 2025 all source RFP (planned to be issued in March of 2025) as well as Evergy self-developed projects.

Evergy also invests significant capital on projects to maintain or improve plant efficiency. Table 57 provides examples of these projects.

Table 57: Environmental Retrofit Project Timeline

Project Description	Unit	Year	Performance Impact
Iatan Station			
Cooling Tower Fill Replacement	Iatan 2	2024	Nominal
LP Turbine L-0 Replacement	Iatan 2	2024	Nominal
Major Turbine Overhaul and New IP Rotor	Iatan 1	2025	Moderate
HP Turbine Bucket Repalcement	Iatan 2	2026	Nominal
Air Heater Basket Replacement	Iatan 2	2026	Nominal
LP Turbine L-1 Replacement	Iatan 2	2026	Nominal
Air Heater Basket Replacement	Iatan 1	2028	Nominal
Lake Road Station			
CAT Engine Remanufacture	Lake Road Landfill	2027	Nominal
Cooling Tower Fill Replacement	Lake Road 2	2028	Nominal
Estimated Performance Impact: Nominal - Less than 0.1% efficiency improvement; Moderate - 0.1 - 0.5% improvement; Significant - Greater than 0.5% improvement			

Section 13: 2024 IRP Joint Agreement Responses

13.1 Staff of the Missouri Public Service Commission (MPSC)

13.1.1 Discussions on Modeling, Assumptions, Processes for IRP

Evergy and Staff met on February 10, 2025 to fulfill the agreement to discuss the Company's capacity expansion modeling, assumptions, and processes prior to the Company's 2025 IRP Annual Update filing.

13.1.2 Economic Development Load Modeling

Evergy continued to include economic development load in its alternative resource plans for the 2025 IRP. Evergy Missouri West is planning for a future resource mix that meets the needs of firmly committed load and has developed several contingency plans to accommodate changes to load growth including additional large customers.

13.2 Missouri Office of the Public Counsel (OPC)

13.2.1 Comparison of Output of Jointly-Owned Resources

The comparison of the energy output of jointly-owned resources is available in the Jointly Owned Generation Output.xlsx file. Please refer to the accompanying workpaper provided with this filing.

There are two constraints in the model which may cause dispatch to differ – the constraint on market reliance which is intended to ensure each utility has a future resource mix that is consistent with meeting its own energy needs at least cost, and the carbon constraint which requires each utility to limit future carbon emissions while meeting energy needs. Differences between the joint owners arise from differences in re-dispatch to optimally comply with carbon policy and serve customers with least-cost energy from their own fleets. Evergy Missouri Metro has more baseload generation and a larger coal fleet than Evergy Missouri West, resulting in less need to dispatch more expensive resources to serve its own load, but a greater need to curtail coal generation in favor of lower or non-emitting resources to meet its carbon constraints.

In practice, SPP dispatches the Evergy fleet and there would not be inconsistencies between joint owners. However, each constraint enables the model to plan for a future resource mix that helps the utility manage a planning objective. For Evergy Missouri West, a primary driver is gaining a resource mix that can serve its energy needs cost-effectively and hedge market volatility. Evergy does not know exactly what future carbon policy might look like or how it will be implemented. The GHG Rule was the path taken by the last presidential administration. The carbon constraints in the model appropriately demonstrate that Evergy Metro will be more affected by future carbon rules because of its larger coal fleet. Since the model optimizes to reduce carbon emissions the most cost effectively, it chooses to reduce output from the highest emitting resources, reducing revenue streams from coal resources and incenting lower or non-emitting resources to provide energy.

13.2.2 TOU Rate Impacts

Following the Commission's order to transition to default TOU rates, the Company modified its potential study TOU impact estimates to better align with that order. The Commission approved four TOU rates: a default TOU rate and three optional TOU rates. Because the default TOU rate (i.e. peak adjustment charge rate) that was approved by the Commission reflects a much lower price differential than the modeled TOU rates in the potential study, it was determined that a lower demand impact would likely result. Therefore, Evergy adjusted the TOU impact downward determined in the potential study for use in its 2024 IRP by 70%, or resulting in 30% of the potential study forecast.

13.3 Renew Missouri (RM)

13.3.1 GHG Rules

Evergy developed several compliance plans for the GHG rules in Section 11.

13.3.2 Storage Economics

Evergy continued to model investment tax credits as part of storage economics using the same assumptions as the 2024 IRP. Storage resources were assumed to qualify for 30% investment tax credits and those located in Evergy’s generation area were modeled as qualifying for 40% investment tax credits beginning in 2028. Investment tax credits are still expected to phase out as envisioned by the Inflation Reduction Act.

Storage installed costs were not updated for this IRP because Evergy has not issued another RFP and is not currently developing storage. There is considerable uncertainty regarding how recent tariffs may affect these resource costs. Evergy plans to issue another RFP this year and gain refreshed cost estimates. Subsequent to this filing Evergy will meet with Renew Missouri to discuss assumptions used in this update.

13.3.3 Clean Energy Investment and Production Tax Credits

Evergy continued to assume new wind and solar resources will qualify for production tax credits. Evergy Missouri West developed several resource plans testing preferences for renewable resources.

13.3.4 Time of Use Pricing and Net Metering Web Content

Evergy's website contains educational content to help customers understand their TOU rate and net metering options. Evergy allows customers with net metering to also participate in TOU rates.

13.4 New Energy Economics (NEE)

13.4.1 Capital Constraints for Wind and Cost Data for Thermal Resources

Evergy agreed to test relaxing capital constraints as wind PPA expire in the 2025 IRP Annual Update. Plan ACDA shows two years with higher wind builds if wind constraints are relaxed beginning in 2035. Other plans relaxing build constraints, such as ACEA also select more wind build. See Section 9.9.1.

Evergy updated cost data for CC and CT resources consistent with its development experience. See Section 5.4.

13.4.2 Performance-Based Accreditation Modeling

Evergy modeled the effects of expected SPP rules for performance-based accreditation and fuel assurance on each individual thermal resource for this IRP.

13.4.3 Coal to Natural Gas Conversions

Evergy Missouri West modeled a natural gas conversion of Jeffrey 2 as part of its base plan testing and chose this conversion as part of its Preferred Plan. Evergy Missouri West also considered the cost and options for coal/natural gas co-firing and natural gas conversion to analyze GHG Rule compliance scenarios and determine optimal compliance options.

13.4.4 Production Cost Modeling

Evergy continued to use the modeling process it used in the 2024 Triennial due to time constraints and confidence in the modeling results. However, Evergy has been testing more granular modeling to provide more detail to stakeholders in future IRPs.

13.4.5 Natural Gas Price Volatility

Evergy continued to use natural gas prices as a critical uncertain factor in IRP modeling. The 2024 IRP natural gas price forecast was used for the 2025 IRP due to lack of updated data from EIA. Evergy is willing to continue to collaborate with stakeholders on how to incorporate fuel volatility and uncertainty into the Company's modeling.

13.4.6 SERVM

SERVM analysis is not included in this IRP, however Evergy is planning to update its models in conjunction with filing the Kansas IRP in April. Currently, Evergy’s primary objective for SERVM analysis is to better understand SPP’s modeling and provide feedback in the SPP stakeholder process. SPP is the reliability coordinator and it determines the reserve margins and resource accreditation, based on tariff provisions and modeling results. Evergy’s resource planning uses expected SPP requirements. SPP’s calculations have financial and planning implications for Evergy, so the Company intends to monitor the modeling inputs and results used by SPP to make sure they are aligned with Evergy’s data and operational experience.

Section 14: Special Contemporary Issues

From the Commission Order, EO-2025-0076 & EO-2025-0078, the following Special Contemporary Resource Planning Issues are addressed as follows:

14.1 Resource Adequacy Scenarios

Model and explicitly present future resource adequacy scenarios based on the following assumptions:

- *Incorporation of the utility's Commission-approved and/or anticipated demand-side programs and the utility's Commission-approved demand-side rates.*
- *Only utility's Commission-approved demand-side rates*
- *Alternative demand-side rates options that may be needed to meet near-term resource adequacy.*
- *Indicate whether or not naturally occurring savings and/or federally sponsored DSM savings are included in the modeling. If yes, these savings should be identified and separated as well*
- *Include an explicit section within the DSM volume and the executive summary where low, medium, and high time-of-use (TOU) differentials are modeled and presented with expected demand savings articulated separate and aside from other demand side management practices.*

Response:

Evergy's base case includes impacts of MEEIA Cycle 4 energy efficiency and demand response programs as approved by the Commission in EO-2023-0369/0370.

Evergy includes estimated impacts of the Commission-ordered time-of-use (TOU) rates from ER-2022-0129/0130 based on its 2023 DSM potential study (see Appendix 8). The 2023 DSM Market Potential Study was conducted by Applied Energy Group (AEG). It included a Realistic Achievable Potential (RAP) reflecting a low retention rate and a Maximum Achievable Potential (MAP) scenario with sensitivity analyses reflecting low, medium and high retention rates. These scenarios are described in detail in Section 8 Demand-Side Resource Analysis Update and the Executive Summary. The expected demand savings in MW are also included in Section 8 Demand-Side Resource Analysis Update.

Federal efficiency standards and the Inflation Reduction Act are included in the Energy Information Annual Energy Outlook (AEO). The AEO is the foundation for the end-use projections underlying the Statistically Adjusted End-use forecast models used to produce the energy and peak forecast. Individual efficiency standards or incentives are not individually quantified by EIA therefore cannot be separately quantified for each efficiency standard or incentive contribution in the forecast. Documentation on the assumptions included in the AEO as well as the end-use load estimates is included in the Company's load forecasting workpapers.

Following the Commission's order to transition to default TOU rates, the Company modified its potential study TOU impact estimates to better align with that order. The Commission approved four TOU rates: a default TOU rate and three optional TOU rates. Because the default TOU rate (i.e. peak adjustment charge rate) that was approved by the Commission reflects a much lower price differential than the modeled TOU rates in the potential study, it was determined that a lower demand impact would likely result. Therefore, Evergy adjusted the TOU impact downward determined in the potential study for use in its 2024 IRP by 70%, or resulting in 30% of the potential study forecast. See Section 8 Demand-Side Resource Analysis Update.

Approximately 12 months have elapsed since Evergy transitioned all eligible residential Missouri customers to default TOU rates. Evergy is evaluating the 2024 TOU summer peak demand impact from the default TOU rates; however, it does not have a final analyses or impact to share to incorporate for this IRP update.

Please refer to Section 8.2 for a description of the demand-side rate scenarios studied in the 2023 DSM Market Potential Study.

14.2 Datacenter Literature Review

Conduct a literature review of best practices on how other utilities are accounting for the addition of data centers in their IRPs and how risks can be minimized.

Response:

The addition of data center load is unprecedented in recent history and has raised questions of how to account for this potential load in utility planning. Given the recency of potential data center demand, industry-wide best practices have yet to be set. However, The Brattle Group prepared a report in May 2024 which analyzes how utilities and RTOs/ISOs have started to think about and incorporate data centers into their load forecasts, and subsequently, IRPs (Appendix 14.2A). This report provides key insights into best practices of other utilities and how to mitigate the risks associated with data center load additions.

Brattle found that demand growth will likely vary depending on the region, as will the ability to moderate this growth through distributed generation, energy efficiency, and demand response. While the report shows some progress in incorporating these new demand drivers, including data centers, into load forecasts, few utilities include a forecast of all new potential demand drivers. Out of the sample of 47 utilities included in the report, only 14 have included data center growth in their public forecasts. Within that group of 14, five entities did not include long-term forecasting of data center growth or did not include data centers in all public load forecasts.

The report also included 3 peer utilities (Ameren Illinois, Black Hills Colorado, Eversource Massachusetts) as well as SPP in its sample. Black Hills and Eversource have included data center growth in public load forecasts but are among the utilities signified as having more limited inclusion of data centers in their forecast, either due to limited long-term forecasting or exclusion of data centers in some load forecasts.

When considering new demand drivers, including data centers, Brattle highlights that risks exist with both over-forecasting and under-forecasting this load. Over-forecasting can lead to excess generation and infrastructure additions. Under-forecasting can ultimately impact reliability, potentially introduce mandatory use of load management measures, and restrict new service connections or expansions. While neither over-forecasting nor under-forecasting is a desired end-result, Brattle suggests under-forecasting is the more challenging of the two in the present circumstances. Demand forecasts have been regularly revised upwards in recent years and the supply chain for many necessary resources has become more constrained and uncertain as well, making it more difficult to respond to new load quickly.

Overall, striking the correct balance for forecasting these loads will be challenging, and no industry best practice has yet emerged. Revisiting how load forecasting should be completed in light of new large loads, like data centers, will likely be necessary. In the interim, Brattle recommends comprehensive inclusion of new demand drivers, including data centers, in load forecasts. Additionally, as highlighted in the Commonwealth of Virginia Industry Document (Appendix 14.2B), load forecasting and resource planning is not the only way to minimize data center risk. Policy and regulation can help lower risk associated with these new large loads, as can investment in other infrastructure such as expanding or enhancing transmission and distribution networks. More best practices will likely emerge in the coming months and years as data center demand comes online.

14.3 Large Load Growth Scenarios

Model large load growth scenarios stemming from: 1) data centers with a demand of 30 megawatts or greater; 2) potential re-shoring of industries, specifically manufacturing or materials refinement; and 3) electrification of buildings and vehicles as a result of federal mandates changes in the marketplace, or evolving consumer preference.

Response:

Evergy Missouri West modeled various load growth scenarios to determine how its Preferred Plan may need to adapt to customer additions and electrification. Section 10.1.1 discusses modeling results for large customer additions, which could include data centers or industrial facilities. Section 10.1.2 examines resource plan needs for high load growth with economy-wide electrification.

14.4 Technology and Methods Available to Comply with EPA Rules

Provide a review of the technology and methods currently available, as well as the dollar impact for relevant and projected resources, to be compliant with the Environmental Protection Agency's rules targeting reduction of fossil fuel-fired power plant pollution.

Response:

Evergy Missouri West has conducted an updated analysis of potential options to comply with EPA's final GHG Rule. Please refer to Section 11 GHG Compliance Plans for a discussion of the analysis and presentation of the results.

14.5 Supercritical Carbon Dioxide Power Cycle Plant

Investigate the option of a supercritical carbon dioxide power cycle plant as a resource candidate in future supply-side generation planning and modeling scenarios.

Response:

While not a commercially available technology, research is underway to demonstrate the feasibility of supercritical carbon dioxide (sCO_2) power cycles. Power cycles based on sCO_2 as the working fluid have the potential to yield higher thermal efficiencies at lower capital cost than state-of-the-art steam-based power cycles. Three U.S. Department of Energy (DOE) Offices (Nuclear Energy, Fossil Energy, and Energy Efficiency and Renewable Energy) are working together to reduce the technical hurdles and support foundational research and development of sCO_2 power cycles.

The Supercritical Transformational Electric Power (STEP) Demo project, led by GTI Energy in collaboration with Southwest Research Institute, GE Vernova's Advanced Research, the U.S. DOE's National Energy Technology Laboratory, and several industry partners, is the world's largest and most advanced indirectly fired sCO_2 power plant designed to demonstrate and validate the sCO_2 Brayton power cycle.

As of October 2024, the 10-megawatt STEP Demo pilot plant in San Antonio, Texas, has successfully completed phase 1 testing, demonstrating operability, efficiency, and commercial readiness of the sCO_2 power cycle. During phase 1 testing, the plant achieved full operational speed of its turbine at 27,000 RPM operating at 500°C and generating 4 MW of grid synchronized power. Following this milestone, the STEP Demo project will enter its final phase, which will involve reconfiguring the plant to enhance efficiency and increase energy output. It will operate at 715°C and demonstrate a Recompression Closed Brayton Cycle (RCBC) configuration. Upon completion, the facility is expected to generate 10 MW hourly.

14.6 Interconnection Cost Estimates

Model for low, medium, and high interconnection cost estimates that are supported by historic total interconnection costs by fuel type for Southwest Power Pool (SPP) in its resource planning scenarios.

Response:

Evergy included low, medium, and high interconnection costs scenarios in the 2024 IRP based on analysis of study data from Berkeley Labs. No new data was available before the 2025 IRP filing. However, Evergy continued to incorporate the results from the 2024 IRP, making interconnection costs part of the critical uncertain factor of build costs. Evergy also updated the low, medium, and high estimates of interconnection costs for thermal resources based on its development experience over the past few months with Viola, McNew, and Mullin Creek.

14.7 Estimated Project Length

Articulate the estimated project length for all generation resources given the current MISO backflow, and the overall demand for generation resources across the United States.

Response:

Evergy is located in the Southwest Power Pool (SPP) and any generator interconnection requests would thus be evaluated by SPP, not MISO. Evergy expects that any generator interconnection requests submitted to SPP for inclusion in the 2024-001 cluster, which will close on March 1, 2025, could receive a generator interconnection agreement by the fourth quarter of 2026. Generator interconnection requests submitted after March 1, 2025, will be evaluated in SPP's new Consolidated Planning Process, which is expected to result in generator interconnection agreements in late 2027 or early 2028 contingent upon final design, approval, and implementation of the new process. Table 6 contains the first year in which the resource option was assumed to be available and is indicative of the project duration. These project durations are based RFP results, expected construction timelines and interconnection availability.

14.8 Energy Storage Technologies

Describe any research, investigation, consideration, and/or inclusion of long-duration energy storage (10 or more hours) as well as non-chemical energy storage technologies the Company performed in the development of its IRP update/ triennial analysis. Nonchemical energy storage technologies mainly refer to thermal or mechanical methods of storing energy which could include storing heat in solid materials such as sand, rocks, or concrete blocks or liquids such as molten salts or water and processes utilizing compression, displacement against gravity, rotation, or accumulation of kinetic energy. Include any details or analysis of costs estimates if relied upon.

Explore the design and feasibility of piloting energy storage projects with the specific objective of enhancing system reliability and increasing capacity accreditation of renewable energy resources. Discuss the opportunities and benefits facilitated by inclusion of the explored technology and detail any identified limitations.

Detail any other emerging technologies intended to improve reliability or resource adequacy discovered by the Company or suggested by stakeholders that was considered and describe any pertinent analysis or findings.

Response:

Evergy, in the past has actively monitored long-duration energy storage developments through our participation in the Electric Power Research Institute. Evergy has recently conducted additional reading and research on long-term energy storage technologies to further understand options, performance characteristics and costs. Notes on the findings along with titles from the sources are included as Appendix 14.8A.

Evergy is also aware and has been following the ongoing Cambridge Evergy Storage Project. A project overview along with highlights and next steps are provided in Appendix 14.8B.

In order to facilitate the improved reliability of our critical generating assets, Evergy is partnering with the Electric Power Research Institute and Dimension Software to deploy an Asset Health Management system in 2025. The key objective of the Asset Health system is the enablement of users to view overall fleet health including the ability to drill down to individual sites, units, systems, and assets. The Asset Health system will clearly show any health issues with key assets and systems while also providing the proposed mitigations. (i.e. repairs, enhanced inspections, procurement of critical spares, ...)

In order to facilitate improved resource adequacy during extreme cold weather events, Evergy is partnering with Benetech to implement a new Winter Solid Fuel readiness program for the 2024/2025 winter season. The program involves sectioning off a portion of the coal pile and then proactively applying a metered flow of Glycol spares to ensure that the coal does not freeze and can be effectively transported, crushed, and burned during extreme cold weather events.

14.9 Coal to Natural Gas Conversions

Evaluate the potential for coal to natural gas conversions.

Response:

Evergy has updated estimates for conversion of coal resources to natural gas based on consultation with pipelines and plant engineers. Evergy Missouri West has included the Jeffrey 2 conversion to natural gas in 2030 as a scenario in the IRP, and in its Preferred Plan for 2025. Evergy Missouri West also tested co-firing and natural gas conversion scenarios as part of its GHG Rule compliance plans in Section 11.