EVERGY MISSOURI WEST

INTEGRATED RESOURCE PLAN

2023 ANNUAL UPDATE

JUNE 2023

** CONFIDENTIAL **

TABLE OF CONTENTS

TABLE OF TABLES

TABLE OF FIGURES

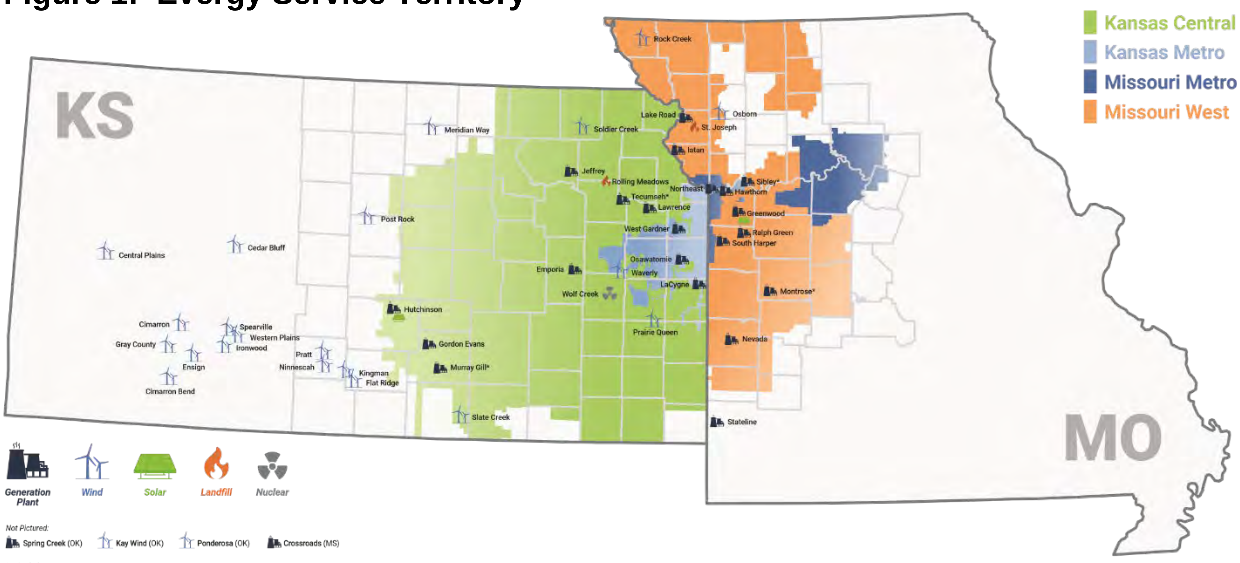
TABLE OF APPENDICES

SECTION 1: EXECUTIVE SUMMARY

1.1 UTILITY INTRODUCTION

Evergy Missouri West ("Missouri West" or "Company") 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. Missouri West also provides regulated steam service to certain customers in the St. Joseph, Missouri area. A map of the entire Evergy service territory which includes Missouri West is provided in Figure 1 below:

Figure 1: Evergy Service Territory



Missouri West is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. Table 1 provides a snapshot of the number of customers served, retail sales and peak demand based upon 2022 data.

Table 1: Missouri West Customers, Retail Sales, and Peak Demand

Jurisdiction	Number of Retail Customers	Retail Sales (MWh)	Net Peak Demand (MW)
Evergy Missouri West	340,298	8,666,707	1,923

Missouri West owns and operates a diverse generating portfolio and Power Purchase Agreements (PPA) to meet customer energy requirements. Table 2, reflect Missouri West's generation assets operating in 2021.

Table 2: Missouri West Capacity and Energy By Resource Type

Jurisdiction	Capacity by Fuel Type	Capacity (MW)	Capacity (%)	Energy (MWh)	Energy (%)
Evergy Missouri West	Coal	463	19.1%	1,770,534	33.1%
	Nat. Gas	1,069	44.1%	478,896	8.9%
	Oil	104	4.3%	20,443	0.4%
	Wind*	783	32.3%	3,068,274	57.3%
	LFG	2	0.1%	8,867	0.2%
	Solar	6	0.3%	4,110	0.1%
	Total	2,427	100.0%	5,351,124	100.0%

* Wind capacity is based upon nameplate

1.2 CHANGES FROM THE 2021 TRIENNIAL IRP AND 2022 ANNUAL UPDATE

Evergy Missouri West submitted its 2021 Triennial IRP filing on April 30, 2021, updated its resource plan on June 10, 2022, with its 2022 IRP Annual Update filing, and filed a Change in Plan Filing on September 26, 2022. This year's 2023 IRP Annual Update reflects updated information and forecasts based on market and policy changes and additional studies that have occurred in the past year.

Changes from the 2021 Triennial IRP, 2022 Annual Update, and 2022 Change in Plan filing:

- Updated market pricing reflecting latest SPP transmission planning model assumptions of future resource mix and potential transmission congestion
- Updated fuel price forecasts, including high, mid, and low natural gas price scenarios

- Carbon Dioxide emissions limitations scenarios reflecting future environmental risks, including high, mid, and low (no) restrictions
- Updated cost estimates and timing assumptions for resource additions based on First Quarter 2023 Request for Proposal (RFP) results
- Modeling of battery storage and hybrid resources as supply-side options
- Inclusion of incentives for new renewable and storage resources based on Inflation Reduction Act
- Updated load forecasts including large new customers in both Missouri and Kansas, and considerations for future large customer growth based on existing economic development pipeline
- Updated demand side management potential study, including four Missouri program options
- Included possible reductions in peak demand from Missouri Commission-ordered mandatory time of use rates
- Updated planning reserve margin consistent with SPP rule changes enacted in 2022
- Increased focus on planning for utility-level (as opposed to Evergy-level) resource needs to better identify each utility's specific energy and capacity needs in the future, reduced level of assumed market availability (for both capacity and energy) and reliance on other Evergy affiliates to meet long-term customer needs
- Removal of Persimmon Creek wind farm (due to the company not advancing the project further in the Missouri West jurisdiction)
- Expanded use of PLEXOS software for production cost modeling and capacity expansion, which was first implemented for 2022 IRP
- Annual refresh of data for existing generators (Capital and Operations & Maintenance costs)

1.3 2023 ANNUAL UPDATE PREFERRED PLAN

1.3.1 INTEGRATED RESOURCE PLAN OVERVIEW

Evergy's integrated resource planning experience spans many decades with its most recent Triennial Preferred Plans filed for both Evergy Metro and Evergy Missouri West in 2021 ("2021 IRP"). Between Triennial IRP filings, Commission regulations require annual updates reflect any material changes to the triennial filing and/or confirmation of the continued applicability of the originally filed Preferred Plan. This document includes the annual update filing for Evergy Missouri West for 2023 ("2023 Update") that, consistent with Commission regulations, outlines material changes to the 2021 IRP.

Due to the many changes in planning considerations over the past year, the Preferred Plan selected for Missouri West in this 2023 IRP Annual Update differs from the 2021 Triennial and 2022 IRP Preferred Plans. The 2023 Preferred Plan adds natural-gas resources to the Missouri West fleet earlier in the planning horizon. It increases the total amount of wind additions but postpones them until 2029. More solar is selected in the first few years of the plan, but there are less solar additions in the later half of the 20-year horizon.

Additionally, the refresh of the demand response potential study shows value in choosing the "Realistically Achievable Potential Plus (RAP+)" level of demand response programs over the Realistically Achievable Potential (RAP) level selected in the 2022 Annual Update. Notably, the new study shows much lower demand response potential than was forecasted in the last study, so the level of capacity and energy reductions which can be achieved from all programs are smaller.

Finally, in the 2022 Annual Update, Evergy identified the potential for an additional accelerated retirement which could be economically replaced, but at that time chose not to identify a specific unit for retirement as part of the Preferred Plan due to the uncertainty around which specific unit would ultimately be the best candidate for retirement. In this Annual Update, Jeffrey Unit 2 has been identified for 2030 retirement as part of the Preferred Plan. There is still significant uncertainty around different environmental regulations which could drive the retirement of Jeffrey Unit 2 or a different Evergy coal unit and thus Jeffrey Unit 2 still remains a “placeholder” for an accelerated retirement. However, given recent regulation released by the Environmental Protection Agency (EPA), it seems more probable that all units would need to install Best Available Control Technology in order to continue operating beyond the early 2030s. Given Jeffrey Units 2 and 3 are the only large units in Evergy’s fleet without Selective Catalytic Reduction (SCR) systems, the capital forecasts used in this IRP (and prior IRPs) assume that SCRs would need to be added if the units do not retire by 2031. This large capital cost to continue operations makes these units the most attractive options for early retirement. Evergy will continue to monitor environmental regulations and make adjustments to retirement plans as needed if conditions change, but at this time believes it is prudent to plan around a medium-term retirement of both Jeffrey Units 2 and 3 in order to avoid a situation where retirements are forced by environmental regulation and replacement capacity has not been procured proactively. Further discussion of environmental regulations is provided in Sections 3.4 and 7.2. Because Missouri West is a minority owner in the Jeffrey Units, these retirements are included in Missouri West’s Preferred Plan. It is important to note that, as an 8% owner, Missouri West does not have ultimate control of this retirement decision, but the lowest-cost resource additions for Missouri West are the same with and without the additional Jeffrey Unit 2 2030 retirement.

Table 3: Evergy Missouri West Preferred Plan Comparison

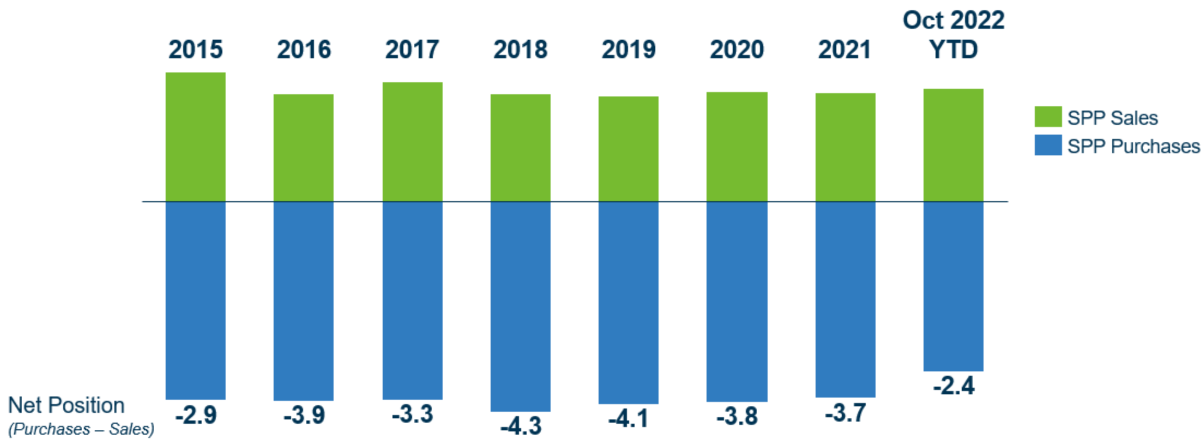
Note: All dates shown in this summary are end-of-year unless otherwise noted. Capacity balance views shown elsewhere in this document represent summer capacity impacts which means that additions are typically shown in the following year (the year in which they will be available for summer capacity)

	2021 Triennial IRP	2022 IRP Annual Update	2023 IRP Annual Update
Retirements	Lake Road 4/6 in 2024 Jeffrey 3 in 2030 Iatan 1 in 2039 Jeffrey 1 in 2039 Jeffrey 2 in 2039	Lake Road 4/6 in 2030 Jeffrey 3 in 2030 Iatan 1 in 2039 Jeffrey 1 in 2039 Jeffrey 2 in 2039	Lake Road 4/6 in 2030 Jeffrey 3 in 2030 Jeffrey 2 in 2030 Iatan 1 in 2039 Jeffrey 1 in 2039
Wind Additions	80 MW in 2025 80 MW in 2026	150 MW in 2024 72 MW in 2026	150 MW in 2029 150 MW in 2030 150 MW in 2031 150 MW in 2032 150 MW in 2033
Solar Additions	120 MW in 2024 80 MW in 2028 80 MW in 2029 80 MW in 2030 80 MW in 2031 80 MW in 2032	48 MW in 2028 72 MW in 2029 72 MW in 2030 72 MW in 2031 72 MW in 2032 72 MW in 2033 72 MW in 2034 72 MW in 2035	150 MW in 2026 150 MW in 2028 150 MW in 2041
Battery Additions			
Hybrid Additions			
Thermal Additions	233 MW CT in 2033 233 MW CT in 2039 233 MW CT in 2040	237 MW CT in 2036 237 MW CT in 2040	143 MW Dogwood CC in 5/2024 260 MW CC in 2027 260 MW CC in 2039
New DSM Programs	RAP	RAP	RAP+

Missouri West has historically been short energy and capacity, fulfilling its load obligations through market purchases from SPP and bilateral capacity contracts (net energy position since 2015 shown in Figure 4). The 2023 IRP Annual Update plan transitions Missouri West to greater self-sufficiency over time. In the 2021 Triennial IRP, stand-alone plans for Missouri West selected early combustion turbine (CT) builds to meet capacity needs, however, joint planning postponed the need for natural-gas capacity as affiliates had enough excess capacity that ensured there would be market capacity available for Missouri West. Similar assumptions were used in the 2022 IRP. Joint planning demonstrated that thermal additions could be postponed and Missouri

West's Preferred Plan included heavy reliance on future capacity deals to meet reserve margin requirements.

Figure 2: Missouri West Net Energy Position (GWh)



For the 2023 IRP, Evergy developed resource plans targeting less market dependence for meeting energy and capacity needs, particularly in the second half of the 20-year IRP planning horizon. The increasing prevalence of low- and negative-energy market prices in SPP, combined with increasing resource adequacy requirements mean that it is unlikely that significant excess capacity will persist in SPP in the long-term. Additionally, as the resource mix transitions and environmental regulations continue to drive baseload retirements, Missouri West must ensure it has energy to serve its load at a stable price, without simply assuming that other Pool members continue to build out sufficient energy resources to meet Missouri West customer energy needs at low prices. Given low wholesale market prices which are generally insufficient to cover all-in costs of new resources, Missouri West does not expect other utilities or merchant generators to build excess resources that are dispatchable or aligned to the load profile of Missouri West's customers as baseload coal resources retire and renewables are added. Notably, the amount of excess energy available from two of Missouri West's closest neighbors, Evergy Kansas Central and Evergy Metro, is expected to decline over time as those utilities are also planning to dedicate proportionately more of their resources to meet *their* respective utility customers' capacity and energy needs.

The 2023 IRP Preferred Plan continues to follow Evergy's strategy of adding to its resource portfolio ratably over time to meet increasing customer needs and transition out aging resources. This strategy considers annual capital spend limits to maintain balance sheet strength and customer rate stability. Spreading investment over time diversifies risk and allows time for robust selection processes to add the best projects available to its fleet. The 2023 Preferred Plan was developed considering a wider variety of options for adding new resources, updated cost assumptions, and new government incentives.

This 2023 IRP also incorporates feedback received from MPSC Staff as part of the Persimmon Creek Certificate of Convenience and Necessity case (outlined below). Evergy Missouri West looks forward to working further with Staff and other stakeholders in the development of the 2024 Triennial in order to implement further modeling improvements and/or assumption adjustments.

- Use of updated SPP Transmission Planning models which include significantly higher level of negative prices
- Updated dispatch assumptions for wind resources which ensure PTC-eligible wind realizes negative revenues when dispatched at negative prices
- Full use of capacity expansion modeling to identify lowest-cost supply-side resource additions; no hard-coded resource additions
- More fulsome explanation of modeling approach and method of using capacity expansion (provided in Section 6.2)

In summary, this 2023 Update is consistent with the Commission's integrated resource planning regulations and highlights changes to the Preferred Plan filed in our 2022 IRP. The changes to Missouri West's Preferred Plan compared to the 2022 IRP are driven by:

- Increased SPP Resource Adequacy requirements and increased load expectation driven by economic development activity
- Updated resource cost assumptions based on recent Requests for Proposal and new incentives under the Inflation Reduction Act

- New Potential Study results for Demand-Side Management programs

For reference, a summary of the Evergy-level Preferred Plan (based on a combination of the Preferred Plans of Missouri West, Evergy Metro, and Evergy Kansas Central) is provided below.

Table 4: Evergy-Level Preferred Plan Comparison

Note: All dates shown in this summary are end-of-year unless otherwise noted. Capacity balance views shown elsewhere in this document represent summer capacity impacts which means that additions are typically shown in the following year (the year in which they will be available for summer capacity)

	2021 Triennial IRP	2022 IRP Annual Update	2023 IRP Annual Update
Retirements	Lawrence 4 in 2023 Lawrence 5 in 2023 Lake Road 4/6 in 2024 Jeffrey 3 in 2030 La Cygne 1 in 2032 La Cygne 2 in 2039 Jeffrey 1 in 2039 Jeffrey 2 in 2039 Iatan 1 in 2039	Lawrence 4 in 2024 Lawrence 5 in 2024 (Coal) Jeffrey 3 in 2030 Lake Road 4/6 in 2030 La Cygne 1 in 2032 La Cygne 2 in 2039 Jeffrey 1 in 2039 Jeffrey 2 in 2039 Iatan 1 in 2039	Lawrence 4 in 2028 Lawrence 5 in 2028 (Coal) Jeffrey 3 in 2030 Jeffrey 2 in 2030 *(Placeholder for add'l accelerated retirement)* Lake Road 4/6 in 2030 La Cygne 1 in 2032 La Cygne 2 in 2039 Jeffrey 1 in 2039 Iatan 1 in 2039
Wind Additions	500 MW in 2025, 2026	300 MW in 2024 500 MW in 2025 450 MW in 2026 450 MW in 2041	199 MW in 5/2023 200 MW in 2024 150 MW in 2029, 2030 300 MW in 2031 450 MW in 2032 300 MW in 2033 150 MW in 2040, 2041
Solar Additions	350 MW in 2023, 2024 500 MW in 2028, 2029, 2030, 2031, 2032, 2033, 2034, 2035	190 MW in 2024 300 MW in 2028 450 MW in 2029, 2030, 2031, 2032, 2033, 2034, 2035 150 MW in 2036	300 MW in 2026 150 MW in 2027 300 MW in 2028, 2029, 2030, 2031 150 MW in 2033, 2034, 2040 450 MW in 2041
Thermal Additions		338 MW Lawrence 5 to NG in 2024	176 MW in 2023 143 MW in 5/2024 781 MW in 2027 338 MW Lawrence 5 to NG in 2028 521 MW in 2028 238 MW in 2032
"Firm Dispatchable"[1]	233MW in 2036, 2037, 2039 2,796MW in 2040	237 MW in 2036 418 MW in 2038 836 MW in 2039 948 MW in 2040	238 MW in 2035 260 MW in 2037 780 MW in 2038 1,278 MW in 2039
New DSM Programs	RAP MO/ RAP - KS	RAP MO/ RAP- KS	RAP+ MO/ Low KS

1) Similar to past IRPs, thermal additions beginning in 2035 are assumed to be non-emitting “firm, dispatchable resources”

SECTION 2: LOAD ANALYSIS AND LOAD FORECASTING UPDATE

2.1 CHANGES FROM THE 2021 TRIENNIAL IRP

Several inputs to the load forecasting models were updated for this filing compared to the 2021 Triennial IRP.

- Historical data for customers, kwh and $/kwh: ending June 2022 vs ending June 2020
- DOE forecasts of appliance and equipment saturations and kwh/unit: Annual Energy Outlook (AEO) 2022 vs AEO 2020
- Economic forecasts from Moody’s Analytics: June 2022 vs June 2020
- Class models in the 2023 Evergy West Update filing are the same as the 2021 Triennial filing: residential, small commercial, big commercial (medium, large, large power) and industrial. However, NUCOR 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 made were to improve the model fit.
- Company utilized EPRI electric vehicle study within its modeling for 2023 Update filing.
- The Company utilized Google Mobility Reports data through June of 2022 to account for load changes resulting from geolocation behaviors induced by the COVID19 pandemic.
- Recently announced new large industrial loads (e.g., META) have not been incorporated into the load forecasts described in this section. However, the latest projections for these loads are factored into Integrated Analysis for the purposes of determining capacity requirements.

Table 5, Figure 3, and Figure 4 below show a lower forecast for both peak and energy for the 2023 Update compared to the 2021 Triennial IRP. Below are the primary reasons for the change in forecast.

- There are some changes from the Energy Information Administration's (EIA) 2020 Annual Energy Outlook (AEO) to the 2022 AEO resulting from updates to end-use efficiency and saturation estimates. The EIA's updates impact to the 2023 IRP Update short-term (2022-2027) growth rate is slightly lower than the 2021 Triennial IRP forecast due to more efficient Commercial end-uses partially offset by increased Residential Base-use intensity. The long-term growth rate is lower compared to 2021 due to lower Commercial intensity estimates long-term. Below is a summary of the impact by class.
- Residential: Total residential intensity changed slightly from the 2020 AEO. There is virtually no change in cooling and heating intensity. The difference lies in the base-use intensity. The slope of the base use forecast in the 2022 AEO is slightly less negative in the near term (2022-2027) and similar to the 2020 AEO thereafter. The difference in base load is explained by updated estimates of miscellaneous intensity as well as TV and related equipment.
- Commercial: Total commercial intensity trajectory declined from the 2020 AEO, with growth being slightly slower throughout the forecast period (2022-2042). The end-uses contributing to the change from the 2020 AEO intensity are primarily Cooling, Heating, Lighting and Miscellaneous in both the near-term and the long-term.
- Industrial: Overall intensity and end-use intensity for industrial were largely unchanged.
- There are some changes from the Moody's Analytics Economic forecasts from 2020 to 2022. Economic forecasts for Population, Households, Employment (both Manufacturing and Non-Manufacturing) and Gross Product (both Manufacturing and Non-Manufacturing) all show lower growth trajectory in the 2022 forecast compared to the 2020 forecast. The lower growth trajectory in the Economic forecast contributes to a lower growth trajectory in the load forecast.

- However, the growth trajectory of Company Commercial load since the 2021 Triennial IRP forecast partially offsets lower economic and end-use intensity forecasts.

Table 5: Evergy MO West Mid-Case Annual Forecast ** Confidential**

[redacted]

Figure 3: Peak Forecasts - 2023 Annual Update Vs. 2021 Triennial IRP

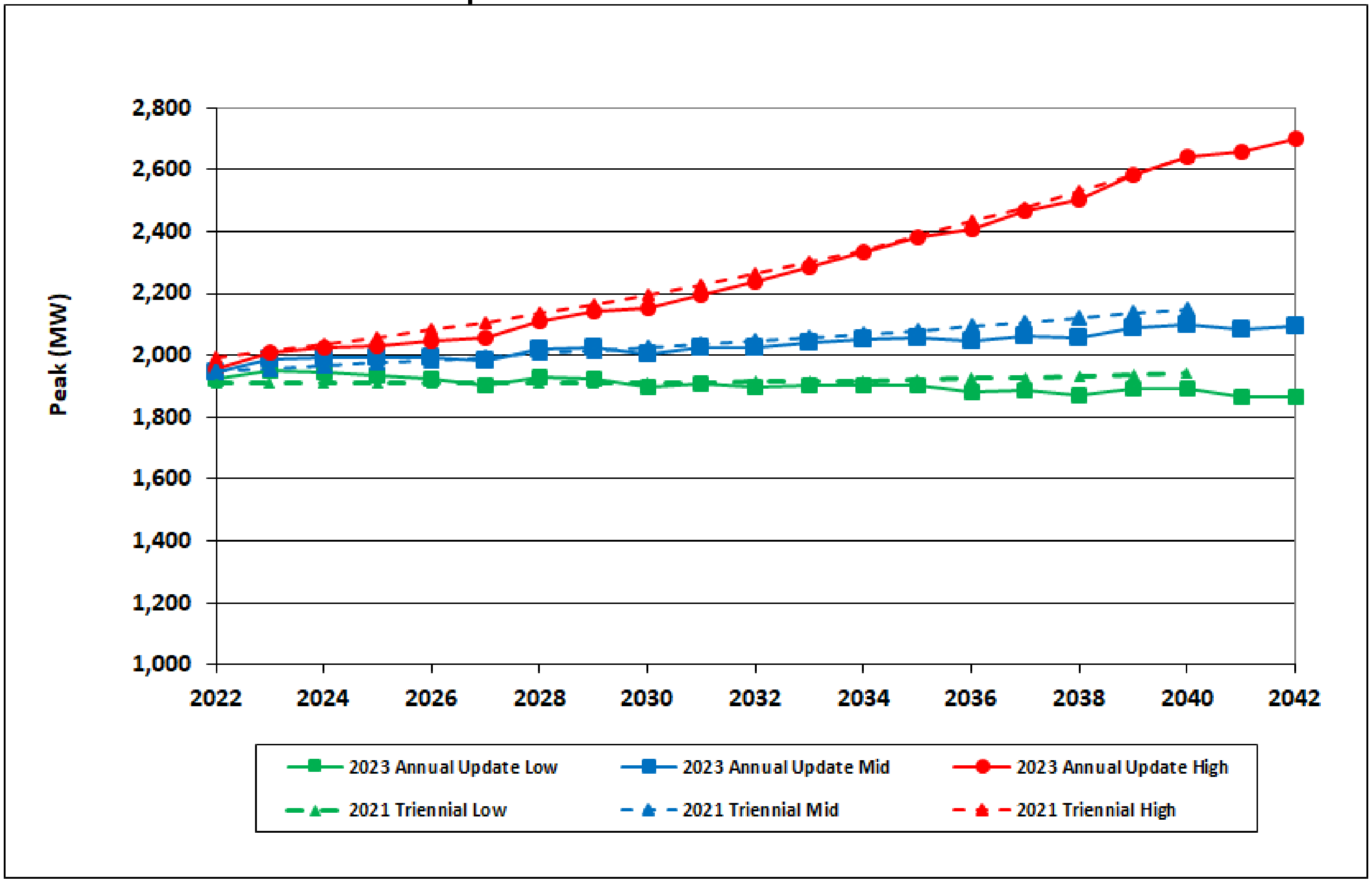
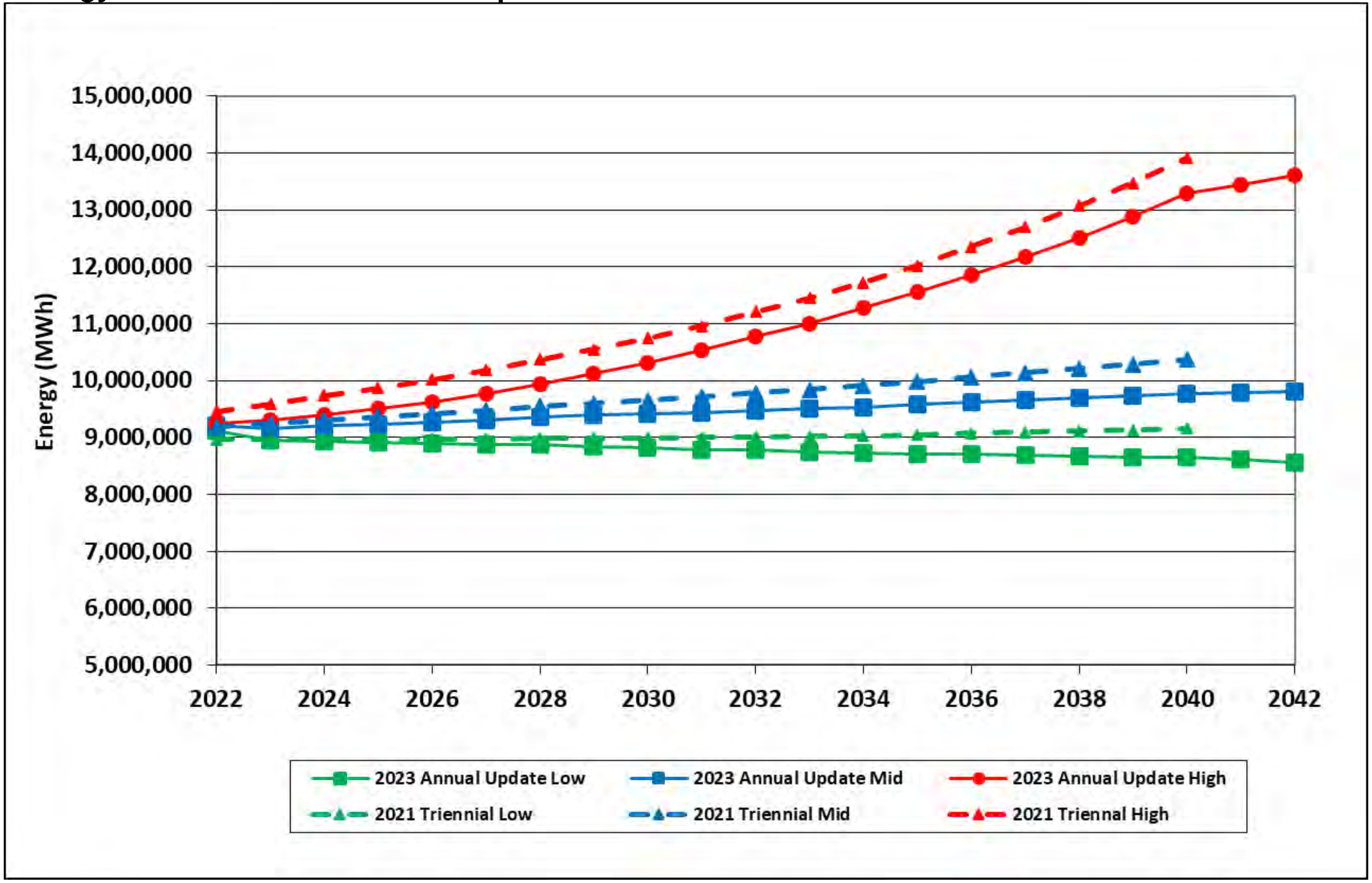


Figure 4: Energy Forecasts - 2023 Annual Update Vs. 2021 Triennial IRP



SECTION 3: SUPPLY-SIDE RESOURCE ANALYSIS UPDATE

3.1 MARKET CONDITIONS AND FUTURE OUTLOOK

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.

SPP conducts the integrated transmission planning process (ITP) on an annual basis, to assess reliability and economic transmission needs up to 10 years in the future. Every five years, SPP also performs a 20-year assessment. To perform these transmission assessments, SPP develops different future resource mix scenarios based on stakeholder feedback, including utility IRP plans. These resource mix assumptions, which include retirements or continued operation of existing resources and additions of new resources, enable the models to predict future economic dispatch of the system, transmission congestion, and resulting price differentials between load and resources.

For the 2023 IRP Annual Update, 1898&Co. used the most recent ITP models to produce market prices using Evergy's load and fuel price assumptions, including high, mid, and low natural gas price scenarios. The most recent ITP included forecasting models for years 2, 5, 10 and 20.

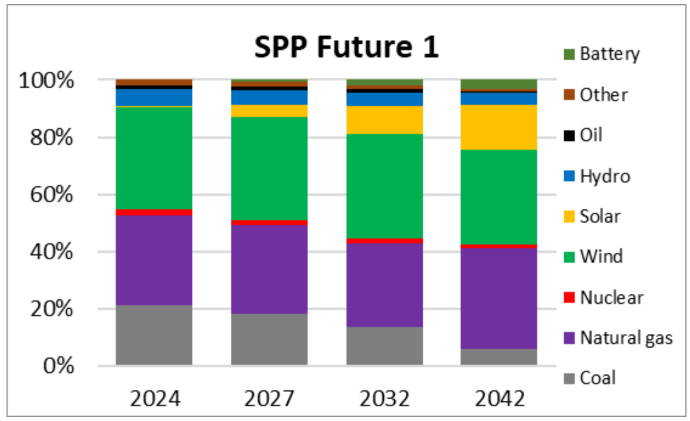
3.1.1 OVERVIEW OF SPP ITP FUTURES

The SPP Future 1 case represents a "business as usual" case with longer retention of existing resources, assuming by 2042 coal resources 56 years and older as well as natural gas and oil generators 50 years and older will retire. The 2024 planning model reflects near-term transmission upgrades and resource additions and is the same for all Futures described.

Figure 5: SPP Future 1 Overview

SPP Future 1				
Resource	2024	2027	2032	2042
Coal	21%	18%	14%	6%
Natural gas	31%	31%	29%	35%
Nuclear	2%	2%	2%	1%
Wind	35%	36%	36%	33%
Solar	1%	4%	10%	16%
Hydro	6%	5%	5%	4%
Oil	2%	1%	1%	0%
Other	2%	1%	1%	1%
Battery	0%	1%	2%	3%

Source: 1898&Co.

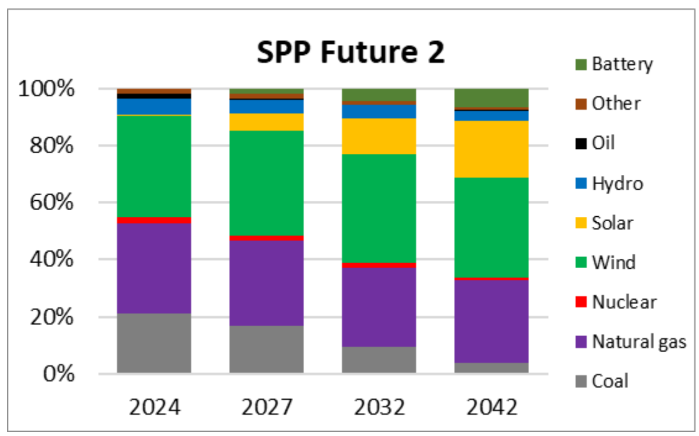


The SPP Future 2 case is an emerging technologies scenario, incorporating growth of electric vehicles and distributed generation as well as higher penetration of renewables and earlier retirement of existing generation. The ages for retirements are reduced to 52 years for coal units and 48 years for natural gas and oil units. Solar and battery resources account for a larger portion of 2042 capacity.

Figure 6: SPP Future 2 Overview

SPP Future 2				
Resource	2024	2027	2032	2042
Coal	21%	17%	9%	4%
Natural gas	31%	30%	28%	29%
Nuclear	2%	2%	2%	1%
Wind	35%	36%	38%	35%
Solar	1%	6%	13%	20%
Hydro	6%	5%	4%	4%
Oil	2%	0%	0%	0%
Other	2%	1%	1%	1%
Battery	0%	2%	4%	7%

Source: 1898&Co.

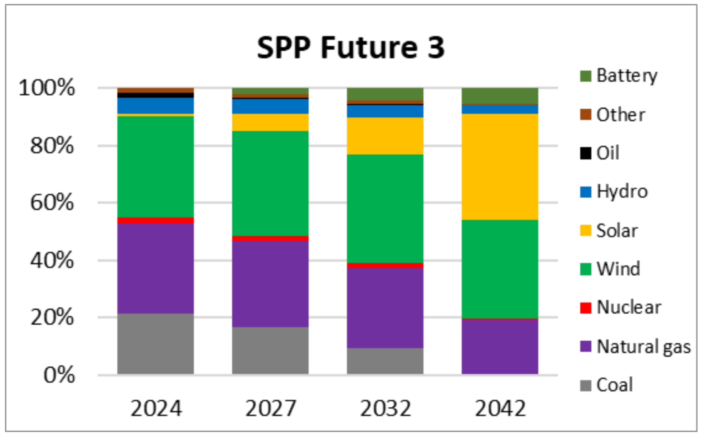


The SPP Future 3 case models accelerated decarbonization. All coal and oil resources are retired by 2042 and new resource build is driven by targeted emissions reductions of approximately95% from 2017 by 2042, leading to much higher reliance on solar. Future 3 is only modeled for 2042, so years 5 and 10 (2027 and 2032) reflect Future 2 models.

Figure 7: SPP Future 3 Overview

SPP Future 3				
Resource	**2024**	**2027**	**2032**	**2042**
Coal	21%	17%	9%	0%
Natural gas	31%	30%	28%	19%
Nuclear	2%	2%	2%	1%
Wind	35%	36%	38%	34%
Solar	1%	6%	13%	37%
Hydro	6%	5%	4%	3%
Oil	2%	0%	0%	0%
Other	2%	1%	1%	1%
Battery	0%	2%	4%	5%

Source: 1898&Co.



The Evergy market price forecasts for the 2023 IRP use a combination of the SPP Futures models. Evergy believes that Future 2 is the most representative forecast considering the recent pace of resource additions in SPP, interconnection queue activity and utility resource plans. However, the IRP also uses market prices from Future 3 to forecast a potential future with more stringent carbon regulation. Evergy believes this Future 3 scenario is particularly informative given the EPA's recently proposed Greenhouse Gas rules, which would drive a similarly aggressive pace of decarbonization.

3.1.2 PRICING ENDPOINTS

Consistent with the 2021 Triennial IRP, Evergy identified natural gas prices and carbon emissions policy as the critical factors to include in its market price forecasts. Nine price series were developed using combinations of high, mid, low natural gas price forecasts and high, mid, and low (no) carbon restriction scenarios. The natural gas forecasts and carbon emissions policy forecasts were updated as explained in later sections. Evergy did not change the 2023 IRP probabilities for each natural gas – carbon emissions policy scenario from the 2021 and 2022 IRPs.

Table 6: Market Pricing Endpoints and Probabilities

Endpoint	NG Price Forecast	Future	Carbon Restriction	Probability
H3C	High	Future 3	Future 3	3%
H2C	High	Future 2	H2C Model	9%
H2N	High	Future 2	None	3%
M3C	Mid	Future 3	Future 3	10%
M2C	Mid	Future 2	M2C Model	30%
M2N	Mid	Future 2	None	10%
L3C	Low	Future 3	Future 3	7%
L2C	Low	Future 2	L2C Model	21%
L2N	Low	Future 2	None	7%

Evergy also did not change the 2023 IRP probabilities for load forecast endpoints compared to the 2022 Annual Update. As a result, the overall endpoint probabilities used for Integrated Analysis are the same as those used in the 2022 Annual Update:

Table 7: Critical Uncertain Factor Probability Distribution

	Low	Mid	High
Load Growth	35%	50%	15%
Natural Gas	35%	50%	15%
CO_2 Restrictions	20%	60%	20%

Table 8: Scenario Weighted Endpoint Probabilities

Endpoint	Load Growth	Natural Gas	CO_2	Endpoint Probability
1	High	High	High	0.5%
2	High	High	Mid	1.4%
3	High	High	Low	0.5%
4	High	Mid	High	1.5%
5	High	Mid	Mid	4.5%
6	High	Mid	Low	1.5%
7	High	Low	High	1.1%
8	High	Low	Mid	3.2%
9	High	Low	Low	1.1%
10	Mid	High	High	1.5%
11	Mid	High	Mid	4.5%
12	Mid	High	Low	1.5%
13	Mid	Mid	High	5.0%
14	Mid	Mid	Mid	15.0%
15	Mid	Mid	Low	5.0%
16	Mid	Low	High	3.5%
17	Mid	Low	Mid	10.5%
18	Mid	Low	Low	3.5%
19	Low	High	High	1.1%
20	Low	High	Mid	3.2%
21	Low	High	Low	1.1%
22	Low	Mid	High	3.5%
23	Low	Mid	Mid	10.5%
24	Low	Mid	Low	3.5%
25	Low	Low	High	2.5%
26	Low	Low	Mid	7.4%
27	Low	Low	Low	2.5%

3.1.3 NATURAL GAS PRICES

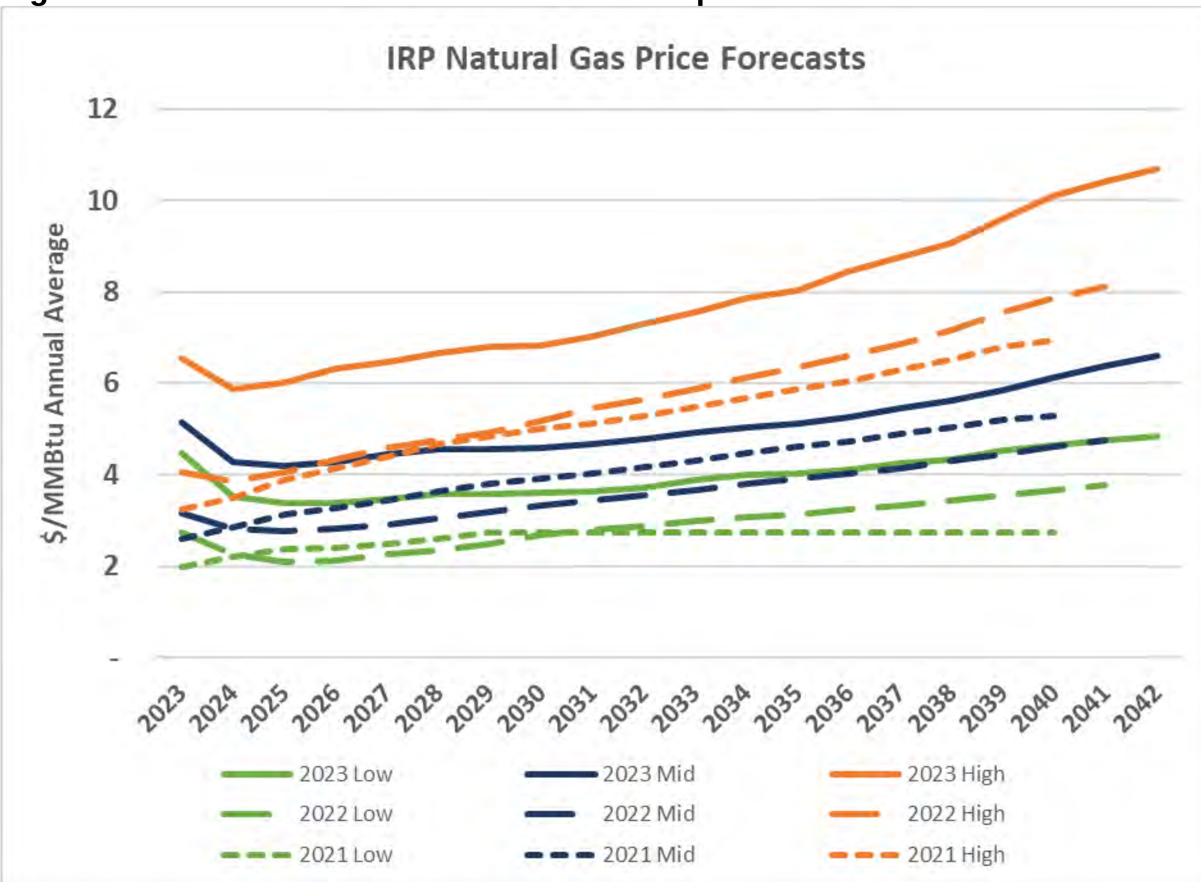
Natural gas forecast prices increased for the 2023 IRP in comparison with previous forecasts.

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. Last year, in response to Evergy's 2022 IRP filings, stakeholders noted a disconnect between the volatile and higher natural gas prices seen in the markets in late 2021 and early 2022 and the lower long term forecast prices in the IRP. The 2023 forecast reflects higher natural gas prices. Natural gas prices have been affected by the Ukraine War, supply chain pressures, global demand, and inflation. While future natural gas prices are uncertain, there are fundamental factors supporting the higher forecast including higher breakeven production costs, producer discipline, and increased global demand despite current lower natural gas prices compared to last year.

The high and low forecasts were developed by using the mid forecast and scaling it based on the fundamental supply and demand forecasts in the EIA Annual Energy Outlook model. 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.

This method was used beginning in the 2022 IRP to derive a wider range of prices based on changes in fundamental assumptions. For the 2021 IRP, the high and low forecasts were derived statistically from the range of vendor forecasts, with the low forecast capped at the five-year historical average.

Figure 8: IRP Natural Gas Price Forecast Comparison



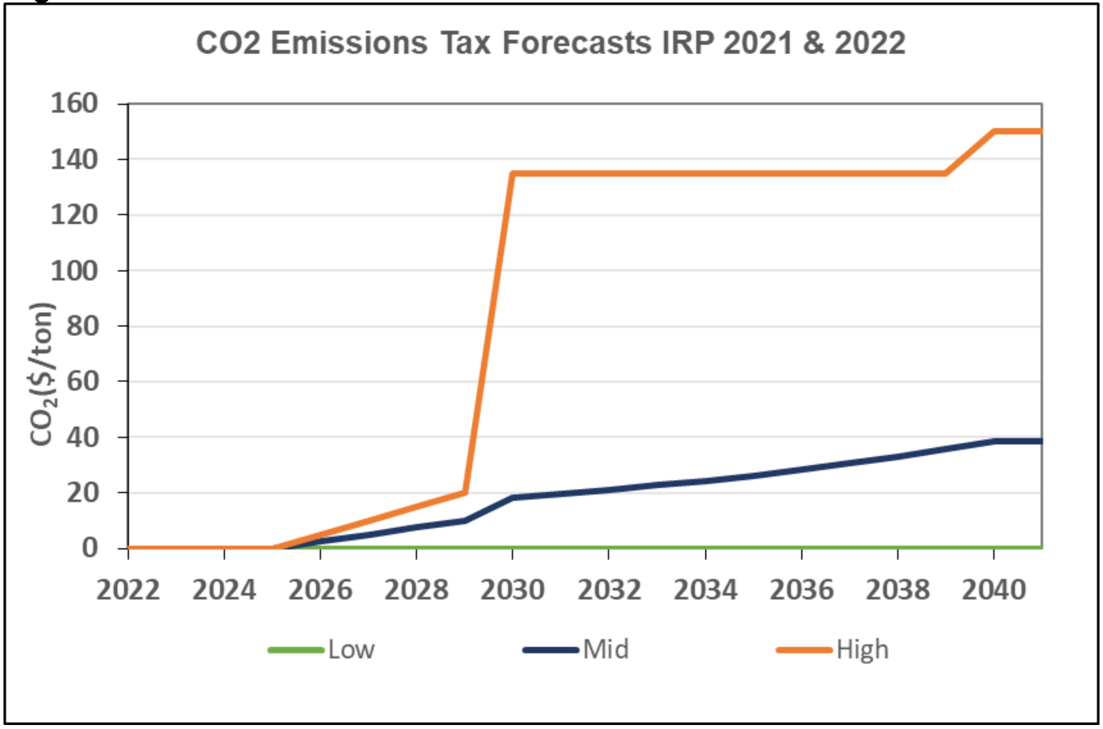
The 2023 IRP natural gas forecasts reflected in the above charts are based on forecasts provided by these third-party sources:

- IHS Markit
- Energy Information Administration
- S&P Global Platts
- Energy Ventures Analysis
- CME Futures
- ICE

3.1.4 CARBON RESTRICTIONS

Since the 2021 Triennial IRP, Evergy has modeled three levels of potential future carbon emissions policies. For the 2021 and 2022 IRPs, the policies were modeled as a carbon emission tax, while for the 2023 IRP they were modeled with both restrictions on carbon emissions production and carbon emissions taxes.

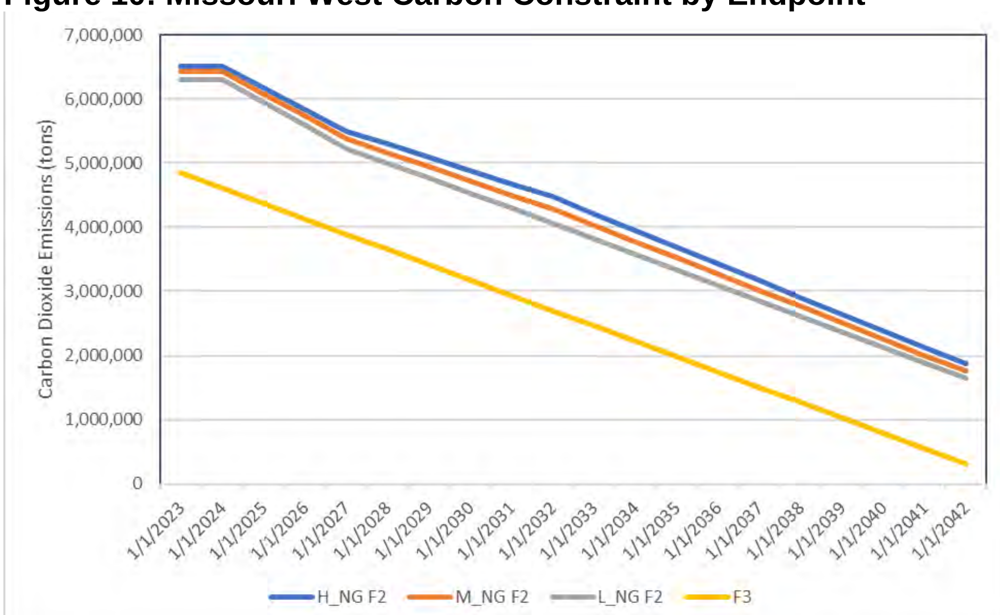
Figure 9: Carbon Tax Forecasts IRP 2021 and 2022



For the 2023 IRP, Evergy modeled carbon restrictions using assumptions built into the SPP futures models, aligning emissions reduction scenarios with market forecast expectations. Evergy discontinued using vendor carbon tax forecasts. Vendor forecasts were no longer available or were outdated considering the current administration and recent policy actions. In addition, Evergy currently expects future carbon policies to be in the form of incentives (such as those in the IRA), or requirements for physical emissions reductions, rather than carbon taxes.

The low forecast for the 2023 IRP has no emissions restrictions with market prices developed using the Future 2 pricing model. The mid forecast uses the same market price forecast but 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 Missouri West'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 in 2042 with a 95% reduction. The high forecast also incorporates a carbon tax which ramps to $25/ton by the end of the twenty-year horizon, consistent with Future 3.

Figure 10: Missouri West Carbon Constraint by Endpoint[1]



[1] H_NG F2: High Natural Gas, Mid Carbon restriction; M_NG F2: Mid Nat Gas, Mid Carbon; L_NG F2: Low Nat Gas, Mid Carbon; F3: High Carbon Restriction (applies in all gas price scenarios)

Table 9: Future 3 Carbon Tax ($/ton)

	Price
2023	**0**
2024	0
2025	0
2026	0
2027	0
2028	0
2029	0
2030	0
2031	0
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	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, refining 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. Because achieving Future 3 would be unlikely based on current technology, new combined cycles and combustion turbines were assumed to have zero emissions beginning in 2036 for Future 3 models, representing the necessary technological breakthroughs. 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.

3.1.5 CONGESTION AND NODAL PRICES

Since the 2022 IRP Annual Update, Evergy has incorporated transmission congestion in its modeling by using market prices at different nodes/zones within the SPP system. The 2021 Triennial IRP used a single market clearing price for all load and resources but included some dispatch adjustments to align resource capacity factors with historical averages.

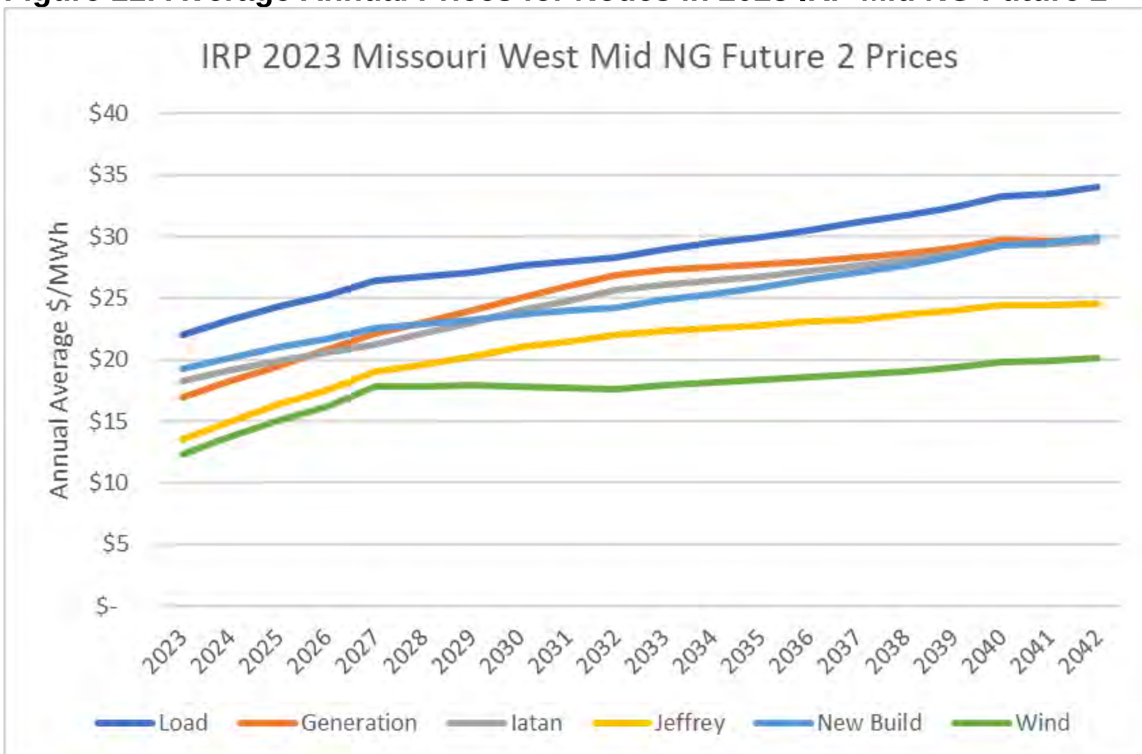
The 2023 IRP pricing models, based on the SPP ITP models, reflect current transmission topology and near-term transmission upgrades. The models use economic dispatch, considering transmission limits, to calculate nodal pricing. The 2022 and 2023 IRP both used pricing at the following locations:

- 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 new solar, batteries, hybrids

Because these models are used to identify future transmission needs, congestion tends to increase in future model years as new resources are assumed without corresponding transmission upgrades that might improve their economic deliverability to load. The base models are likely to overestimate future congestion, however future transmission upgrades are uncertain. The long-term transmission planning processes attempt to identify and select beneficial transmission projects that can reduce the total costs to serve load. Development of new resources may exacerbate congestion, but it can take time for potential savings to reach a tipping point where transmission becomes cost effective. Lags in planning and uncertainty around the timing and viability of new resource additions can also delay new transmission investment. Given the significant build-out of renewable resources between 2032 and 2042, which is not accompanied by enabling transmission investment and thus results in a significant increase in congestion in the “base” SPP model, Evergy assumes congestion is held constant over this second decade of the planning horizon.

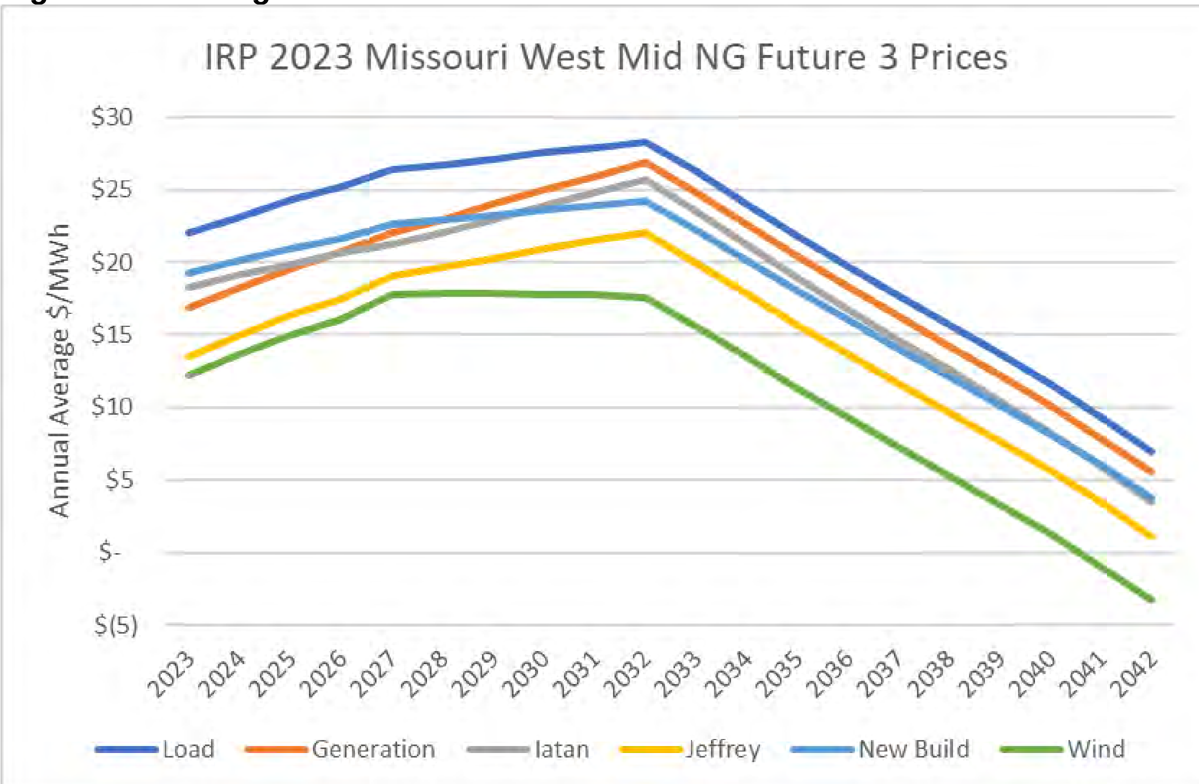
The new SPP ITP models, used for the 2023 IRP pricing, reflect increased congestion, particularly in the western part of Evergy’s footprint.

Figure 11: Average Annual Prices for Nodes in 2023 IRP Mid NG Future 2



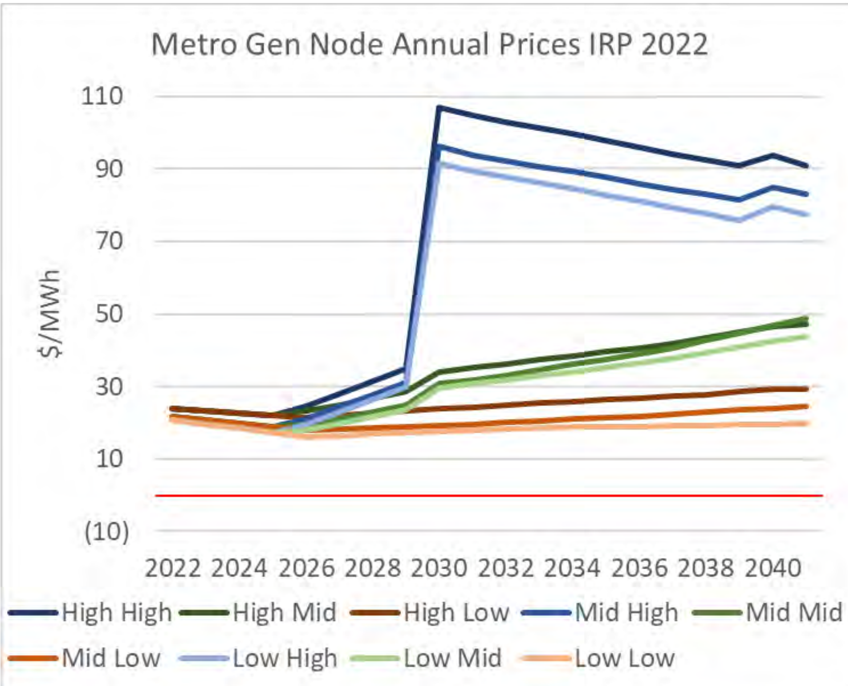
Future 3, used for the high carbon restriction scenarios in IRP 2023 predicts a decreasing price future, as resource additions continue to have fixed costs, but no production costs. Market prices are driven down by a high penetration of zero cost renewable resources, that may also have production tax credits, making their marginal production cost negative.

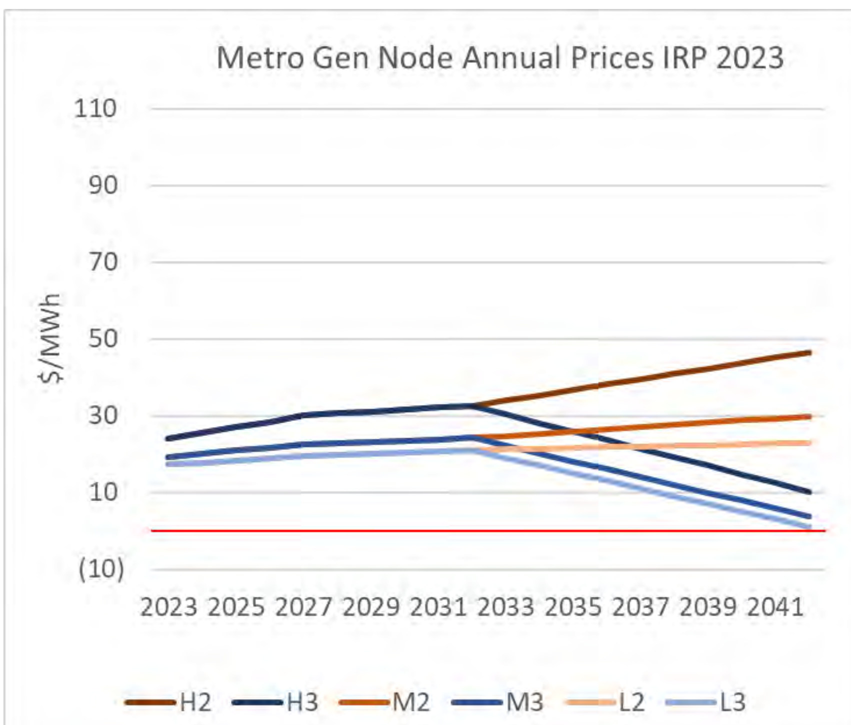
Figure 12: Average Annual Prices for Nodes in 2023 IRP Mid NG Future 3



Prices are also generally lower than prices in the 2021 and 2022 IRPs due to higher expected renewable penetration in the future resource mix. Prices in the 2021 and 2022 IRPs also reflected explicit carbon emissions taxes for the mid and high carbon scenarios which resulted in higher production costs and higher market prices. The change in planning assumption to a carbon restriction results in lower prices as the tax no longer impacts production costs.

Figure 13: 2022 IRP and 2023 IRP Market Price Comparison
Note: Evergy Metro Generation Node is used in the graphs below for comparison purposes as a relatively "average" pricing node

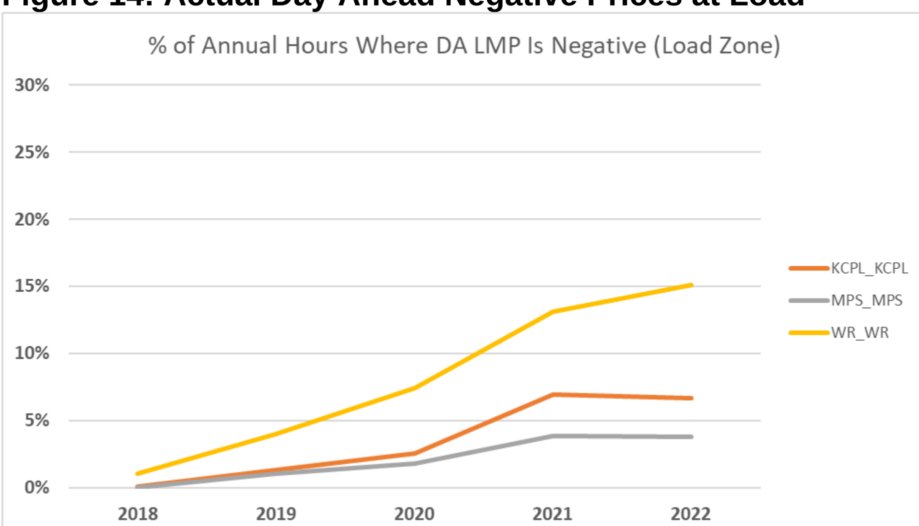




3.1.6 NEGATIVE PRICES

The 2023 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. When Evergy began using SPP ITP models for its pricing forecast in the 2022 IRP, it also introduced negative pricing into the IRP analysis. The previous software, used for the 2021 Triennial IRP and prior IRPs did not calculate negative prices. The 2022 IRP price forecasts had a small percentage of negative prices, which was consistent with the modeling assumptions in the most current version of the SPP ITP model available, which had slightly dated assumptions given the pace of change in SPP resource additions. The 2023 market price forecasts have the most up-to-date planning assumptions and align more closely with recent SPP experience.

Figure 14: Actual Day Ahead Negative Prices at Load



KCPL_KCPL: Metro
MPS_MPS: Missouri West
WR_WR: Kansas Central

Figure 15: 2023 IRP Modeled Negative Prices at Load

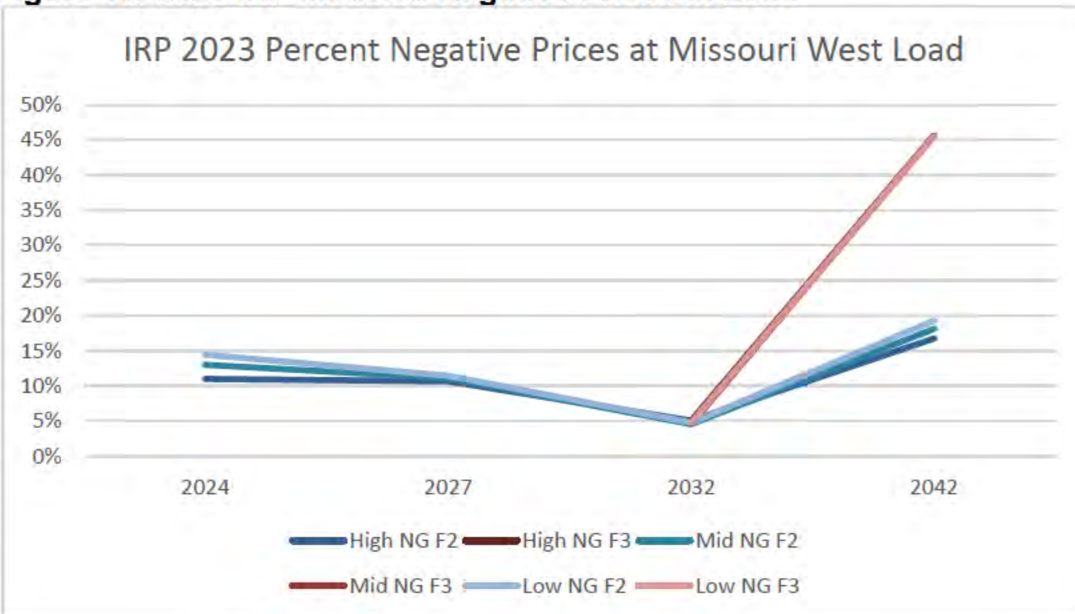


Figure 16: Actual Day Ahead Negative Prices at Generator Nodes

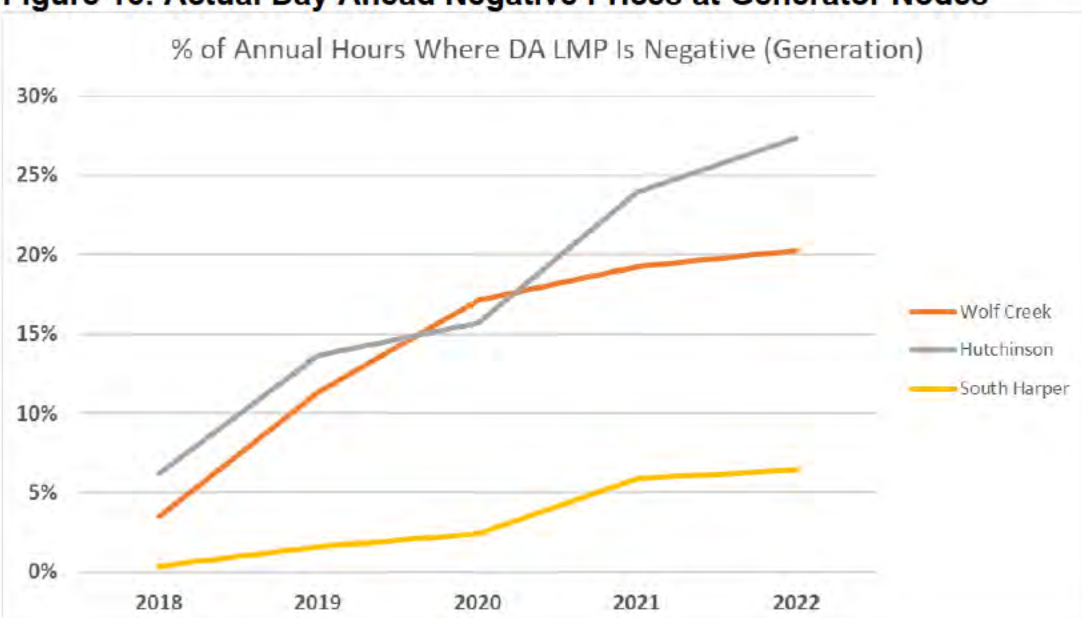


Figure 17: 2023 IRP Modeled Negative Prices at Generator Nodes

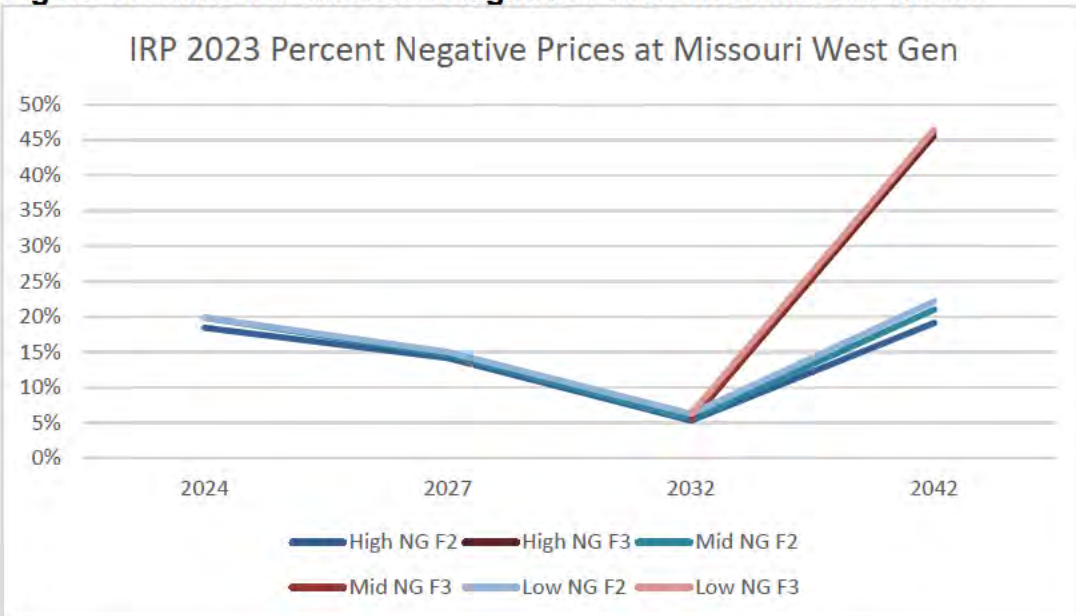


Figure 18: Actual Day Ahead Negative Prices at Wind Nodes

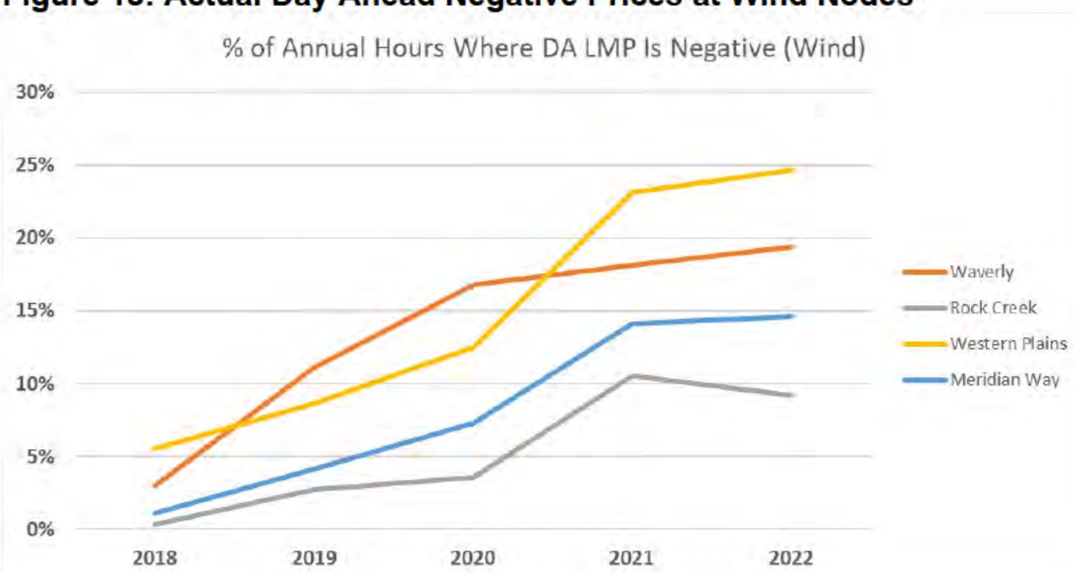
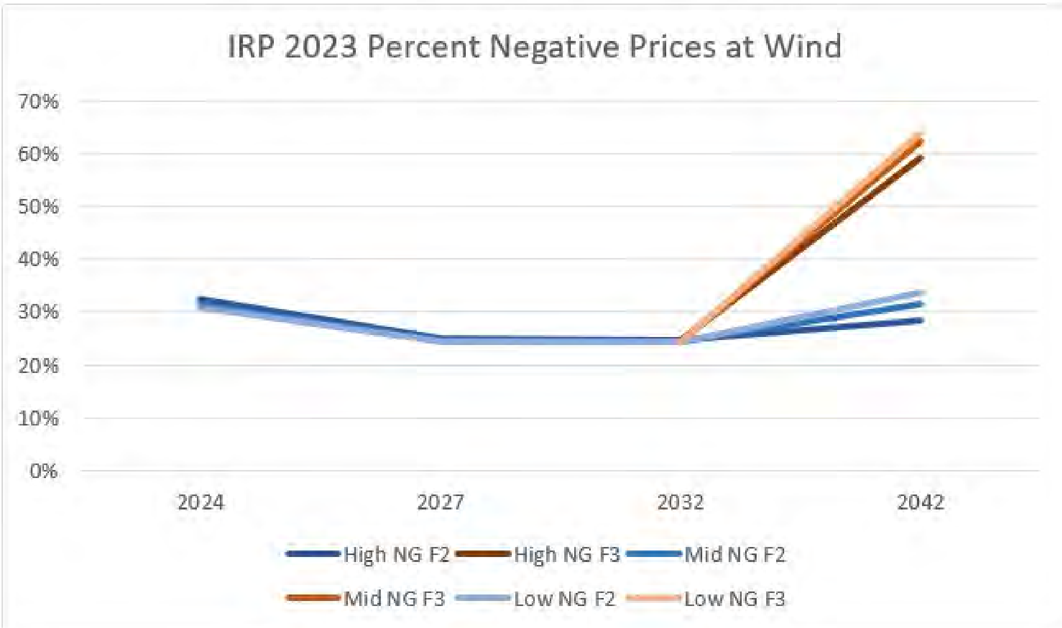


Figure 19: 2023 IRP Modeled Negative Prices at Wind Nodes



3.2 SUPPLY-SIDE TECHNOLOGY CHANGES FROM THE 2021 TRIENNIAL IRP

For the 2023 Annual Update, Evergy considered more options for resource additions, based on stakeholder feedback and solicitation of offers for resources.

2023 Request for Proposal (RFP)

In January 2023, Evergy issued a request for proposals for new resources. In March 2023, Evergy received offers for wind, solar, solar-hybrid, and battery storage resources from various suppliers, with different contract structures, locations, and technologies offered. Evergy used the information from the RFP to estimate the near-term availability of resources, expected costs, and operating characteristics. Evergy received offers for both Build-Transfer (i.e., owned resources) and Power Purchase Agreements (PPA) through this RFP, however, all resources evaluated in this IRP are assumed to be owned, consistent with the approach used in past IRPs. This consistency of assumptions enables better comparison of "generic" resource options and leaves the evaluation of different ownership structures (e.g., PPA) to more detailed analysis during the resource procurement process.

Natural Gas Resources

Evergy is currently conducting a study to determine optimal locations to build new natural gas resources in the future. While the study is not complete in time for this IRP filing, resource specifications and costs were updated in the IRP modeling analysis. Evergy has determined that due to interconnection queue times and siting needs, the earliest operational year for a new natural gas resource is 2028. Simple and combined cycle technology is rapidly evolving towards hydrogen blending capable, emissions-controlled combustors. Evergy anticipates that whatever technology is ultimately selected will be hydrogen combustion capable at a 30% blend or higher.

Other Resources

Evergy considered the purchase of ownership shares of Dogwood Energy Center for Missouri West based on the results of a late 2022 capacity Request for Proposal. If purchased, this resource would be available to Missouri West in 2024.

Evergy also considered the addition of Persimmon Creek Wind and the currently-merchant 8% share of Jeffrey Energy Center for Kansas Central.

Discussion of Resource Options and Economics

Key changes in market conditions in the past few years have driven changes to expected availability and installed costs of new resources. Last year, Evergy noted high inflation and supply chain pressures increasing the cost of materials and limiting their availability. Uncertainty around US government trade policies and tariffs also contributed to solar panel scarcity.

The Inflation Reduction Act, which was passed after the 2022 IRP filing, extended and created new incentives for zero-carbon-emitting resources. Currently US agencies are formalizing regulations which will clarify how resources will qualify and account for these incentives. Despite some uncertainties about the final rules, The Inflation Reduction Act may be spurring demand for qualifying projects, as intended by lawmakers.

The SPP interconnection queue continues to be highly backlogged, slowing the ability of new projects to assess their economic viability considering transmission upgrade costs, and increasing their lag time to achieve commercial operation.

While the addition of new resources is likely to be slowed, the need for new resources is forecasted to increase. As part of its electric reliability planning, SPP ensures that it has the resources to meet demand at all times. SPP requires Evergy and all load-serving entities to own or contract for enough capacity to meet this objective. SPP uses updated weather and system operational data as well as lessons learned from events such as Winter Storm Uri to perform reliability studies. Recently, SPP raised the summer reserve margin from 12% to 15% of peak load beginning in summer 2023. This means that load-serving entities must maintain more capacity as a percent of load. SPP Stakeholders continue to work through future rule changes affecting capacity needs, including winter reserve margin requirements, which are currently voluntary. SPP is also considering changes to how much credit it gives to each resource to meet capacity needs, termed capacity accreditation. This summer, SPP planned to implement Effective Load Carrying Capability (ELCC), which aligns capacity accreditation with resource contribution at peak times for resources that are limited by weather (Wind, Solar) or duration (Batteries), effectively decreasing the credit these resources receive, however it was postponed by a FERC decision. Evergy expects ELCC, or a similar capacity accreditation method to be implemented in the future, as well as a new method that will decrease capacity accreditation for other non-fuel-limited resources based on operational performance, specifically forced outage history (performance-based accreditation).

Refreshed capital cost assumptions for new resources are shown in Table 17 below. Capital cost assumptions for the same resources are shown for the 2021 Triennial IRP and the 2022 Annual Update for comparison. "First Year" represents the first year in which the resource option was assumed to be available based on RFP results and/or expected construction timeline. "Capacity" shown in the table below represents the assumed size of one "project" of that resource type, which was an input into capacity expansion modeling (described further in 6.2)

Table 10: Supply-Side Technology Options ** Confidential **

[redacted]

Installed capital costs for zero-emitting technologies rose substantially and longer lead times to commercial operation were observed based on the 2023 RFP offers.

The capital cost increases may be mitigated by the increased incentive values provided by the Inflation Reduction Act. Evergy incorporated expected Inflation Reduction Act incentives in the modeling of new resource economics, including a 10-year production tax credit (PTC) for wind and solar, which are valued as reducing revenue requirements by 100% of the pre-tax value for every MWh of output. Wind and Solar resources were assumed to be dispatchable, offering into the market at the negative value of the credit to enable production and receipt of the credits, if economic. Batteries were expected to receive an investment tax credit (ITC) of 30% of installed cost upon commercial operation. The Inflation Reduction Act phases out incentives as US targets are achieved. Both PTC and ITC credit eligibility for new resources was assumed to reduce to 75% in 2034, 50% in 2035, and end in 2036.

Table 11: Inflation Reduction Act Incentives Modeled for New Resources

Resource	Incentive Modeled	Max Capacity Factor	Max Incentive (2023 $/kW)
Wind	PTC, 10 Years	48%	1,421
Solar	PTC, 10 Years	26%	756
Battery	ITC Upfront	17%	489
Solar-Hybrid	PTC, 10 Years Solar; ITC Upfront Battery	42%	639

Note: Currently operating resources were modeled based on years of remaining PTC eligibility. ITC incentive based on installed cost.

Installed cost estimates decreased for Combustion Turbine and Combined Cycle technologies. These cost decreases may be due to better information as opposed to actual technological improvements. Past costs were based on publicly available information, and likely did not reflect regional differences. Costs this year reflect engineering firm estimates particular to Evergy.

Last year, Evergy planned to wait on Combined Cycle and Combustion Turbine additions until technological improvements made non-emitting, dispatchable resources attainable as an alternative – assumed to be after 2035. Evergy did not model additions of these resources before 2036, reasoning that existing non-emitting resources could economically replace retiring coal and meet load growth until that time. This year, based on Evergy's forecasted need for more capacity earlier due to SPP requirements as well as potential load growth, Evergy will consider building hydrogen-capable natural gas-fired resources sooner. Evergy assumes that these resources will procure firm natural gas transportation to ensure energy production is available when needed and capacity will be accredited by SPP and includes these costs in modeling. These resources, while not zero-emitting, still offer considerable carbon emissions reductions compared to coal resources. For Evergy's Future 3 modeling (High carbon restriction scenario), new natural gas (CT or CC) is assumed to become carbon-free in years beyond 2035, consistent with the expected technological innovation that would need to occur to achieve minimal emissions system-wide.

Costs modeled for all new resources in future years reflect the expectation of continued technology improvements over time, based on publicly available capital cost forecasts from the Energy Information Administration (EIA) and the National Renewable Energy Laboratory (NREL). The cost curves available in these forecasts were averaged and applied to the near-term capital costs.

3.3 CAPITAL PLAN UPDATE FROM THE 2021 TRIENNIAL IRP

Evergy continues to utilize a combination of condition-based planning, operating estimates, and industry expertise when formulating a 20-year capital plan for each unit in the generation fleet. Near term budgeting is based on equipment condition based on advanced pattern recognition (APR) models along with routine predictive maintenance and visual inspections. Long term budgeting is dictated by historical condition of the units along with industry and original equipment manufacturer (OEM) guidance. When possible, individual unit outages are spread out to avoid the risk of a generation capacity deficiency and some maintenance cycles may be altered by up to a year.

3.4 ENVIRONMENTAL REGULATION CHANGES FROM THE 2021 TRIENNIAL IRP

Material changes from 2022 are shown in italics.

3.4.1 AIR EMISSION IMPACTS

3.4.1.1 National Ambient Air Quality Standards

The Clean Air Act (CAA) requires the Environmental Protection Agency (EPA) to set National Ambient Air Quality Standards (NAAQS) for six air pollutants which are considered harmful to public health and the environment. These pollutants include particulate matter (PM), ozone, sulfur dioxides (SO_2), nitrogen dioxide (NO_x), carbon monoxide (CO) and Lead (Pb). Following is a brief description and current state of each NAAQS.

3.4.1.2 Particulate Matter

In 2012, the EPA strengthened the PM standard and maintained the same requirements in a 2020 final action. The Kansas City area is currently in attainment of the PM NAAQS. No additional emission control equipment is currently needed to comply with this standard. It is not known whether the Kansas City area will remain in attainment of a future revision of the standard. *In January 2023, the EPA proposed strengthening the primary annual PM2.5 (particulate matter less than 2.5 microns in diameter) NAAQS. The EPA is proposing to lower the primary annual PM2.5 NAAQS from 12.0 µg/m3 (micrograms per cubic meter) to a level that would be between 9.0 and 10.0 µg/m3. The EPA is proposing to retain the other PM NAAQS at their current levels*. Future non-attainment of revised standards could require additional reduction technologies, emission limits, or both on fossil-fueled units.

3.4.1.3 Ozone

In 2015, the EPA strengthened the NAAQS for ozone and maintained the same requirement in a 2020 final action. The Kansas City area is currently in attainment of the ozone NAAQS. No additional emission control equipment is currently needed to comply with this standard. *In March 2023, the EPA released a revised draft Policy Assessment for Reconsideration of the Ozone NAAQS recommending the EPA retain the current 2015 Ozone NAAQS. EPA anticipates issuing a proposed decision in the reconsideration of the ozone NAAQS in 2024.* Future non-attainment of revised standards could result in regulations requiring additional nitrogen oxides (NOx) reduction technologies, emission limits or both on fossil-fueled units. NOx is considered a precursor pollutant for ozone formation.

3.4.1.4 Sulfur Dioxide

In 2010, the EPA strengthened the NAAQS for SO_2 and maintained the same requirement in a 2019 final action. The Kansas City area is currently in attainment of the SO_2 NAAQS. No additional emission control equipment is currently needed to comply with this standard. Future non-attainment of revised standards could result in regulations requiring additional SO_2 reduction technologies, emission limits or both on fossil-fueled units.

3.4.1.5 Carbon Monoxide

In 2011, the EPA maintained the existing 1971 NAAQS for CO. The Kansas City area is currently in attainment of the CO NAAQS. No additional emission control equipment is currently needed to comply with this standard. Future non-attainment of revised standards could result in regulations requiring additional CO reduction technologies, emission limits or both on fossil-fueled units.

3.4.1.6 Lead

In 2016, the EPA maintained the existing 2008 NAAQS for Lead (Pb). The Kansas City area is currently in attainment of the Pb NAAQS. No additional emission control equipment is currently needed to comply with this standard. Future non-attainment of revised standards could result in regulations requiring additional Pb reduction technologies, emission limits or both on fossil-fueled units.

3.4.1.7 <u>Cross-State Air Pollution Rule</u>

In 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR), requiring eastern and central states to significantly reduce power plant emissions that cross state lines and contribute to ozone and fine particle pollution in downwind states. The CSAPR Update Rule took effect in 2017 with more stringent ozone-season NO_x emission budgets for electric generating units (EGUs) in many states to address significant contribution to modeling nonattainment and maintenance areas in downwind states with respect to the 2008 ozone NAAQS. In 2021 EPA published the final Revised CSAPR Update rule which found that nine states including Kansas, Missouri, and Oklahoma have insignificant impact on downwind states' nonattainment and/or maintenance areas. As a result, no additional reductions in these states' allowances were required.

When EPA lowered the Ozone NAAQS in 2015, impacted states were required to submit Interstate Transport State Implementation Plans (ITSIPs) to address the "Good Neighbor" obligations in the Clean Air Act. These ITSIPs were due to EPA in 2018. The EPA did not act on these submissions and was challenged in a court filing in May 2021 to address them. In February 2022, the EPA published proposed disapprovals of ITSIPs for nineteen states including Missouri while in April 2022, EPA issued final approval of the Kansas ITSIP.

In April 2022, the EPA published in the Federal Register a proposed Federal Implementation Plan (FIP) to resolve the outstanding "Good Neighbor" obligations with respect to the 2015 Ozone NAAQS for 26 states including Missouri and Oklahoma. This FIP would establish a revised CSAPR ozone season NOx emissions trading program for electric generating units, a new daily backstop NOx limit for applicable coal-fired units larger than 100MW, and unit-specific NOx emission rate limits for certain industrial emissions units. The proposed FIP includes reductions to the state ozone season NOx allowance allocations for Missouri and Oklahoma beginning in 2023 *with additional reductions in future years. In March 2023, the EPA issued the final ITFIPs for twenty-three states, including Missouri and Oklahoma*. The Company currently complies with the existing CSAPR regulations 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.

3.4.1.8 <u>Regional Haze</u>

In June 2005, the EPA finalized amendments to the July 1999 Regional Haze Rule. These amendments apply to the provisions of the Regional Haze Rule that require emission controls for industrial facilities emitting air pollutants that reduce visibility by causing or contributing to regional haze. The pollutants that reduce visibility include $PM_{2.5}$, and compounds which contribute to $PM_{2.5}$ formation, such as NO_x, and SO_2.

Under the 1999 Regional Haze Rule, states are required to set periodic goals for improving visibility in natural areas. As states work to reach these goals, they must periodically develop regional haze implementation plans that contain enforceable measures and strategies for reducing visibility-impairing pollution. The Regional Haze Rule directs state air quality agencies to identify whether visibility-reducing emissions from affected sources are below limits set by the state or whether retrofit measures are needed to reduce emissions.

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 31, 2021. Evergy worked with the Kansas Department of Health and Environmental (KDHE) and the Missouri Department of Natural Resources (MDNR) as they worked to draft their SIP revisions. *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 of August 15, 2022. As a result, on August 30, 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.* MDNR shared a draft of this SIP revision in March 2022 which does not require any additional reductions from the Evergy generating units in the state. The Kansas SIP revision was placed on public notice in June 2021 and requested no additional emission reductions by electric utilities based on the significant reductions that were achieved during the first implementation period. KDHE submitted the Kansas SIP revision in July 2021. EPA is waiting for additional states to submit their SIP revisions before they review and either approve or disapprove these SIP revisions. *In March 2023, several environmental organizations notified the EPA of their intent to sue for failure of the EPA to timely approve or disapprove of the SIP revisions submitted by Kansas and seven other states.*

Evergy Missouri West's existing emission controls at its Jeffrey and Iatan Generating Stations maintain compliance with these 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.

3.4.1.9 <u>Greenhouse Gases</u>

In May 2023, the EPA proposed CO2 emission limits and guidelines for fossil fuel fired electric generating units. The proposal regulations would impose CO_2 emission limitations for existing coal, oil and natural gas-fired boilers, existing large natural gas fired combined cycle combustion turbines and new natural gas fired simple and combined cycle combustion turbines. EPA established these *proposed emission limitations based on utilizing such technologies as hydrogen co-firing with natural gas, and carbon capture and sequestration (CCS). It is highly likely this proposed regulation will face administrative and legal challenges prior to finalization. However, this regulation* could require *hydrogen co-firing with natural gas*, *natural gas co-firing with coal, reduced generation, carbon capture and sequestration, alternate generation, or demand reduction technologies.*

3.4.1.10 Mercury and Air Toxics Standards

In April 2023, the EPA released a proposal to tighten certain aspects of the mercury and air toxics standards (*MATS) rule. The EPA is proposing to lower the emission limit for particulate matter (PM), require the use of PM continuous emissions monitors (CEMS) and lower the mercury emission limit for lignite coal-fired electric generating units (EGUs). The EPA is also soliciting comment on further strengthening of the PM emission limitation beyond the proposal*. *When implemented in 2016*, these mercury and air toxics standards (MATS) for power plants reduced emissions from new and existing coal and oil-fired electric generating units (EGUs). Control equipment was installed to comply with this rule. No additional emission control equipment is currently needed to comply with the current *or proposed* standards. *However, further strengthening of the PM emission limitation could require* Evergy Missouri West to *consider additional PM controls* at the Jeffrey Energy Center.

3.4.2 WATER EMISSION IMPACTS

3.4.2.1 Effluent Limitation Guidelines (ELG)

In 2015, EPA established the effluent limitations guidelines (ELG) and standards for wastewater discharges, including limits on the amount of toxic metals and other pollutants that can be discharged. Implementation timelines for this 2015 rule varied from 2018 to 2023. In April 2019, the U.S. Court of Appeals for the 5th Circuit (5th Circuit) issued a ruling that vacated and remanded portions of the original ELG rule.

In October 2020, the EPA published the final ELG Reconsideration Rule. This rule adjusts numeric limits for flue gas desulfurization (FGD) wastewater and adds a 10% volumetric purge limit for bottom ash transport water. The timeline for final FGD wastewater compliance is now as soon as possible on or after one year following publication of the final rule in the federal register but no later than December 31, 2025. *On July 26, 2021, EPA initiated a supplemental rulemaking to strengthen certain discharge limits in the ELG regulation. EPA proposed this supplemental rulemaking on March 29, 2023. In the 2023 proposal EPA removes the 10% volumetric purge allowance on bottom ash wastewater and proposes zero liquid discharge for both FGD wastewater and bottom ash wastewater. In addition, the proposal established new discharge limitations for coal combustion residual (CCR) leachate. Compliance with these new limitations must be as soon as feasible no later than December 31, 2029.* Evergy is currently in compliance with this regulation, and intends any required upgrades to be in place prior to the 2029 deadline.

3.4.2.2 <u>Clean Water Act Section 316(A)</u>

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.

3.4.2.3 <u>Clean Water Act Section 316(B)</u>

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.

3.4.2.4 Zebra Mussel Infestation

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

3.4.2.5 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.

3.4.3 WASTE MATERIAL IMPACTS

3.4.3.1 Coal Combustion Residuals (CCR's)

In April 2015, the EPA finalized regulations to regulate CCRs under the Resource Conservation and Recovery Act (RCRA) subtitle D to address the risks from the disposal of CCRs generated from the combustion of coal at electric generating facilities. The rule requires periodic assessments; groundwater monitoring; location restrictions; design and operating requirements; recordkeeping and notifications; and closure, among other requirements, for CCR units.

In March 2019, the D.C. Circuit issued a ruling to grant the EPA's request to remand the Phase I, Part I CCR rule in response to a prior court ruling requiring the EPA to address un-lined surface impoundment closure requirements. In August 2020, the EPA published the Part A CCR Rule. This rule reclassified clay-lined surface impoundments from "lined" to "un-lined" and established a deadline of April 11, 2021 to initiate closure. In November 2020, the EPA published the final Part B CCR Rule. This rule includes a process to allow unlined impoundments to continue to operate if a demonstration is made to prove that the unlined impoundments are not adversely impacting groundwater, human health, or the environment. Evergy Missouri West is in compliance with the Part A CCR rule which included initiating closure of all unlined impoundments by the deadline of April 11, 2021.

In January 2022, EPA published proposed determinations for facilities that filed closure extensions for unlined or clay lined CCR units. These proposed determinations include various interpretations of the CCR regulations and compliance expectations that may impact all owners of CCR units. These interpretations could require modified compliance plans such as different methods of CCR unit closure. Additionally, it includes more stringent remediation requirements for units that are in corrective action or forced to go into corrective action. Future rule modifications could require additional monitoring or remediation of current or closed impoundments and landfills along with additional requirements related to design and construction of future units to more stringent standards.

In May 2023, EPA released a proposed rulemaking on legacy CCR units. This regulation, if finalized, will expand the number of CCR units subject to regulation under the Federal CCR rule. Future rule modifications could require additional monitoring or remediation of current or closed impoundments and landfills along with additional requirements related to design and construction of future units to more stringent standards.

SECTION 4: TRANSMISSION AND DISTRIBUTION UPDATE

4.1 CHANGES FROM THE 2021 TRIENNIAL IRP

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

4.1.1 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 A 2023 SPP Transmission Expansion Plan Report.pdf and Appendix A1 2023 SPP Transmission Expansion Plan Project List.xls.

4.1.2 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

4.1.2.1 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

4.1.2.1.1 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.

4.1.2.1.2 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.

4.1.2.1.3 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 7,000 CFCIs have been installed in the Evergy service territory.

4.1.2.1.4 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.

4.1.2.1.5 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.

4.1.2.1.6 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.

4.1.3 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.

4.1.3.1 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.

4.1.3.2 New Transmission Technologies

Static Condensers (STATCOMs) and Synchronous Condensers (SynCon) 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.
- 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 5: DEMAND-SIDE RESOURCE ANALYSIS UPDATE

5.1 CHANGES FROM THE 2021 TRIENNIAL IRP

Evergy engaged the Applied Energy Group (AEG) Team to conduct this Demand-Side Management (DSM) Market Potential Study in 2023. It evaluates various categories of electricity DSM resources in the residential, commercial, and industrial sectors of Evergy's service territory in Missouri for the years 2024-2043. The resource categories investigated are: Energy Efficiency, Demand Response, and Demand-Side Rates.

The key objectives of the study are to:

- Perform a comprehensive analysis that complies with the respective statutory requirements of the Missouri Public Service Commission
- Develop annual energy and peak demand potential estimates for the DSM resource categories by customer class for each Evergy jurisdiction for the time period of 2024 to 2043
- Develop baseline projections of annual electricity use and peak demand for each Evergy jurisdiction, accounting for future codes and standards, naturally occurring energy efficiency, opt-out customers, and smart connected devices
- Identify a subset of economic and program potential that is applicable to low-income customers
- Conduct a reliable, accurate and useful residential appliance saturation survey
- Quantify potential program savings from the DSM initiatives at various levels of cost
- Support Evergy's effort to offer programs to all customer market segments while achieving the ultimate goal of all cost-effective demand-side savings

The study assesses various tiers of potential including technical, economic, maximum achievable, and realistic achievable potential. Based on the RAP and MAP potential scenario results from the DSM Potential Study, AEG developed four scenarios for energy efficiency portfolio comprised of cost-effective measures. AEG also developed six scenarios for Demand Response and Demand-Side Rates portfolio to reflect the Commission's new TOU rate case order for the Missouri residents. The MAP scenarios developed in the potential study include three levels of retention rate for the TOU rates.

The RAP scenario only utilizes the low retention rate level. MAP low retention was used in the Integrated Analysis in Section 6. These portfolios were considered during the integration phase of Evergy's IRP process to determine which DSM portfolio was optimal based on Evergy's supply options.

As part of the study, AEG also conducted an appliance saturation analysis to collect a variety of appliance and end-use data from Residential Customers accounts. Residential Appliance Saturation Study (RASS) portion of the study and results can be found in Exhibit A of Evergy 2023 DSM Market Potential Study.

Table 12 and Table 13 shows the descriptions for all scenarios. The entire Evergy 2023 DSM Market Potential Study conducted by AEG can be found in Appendix C and confidential avoided costs can be found in Appendix C1.

Table 12: Scenarios Descriptions - Energy Efficiency Portfolio

Scenario	Participation Assumptions	Incentive Assumptions	Non-incentives
RAP	Participation directly pulled from incremental purchases in the Realistic Achievable Potential scenario in the Potential Study.	Incentive developed based on incremental costs from the Potential Study. Incentives assumed to be 50% of incremental costs (except Low Income which is 100%).	Non-incentives developed based on the incentive levels and benchmarked factors of Evergy 2021 actual spending and/or similar programs from other utilities.
MAP	Participation directly pulled from incremental purchases in the Maximum Achievable Potential scenario in the Potential Study.	Incentive developed based on incremental costs from the Potential Study. Incentives assumed to be 100% of incremental costs.	
RAP -	Participation represents 75% of the RAP levels.	Incentive developed based on incremental costs from the Potential Study. Incentives assumed to be 50% of incremental costs (except Low Income which is 100%).	
RAP +	Participation represents the median levels between the RAP and MAP participation.	Incentive developed based on incremental costs from the Potential Study. Incentives assumed to be 50% of incremental costs	

Table 13: Scenarios Descriptions - Demand Response and Demand-Side Rates Portfolio – MAP

Baseline (Base load)	Scenario	Assumptions	TOU Impact	DR/DSR Impact
All DR/DSR MAP Scenarios incorporate the EE MAP annual peak savings as a negative adjustment to Basliene MW. Because the EE savings in MAP are larger than RAP the MAP scenario reduces baseline MW more, leaving less potential for DR/DSR.	**MAP High-Retention**	Industry best practice participation and impacts across new DR programs, incremental growth in existing programs, highest possible retention on the default TOU (Standard) rate.	Highest TOU impact and reduction in total MW across MAP scenarios. This reduces potential for other DR/DSR programs.	Lowest DR/DSR impacts across all MAP scenarios because TOU and EE have the highest impacts on potential and lead to the lowest peak demand available for remaining programs to impact.
	MAP Medium Retention	Industry best practice participation and impacts across new DR programs, incremental growth in existing programs, medium level of retention on the default TOU (Standard) rate.	Medium TOU impact and reduction in total MW. This reduces potential for other DR/DSR programs (but by less than the High retention scenarios).	Higher DR/DSR impacts than the MAP High-Retention Scenario because TOU impacts on potential are lower and lead to more peak demand available for remaining programs to impact. EE impacts on potential remain the same across all MAP scenarios.
	MAP Low Retention	Industry best practice participation and impacts across new DR programs, incremental growth in existing programs, low of retention on the default TOU (Standard) rate.	Lowest TOU impact and reduction in total MW across MAP scenarios. This reduces potential for other DR/DSR programs (but by less than the Medium or High retention scenarios).	Highest DR/DSR impacts than the MAP Medium- and High-Retention scenarios because TOU impacts on potential are lowest and lead to the most peak demand available for remaining programs to impact. EE impacts on potential remain the same across all MAP scenarios.

Table 14: Scenarios Descriptions - Demand Response and Demand-Side Rates Portfolio – RAP

Baseline (Base load)	Scenario	Assumptions	TOU Impact	DR/DSR Impact
The DR/DSR RAP scenario similarly incorporates the EE RAP annual peak savings. RAP impacts from EE are lower than MAP impacts form EE and restrict potential less.	**RAP Low Retention**	Industry best practice participation and impacts across new DR programs, limited growth in existing programs, low of retention on the default TOU (Standard) rate, and assumption of a four-year learning curve to respond to the rate.	Same TOU retention as the MAP Low Retention scenario, but lower TOU impact in the early years due to a TOU-response learning curve, and slightly higher impacts in the out years because the RAP baseline is higher than the MAP baseline.	Similar DR/DSR impacts as the MAP Low-Retention Scenario because TOU impacts on potential are lowest and lead to the most peak demand available for remaining programs to impact. EE impacts on potential are smaller in RAP scenarios than MAP scenario. Slightly lower DR/DSR impacts than MAP because of limited growth in existing programs.
	RAP Plus	Industry best practice impacts and 10% increase in participation from RAP across all DR/DSR programs, low of retention on the default TOU (Standard) rate, and assumption of a four-year learning curve to respond to the rate.	Same TOU retention and TOU impacts as the RAP Low Retention Scenario.	Higher DR/DSR impacts across all RAP and MAP scenarios because participation increased by 10% (excluding TOU) and TOU and EE have the lowest impact on potential, lead to the most peak demand available for remaining programs to impact.
	RAP Minus	Industry best practice impacts and 15% decrease in participation from RAP across all DR/DSR programs, a 15% decrease in the low of retention rate on the default TOU (Standard) rate, and assumption of a four-year learning curve to respond to the rate.	Lowest TOU impacts across all scenarios because of a 15% decrease in the default TOU retention rate. TOU impacts are lowest in the early years due to a TOU-response learning curve.	Lowest DR/DSR impacts across all RAP and MAP scenarios because participation decreased by 15% (including TOU retention on the deafult rate).

5.2 2023 DSM MARKET POTENTIAL STUDY RESULTS SUMMARY

Annualized energy and demand savings for the 20-year planning horizon are presented in the tables below as well as the associated program costs. More results can be found in and Appendix C Evergy 2023 DSM Market Potential Study and workpapers.

Table 21 presents the 20-year incremental annualized energy savings due to the potential demand-side programs in four scenarios.

Table 15: Evergy Missouri West Incremental Energy Savings (MWH)

Year	RAP	RAP-	RAP+	MAP
2024	30,262	22,696	40,598	50,901
2025	32,693	24,519	43,548	54,368
2026	32,996	24,747	43,496	53,945
2027	33,578	25,184	43,783	53,919
2028	34,678	26,009	44,799	54,835
2029	34,403	25,802	44,003	53,504
2030	36,743	27,557	46,579	56,297
2031	37,218	27,913	46,790	56,229
2032	37,672	28,254	46,924	56,028
2033	38,095	28,571	47,022	55,789
2034	37,505	28,128	45,990	54,302
2035	38,226	28,670	46,508	54,607
2036	39,867	29,900	48,162	56,263
2037	39,270	29,452	47,029	54,586
2038	38,818	29,114	46,150	53,270
2039	35,674	26,756	40,995	46,096
2040	34,798	26,099	39,596	44,169
2041	33,002	24,751	37,138	41,045
2042	33,274	23,531	34,964	38,325
2043	33,670	23,654	34,599	37,103

Table 22 presents the 20-year incremental annualized demand savings due to the potential demand-side programs. Note that there are three MAP scenarios developed for the Demand Response and Demand-Side Rates portfolio. However only the demand savings are differentiated for the three MAP scenarios since there are no energy savings quantified for the Demand Response and Demand-Side Rate portfolios.

Table 16: Evergy Missouri West Incremental Demand Savings (MW)

Year	RAP	RAP-	RAP+	MAP(Low)	MAP(Med)	MAP(High)
2024	137	116	151	176	190	200
2025	42	36	48	37	35	34
2026	35	29	40	33	33	33
2027	21	17	24	18	18	18
2028	12	9	15	17	17	17
2029	11	8	14	16	16	16
2030	11	9	15	17	17	17
2031	12	9	14	17	17	17
2032	11	8	13	16	16	16
2033	13	10	16	18	18	18
2034	11	8	13	15	15	15
2035	11	8	13	15	15	15
2036	11	8	13	15	15	15
2037	10	7	12	13	14	14
2038	12	9	14	16	16	15
2039	10	7	11	12	12	12
2040	10	7	11	12	12	12
2041	8	6	9	10	10	10
2042	8	6	9	9	9	9
2043	8	6	9	9	9	9

Table 23 presents the 20-year cumulative annualized energy savings due to the potential demand-side programs.

Table 17: Evergy Missouri West Cumulative Energy Savings (MWH)

Year	RAP	RAP-	RAP+	MAP
2024	30,262	22,696	40,598	50,901
2025	62,954	47,216	84,145	105,269
2026	95,950	71,962	127,641	159,213
2027	127,748	95,811	169,231	210,533
2028	160,219	120,164	211,333	262,183
2029	192,083	144,062	252,236	312,026
2030	226,352	169,764	295,820	364,808
2031	260,904	195,678	339,390	417,262
2032	295,955	221,966	383,140	469,566
2033	331,058	248,294	426,536	521,095
2034	360,672	270,504	462,418	563,079
2035	389,164	291,873	496,453	602,479
2036	419,802	314,852	533,005	644,759
2037	449,377	337,032	568,027	685,040
2038	478,537	358,903	602,349	724,329
2039	496,739	372,554	620,961	743,168
2040	512,885	384,664	636,848	758,617
2041	525,104	393,828	647,676	767,886
2042	535,698	400,349	654,179	772,044
2043	545,816	406,339	659,495	774,218

Table 24 presents the 20-year cumulative annualized demand savings due to the potential demand-side programs.

Table 18: Evergy Missouri West Cumulative Demand Savings (MW)

Year	RAP	RAP-	RAP+	MAP(Low)	MAP(Med)	MAP(High)
2024	137	116	151	176	190	200
2025	179	152	199	214	225	233
2026	214	181	239	247	258	267
2027	235	198	263	265	276	284
2028	247	207	277	282	293	302
2029	257	215	291	298	310	318
2030	269	224	306	316	327	335
2031	280	233	320	333	344	352
2032	291	241	333	348	360	368
2033	304	251	349	367	378	386
2034	315	259	362	382	393	401
2035	326	267	376	397	408	416
2036	336	275	389	412	423	432
2037	346	282	401	426	437	446
2038	358	291	415	442	453	461
2039	368	299	426	454	465	473
2040	377	306	436	466	477	485
2041	385	312	445	475	486	494
2042	393	318	454	485	495	504
2043	402	324	463	493	504	512

Table 25 presents the total portfolio budget by year for the 20-year planning horizon for each of the program design scenarios.

Table 19: Evergy Missouri West Program Costs (Nominal Dollars, 000$)

Year	RAP	RAP-	RAP+	MAP
2024	$ 19,296	$ 15,541	$ 24,271	$ 51,354
2025	$ 17,323	$ 13,414	$ 22,373	$ 52,127
2026	$ 18,101	$ 14,011	$ 23,228	$ 53,403
2027	$ 18,553	$ 14,300	$ 23,750	$ 55,248
2028	$ 19,365	$ 14,908	$ 24,610	$ 57,198
2029	$ 19,886	$ 15,298	$ 25,099	$ 58,121
2030	$ 20,741	$ 15,941	$ 25,990	$ 59,943
2031	$ 21,060	$ 16,181	$ 26,201	$ 60,140
2032	$ 21,385	$ 16,424	$ 26,403	$ 60,242
2033	$ 21,795	$ 16,733	$ 26,708	$ 60,716
2034	$ 21,908	$ 16,808	$ 26,664	$ 60,369
2035	$ 22,122	$ 16,970	$ 26,719	$ 60,144
2036	$ 22,116	$ 16,965	$ 26,511	$ 59,307
2037	$ 22,123	$ 16,971	$ 26,339	$ 58,532
2038	$ 22,165	$ 17,003	$ 26,219	$ 58,016
2039	$ 21,074	$ 16,185	$ 24,186	$ 51,952
2040	$ 20,853	$ 16,020	$ 23,727	$ 50,543
2041	$ 20,388	$ 15,670	$ 23,027	$ 48,768
2042	$ 18,958	$ 14,599	$ 21,151	$ 44,157
2043	$ 19,550	$ 15,043	$ 21,506	$ 44,499

5.3 UPDATED AVOIDED DEMAND AND ENERGY COSTS

5.3.1 AVOIDED DEMAND COST

The technology costs were updated through discussion with engineering firms and outside parties in order to ensure the values represent current market conditions. Following is a brief discussion of these three components that make up the avoided cost:

1. **Capital cost** includes two components – the cost of the power plant construction and the cost of the transmission interconnection. A levelized fixed charge rate is applied to these capital costs to arrive at an annual cost for the plant and the related transmission interconnection. This levelized fixed charge rate accounts for the weighted cost of capital, capturing the cost of debt, equity, and preferred equity, as well as the impact of deferred taxes, depreciable lives, income taxes, and property taxes.
2. The **Fixed Operations and Maintenance (FOM) cost** assumptions are provided by an outside vendor and, as such, are considered proprietary information available only to those under license. The FOM cost includes items such as operating labor for plant personnel, maintenance costs for different sections of the plant, and overhead charges for administrative and support labor. An annual FOM cost is calculated and then divided by the size of the power plant to arrive at an annual FOM cost/kW-Yr.
3. The **cost of firm gas transportation** represents the cost of pipeline upgrades to ensure that natural gas supplies are available when needed at the power plant. These capital cost estimates are highly confidential cost projections provided by gas pipeline companies and can vary due to the proximity of existing feed lines. These estimates are converted to an annual cost/kW-Yr, similar to the FOM costs.

The sum of the levelized annual capital cost, the FOM, and the firm gas transportation cost are combined to arrive at a total avoided cost on a dollar per kilowatt-year basis.

A market-based approach drawn from the Commission approved MEEIA 3 plan is being used for the annual avoided capacity cost. Evergy has developed a probability weighted approach to calculate the avoided capacity cost when the IRP projects that a capacity shortfall will occur. The approach models six scenarios taking into account the possibility of unit retirements as well as multiple levels of load forecast. For each scenario, the market-based approach above is used when the scenario is long capacity, and the avoided cost of a CT is used beginning in the year that the individual scenario becomes short on capacity[2]. The final annual avoided capacity cost is the probability weighted cost of the six scenarios. The technology cost calculation ($/kW-year) can be found in Appendix C1. The calculation of the probability weighted avoided demand cost for the DSM Potential Study can be found in workpaper “Metro and Missouri West Avoided Capacity Cost Framework Nov 2022 (CONFIDENTIAL).xlsx”.

5.3.2 AVOIDED ENERGY COST

The energy price forecast used for the Evergy 2023 DSM Market Potential Study was based on the expected value of all market price scenarios from the 2022 IRP Annual Updates[3]. For the 2022 IRP Annual Update, there were a total of nine different energy price curves used in the evaluation of each Alternative Resource Plan, which represented a high, mid and low gas price coupled with and without a CO2 cost. In the IRP analysis, these nine price curves are combined with high, mid and low load uncertainties to derive the 27 endpoint scenarios used to measure the expected value of revenue requirement for plan rankings. Table 20 shows the twenty-seven endpoint scenarios.

[2] Avoided cost of CT was provided for potential study in late 2022 prior to updated estimate provided by engineering firm for 2023 Annual Update modeling – reflected latest publicly-available information at that time

[3] [3] The avoided energy cost were needed very early in the DSM potential study before updated energy costs for 2023 Annual Update are developed

Table 20: Twenty-Seven Endpoint Scenarios

Endpoint	Load Growth	Natural Gas	CO2	Endpoint Probability
1	High	High	High	0.45%
2	High	High	Mid	1.4%
3	High	High	Low	0.5%
4	High	Mid	High	1.5%
5	High	Mid	Mid	4.5%
6	High	Mid	Low	1.5%
7	High	Low	High	1.1%
8	High	Low	Mid	3.2%
9	High	Low	Low	1.1%
10	Mid	High	High	1.5%
11	Mid	High	Mid	4.5%
12	Mid	High	Low	1.5%
13	Mid	Mid	High	5.0%
14	Mid	Mid	Mid	15.0%
15	Mid	Mid	Low	5.0%
16	Mid	Low	High	3.5%
17	Mid	Low	Mid	10.5%
18	Mid	Low	Low	3.5%
19	Low	High	High	1.1%
20	Low	High	Mid	3.2%
21	Low	High	Low	1.1%
22	Low	Mid	High	3.5%
23	Low	Mid	Mid	10.5%
24	Low	Mid	Low	3.5%
25	Low	Low	High	2.5%
26	Low	Low	Mid	7.4%
27	Low	Low	Low	2.5%

SECTION 6: INTEGRATED RESOURCE PLAN AND RISK ANALYSIS UPDATE

6.1 CHANGES FROM THE 2021 TRIENNIAL IRP

Evergy Missouri West submitted its 2021 Triennial IRP filing on April 30, 2021, updated its resource plan on June 10, 2022, with its 2022 IRP Annual Update filing, and filed a Change in Plan Filing on September 26, 2022. This year's 2023 IRP Annual Update reflects updated information and forecasts based on market and policy changes and additional studies that have occurred in the past year.

Changes from the 2021 Triennial IRP, 2022 Annual Update, and 2022 Change in Plan filing:

- Updated market pricing reflecting latest SPP transmission planning model assumptions of future resource mix and potential transmission congestion
- Updated fuel price forecasts, including high, mid, and low natural gas price scenarios
- Carbon Dioxide emissions limitations scenarios reflecting future environmental risks, including high, mid, and low (no) restrictions
- Updated cost estimates and timing assumptions for resource additions based on First Quarter 2023 Request for Proposal (RFP) results
- Modeling of battery storage and hybrid resources as supply-side options
- Inclusion of incentives for new renewable and storage resources based on Inflation Reduction Act
- Updated load forecasts including large new customers in both Missouri and Kansas, and considerations for future large customer growth based on existing economic development pipeline
- Updated demand response potential study, including four Missouri program options
- Included possible reductions in peak demand from Missouri Commission-ordered mandatory time of use rates

- Updated planning reserve margin consistent with SPP rule changes enacted in 2022
- Increased focus on planning for utility-level (as opposed to Evergy-level) resource needs to better identify each utility's specific energy and capacity needs in the future, reduced level of assumed market availability (for both capacity and energy) and reliance on other Evergy affiliates to meet long-term customer needs
- Removal of Persimmon Creek wind farm due to not executing under the Commission ordered Certificate of Convenience and Necessity with conditions
- Expanded use of PLEXOS software for production cost modeling and capacity expansion, which was first implemented for 2022 IRP
- Annual refresh of data for existing generators (Capital and Operations & Maintenance costs)

6.2 ALTERNATIVE RESOURCE PLAN DEVELOPMENT

6.2.1 CAPACITY EXPANSION PLANNING

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

Unless otherwise noted in the description of the Modeling Approach below, capacity expansion modeling was performed using the "Mid-Mid-Mid" endpoint, based on the Mid natural gas price forecast, Mid load forecast, and Mid level of carbon restrictions (based on SPP Future 2 model as described in 3.1.4). This was, again to provide easier comparisons between resource plans because a capacity expansion model will often generate different resource plans in different market scenarios. Evergy believes this approach provides a viable assessment of our current "base" expectations and that using these capacity expansion results, with revenue requirements for these Alternative Resource Plans calculated across all 27 endpoints, enables a robust analysis of these "base-case" Alternative Resource Plans across a wide variety of potential future scenarios.

For this year's Annual Update, the supply-side options available for selection by Missouri West in each year are outlined below. In each year, the model could select up to the number of megawatts listed in the table below by selecting "projects" of that resource type. The capacity and cost of each resource type are included in Table 9. In any given year, resource additions were constrained to only one "project" per year based on Missouri West's assumed ability to finance these additions. This assumption also ensures that resources are added ratably over time as opposed to being stacked in one year, to drive more stable rate impacts over time. As an example, in 2027, capacity expansion could select *either* 150 MW of wind, 150 MW of battery storage, 150 MW of solar-storage hybrid, *or* 150 MW of solar. In 2028, it could select any of those options *or* a 260 MW combined cycle (based on an assumed ½ combined cycle project, on the assumption that CC builds can likely be shared across jurisdictions to drive economies of scale) *or* a 238 MW combustion turbine. The phased in availability of options in the table below is based on Request for Proposal responses (e.g., no solar projects received in the RFP had in-service dates before end-of-year 2026 and thus solar was not available for capacity expansion until 2027) or expected construction timeline (i.e., five years is currently the expected shortest time required to build new natural gas resources given SPP interconnection queue delays and permitting / construction timelines).

Table 21: Missouri West Builds Available (MW)

Resource	2024	2025	2026	2027	2028	2034	2039
Wind			150	150	150	150	150
Solar			150	150	150	150	150
Battery			150	150	150	150	150
Solar Hybrid						267	
Combined Cycle					260	260	260
Combustion Turbine					476	476	476
Dogwood CC	143						

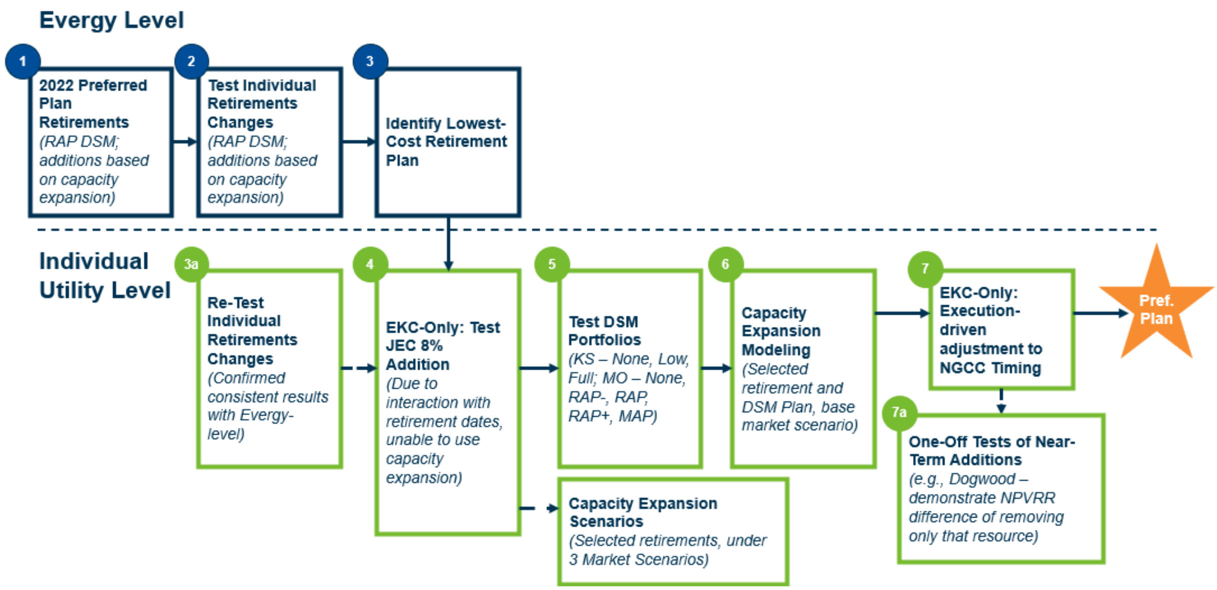
Note: Each year shown represents the MW available by resource type in that year and following years until the next year shown in the table, which represents updated constraints

6.2.2 OVERALL MODELING APPROACH

As described previously, the updated modeling approach for the 2023 Annual Update focused primarily on performing capacity expansion planning at the individual utility level (as opposed to the Evergy level) to ensure a targeted assessment of each utility's customers' energy and capacity needs. However, due to the large number of co-owned coal units in Evergy's portfolio, potential plant retirement options were tested at the Evergy level first before moving to the individual utility level. From there, these retirements were re-tested at the individual utility level, different demand-side management portfolios were compared, capacity expansion was performed in a "High" scenario (high natural gas prices, high carbon restriction) and "Low" scenario (low natural gas prices, no carbon restriction), and ultimately a Preferred Plan was generated using the selected plant retirement plan, selected DSM portfolio, and with capacity expansion-generated supply-side resource additions. In order to ease comparison of resource plans, particularly as it relates to near-term decisions (e.g., addition of a share of the Dogwood Combined Cycle plan), additional plans were created where that resource addition was removed as a capacity expansion option and a new lowest-cost plan was generated. As a result, the Preferred Plan can then be compared to this new plan to show the cost savings created by that specific decision.

Given this process is very different from the process used in past IRPs, and in order to make the process more transparent, the results outlined below will be described in the various stages outlined in the graphic below.

Figure 20: High-Level Modeling Approach



6.3 EVERGY-LEVEL RETIREMENT ANALYSIS

As described above, Evergy-level modeling was used to determine whether changing the coal retirements from the 2022 Preferred Plan could result in lower NPVRR. This analysis was performed primarily at the Evergy level (as opposed to the Missouri West level) due to the number of jointly-owned units in Evergy's portfolio. However, additional testing was performed at the individual utility level to ensure any change in retirements at the Evergy level was also beneficial or approximately neutral for the individual utilities (results described below).

Table 22: Evergy Joint Planning Alternative Resource Plan Naming Convention

Demand-Side Management Potential	Early Retirements	Coal to NG	Other
B. RAP MO, No DSM KS	A. None (2021/22 Preferred Plan)	A. Lawrence 5 to NG 2024	A. None
J. MAP MO, Full DSM KS	B. Extend Lawrence 4 & 5 to 2028	B. Lawrence 5 to NG 2029	D. High/High
	C. Jeffrey 2 Retires 2030	C. Hawthorn 5 to NG 2027	E. Low/Low
	D. Iatan 1 Retires 2030	D. Jeffrey 3 to NG 2030	F. Only Renewable/Storage Build
	E. Hawthorn 5 Retires 2027	E. Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039	N. No Major Environmental Costs
	F. LaCygne 2 Retires 2032		
	G. Jeffrey 1 & 2 Retire 2030		
	H. Extend Lawrence 4 & 5 to 2028, Extend all others past 2042		
	I. Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030		
	J. All Earliest Retirements		
	K. Extend Lawrence 4 & 5 to 2028, Extend Jeffrey 3 to 2039		
	L. Extend Lawrence 4 & 5 to 2028, Extend Jeffrey 3 to 2039, Iatan 1 Retires 2030, LaCygne 2 Retires 2032		

Note: Letters which are excluded from naming convention above (e.g., "A" Demand Response Potential) were used in IRP development for one or more utilities but not used at the Evergy Joint Planning level.

Table 23: Overview of Joint-Planning Resource Plans

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Evergy BAAA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 300 MW Wind 2031 450 MW Wind 2032 450 MW Wind 2034 150 MW Wind 2035 300 MW Wind 2041 450 MW Wind 2042	300 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 150 MW Solar 2031 300 MW Solar 2033 150 MW Solar 2041		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 1 CT (238 MW) in 2039 2 CC (1041 MW) in 2039 3 CC (1562 MW) in 2040
Evergy BACA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 K Hawthorn5: Dec 31, 2026 Jeffrey 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2032 150 MW Wind 2033 450 MW Wind 2034 150 MW Wind 2035 450 MW Wind 2041 450 MW Wind 2042	150 MW Solar 2027 300 MW Solar 2028 300 MW Solar 2029 600 MW Solar 2030 600 MW Solar 2031		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Coal to NG (375 MW) in 2027 1 CT (238 MW) in 2033 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 1 CT (238 MW) in 2039 2 CC (1041 MW) in 2039 3 CC (1,562 MW) in 2040
Evergy BADA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 3: Dec 31, 2029 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2032 450 MW Wind 2033 450 MW Wind 2034 300 MW Wind 2035 450 MW Wind 2042	150 MW Solar 2028 450 MW Solar 2029 600 MW Solar 2030 600 MW Solar 2031 150 MW Solar 2035 300 MW Solar 2041		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Jeffrey 3 NG (727 MW) in 2030 1 CC (521 MW) in 2037 1 CC (521 MW) in 2038 1 CC (521 MW) in 2039 3 CC (1562 MW) in 2040
Evergy BAEA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 3: December 31, 2029 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 2: December 31, 2038 Iatan 1: Dec 31, 2039 Jeffrey 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 300 MW Wind 2031 450 MW Wind 2032 450 MW Wind 2033 450 MW Wind 2034 300 MW Wind 2041 450 MW Wind 2042	150 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 150 MW Solar 2031 450 MW Solar 2035		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Jeffrey 3 NG (727 MW) in 2030 1 CC (521 MW) in 2037 1 CC (521 MW) in 2038 1 CC (521 MW) in 2039 Jeffrey 2 NG (730 MW) in 2039 2 CC (1041 MW) in 2040

Table 24: Overview of Joint-Planning Resource Plans (continued)

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Evergy BBBA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 300 MW Wind 2031 450 MW Wind 2032 450 MW Wind 2034 150 MW Wind 2035 300 MW Wind 2041 450 MW Wind 2042	300 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 150 MW Solar 2031 300 MW Solar 2033 150 MW Solar 2041		Dogwood (143 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 1 CT (238 MW) in 2039 2 CC (1041 MW) in 2039 3 CC (1562 MW) in 2040
Evergy BCAA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 2&3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2032 150 MW Wind 2033 450 MW Wind 2034 450 MW Wind 2041 450 MW Wind 2042	450 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 300 MW Solar 2031 150 MW Solar 2040		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 1 CC (521 MW) in 2031 1 CT (238 MW) in 2033 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 2 CC (1041 MW) in 2039 2 CC (1041 MW) in 2040
Evergy BDAA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 Iatan 1: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Jeffrey 1&2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2032 150 MW Wind 2033 450 MW Wind 2034 300 MW Wind 2035 300 MW Wind 2041 450 MW Wind 2042	300 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 300 MW Solar 2031 150 MW Solar 2035		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 1 CC (521 MW) in 2031 1 CT (238 MW) in 2033 1 CC (521 MW) in 2033 1 CT (238 MW) in 2036 2 CC (1041 MW) in 2039 3 CC (1562 MW) in 2040
Evergy BEAA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Hawthorn 5: December 31, 2027 Jeffrey 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1&2: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2032 450 MW Wind 2034 150 MW Wind 2035 300 MW Wind 2041 450 MW Wind 2042	150 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 600 MW Solar 2031 150 MW Solar 2041	150 MW Hybrid-Solar 2033 117 MW Hybrid-Battery 2033	Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 1 CC (521 MW) in 2028 1 CC (521 MW) in 2033 1 CT (238 MW) in 2036 1 CC (521 MW) in 2038 2 CC (1041 MW) in 2039 3 CC (1562 MW) in 2040
Evergy BFAA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 2 & 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039 Jeffrey 1: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2031 150 MW Wind 2032 450 MW Wind 2034 300 MW Wind 2035 300 MW Wind 2041 450 MW Wind 2042	300 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 300 MW Solar 2032 150 MW Solar 2035		Dogwood (143 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 1 CT (238 MW) in 2032 2 CC (1041 MW) in 2033 1 CT (238 MW) in 2036 2 CC (1041 MW) in 2039 3 CC (1562 MW) in 2040

Table 25: Overview of Joint-Planning Resource Plans (continued)

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Evergy BGAA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 1, 2, & 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 300 MW Wind 2032 150 MW Wind 2033 450 MW Wind 2034 300 MW Wind 2035 450 MW Wind 2041 450 MW Wind 2042	600 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 150 MW Solar 2032 150 MW Solar 2040		Dogwood (143 MW) in 2024 Lawrence 5 NG (338 MW) in 2024 Jeffrey 8% (176 MW) in 2024 3 CT (714 MW) in 2031 1 CC (521 MW) in 2031 1 CT (238 MW) in 2033 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 1 CC (521 MW) in 2039 2 CC (1041 MW) in 2040
Evergy BHAA	RAP MO, No DSM KS;	Lawrence 4: Dec 31, 2028 Lawrence 5 Coal: Dec 31, 2028 Lake Road 4/6: Dec 31, 2030	199 MW Persimmon Wind 2023 200 MW Wind 2025 300 MW Wind 2029 450 MW Wind 2030 450 MW Wind 2031 450 MW Wind 2032 450 MW Wind 2033 450 MW Wind 2034 300 MW Wind 2042	150 MW Solar 2029 600 MW Solar 2035 750 MW Solar 2041		Dogwood (143 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2037 2 CC (1041 MW) in 2039 1 CC (521 MW) in 2040 1 CC (521 MW) in 2042
Evergy BIBA	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 2 & 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039 Jeffrey 1: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2032 150 MW Wind 2033 450 MW Wind 2034 450 MW Wind 2041 450 MW Wind 2042	450 MW Solar 2028 600 MW Solar 2029 600 MW Solar 2030 300 MW Solar 2031 150 MW Solar 2040		Dogwood (143 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2031 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 2 CC (1041 MW) in 2039 2 CC (1041 MW) in 2040
Evergy BIBD	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2028 Lawrence 4: Dec 31, 2028 Jeffrey 2 & 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039 Jeffrey 1: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 450 MW Wind 2026 450 MW Wind 2030 450 MW Wind 2032 450 MW Wind 2034 450 MW Wind 2035	600 MW Solar 2027 600 MW Solar 2028 600 MW Solar 2029 300 MW Solar 2031	150 MW Hybrid-Solar 2033 117 MW Hybrid-Battery 2033	Dogwood (143 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2031 1 CC (521 MW) in 2033 1 CC (521 MW) in 2036 1 CC (521 MW) in 2039 3 CC (1562 MW) in 2040
Evergy BIBE	RAP MO, No DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Jeffrey 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1 & 2: Dec 31, 2032 Iatan 1: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039		150 MW Solar 2029 600 MW Solar 2030 600 MW Solar 2032 300 MW Solar 2033 150 MW Solar 2034		Dogwood (143 MW) in 2024 Jeffrey 8% (176 MW) in 2024 Lawrence 5 NG (338 MW) in 2029 1 CC (521 MW) in 2031 2 CT (476 MW) in 2031 1 CC (521 MW) in 2033 1 CT (238 MW) in 2036 1 CT (238 MW) in 2037 2 CC (1041 MW) in 2039 3 CC (1562 MW) in 2040

Table 26: Overview of Joint-Planning Resource Plans (continued)

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Evergy JEAF	MAP MO, Full DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Hawthorn 5: Dec 31, 2027 Jeffrey 3: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030 LaCygne 1: Dec 31, 2032 Iatan 1: Dec 31, 2039 LaCygne 2: Dec 31, 2039 Jeffrey 1 & 2: Dec 31, 2039	199 MW Persimmon Wind 2023 200 MW Wind 2025 300 MW Wind 2032 3000 MW Wind 2032	1200 MW Solar 2028 750 MW Solar 2031 150 MW Solar 2033 150 MW Solar 2040	1200 MW Hybrid-Solar 2033 936 MW Hybrid-Battery 2033 750 MW Battery-Gen 2039 1500 MW Battery-Wind 2039 900 MW Battery-Gen 2040	Lawrence 5 NG (338 MW) in 2024
Evergy JJAF	MAP MO, Full DSM KS;	Lawrence 5 Coal: Dec 31, 2023 Lawrence 4: Dec 31, 2024 Hawthorn 5: Dec 31, 2025 Jeffrey 1, 2, & 3: Dec 31, 2030 LaCygne 1 & 2: Dec 31, 2030 Iatan 1 & 2: Dec 31, 2030 Lake Road 4/6: Dec 31, 2030	199 MW Persimmon Wind 2023 200 MW Wind 2025 2250 MW Wind 2026 2400 MW Wind 2033	150 MW Solar 2026 1800 MW Solar 2031	150 MW Battery-Gen 2026 150 MW Battery-Wind 2026 150 MW Battery-Wind 2028 1200 MW Battery-Gen 2030 1500 MW Battery Wind 2030 1500 MW Hybrid-Solar 2030 1170 MW Hybrid-Battery 2030 150 MW Hybrid-Solar 2032 117 MW Hybrid-Battery 2032 150 MW Hybrid-Solar 2033 117 MW Hybrid-Battery 2033	Lawrence 5 NG (338 MW) in 2024

Note: For these modeled resource plans, Dogwood and Jeffrey 8% were assumed to be in place in all plans with capacity expansion used to solve for all other resource additions. Because this modeling is being used only to assess which retirement changes reduce costs, these decisions around builds are not critical (as long as the approach used for all retirements is consistent). The evaluation of resource additions for the ultimate Preferred Plan occurred at the individual utility level and did not include any hardcoded resource additions (Section 6.6).

6.4 REVENUE REQUIREMENT – EVERGY-LEVEL RETIREMENT ANALYSIS

For each of the Alternative Resource Plans developed, integrated analysis yielded an expected value of the Net Present Value of Revenue Requirement shown in Table 26 below.

These results, along with the by-scenario results in Section 6.5, indicate that an earlier retirement of Jeffrey Unit 2 in 2030, as well as a delay of the Lawrence Unit 4 retirement and Lawrence Unit 5 transition to natural gas, is more economic than the 2022 Preferred Plan. Based on this, and supported by Missouri West-level modeling below, the 2023 Preferred Plan for Missouri West includes the retirement of its portion of Jeffrey Unit 2 in 2030. There is still significant uncertainty around different environmental regulations which could drive the retirement of Jeffrey Unit 2 or a different Evergy coal unit and thus Jeffrey Unit 2 still remains a “placeholder” for an accelerated retirement. However, given recent regulation released by the Environmental Protection Agency (EPA), it seems more probable that all units would need to install Best Available Control Technology in order to continue operating beyond the early 2030s. Given Jeffrey Units 2 and 3 are the only large units in Evergy’s fleet without Selective Catalytic Reduction (SCR) systems, the capital forecasts used in this IRP (and prior IRPs) assume that SCRs would need to be added if the units do not retire by 2031. This large capital cost to continue operations make these units the most attractive options for early retirement.

Table 27: Joint-Planning Twenty-Year Net Present Value Revenue Requirement

Rank	Plan	NPVRR ($M)	Difference	Description
1	BIBA	62,248		Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030
2	BCAA	62,295	47	Jeffrey 2 Retires 2030
3	BBBA	62,382	135	Extend Lawrence 4 & 5 to 2028
4	BAAA	62,430	182	2021/22 Preferred Plan
5	BIBD	62,449	201	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; High/High
6	BDAA	62,604	356	Iatan 1 Retires 2030
7	BGAA	62,608	360	Jeffrey 1 & 2 Retire 2030
**8	[redacted]	[redacted]	[redacted]	[redacted]**
9	BADA	62,707	459	Jeffrey 3 to NG 2030
10	BACA	62,742	494	Hawthorn 5 to NG 2027
11	BAEA	62,753	505	Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039
12	BEAA	62,757	510	Hawthorn 5 Retires 2027
13	BHAA	62,778	531	Extend Lawrence 4 & 5 to 2028, Extend all others past 2042
14	BIBE	64,405	2,157	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Low/Low

6.5 BY-SCENARIO RESULTS – EVERGY-LEVEL RETIREMENT ANALYSIS

Table 27, Table 28, and Table 29 show the expected value of NPVRR for the joint plans assuming high, mid, and low CO_2 restrictions.

Table 28: Joint Plan Results - High CO_2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	BIBD	62,747		Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; High/High
2	BIBA	62,917	170	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030
3	BCAA	62,942	196	Jeffrey 2 Retires 2030
4	BGAA	63,236	490	Jeffrey 1 & 2 Retire 2030
5	BBBA	63,580	833	Extend Lawrence 4 & 5 to 2028
6	BDAA	63,595	848	Iatan 1 Retires 2030
7	BAAA	63,605	859	2021/22 Preferred Plan
** [redacted]		[redacted]	[redacted]	[redacted] **
9	BACA	63,819	1,073	Hawthorn 5 to NG 2027
10	BEAA	63,946	1,199	Hawthorn 5 Retires 2027
11	BADA	64,455	1,709	Jeffrey 3 to NG 2030
12	BAEA	64,601	1,855	Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039
13	BHAA	65,208	2,462	Extend Lawrence 4 & 5 to 2028, Extend all others past 2042
14	BIBE	66,941	4,195	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Low/Low

Table 29: Joint Plan Results - Mid-CO_2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	BIBA	62,174		Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030
2	BBBA	62,184	10	Extend Lawrence 4 & 5 to 2028
3	BCAA	62,226	52	Jeffrey 2 Retires 2030
4	BAAA	62,236	62	2021/22 Preferred Plan
5	BADA	62,366	192	Jeffrey 3 to NG 2030
6	BHAA	62,368	194	Extend Lawrence 4 & 5 to 2028, Extend all others past 2042
7	BAEA	62,384	210	Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039
8	BIBD	62,417	243	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; High/High
9	BDAA	62,445	271	Iatan 1 Retires 2030
**[redacted]	[redacted]	[redacted]	[redacted]	[redacted]**
11	BGAA	62,522	348	Jeffrey 1 & 2 Retire 2030
12	BEAA	62,534	361	Hawthorn 5 Retires 2027
13	BACA	62,553	379	Hawthorn 5 to NG 2027
14	BIBE	64,500	2,327	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Low/Low

Table 30: Joint Plan Results - No CO_2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	BHAA	61,580		Extend Lawrence 4 & 5 to 2028, Extend all others past 2042
2	BIBE	61,583	3	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Low/Low
3	BBBA	61,781	201	Extend Lawrence 4 & 5 to 2028
4	BIBA	61,800	220	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030
5	BAAA	61,835	255	2021/22 Preferred Plan
6	BCAA	61,854	274	Jeffrey 2 Retires 2030
7	BADA	61,982	402	Jeffrey 3 to NG 2030
8	BAEA	62,011	431	Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039
9	BDAA	62,090	510	Iatan 1 Retires 2030
**[redacted]		[redacted]	[redacted]	[redacted]*
11	BACA	62,233	653	Hawthorn 5 to NG 2027
12	BGAA	62,237	657	Jeffrey 1 & 2 Retire 2030
13	BEAA	62,238	658	Hawthorn 5 Retires 2027
14	BIBD	62,247	667	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; High/High

6.6 EVERGY MISSOURI WEST RESOURCE PLANS

To make results clearer given the increased use of capacity expansion modeling in this IRP, Missouri West analysis will be divided into 5 sections, which ultimately culminate in the creation of 18 Alternative Resource Plans.

- Testing retirement options to ensure alignment with Evergy-level analysis
- Evaluation of Capacity Expansion sensitivities (perform capacity expansion under different market price scenarios to supplement "Base" modeling)
- Testing DSM portfolio levels to identify lowest-cost option
- Preferred Plan development using Capacity Expansion modeling
- Incremental tests of near-term decisions (e.g., Dogwood addition) to assess robustness across scenarios and impact on NPVRR

Supply-side resource additions were not an input into any of these Alternative Resource Plans. All additions were selected using capacity expansion modeling subject to the constraints denoted by the "Other" column above.

Table 31: Evergy Missouri West Alternative Resource Plan Naming Convention

Demand-Side Management Potential	Early Retirements	Coal to NG	Other
A. RAP	A. None (2021/22 Preferred Plan)	A. None	A. None
C. MAP	C. Jeffrey 2 Retires 2030		B. No Wind
E. RAP+	D. Iatan 1 Retires 2030		C. No Dogwood
G. RAP-	G. Jeffrey 1 & 2 Retire 2030		D. High/High
M. No DSM			E. Low/Low
			O. No New Renewable/Storage Builds

Table 32: Evergy Missouri West Alternative Resource Plan Overview

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Missouri West AAAA	RAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2042	150 MW Solar 2027 150 MW Solar 2029		Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2040
Missouri West AAAB	RAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039		150 MW Solar 2027 150 MW Solar 2029 150 MW Solar 2030 150 MW Solar 2031 150 MW Solar 2032 150 MW Solar 2033 150 MW Solar 2034 150 MW Solar 2035 150 MW Solar 2041 150 MW Solar 2042		Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2038 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2040
Missouri West AAAC	RAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034	150 MW Solar 2028 150 MW Solar 2035 150 MW Solar 2041 150 MW Solar 2042	150 MW Battery-Wind 2026	1/2 CC (260 MW) in 2029 1/2 CC (260 MW) in 2039
Missouri West ACAA	RAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 2 & 3: Dec 31, 2030 Jeffrey 1: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2042	150 MW Solar 2027 150 MW Solar 2029		Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2040
Missouri West ACAC	RAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 2 & 3: Dec 31, 2030 Jeffrey 1: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034	150 MW Solar 2027 150 MW Solar 2028 150 MW Solar 2041	150 MW Battery-Wind 2026	1/2 CC (260 MW) in 2029 1/2 CC (260 MW) in 2039 1/2 CC (260 MW) in 2042
Missouri West ACAD	RAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 2 & 3: Dec 31, 2030 Jeffrey 1: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2026 150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2035	150 MW Solar 2027 150 MW Solar 2029		Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2038 1/2 CC (260 MW) in 2041

Table 33: Evergy Missouri West Alternative Resource Plan Overview (continued)

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Missouri West ACAE	RAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 2 & 3: Dec 31, 2030 Jeffrey 1: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2032 150 MW Wind 2033	150 MW Solar 2027 150 MW Solar 2031		Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2039
Missouri West ADAA	RAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2030	150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2042	150 MW Solar 2026 150 MW Solar 2027 150 MW Solar 2041		1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2030 1/2 CC (260 MW) in 2040
Missouri West AGAA	RAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 1, 2 & 3: Dec 31, 2030 Iatan 1: Dec 31, 2039	150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2042	150 MW Solar 2026 150 MW Solar 2027 150 MW Solar 2041		1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2030 1/2 CC (260 MW) in 2040
Missouri West CAAA	MAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2042	150 MW Solar 2028		Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2029 1/2 CC (260 MW) in 2040
Missouri West CCAA	MAP	Lake Road 4/6: Dec 31, 2030 Jeffrey 2 & 3: Dec 31, 2030 Jeffrey 1: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2042	150 MW Solar 2028		Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2029 1/2 CC (260 MW) in 2040
Missouri West EAAA	RAP+	Lake Road 4/6: Dec 31, 2030 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034	150 MW Solar 2027 150 MW Solar 2029 150 MW Solar 2042		Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2040

Table 34: Evergy Missouri West Alternative Resource Plan Overview (continued)

Plan Name	DSM Level	Retirements	Renewable Additions		Storage/Hybrid Additions	Thermal Additions
Missouri West ECAA	RAP+	Lake Road 4/6: Dec 31, 2030 Jeffrey 2 & 3: Dec 31, 2030 Jeffrey 1: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034	150 MW Solar 2027 150 MW Solar 2029 150 MW Solar 2042		Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2040
Missouri West ECAO	RAP+	Lake Road 4/6: Dec 31, 2030 Jeffrey 2 & 3: Dec 31, 2030 Jeffrey 1: Dec 31, 2039 Iatan 1: Dec 31, 2039				Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2031 1/2 CC (260 MW) in 2036 1/2 CC (260 MW) in 2037
Missouri West GAAA	RAP-	Lake Road 4/6: Dec 31, 2030 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034	150 MW Solar 2026 150 MW Solar 2029 150 MW Solar 2040 150 MW Solar 2041		Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2039
Missouri West GCAA	RAP-	Lake Road 4/6: Dec 31, 2030 Jeffrey 2 & 3: Dec 31, 2030 Jeffrey 1: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2042	150 MW Solar 2028 150 MW Solar 2041	150 MW Battery-Wind 2026	Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2029 1/2 CC (260 MW) in 2039
Missouri West MAAA	No DSM	Lake Road 4/6: Dec 31, 2030 Jeffrey 3: Dec 31, 2030 Jeffrey 1 & 2: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2030 150 MW Wind 2031 150 MW Wind 2032 150 MW Wind 2034 150 MW Wind 2035 150 MW Wind 2041	150 MW Solar 2027 150 MW Solar 2029 150 MW Solar 2042	150 MW Battery-Wind 2026 150 MW Battery-Wind 2033	Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2039
Missouri West MCAA	No DSM	Lake Road 4/6: Dec 31, 2030 Jeffrey 2 & 3: Dec 31, 2030 Jeffrey 1: Dec 31, 2039 Iatan 1: Dec 31, 2039	150 MW Wind 2029 150 MW Wind 2030 150 MW Wind 2032 150 MW Wind 2033 150 MW Wind 2034 150 MW Wind 2042	150 MW Solar 2027 150 MW Solar 2041	150 MW Battery-Wind 2026	Dogwood (143 MW) in 2024 1/2 CC (260 MW) in 2028 1/2 CC (260 MW) in 2031 1/2 CC (260 MW) in 2040

Refer to Appendix B, Capacity Balance Spreadsheets, for tables which provide the Missouri West forecast of capacity balance over the twenty-year planning period for each of the Alternative Resource Plans outlined above. These capacity forecasts include renewable and generation additions. The capacity for existing and new renewable facilities is based on expected accreditation under the Effective Load Carrying Capability methodology.

6.7 REVENUE REQUIREMENT – EVERGY MISSOURI WEST

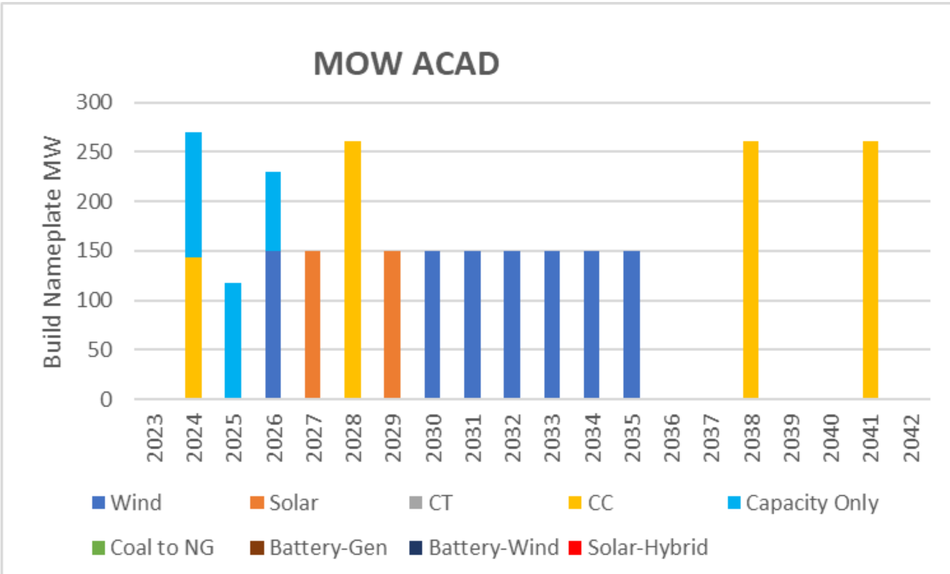
Table 35: Retirement Re-Testing
Evergy Missouri West Twenty-Year Net Present Value Revenue Requirement

Missouri West Retirement Rankings

Rank	Plan	NPVRR ($M)	Difference	Description
1	AGAA	10,858		RAP; Jeffrey 1 & 2 Retire 2030
2	ACAA	10,858	0	RAP; Jeffrey 2 Retires 2030
3	AAAA	10,954	96	RAP; 2021/2022 Preferred Plan
4	ADAA	11,004	146	RAP; Iatan 1 Retires 2030

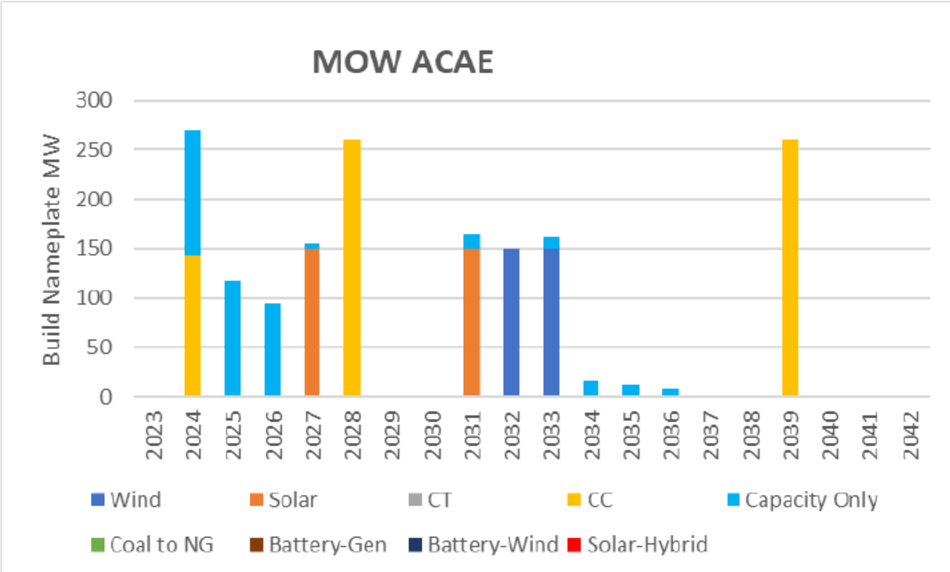
At the Missouri West level, retiring Jeffrey 2 reduces NPVRR by $96 million compared to the 2021/2022 Preferred Plan retirements. This plan is the same cost as the plan which also retires Jeffrey 1 (meaning that Missouri West's 8% share of Jeffrey 1, 2, and 3 would all be retired in 2030 given Jeffrey 3 is retiring in 2030 in the 2021/2022 Preferred Plan). The additional retirement of Jeffrey 1 is not economic at the Evergy level or for Evergy Kansas Central. Given Missouri West is a minority unit of Jeffrey Energy Center, the Jeffrey 1 retirement is not included in Missouri West's Preferred Plan at this time.

Figure 21: Capacity Expansion "High" Scenario Supply-Side Additions



Capacity expansion modeling performed specifically in the High Gas – High Carbon Restriction ("High/High" or "High") scenario shows an increased level of wind builds compared to the Preferred Plan given the increased value of zero-carbon energy in a heavily carbon-restricted market. Despite high gas prices and carbon restrictions, capacity expansion also selects Dogwood in 2024 and builds additional Combined Cycle plants in 2028, 2038, and 2041 as part of the lowest-cost plan. In this scenario, new Combined Cycle resources (excludes Dogwood) are assumed to transition to non-emitting operations beyond 2035. Dogwood is assumed to emit carbon based on current parameters throughout the timeframe.

Figure 22: Capacity Expansion "Low" Scenario Supply-Side Additions



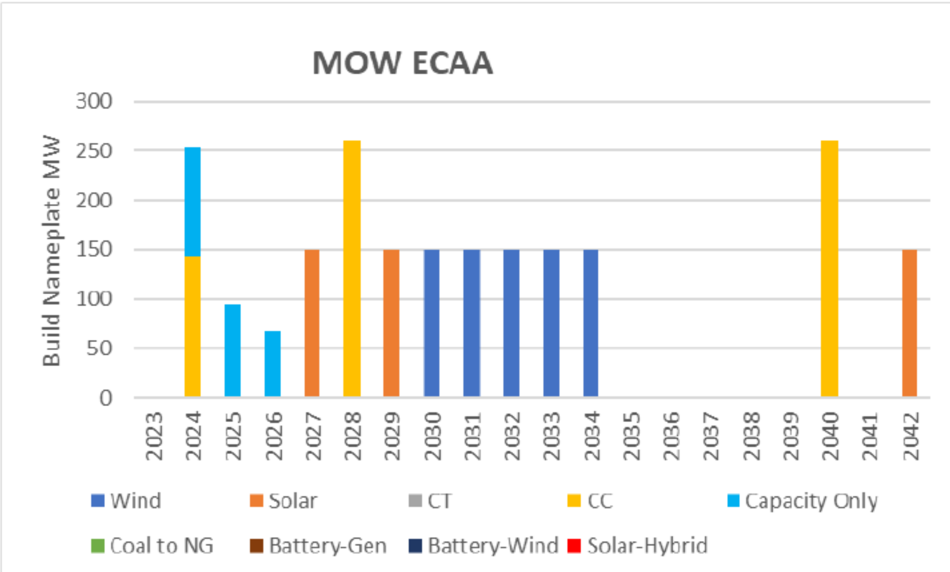
Capacity expansion modeling performed specifically in the Low Gas – Low Carbon Restriction ("Low/Low" or "Low") scenario shows a reduced level of wind and solar builds compared to the Preferred Plan given the reduced value of zero-carbon energy without the imposition of carbon restrictions. Similar to the Preferred Plan, capacity expansion selects Dogwood in 2024 and builds additional Combined Cycle plants in 2028 and 2039 as part of the lowest-cost plan.

Table 36: DSM Portfolio Comparison
Evergy Missouri West Twenty-Year Net Present Value Revenue Requirement

Rank	Plan	NPVRR ($M)	Difference	Description
1	ECAA	10,838		RAP+; Jeffrey 2 Retires 2030
2	ACAA	10,858	20	RAP; Jeffrey 2 Retires 2030
3	GCAA	10,878	39	RAP-; Jeffrey 2 Retires 2030
4	MCAA	10,975	137	No DSM; Jeffrey 2 Retires 2030
5	CCAA	11,018	180	MAP; Jeffrey 2 Retires 2030

Holding the retirement plan constant across all Plans and allowing capacity expansion to solve for the lowest-cost portfolio of supply-side resources, RAP+ is the lowest cost DSM portfolio for Missouri West. RAP+ reduces costs by $20M compared to RAP, which is the assumed level of DSM in the 2021/2022 Preferred Plan. Additionally, deploying no new DSM and deploying the Maximum Achievable Potential (MAP) level of DSM are both significantly higher cost than RAP+.

Figure 23: Preferred Plan Supply-Side Additions (Capacity Expansion-Generated)



Utilizing the lowest-cost retirement (2021/2022 Preferred Plan plus acceleration of Jeffrey-2 retirement to 2030) and DSM (RAP+) options, based on a Mid/Mid (mid natural gas price, mid carbon restriction) scenario, capacity expansion generates the resource addition portfolio above as the lowest-cost plan. This plan (ECAA) is the plan ultimately selected as Missouri West's Preferred Plan.

Table 37: Plan Comparison with and without Dogwood Addition
Evergy Missouri West Twenty-Year Net Present Value Revenue Requirement

Rank	Plan	NPVRR	Difference	Description
1	ACAA	10,858		RAP; Jeffrey 2 Retires 2030
2	ACAC	10,867	8	RAP; No Dogwood, Jeffrey 2 Retires 2030

To supplement these analyses, ACAC was generated using capacity expansion with Dogwood removed as a candidate supply-side resource option. This analysis was done to show the impact of Dogwood on the costs of the resource plan, while retaining use of capacity expansion to generate the lowest-cost resource plan.

Table 38: All Alternative Resource Plans
Evergy Missouri West Twenty-Year Net Present Value Revenue Requirement

Rank	Plan	NPVRR($M)	Difference	Description
1	ECAA	10,838		RAP+; Jeffrey 2 Retires 2030
2	ACAD	10,851	12	RAP; Jeffrey 2 Retires 2030; High/High
3	AGAA	10,858	20	RAP; Jeffrey 1 & 2 Retire 2030
4	ACAA	10,858	20	RAP; Jeffrey 2 Retires 2030
5	ACAC	10,867	28	RAP; No Dogwood, Jeffrey 2 Retires 2030
6	GCAA	10,878	39	RAP-; Jeffrey 2 Retires 2030
7	EAAA	10,943	105	RAP+
8	AAAA	10,954	115	RAP
9	GAAA	10,958	120	RAP-
10	AAAC	10,966	128	RAP; No Dogwood
11	MCAA	10,975	137	No DSM; Jeffrey 2 Retires 2030
12	ADAA	11,004	166	RAP; Iatan 1 Retires 2030
13	CCAA	11,018	180	MAP; Jeffrey 2 Retires 2030
14	AAAB	11,100	262	RAP; No Wind
15	CAAA	11,113	275	MAP
16	MAAA	11,184	346	No DSM
17	ACAE	11,383	545	RAP; Jeffrey 2 Retires 2030; Low/Low
18	ECAO	11,487	649	RAP+; Jeffrey 2 Retires 2030; No New Renewable/Storage Builds

6.8 BY-SCENARIO RESULTS – EVERGY MISSOURI WEST

Table 32, Table 33, and Table 34 show the expected value of NPVRR for Missouri West alternative resource plans assuming high, mid, and low CO_2 restrictions.

Table 39: Evergy Missouri West Plan Results – High CO_2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	ACAD	10,846		RAP; Jeffrey 2 Retires 2030; High/High
2	ACAC	10,961	115	RAP; No Dogwood, Jeffrey 2 Retires 2030
3	GCAA	11,005	158	RAP-; Jeffrey 2 Retires 2030
4	AGAA	11,007	160	RAP; Jeffrey 1 & 2 Retire 2030
5	AAAC	11,103	257	RAP; No Dogwood
6	MCA A	11,127	281	No DSM; Jeffrey 2 Retires 2030
7	ADAA	11,150	304	RAP; Iatan 1 Retires 2030
8	CCAA	11,166	320	MAP; Jeffrey 2 Retires 2030
9	ECAA	11,254	407	RAP+; Jeffrey 2 Retires 2030
10	CAAA	11,270	424	MAP
11	ACAA	11,306	460	RAP; Jeffrey 2 Retires 2030
12	GAAA	11,362	516	RAP-
13	EAAA	11,368	522	RAP+
14	AAAA	11,411	565	RAP
15	AAAB	11,466	620	RAP; No Wind
16	MAAA	11,677	831	No DSM
17	ECAO	11,751	905	RAP+; Jeffrey 2 Retires 2030; No New Renewable/Storage Builds
18	ACAE	12,383	1,536	RAP; Jeffrey 2 Retires 2030; Low/Low

Table 40: Evergy Missouri West Plan Results – Mid CO_2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	ECAA	10,743		RAP+; Jeffrey 2 Retires 2030
2	ACAA	10,757	14	RAP; Jeffrey 2 Retires 2030
3	AGAA	10,834	91	RAP; Jeffrey 1 & 2 Retire 2030
4	EAAA	10,846	103	RAP+
5	AAAA	10,850	108	RAP
6	ACAC	10,852	109	RAP; No Dogwood, Jeffrey 2 Retires 2030
7	ACAD	10,852	110	RAP; Jeffrey 2 Retires 2030; High/High
8	GCAA	10,860	117	RAP-; Jeffrey 2 Retires 2030
9	GAAA	10,866	123	RAP-
10	AAAC	10,943	200	RAP; No Dogwood
11	MCAA	10,951	208	No DSM; Jeffrey 2 Retires 2030
12	ADAA	10,980	238	RAP; Iatan 1 Retires 2030
13	CCAA	10,994	251	MAP; Jeffrey 2 Retires 2030
14	AAAB	11,034	291	RAP; No Wind
15	MAAA	11,077	334	No DSM
16	CAAA	11,087	344	MAP
17	ACAE	11,282	539	RAP; Jeffrey 2 Retires 2030; Low/Low
18	ECAO	11,633	890	RAP+; Jeffrey 2 Retires 2030; No New Renewable/Storage Builds

Table 41: Evergy Missouri West – No CO_2 Restrictions

Rank	Plan	NPVRR ($M)	Difference	Description
1	ACAE	10,687		RAP; Jeffrey 2 Retires 2030; Low/Low
2	ECAA	10,708	21	RAP+; Jeffrey 2 Retires 2030
3	ACAA	10,715	28	RAP; Jeffrey 2 Retires 2030
4	AGAA	10,782	95	RAP; Jeffrey 1 & 2 Retire 2030
5	ECAO	10,786	99	RAP+; Jeffrey 2 Retires 2030; No New Renewable/Storage Builds
6	GCAA	10,803	116	RAP-; Jeffrey 2 Retires 2030
7	AAAA	10,805	118	RAP
8	EAAA	10,808	121	RAP+
9	ACAC	10,817	130	RAP; No Dogwood, Jeffrey 2 Retires 2030
10	GAAA	10,830	143	RAP-
11	ACAD	10,849	162	RAP; Jeffrey 2 Retires 2030; High/High
12	MCAA	10,895	208	No DSM; Jeffrey 2 Retires 2030
13	AAAC	10,900	213	RAP; No Dogwood
14	ADAA	10,929	242	RAP; Iatan 1 Retires 2030
15	AAAB	10,930	243	RAP; No Wind
16	CCAA	10,942	255	MAP; Jeffrey 2 Retires 2030
17	MAAA	11,014	327	No DSM
18	CAAA	11,031	344	MAP

6.9 SUMMARY AND EVALUATION

The lowest-cost plan for Evergy Missouri West includes the early retirement of Jeffrey Unit 2 in 2030 in addition to the retirements included in the 2022 Preferred Plan, the RAP+ portfolio of DSM, and the resource additions selected by capacity expansion and shown in Figure 24. This retirement plan aligned with the Joint Planning conducted at the Evergy level and includes an optimized mix of new resource additions selected based on Missouri West customers' specific energy and capacity needs. By-scenario results also show that the retirement of Jeffrey 2 (in addition to retirements already identified in the 2022 Preferred Plan) is part of the lowest-cost plan regardless of carbon restriction level. In addition, the lowest-cost plan for each of the three levels of carbon restrictions includes the addition of Dogwood in 2024, solar in 2027, and a new Combined Cycle resource in 2028. As a result, this plan – denoted as ECAA – has been selected as the new Missouri West Preferred Plan.

SECTION 7: RESOURCE ACQUISITION STRATEGY

7.1 <u>2022 ANNUAL UPDATE PREFERRED PLAN</u>

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).

Missouri West has selected ECAA as its Preferred Plan. This plan is lower cost than AAAA, which includes the 2022 Preferred Plan retirements and DSM additions.

Due to the many changes in planning considerations over the past year, the Preferred Plan selected for Missouri West in this 2023 IRP Annual Update differs from the 2021 Triennial and 2022 IRP Preferred Plans. The 2023 Preferred Plan adds natural gas resources to the Missouri West fleet earlier. It increases the total amount of wind additions, but postpones them until 2030. More solar is selected in the first few years of the plan, but there are less solar additions in the 20-year horizon.

Additionally, the refresh of the demand response potential study shows value in choosing the RAP+ level of demand response programs over the RAP level selected in the 2022 Annual Update. Notably, the new study shows much lower demand response potential than was forecasted in the last study, so the level of capacity and energy reductions which can be achieved from all programs are smaller.

Finally, in the 2022 Annual Update, Evergy identified the potential for an additional accelerated retirement which could be economically replaced, but at that time chose not to identify a specific unit for retirement as part of the Preferred Plan due to the uncertainty around which specific unit would ultimately be the best candidate for retirement. In this Annual Update, Jeffrey Unit 2 has been identified for 2030 retirement as part of the Preferred Plan. There is still significant uncertainty around different environmental regulations which could drive the retirement of Jeffrey Unit 2 or a different Evergy coal unit and thus Jeffrey Unit 2 still remains a “placeholder” for an accelerated retirement. However, given recent regulation released by the Environmental Protection Agency (EPA), it seems more probable that all units would need to install Best Available Control Technology in order to continue operating beyond the early 2030s. Given Jeffrey Units 2 and 3 are the only large units in Evergy's fleet without Selective Catalytic Reduction (SCR) systems, the capital forecasts used in this IRP (and prior IRPs) assume that SCRs would need to be added if the units do not retire by 2031. This large capital cost to continue operations make these units the most attractive options for early retirement. Evergy will continue to monitor environmental regulations and make adjustments to retirement plans as needed if conditions change, but at this time believes it is prudent to plan around a medium-term retirement of both Jeffrey Units 2 and 3 in order to avoid a situation where retirements are forced by environmental regulation and replacement capacity has not been procured proactively. Further discussion of environmental regulation is provided in Sections 3.4 and 7.2. Because Missouri West is a minority owner in the Jeffrey Units, these retirements are included in Missouri West's Preferred Plan. It is important to note that, as an 8% owner, Missouri West does not have ultimate control of this retirement decision, but the lowest-cost resource additions for Missouri West are the same with and without the additional Jeffrey-2 2030 retirement.

The Evergy Missouri West Preferred Plan ECAA for the 20-year planning period is shown in Table 42 below:

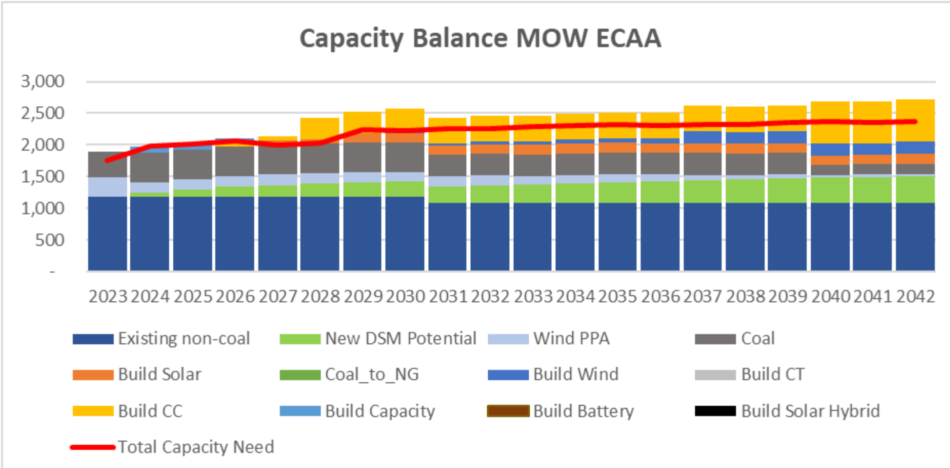
Table 42: Evergy Missouri West Planning Preferred Plan ECAA

MOW ECAA Plan Summary

Year	Wind (MW)	Solar (MW)	Battery (MW)	Thermal (MW)	Capacity Only (Annual MW)	DSM (Annual MW)	Retirements (MW)
2023	0	0	0	0	0	73	0
2024	0	0	0	143	110	81	0
2025	0	0	0	0	94	128	0
2026	0	0	0	0	67	164	0
2027	0	150	0	0	0	183	0
2028	0	0	0	260	0	201	0
2029	0	150	0	0	0	216	0
2030	150	0	0	0	0	230	0
2031	150	0	0	0	0	243	117
2032	150	0	0	0	0	253	0
2033	150	0	0	0	0	260	0
2034	150	0	0	0	0	270	0
2035	0	0	0	0	0	283	0
2036	0	0	0	0	0	297	0
2037	0	0	0	0	0	307	0
2038	0	0	0	0	0	322	0
2039	0	0	0	0	0	333	0
2040	0	0	0	260	0	344	187
2041	0	0	0	0	0	353	0
2042	0	150	0	0	0	362	0

7.1.1 PREFERRED PLAN COMPOSITION

Figure 24: Preferred Plan Capacity Composition



The Evergy Missouri West Preferred Plan includes the following renewable additions: 150 MW solar generation in 2026, 2028, and 2041; 150 MW of wind generation in each year 2029-2033. Additionally, 143 MW share of Dogwood Energy Center in 2023, and combined cycle additions of 260 MW in 2027 and 2039. The Preferred Plan also includes the RAP+ level of DSM for Evergy Missouri West.

Note: All dates listed in this summary are end-of-year unless otherwise noted. Capacity balance views shown elsewhere in this document represent summer capacity impacts which means that additions are typically shown in the following year (the year in which they will be available for summer capacity)

7.2 MONITORING CHANGING CONDITIONS AND MAINTAINING FLEXIBILITY

The primary goals in selecting a Preferred Plan are to evaluate whether near-term actions are robust across various future market scenarios and to maintain as much flexibility as possible to adjust to changing market conditions in the medium- and long-term horizon. The planning environment has continued to evolve and become more dynamic – creating an increased value for maintaining flexibility. Some of the current key sources of uncertainty related to Evergy Missouri West's resource plans are described below, as well as a discussion of how this uncertainty has been and will be factored into planning processes and resource planning decision-making.

Commodity Prices: As expected, the dramatic increase in natural gas prices seen in late 2021 and 2022 has subsided and natural gas prices have now returned to levels seen in 2020 and prior. The experience of those elevated prices, however, demonstrated the value of considering a wide range of potential price scenarios in resource planning analysis given the large amount of uncertainty inherent in forecasting commodity prices. To that end, Evergy has utilized a wider range (lower "Low" and higher “High”) of natural gas price forecasts in this 2023 IRP, created based on both publicly-available and proprietary third-party forecasts. The Preferred Plan has been tested across this wide range of potential commodity price futures, as described in the Integrated Risk Analysis section.

Renewable Resource Construction Costs: Driven by tight supply chains, increasing incentives for “on-shoring” of manufacturing, and increased demand driven by the Inflation Reduction Act, there has been an increase in the construction cost for new renewable generation. Evergy has incorporated this increase into the cost assumptions utilized for this IRP based on the results of its early 2023 All-Source Request for Proposal (RFP). Based on these near-term prices for renewable projects, a third-party cost curve is then used to forecast future cost reductions and to create a long-term forecast for renewable resource costs. These increased costs, combined with the delayed availability of solar projects based on the RFP, have, based on capacity expansion modeling results explained in the Integrated Risk Analysis section, resulted in less renewable additions during the first few years of the Preferred Plan.

SPP Interconnection Queue: The SPP Interconnection Queue continues to be severely backlogged, although SPP is making progress in addressing this issue and redesigning its processes to mitigate the risk of future backlogs. In addition, there is continued uncertainty around upgrade costs which will be assigned to specific projects once they complete the interconnection study process, which can create cost uncertainty depending on the maturity of individual projects. Evergy believes that the ratable approach to renewables included in this Preferred Plan allow it to better manage this risk and make adjustments as needed but will continue to monitor SPP’s efforts to mitigate the existing backlog and determine cost allocation methods which will effectively share costs between renewable interconnection customers and the rest of the Pool, as appropriate. Evergy is closely monitoring SPP's development of the Consolidated Planning Process and the Joint Targeted Interconnection Queue study, which both should serve to provide improved schedule and upgrade cost certainty for future resource additions. In parallel, Evergy is working with SPP and other members to develop other methods to ensure the Interconnection Queue does not become a barrier to ensuring the reliability of the SPP system or the ability of members to meet their resource adequacy requirements.

Distributed Energy Resources (DERs): While Evergy has not yet seen significant penetration of distributed energy resources to the point that it impacts our long-term plan, the continued expansion of electrification, DER aggregation driven by FERC Order 2222, and other policy changes which could influence DER adoption will all continue to be monitored and factored into Evergy's long-term plans as needed.

Electrification: Across Evergy's system, the potential for broad electrification (e.g., vehicles, space / water heating) will continue to be an uncertainty in the development of load forecasts and long-term plans. Evergy incorporates forecasts for electric vehicle adoption into its load forecasts used in IRP planning and these forecasts are updated regularly. Evergy also performed a broader electrification potential study for the 2021 Triennial IRP which was included as the "high" case in this 2023 Annual Update as well. Going forward, Evergy will continue to monitor actual electrification activity in its service territory and update load forecasts for IRP filings. This monitoring and forecasting activity will also be informed by the availability of programs and technology which can mitigate the impact of electrification on peak demand (and thus Evergy's capacity requirements).

Economic Development: Evergy continues to see robust economic development activity with large new customer loads evaluating locating in the service territory. The impact of these potential new customers on Evergy's overall planning activities will depend on specific rate structures and tariffs which the customers participate in, but, given the magnitude of some potential new loads, they still represent an uncertainty which needs to be monitored and incorporated into Evergy's load forecasts as they come to fruition. Based on accelerated activity in this economic development space since the 2022 Annual Update, Missouri West has included a buffer of 40-100 MW above its current SPP capacity requirement beginning in 2026 in this Annual Update. The current Missouri West pipeline for potential economic development which could be online by 2026 far exceeds this amount, but this small buffer mitigates the risk of being unable to serve new customers in a timely manner while also mitigating the risk of increasing SPP capacity requirements (described in more detail below). While planning to serve the full economic development pipeline would likely result in procuring / building capacity for customers who did not ultimately materialize, having this small buffer is critical for allowing Missouri West to support timely growth in its service territory. Evergy is taking a similar approach to planning for potential new economic development projects across each of its jurisdictions.

Reliability and Resource Adequacy: As discussed and agreed with parties following the 2021 IRP, Evergy plans to integrate more detailed reliability risk analysis into its IRP beginning with the 2024 Triennial filing. In the interim, there continues to be significant uncertainty regarding SPP's resource adequacy requirements and, ultimately, how reliability risk should be evaluated and incorporated into planning processes – not just for Evergy or for SPP, but for the entire electric utility industry. Following Winter Storm Uri in 2021, SPP, other Regional Transmission Organizations (RTOs), NERC, and FERC have all initiated efforts to promote changes in resource adequacy processes and requirements so they can be better tailored to a low-carbon resource mix given an increasing dependence of customers on electricity as the economy continues to electrify. It is still uncertain what the ultimate impact of these efforts will be in terms of new Standards and Requirements, but some of the potential impacts are described below. Given the significant amount of uncertainty in these areas and the potential for significant impacts to Evergy's resource planning, Evergy is participating actively in both SPP and NERC activities related to these topics.

Multi-season adequacy: Across the US, RTOs are modifying their resource adequacy constructs to change how they evaluate adequacy in, at the very least, the winter season and, in many cases, all four seasons. Evergy has historically focused on planning for the summer season given our status as a summer-peaking utility. However, as SPP's requirements change, it is likely that Evergy's planning processes will also need to change. SPP is currently evaluating two-season (winter and summer) performance-based accreditation (discussed below) and reviewing other resource adequacy requirements related to the winter season. SPP is currently expecting to implement an interim winter resource adequacy requirement for the 2024/2025 winter season (based on applying the summer reserve margin to winter load), with the implementation of a standalone winter requirement in the following winter. It is still uncertain how this standalone requirement will be implemented, thus Evergy continues to participate actively in SPP policy development.

Resource Accreditation: Earlier this year, FERC rejected SPP's proposal to implement the Effective Load Carrying Capability (ELCC) methodology for renewable accreditation, which would reduce the capacity credit given to renewable resources. ELCC remains the industry standard for renewable accreditation and FERC's stated rationale for rejecting the proposal was based largely on the discrepancy between accreditation approaches for renewable and thermal generators. In response to this feedback, SPP is currently planning to file parallel requests with FERC to implement ELCC and Performance-Based Accreditation for thermal generators at the same time in 2026. This parallel implementation creates significant uncertainty around capacity accreditation which will be received beginning in 2026 given these two methodologies are more "black-box" and they create variability in the credit a resource will receive from season to season and year to year. To factor in this risk and uncertainty, capacity expansion modeling in the 2023 Annual Update allowed a lower level of market capacity purchases for each jurisdiction beginning in 2026. This reflects the expectation that excess capacity available in SPP will decline and other Load-Responsible Entities (LRE) will be less willing to sell their excess in order to manage their own resource adequacy risk.

Fuel Supply Requirements: Given challenges with natural gas supply during Winter Storm Uri and similar extreme winter events, many RTOs and NERC are evaluating how the firmness of fuel supply should be considered in determining a resource’s contribution to meeting Adequacy requirements. Changes in this area could potentially materialize in the form of on-site fuel or firm transport requirements for individual generators or minimum reliability attributes at the overall RTO level in terms of on-site fuel availability. SPP continues to evaluate this requirement in the context of other Resource Adequacy Requirement changes (particularly for the winter).

Reserve Margin: Soon after the 2022 Annual Update was filed, SPP increased the Planning Reserve Margin (i.e., the amount of accredited capacity that an LRE must maintain in excess of its load) from 12% to 15% beginning with the summer 2023 season. SPP has also indicated that they expect future increases to the Reserve Margin as the resource mix continues to become more intermittent and we see more extreme weather. At this time, it is uncertain when the next increase could be implemented, but it’s possible it could be as soon as 2025 or 2026 summer. Based on SPP’s preliminary evaluations of potential winter Resource Adequacy Requirements, it is also possible that the winter Reserve Margin will be much higher than the summer Reserve Margin.

Energy Adequacy (as opposed to Capacity Adequacy): A relatively new concept in this space is the distinction being made between “energy adequacy” and the more traditional view of “resource adequacy” or “capacity adequacy”, with the more traditional view being focused on maintaining sufficient capacity to meet peak hour requirements, plus a level of reserves to mitigate risk (with risk being driven by load uncertainty and resource performance, generally). A key focus of NERC over the last couple of years has been on exploring additional / modified Reliability Standards which expand that traditional focus to a broader view of “Energy Adequacy” which takes into account all hours – not just peaks – and incorporates a greater range of uncertainties given the quickly-changing resource mix (both supply- and demand-side resources). NERC has established Standard Drafting Teams to develop new Reliability Standards which will require the performance of

Energy Assessments. It is uncertain how these potential Standards will ultimately impact SPP analysis and requirements, but Evergy continues to monitor them closely.

In addition to monitoring these specific uncertainties, Evergy also monitors all Critical Uncertain Factors on an ongoing basis to identify any significant changes in long-term outlooks for these items.

Critical Uncertain Factor: CO_2

The passage of the Inflation Reduction Act and the EPA publishing several more stringent draft rules for fossil plants have demonstrated it is more likely that carbon reductions will be realized through a mix of renewable incentives (e.g., Production Tax Credits), carbon emission caps, and other stringent emission restrictions on fossil plants which drive the need for new retrofits. As a result of these changes, Evergy moved away from exclusively using a carbon tax (which was used in historical IRPs, including the 2022 Annual Update) to utilize carbon restriction scenarios instead, which are aligned with carbon restriction scenarios developed through the SPP economic model development process. As a result of this change, a higher level of carbon restrictions actually drives down average SPP energy market prices (as renewables are built out aggressively based on incentives and the need for carbon-free energy) and drives up fixed costs as fossil plants must be retrofitted or replaced with other non-emitting resources. As opposed to a carbon tax, which is a variable cost that impacts a resource's market offer cost, these fixed costs are not recoverable in the SPP energy market and thus do not drive up energy prices. It is possible that ultimately a CO_2 tax may become the more likely scenario again, thus Evergy continues to monitor policy developments to determine whether an adjustment is necessary, but for this Update, an "incentives plus restrictions" approach is more representative of Evergy's expectations for the future.

Critical Uncertain Factor: Load

Load forecasts are updated on an annual basis as part of the company's annual budgeting and IRP process. In addition, updated forecasts for economics, end-use efficiency and saturations, electrification and distributed energy resources are incorporated into these load forecasts whenever they become available.

Critical Uncertain Factor: Natural Gas

Natural Gas forecasts are updated weekly with executive updates provided on a monthly basis.

The items described above are considered in ongoing updates to Evergy's IRP on either an annual or triennial basis (depending on the pace of change). In each IRP, Evergy works to take an integrated view of the need for changes to its prior Preferred Plan. Specifically, the IRP process utilizes the latest understanding of the inputs outlined below in order to confirm the prior Preferred Plan or identify a new Preferred Plan through the risk analysis framework outlined in the IRP rules. Note that not all of the detailed items listed below will have updates in or appear specifically in every IRP, but these types of items are monitored on an ongoing basis and changes will be incorporated as they arise.

Existing resource portfolio:

- Expected ongoing capital and O&M costs, including the cost of life extension projects, where relevant
- Potential alternative retirement dates, often based on the potential to avoid significant retrofits or overhaul costs
- Available supply-side resource options:
- Assessment of current costs and risks associated with new resources
- Potential for changes (i.e., extensions) to Power Purchase Agreements or Capacity Sales
- Options for "non-traditional" new resources, including existing facility expansions

Available demand-side resource options:

- Latest forecast for DSM adoption and costs, informed by actual adoption data, where available, and program approval

Alternative resource plans:

Each IRP which includes the evaluation of changing conditions will include the assessment of alternative resource plans which include Evergy's long-term load forecast and long-term capacity plan designed to meet capacity requirements (factoring in potential retirement dates and replacement resource options)

These ARPs will be built based on the latest Resource Adequacy Requirements and supplemented by qualitative or quantitative assessments of reliability / resiliency risk where needed

Finally, the Company monitors conditions which could specifically impact its near-term Implementation Plan to determine whether portions of the plan should be reevaluated and/or changed. These near-term actions have varying "points of commitment" which impact when and how they should be monitored by the Company prior to reaching these points.

Plan Retirements: From a system perspective, a plant retirement decision can be changed up until the point when the unit is unregistered from the SPP market. There are interim steps (for example, beginning the SPP retirement study process at least 12 months in advance, regulatory filings, workforce changes) which can complicate changes in retirement plans, but flexibility still exists up until the point the unit is removed from the SPP market. There is generally minimal cost obligation associated with the retirement prior to the retirement of the unit and the beginning of decommissioning / dismantling. Through the process leading up to the retirement, the primary considerations which can impact a final decision are:

Macroeconomic drivers: Significant, structural (long-term) changes in the policy and market environment (e.g., natural gas or CO_2 prices) could trigger a reevaluation of a retirement

Environmental regulations: Specifically, the expectation / certainty around necessary environmental retrofits (and the timing of when these retrofits will be needed)

Conversion options: In some cases (such as Lawrence 5), an option may be available to maintain or convert to natural gas operations at a site as opposed to retiring the unit. These opportunities can be evaluated based on the long-term capacity value they provide and the cost of continued gas operations. For this IRP, Evergy has evaluated additional potential natural gas conversions at Jeffrey Energy Center and Hawthorn Unit 5. At this stage, retiring Jeffrey Units 2 and 3 is more economic than converting them to natural gas and retaining Hawthorn Unit 5 as a coal plant is more economic than converting to gas given the high cost of natural gas firm service required for capacity accreditation and the very low expected capacity factor of converted coal units. However, Evergy will continue to evaluate these options in the future as an alternative to retirement given the potential conversion offers to retain accredited capacity, reduce the need for environmental retrofits, and reduce operating costs.

Long-term seasonal cycling: In some cases, seasonal cycling (i.e., operating only during winter and summer) could be an alternative to retirement which creates significant cost savings while maintaining valuable capacity for when it's needed most. These opportunities can be evaluated based on the long-term capacity value they provide and the cost of continued operations. Evergy has begun evaluation of the potential for seasonal cycling on a short-term basis in order to inform our understanding of future longer-term seasonal cycling options. The decision-making around short-term seasonal cycling is based on near-term market dynamics(e.g., expected demand, expected renewable output, gas prices) which will vary from season to season.

Other investment needs: As a plant retirement date nears, significant emergent investment needs can impact the ultimate retirement decision (i.e., a large equipment failure can trigger a retirement acceleration)

Maintenance of interconnection rights: Given the uncertainty referenced above in the SPP Interconnection Queue, the maintenance of interconnection rights becomes a very important factor in managing plant retirements in conjunction with new resource additions. SPP's Replacement process allows new resources to utilize the interconnection rights of a retiring unit so, ultimately, a retirement decision could be impacted by the ability to use the unit's interconnection point for a new resource and thus "repower" the site with an alternative generating facility.

Increases in load forecast and/or Resource Adequacy requirements: As described above, Evergy has seen increased economic development activity and ongoing changes to SPP Resource Adequacy requirements. Either of these factors could cause a change to a retirement decision if, for example, a unit needs to be retained to serve a new large load or to meet an increased capacity requirement.

Resource Additions: Typically, resource additions include a "notice-to-proceed" (NTP) date which would be the "point of commitment" for that resource. Often these NTPs are conditioned on certain approvals (e.g., tied to regulatory proceedings) which enables flexibility to respond to changing conditions. There is typically minimal cost obligation prior to the NTP point. From that point, costs would be incurred based on the payment and/or construction schedule associated with the project. Primary considerations when making final resource additions decisions are outlined below. Construction costs: Through the negotiation process with developers or suppliers, expected resource costs are often updated multiple times prior to NTP. This allows for continued reevaluation of projects based on up-to-date cost expectations.

Tax credit eligibility: Changes to tax credit eligibility of specific projects or all renewable projects can ultimately impact economics and trigger reevaluation of resource additions.

Project maturity: A key consideration in evaluating near-term resource additions is project maturity because a relatively mature project provides greater certainty in timeline and cost. Key factors which indicate project maturity are site control and equipment (e.g., panels, turbines) availability.

Interconnection queue status: Due to the current backlog of interconnection queue requests, the availability of projects with favorable queue positions is a key consideration in selecting and procuring new resources. For most

Generator Interconnect queue clusters, the study process has well-defined milestones that allow visibility into when study results and an Interconnection Agreement could be expected. Given the current backlog in the Interconnect queue, this timeline is less clear for some clusters, which is why queue status is such a critical consideration in the evaluation of new projects.

Location and Transmission Risk: There can be significant variability in the locational value of different resources (e.g., expected locational marginal price and/or curtailment risk). Additionally, a resource's location on the transmission system (or distribution, in some cases) influences the expected cost of incremental system upgrades in order to support the interconnection. As a result, this is assessed in comparing different potential resource additions and determining the ultimate expected attractiveness of the options available.

Demand-Side Management: The implementation of DSM programs is managed through the MEEIA process and thus points of commitment align with MEEIA Cycle approvals. These approval processes, and the potential studies and stakeholder processes which support them, are the primary driver of ultimate DSM implementation.

7.3 IMPLEMENTATION PLAN

7.3.1 SUPPLY-SIDE IMPLEMENTATION SCHEDULES

The Preferred Plan includes acquiring approximately 143 MW of Dogwood Energy Center in 2024, 150 MW of solar for 2027 and 260 MW of a combined cycle for 2028. The combined cycle plant in 2028 is anticipated to be a portion of a larger combined cycle plant to be shared with Evergy Kansas Central.

7.3.1.1 Dogwood Energy Center

The Preferred Plan includes acquiring an approximately 143 MW equity stake in the Dogwood combined cycle plant, with all 143 MW being assigned to Evergy Missouri West. As the resource is already existing and operating in the SPP, the typical construction timelines were not required. This resource was offered to Missouri West as part of a late 2022 capacity RFP. As a result of RFP offer analysis which indicated that Dogwood was likely an attractive resource option for Missouri West to pursue, Missouri West began negotiations with the owner of Dogwood in early 2023, with the ultimate decision to pursue the purchase dependent on whether it aligned with the Preferred Plan selected through this 2023 IRP. These negotiations are ongoing and ultimately closing on this purchase is dependent on the successful conclusion of negotiations, as well as securing any necessary regulatory approval. A schedule of the major milestones expected to reach agreement on an asset purchase agreement and final close of a transaction are provided in Table 42 below:

Table 43: Dogwood Milestone Schedule

Dogwood	Expected Completion
Final Definitive Sales Agreement	June 2023
File Application for Certificate of Convenience and Necessity (CCN)	June 2023
Determine Market Services Arrangement and Coordination Structure with Other Owners	March 2024
Expected CCN Order	March 2024
Submit Market Changes to SPP	April 2024
Final Transaction Close	May 2024

7.3.1.2 2026 Solar Addition

The 2026 solar addition is modeled from responses to Evergy's 2023 All-Source RFP. Evergy plans to evaluate the offered supply side resources and move forward with the acquisition process out of the RFP offered projects. While end-of-year 2026 is slightly outside the 3-year window for implementation plans, there will be activity that takes place in the planning window for the solar farm. For construction of solar assets, the timeline will vary depending on site control and SPP maturity with high level major milestones falling within a range with outside dates depicted in Table 44. Evergy expects to continue negotiations with the respondents to the 2023 All-Source RFP in 2023 to in preparation for the 2026 solar additions contemplated in the IRP. These activities will be completed in anticipation of future regulatory proceedings which could include certificates of convenience and necessity and general rate cases.

Table 44: Solar Milestone Schedule

Illustrative Milestone Schedule (By Developer or Evergy)	Outside Completion
Site Control Complete	December 2023
Major Commercial Agreements Complete (BTA, EPC, etc.)	June 2024
Environmental and Land Permitting Complete	October 2024
Regulatory Approvals	January 2025
Detailed Design and Engineering	January 2025
Equipment Acquisition and Delivery	January 2026
Construction Complete	October 2026
Testing and Commissioning	November 2026
Commercial Operation	December 2026

In addition to the renewable additions identified above, the IRP has identified a need for firm, dispatchable generation in 2027 (260MW) for Evergy Missouri West and in 2027 and 2028 for Kansas Central (1,040 MW). While commercial operation for these sites is outside the traditional implementation period for the IRP, there are significant steps that need to be completed within three years to be successful by those dates. As of June 2023, there are 33.9 GW of projects in the SPP interconnection queue for SPP Central which is composed of Kansas and Missouri. However, there are only 167 MW of thermal interconnection positions within that backlog. In order for Evergy to successfully place a site in service by 2027 Evergy anticipates competitively bidding the vast majority of costs within the hydrogen blending capable combined cycle projects but understands that, with a lack of thermal offerings in the 2023 All-Source RFP, projects will ultimately be delivered by Evergy. To that end, Evergy launched a Conventional Generation Siting Study in the Spring of 2023 to select sites and technologies that will be favorable for future conventional generation use. This study will serve as feed-stock for the initial design and engineering of the projects. Early-stage activities will represent a small portion of the overall cost of the project and will be completed in anticipation of future regulatory proceedings which may include predetermination and certificates of convenience and necessity. An anticipated project acquisition milestone schedule is depicted below.

Table 45: Combined Cycle Implementation Milestones

Illustrative Milestone Schedule (By Developer or Evergy)	Phase I (2028) Outside Completion	Phase II (2029) Outside Completion
Site Control Complete	December 2023	December 2023
SPP Large Generator Interconnection Application	December 2023	December 2023
Environmental and Land Permitting Complete	October 2024	October 2024
Design Spec & Engineering, Procurement, and Construction Award	October 2024	October 2024
State Utility Regulatory Approvals (CCN and/or Predetermination)	December 2024	December 2024
Detailed Design and Engineering	April 2025	April 2025
Major Equipment Requisition	July 2025	July 2025
Major Equipment Acquisition and Delivery	March 2027	March 2028
Construction Complete	July 2027	July 2028
Testing and Commissioning	November 2027	November 2028
Commercial Operation	December 2027	December 2028

In order to achieve a more optimized hydrogen blending capable combined cycle build plan across all of Evergy's utilities, the Missouri West site of ~260 MWs will reflect a partial ownership of a site that is expected to fulfill Evergy Kansas Central's needs as well. This shared facility allows for a more fully optimized deployment of resources and a cohesive strategy to build out hydrogen capable firm-dispatchable resources. This should allow Evergy and the eventual supporting stakeholders both internally and externally to focus on the delivery of the CCGT projects for the benefit of customers.

There are also environmental retrofit projects continuing or expected to be continued or initiated during the three-year implementation period. Table 41 below provides estimated dates for major projects currently expected.

Table 46: Environmental Retrofit Project Timeline

Milestone Description	2023 IRP Date Range
Iatan 1 - Landfill Phase 1B Cover	2021 - 2023
Iatan 1 - Landfill Phase 2B Cover	2023-2024
Iatan 1 - Landfill Phase 2A Cover	2025-2026
Iatan 1 - Ash Pond Closure	2021
Iatan 1 - Intake Modification	2021 - 2023
Iatan 2 - Landfill Phase 1B Cover	2021 - 2023
Iatan 2 - Landfill Phase 2B Cover	2023-2024
Iatan 1 - Landfill Phase 2A Cover	2025-2026
Jeffrey 1 - Fly Ash Landfill Area 1 Permit Modification	2021 - 2024
Jeffrey 1 - Fly Ash Landfill Area 1 Cover	2023 - 2028
Jeffrey 1 - Fly Ash Landfill Area 2 Cover	No longer planned
Jeffrey 1 - FGD Landfill Leachate Pond	2021
Jeffrey 1 - FGD Landfill Cell 1C Cover	2021 - 2024
Jeffrey 1 - Bottom Ash Settling Area Closure	2021 - 2026
Jeffrey 1 - Bottom Ash Landfill Closure	2021 - 2026
Jeffrey 1 - Bottom Ash Conversion	2021
Jeffrey 1 - Effluent Guidelines FGD Wastewater	2021 - 2025
Jeffrey 2 - Fly Ash Landfill Area 1 Permit Modification	2021 - 2024
Jeffrey 2 - Fly Ash Landfill Area 1 Cover	2023 - 2028
Jeffrey 2 - Fly Ash Landfill Area 2 Cover	No longer planned
Jeffrey 2 - FGD Landfill Leachate Pond	2021
Jeffrey 2 - FGD Landfill Cell 1C Cover	2021 - 2024
Jeffrey 2 - Bottom Ash Settling Area Closure	2021 - 2026
Jeffrey 2 - Bottom Ash Landfill Closure	2021 - 2026
Jeffrey 2 - Bottom Ash Conversion	2021
Jeffrey 2 - Effluent Guidelines FGD Wastewater	2021 - 2025
Jeffrey 3 - Fly Ash Landfill Area 1 Permit Modification	2021 - 2024
Jeffrey 3 - Fly Ash Landfill Area 1 Cover	2023 - 2028
Jeffrey 3 - Fly Ash Landfill Area 2 Cover	No longer planned

Jeffrey 3 - FGD Landfill Leachate Pond	**2021**
Jeffrey 3 - FGD Landfill Cell 1C Cover	**2021 - 2024**
Jeffrey 3 - Bottom Ash Settling Area Closure	**2021 - 2026**
Jeffrey 3 - Bottom Ash Landfill Closure	**2021 - 2026**
Jeffrey 3 - Bottom Ash Conversion	**2021**
Jeffrey 3 - Effluent Guidelines FGD Wastewater	**2021 - 2025**
Lake Road 4/6 - 316(b) Study	**2021 - 2024**
Sibley 1 - Fly Ash Impoundment Closure	**2021**
Sibley 2 - Fly Ash Impoundment Closure	**2021**
Sibley 3 - Fly Ash Impoundment Closure	**2021**

7.3.2 DEMAND-SIDE MANAGEMENT

Effective June 11, 2022, the Commission approved the Company's application to extend its Missouri Energy Efficiency Investment Act (MEEIA) Cycle 3 programs an additional year. The relative impacts of the new targets for the extension will be reflected in the next IRP annual update. Table shows the current schedule for the ongoing DSM Programs.

Table 47: Demand-Side Management Programs

Program Name	Program Type	Segment	Program Implemented	Annual Report	Program Duration	EM&V Completed and draft report available
Energy Saving Products	Energy Efficiency	Residential	Jan., 2020	90-days following Plan Year	4-Years	1-Yr following Plan Year
Online Home Energy Audit	Educational	Residential	Jan., 2020	90-days following Plan Year	3-Years	1-Yr following Plan Year
Heating, Cooling & Home Comfort	Energy Efficiency	Residential	Jan., 2020	90-days following Plan Year	4-Years	1-Yr following Plan Year
Income-Eligible Multi-Family	Energy Efficiency	Residential	Jan., 2020	90-days following Plan Year	6-Years	1-Yr following Plan Year
Income-Eligible Single-Family	Energy Efficiency	Residential	Jan., 2023	90-days following Plan Year	1-Year	1-Yr following Plan Year
Research and Pilot	Energy Efficiency	Residential	Jan., 2023	90-days following Plan Year	1-Year	1-Yr following Plan Year
Home Energy Report	Energy Efficiency	Residential	Jan., 2020	90-days following Plan Year	3-Years	1-Yr following Plan Year
PAYS	Energy Efficiency	Residential	Sep., 2021	90-days following Plan Year	3-Years	1-Yr following Plan Year
Residential Demand Response	Demand Response	Residential	Jan., 2020	90-days following Plan Year	4-Years	1-Yr following Plan Year
Business Standard	Energy Efficiency	C&I	Jan., 2020	90-days following Plan Year	4-Years	1-Yr following Plan Year
Business Custom	Energy Efficiency	C&I	Jan., 2020	90-days following Plan Year	4-Years	1-Yr following Plan Year
Business Process Efficiency	Energy Efficiency	C&I	Jan., 2020	90-days following Plan Year	3-Years	1-Yr following Plan Year
Online Business Energy Audit	Educational	C&I	Jan., 2020	90-days following Plan Year	3-Years	1-Yr following Plan Year
Business Smart Thermostat	Demand Response	C&I	Jan., 2020	90-days following Plan Year	3-Years	1-Yr following Plan Year
Business Demand Response	Demand Response	C&I	Jan., 2020	90-days following Plan Year	4-Years	1-Yr following Plan Year

7.3.3 EVALUATION MEASUREMENT AND VERIFICATION

Below is the expected EM&V schedule for the proposed MEEIA cycle plans.

Table 48: Evaluation, Measurement, and Verification Schedule

Estimated EM&V Schedule - MEEIA 4	
1st Annual EM&V Begins	Day 1 of PY 1
1st Annual Draft Report	90 days after the end of PY 1
1st Annual Program Report	180 days after the end of PY 1
2nd Annual EM&V Begins	Day 1 of PY 2
2nd Annual Draft Report	90 days after the end of PY 2
2nd Annual Program Report	180 days after the end of PY 2
3rd Annual EM&V Begins	Day 1 of PY 3
3rd Annual Draft Report	90 days after the end of PY 2
3rd Annual Program Report	180 days after the end of PY 2
4th Annual EM&V Begins	Day 1 of PY 3
4th Annual Draft Report	90 days after the end of PY 3
4th Annual Program Report	180 days after the end of PY 3

SECTION 8: 2021 IRP JOINT AGREEMENT RESPONSES

Resolved alleged Concerns and Deficiencies which were not addressed in the 2022 Annual Update are addressed as follows:

8.1 STAFF OF THE MISSOURI PUBLIC SERVICE COMMISSION (STAFF)

Addressed in 2022 Annual Update

8.2 NEW ENERGY ECONOMICS (NEE)

NEE Deficiency 2 - Solar hybrid and battery storage resource options considered in capacity expansion modeling

NEE Concern 2 - Plan performance summaries as discrete scenarios and develop an alternative approach to evaluating special contemporary issues will be addressed in the 2024 Triennial IRP.

NEE Concern 3 – A description of reliability considerations can be found in Section 7.2. A standalone reliability analysis of extreme weather effects on resources will be in the next Triennial IRP.

8.3 RENEW MISSOURI

Addressed in 2022 Annual Update

8.4 SIERRA CLUB (SC)

Sierra Club Deficiency 8 - Solar hybrid and battery storage resource options considered in capacity expansion modeling.

SECTION 9: SPECIAL CONTEMPORARY ISSUES

From the Commission Order, EO-2023-0101, the following Special Contemporary Resource Planning Issues are addressed as follows:

9.1 URBAN HEAT ISLAND

Explore the feasibility, impacts, and potential mitigation of a potentially more pronounced urban heat island over the greater Kansas City urban area over a twenty-year IRP cycle.

Response:

Urban Heat Island (UHI) has been supported and studied by key regional entities, such as the University of Missouri-Kansas City ("UMKC"), Mid-America Regional Council ("MARC") and others, with shared interest in Kansas City for several years. Evergy has been involved in several UHI initiatives. Specifically, Evergy has supported and participated in the following:

- Dr. Fengpeng Sun's (UMKC) UHI Mapping Campaign (Heat Watch Kansas City) with the Climate Adaptation Planning and Analytics ("CAPA")/ National Integrated Heat Health Information System ("NIHHIS") Kansas City Heat conducted during the summer of 2021.
- Beginning in 2019, Evergy led a UHI cohort to assemble organizations and stakeholders, including the Missouri Office of Public Counsel ("OPC"). Evergy supported the effort through its leadership, meeting orchestration and providing high-level data, where appropriate.
- Additional internal research was performed by Evergy's Missouri Energy Efficiency Act ("MEEIA") implementer to identify energy efficient and demand reducing measures that would most impact UHI effects along with the identification of the most cost effective and positively impacted customer types.
- Evergy partnered with the Arbor Day Foundation and Bridging the Gap for the past five years for its Energy Saving Trees program. The program offers free

trees to our customers but with an increased focus on high UHI areas. Trees are a primary way to impact UHI effects. Through 2022 Evergy, in partnership with Bridging the Gap and the Arbor Day Foundation, has provided 1,861 - two to six-foot - trees to customers. This results in approximately 33,500 pounds of air pollutants absorbed and over 3 million MWh of energy saved over 20-years[4].

- Also, during its MEEIA Cycle 3 extension year for 2023, Evergy agreed to further support Urban Heat Island Research and Development with stakeholder engagement to create a feasibility and vulnerability study. As part of this agreement, Evergy committed to and has completed hosting four local stakeholder collaborative sessions.
- Evergy is finalizing a permanent structure for UHI support and mitigation beginning in 2024 but contingent on its MEEIA Cycle 4 portfolio approval. It is anticipated that the permanent structure will include short- and long-term regional climate simulations and projections.

Previously Conducted Research:

- Lawrence Berkley National Laboratory – Heat Island Mitigation Assessment and Policy Development for the Kansas City Region – 2019 White Paper[5]
- CAPA/NIHHIS Kansas City Heat Watch – 2021 Led by UMKC[6]

9.2 PERFORMANCE-BASED ACCREDITATION

Address modeling for low, medium, and high performance base accreditation of existing and planned generation units by updating its annual IRP filing with what Evergy (or Southwest Power Pool (SPP)) believes is the likely (or known) performance accreditation amount for each of its existing generating units, and

[4] Numeric values provided by the Arbor Day Foundation
[5] https://eta-publications.lbl.gov/sites/default/files/gilbert_et_al_2019_kansas_city_uhi_mitigation_0.pdf
[6] OSF | Heat Watch Kansas City (2021) - https://osf.io/5d3uk/

including the rationale for calculating that amount for each of its new supply side resources modeled in its IRP.

Response:

Due to uncertainty in the implementation of Performance-Based Accreditation (PBA) created by FERC's rejection of SPP's ELCC filing, as well as the dynamic nature of PBA calculations and their impact on Planning Reserve Margins, Evergy has not yet integrated PBA directly into IRP analysis. However, a High, Medium, and Low potential impact of Evergy's existing fleet has been calculated as described below. In addition, the potential impact on any new thermal units in Evergy's fleet are estimated below based on class average information provided by SPP (using a class average is SPP's expected approach to applying PBA onto new resources).

Performance-Based Accreditation is complex because, in addition to reducing the accredited capacity awarded to a thermal resource, it also requires a move from an Installed Capacity (ICAP) Planning Reserve Margin (i.e., SPP's current 15% reserve margin) to an Unforced Capacity (UCAP) Planning Reserve Margin. This is because forced outages (which are the primary driver of PBA) are already embedded in the calculation of an ICAP Planning Reserve Margin. For example, if the Planning Reserve Margin (PRM) is 15%, a portion of that reserve margin is to account for an expected level of forced outages across the Pool (to ensure that sufficient resources are available to replace those units that are unavailable). When forced outages are being applied to the capacity accreditation of thermal resources through PBA, if they were also included in the Planning Reserve Margin, it would create a double-counting of those outages and would reduce the overall capacity requirement. It's important to note that PBA is not designed to actually increase the overall capacity requirement of the Pool in total. It is designed to ensure resources are incentivized based on their actual reliability performance and historical ability to serve peak load (essentially by giving more capacity credit to resources with above-average performance and giving less capacity credit to resources with below-average performance).

The method SPP was originally planning to implement would have utilized seasonal EFOR-d (Demand-adjusted Equivalent Forced Outage Rate) from the last five years with the worst season excluded for each unit. This exclusion was designed to avoid penalizing units who had significant forced outages in one season from being impacted by that one extreme event for the next five years when it is likely that the cause of the extreme outage was mitigated as a result of repairs (and thus that season's EFOR-d is not representative of "normal" expected performance). However, with FERC's rejection of ELCC, SPP is now evaluating alternative approaches to this calculation, including approaches which do not allow for the exclusion of the worst season. In order to be conservative in these scenarios, the "medium" or "base" case below assumes only the exclusion of the 2022 Jeffrey Unit 3 outage, but includes all other seasons for all other units. This Jeffrey Unit 3 outage is excluded based on current SPP conversations, which indicate there will be some limited provision for exclusion of "catastrophic" outages.

Scenarios Calculated:

Medium: Calculates accreditation reduction based on 2018-2022 average EFOR-d for each unit. Only adjustment made for Jeffrey Unit 3 2022 outage. Uses SPP 5-year average EFOR-d to estimate conversion from ICAP to UCAP PRM. This calculation is (1+ICAP PRM)*(1-EFOR-d)-1. Calculation of UCAP PRM is the same in all three scenarios to simulate consistent overall SPP performance and only vary Evergy unit performance.

Low: Calculates accreditation reduction based on best year of the last five at the Evergy level. Chosen to represent better-than-average reliability performance, which results in a net increase in capacity credit.

High: Calculates accreditation reduction based on the worst year of the last five at the Evergy level. Chosen to represent worse-than-average reliability performance, which results in a larger net decrease in capacity credit.

Figure 25: Capacity Accreditation Scenarios

Summer Scenarios

Evergy Load	10,421
Evergy Need (Incl. 15% PRM)	11,984
SPP ICAP PRM	15%
SPP AVG. EFORd	7.50%
SPP UCAP PRM	6.4%

Accredited MWs Lost (2026)	
Current to Low Scenario	735
Current to Med Scenario	1,082
Current to High Scenario	1,704

Scenario	New PRM	New Need	Diff (15%)	Acc Loss	Net Impact
Low	6.4%	11,085	899	735	164
Medium	6.4%	11,085	899	1082	(184)
High	6.4%	11,085	899	1704	(806)

Winter Scenarios

Evergy Load	8,266
Evergy Need (Incl. 15% PRM)	9,506
SPP ICAP PRM	15%
SPP AVG. EFORd	11.20%
SPP UCAP PRM	2.1%

Accredited MWs Lost (2026)	
Current to Low Scenario	762
Current to Med Scenario	1,124
Current to High Scenario	1,160

Scenario	New PRM	New Need	Diff (15%)	Acc Loss	Net Impact
Low	2.1%	8,441	1,065	762	302
Medium	2.1%	8,441	1,065	1124	(60)
High	2.1%	8,441	1,065	1160	(95)

The scenarios above demonstrate the large range of potential impacts that PBA can have on overall capacity position. Based on the most likely "Medium" case, the impact is fairly small at the Evergy level, but it still highlights the importance of planning for a small amount of incremental capacity buffer in the future (above the current PRM requirement) to avoid short-falls. This is accomplished in the 2023 Annual Update through the inclusion of an assumed additional new customer load beginning in 2026 for each jurisdiction. This allows Evergy to plan not only for potential new customer loads, but also to mitigate the risk of PBA impacts on overall capacity position.

In addition to this impact on Evergy's existing resources, the data below shows the class average EFOR-d for Combined Cycles and Combustion Turbines. Any new thermal resources added to Evergy's fleet would initially be accredited based on these class averages, which would essentially mean they have no net impact on capacity accreditation because they're assumed to have average performance. As they operate, their net capacity impact will depend on whether they perform worse or better than average. Given they would be new resources, it would be likely that their performance would be better than average (because average includes a mix of new and old resources).

Table 49: Summer and winter SPP weighted average results for EFORd and EFOF

Equation	Summer Season SPP Weighted Average	Winter Season SPP Weighted Average
EFORd	7.5%	11.2%
EFOF	5.7%	6.1%

Table 50: Summer season weighted average EFORd results by size and fuel type

EFORD WEIGHTED AVERAGE BY SIZE AND FUEL TYPE FOR THE SUMMER SEASON	1-50	51-100	101-150	151-200	201-300	301-400	401-500	501-600	600+
Coal		5.9%	7.2%	5.3%	7.0%	5.0%	10.7%	5.6%	9.4%
Hydro	4.4%	0.9%	0.6%						
Natural Gas and Other Gases	8.1%	9.0%	8.4%	4.1%	3.1%	11.4%	15.0%	9.9%	
Nuclear									1.2%
Petroleum	11.6%	12.1%							

9.3 THIRD-PARTY AGGREGATOR DEMAND RESPONSE

Model for low, medium, and high participation scenarios of commercial and industrial customers electing to participate in demand response activities based on the introduction of third-party ARCs within its footprint and provide an analysis of that impact ARCs would have on its IRP.

Response:

Demand response is a valuable tool for the electric industry to help maintain the supply and demand balance on the electric grid and to reduce system peak demand. To assess the range of benefits demand response management can provide in the context of this SCI, however, it is important to create distinctions between the two types of demand response: “wholesale market demand response,” where demand response products are utilized within the Southwest Power Pool (SPP) regional wholesale market, and “retail demand response programs,” such as those administered by Evergy (through MEEIA) to reduce peak demand on Evergy’s distribution grid. Evergy only operates within SPP and SPP does not administer a capacity market auction process (such as is conducted by other RTOs/ISOs, for example, MISO or PJM).

Evergy’s demand response programs offered through MEEIA are designed to offset Evergy’s peak electricity needs, and thereby offset Evergy’s resource adequacy requirements for long-term capacity planning, which is a construct unique to the SPP market compared to other FERC-jurisdictional organized wholesale markets. In contrast, demand response offers submitted to SPP’s wholesale market (such as those provided by a third-party Aggregator of Retail Customers (ARCs)) are not utilized in Evergy’s retail operations, but instead are treated as an alternative form of supply to SPP. The distinctions between distinct types of demand response activity within SPP --retail demand response and wholesale market demand response--are discussed further below.

SPP Market Operations. The SPP wholesale energy market serves as a clearinghouse for entities that buy and sell electricity.

One of SPP’s primary responsibilities is to maintain supply and demand on the transmission grid across its 14-state footprint. As supply and demand fluctuate constantly, SPP conducts a competitive market process to determine which resource to select to meet the next increment of demand. When demand for electricity increases, for example, SPP can choose to either augment supply by turning on a conventional generation resource, or to select a demand response offer (one in which a customer has submitted a bid to voluntarily reduce their demand in exchange for a price). SPP's market clearing process also accounts for locational and transmission constraints and associated costs. SPP's market clearing process also accounts for locational and transmission constraints and associated costs. SPP may select a demand response offer if such election will result in a lower average cost of electricity to the market[7].

As a member of SPP, Evergy procures energy from SPP at a wholesale market price and delivers the electricity to retail customers using Evergy's distribution grid . SPP has responsibility for overseeing operation of the transmission grid, while Evergy has responsibility for energy deliveries to retail customers. The transfer of responsibilities for energy deliveries occurs at the transmission-distribution interface. (In other words, SPP has no oversight or visibility into distribution grid operations.)

Impacts of ARCs. Because ARC demand response is effectively an alternative form of supply for the SPP market, ARC participation does not have a direct impact on Evergy's IRP planning requirements. Several other areas of potential impact, however, merit further discussion. These include resource adequacy, planning and infrastructure needs, and operations, as further discussed below. ARCs are also expected to compete with the pool of eligible customers participating in Evergy's MEEIA demand response programs that are designed to reduce peak demand on Evergy's distribution grid.

Resource Adequacy. An important distinction between SPP and other organized wholesale market regions is the entity responsible for procurement of adequate resources to serve the needs of the grid reliably ("resource adequacy"). In SPP, it is the responsibility of Load Responsible Entities (LREs, such as Evergy), to ensure adequate resources are under Evergy's ownership or control to meet Evergy's forecasted peak energy needs for its service territory, plus a reserve margin established by SPP to account for unplanned events. SPP's resource adequacy requirements allow Evergy to utilize qualified resources enrolled in Evergy-sponsored

[7] Because demand response reduces the total billing units for energy, a "Net Benefits Test" is applied to Demand Response Offers to ensure that the election of a demand response bid will reduce the overall net cost of energy supply.

retail demand response programs to offset Evergy’s peak load forecast, and thereby defer construction or procurement of additional resources. As described above, ARC demand response offers are by SPP to serve as a supply resource for the wholesale market. Therefore, these wholesale resources do not count towards Evergy’s resource adequacy requirements. Third-party ARC activities will not reduce the planning thresholds for Evergy’s IRP.

Infrastructure. An additional consideration of ARC activity is the impact on Evergy’s infrastructure planning. There are currently no requirements in SPP for ARCs to provide advance notification to Evergy or to coordinate wholesale market demand response events with Evergy before dispatch begins. ARC’s control market dispatch directly with SPP and operational coordination directly with the retail customer whose demand response offer is submitted to the SPP market. Thus, Evergy must still procure, plan for, acquire, and manage daily energy supplies to serve customer load based on historic usage patterns, without awareness of how much or when a wholesale market demand response event might be used and reduce customer demand. Evergy further notes that wholesale market resources tend to operate in response to high market prices, which may not be correlated to Evergy’s peak load conditions. Importantly, at the end of an ARC- controlled demand response event, customers will have the expectation of being able to “turn the switch back on,” and resume energy consumption at desired levels. For these reasons, infrastructure must be maintained to serve customers based on normal, expected consumption patterns.

Operations. The lack of visibility by Evergy into wholesale market demand response activity, may increase operational volatility on the distribution system and create more uncertainty in long-term forecasting activities as ARC penetration increases over time, as is widely expected, especially once SPP implements the requirements of FERC Order 2222 (which will also enhance the participation options in the wholesale market by distributed energy resources and third-party aggregators).

Impacts to Evergy’s Demand Response Programs. While the presence of third-party ARCs will not reduce Evergy’s resource adequacy or infrastructure needs, such activity does have the potential to impact Evergy's existing MEEIA programs, since ARCs will compete with Evergy for enrollment of the same pool of customers willing to participate in a demand response program – retail or wholesale. The pool of Commercial and Industrial (C&I) customers eligible or likely to participate in MEEIA's demand response program has been derived through Evergy's DSM Potential Study (described in Section 5 of this IRP). Competition with ARCs for this "fixed" pool of eligible customers, therefore, is anticipated to reduce the pool of customers participating in utility retail programs. ARC participation will therefore impact IRP planning by increasing Evergy's resource adequacy needs. The key assumptions and impacts of the analysis are addressed further below.

Analysis. Evergy conducted a DSM Potential Study to determine the total pool of C&I customers in Evergy's service territory eligible to participate in demand response programs. The results of the DSM Potential Study have been used to establish the total pool of customers (and corresponding demand response potential in MW) which may choose to either enroll in an Evergy retail demand response program or participate in a wholesale market demand response program. (Evergy has utilized the "Realistic Achievable Potential (RAP)-Low Retention Assessment" scenario for this assessment, which is the same baseline Evergy has chosen for assessment of Evergy-sponsored demand response programs.)

As there is no market criteria or other guidelines by which to define "low, medium, and high participation scenarios" for ARCs, for this exercise, Evergy has selected the following assumptions. These assumptions are not supported by any market data. The percent of eligible C&I customers that will choose to enroll with an ARC instead of with Evergy is assumed to be 10%, 30%, and 50% of the total customer pool for the "Low," "Medium," and "High" scenarios, respectively. The total demand response potential for all C&I customers ("Demand Response Potential"), the percent of customers that may choose to participate with an ARC ("ARC Participation Rates (%)") within the wholesale market, and the corresponding reduction in demand response potential (MW) ("ARC Participation Rates (MW)") available to participate in Evergy's programs is summarized in Table 50. Since the loss of these customers would mean that less demand response potential would exist to offset Evergy's resource adequacy needs, the impacts of ARC participation are expected to increase the capacity needed by Evergy to fulfill Evergy's resource adequacy requirements ("Increase in Resource Adequacy Requirements (MW)") as required by SPP.

(Note that Evergy has prepared this assessment for the 2024 and 2025 planning years only, given the proposed implementation by SPP of FERC 2222 in the third quarter of 2025, and the anticipation that after this occurs, current restrictions on ARC participation will no longer apply.)

Table 51: IRP IMPACT ASSESSMENT FROM ARCS (MISSOURI WEST)

PLANNING YEAR	2024	2025
Demand Response Potential (MW) (Summer)	68 MW	79 MW
ARC Participation Rates (%)		
Low (%)	10%	10%
Medium (%)	30%	30%
High (%)	50%	50%
ARC Participation Rates (MW)		
Low (MW)	4	6
Medium (MW)	13	17
High (MW)	22	29
Increase in Resource Adequacy Requirements (MW)		
Low (MW)	4	6
Medium (MW)	13	17
High (MW)	22	29

9.4 SPP RESERVE PLANNING MARGIN

Adjust its IRP modeling to account for the new fifteen percent reserve planning margin recently set by SPP.

Response:

All resource plans evaluated in this IRP utilized the new fifteen percent reserve margin.

9.5 IRA BENEFITS

Account for and explicitly identify cost reductions, tax credits (including all available tax credits for renewable and storage assets), additional funding sources, and other potential benefits from the Inflation Reduction Act and incorporate those changes into its IRP modeling as appropriate.

Response:

The Inflation Reduction Act (IRA) was landmark legislation passed in 2022 that transforms the incentives for "green" supply side resources. The biggest benefit to utility scale renewable energy projects comes in the form of tax credits for the projects; wind, solar and stand alone storage. Those tax credits can come in two forms, Production Tax Credits ("PTCs"), which are applied to the energy production of the site and earned over ten years and Investment Tax Credits ("ITCs"), which are applied to the qualified initial investment costs of the project. Of significant importance to utilities that are subject to normalization rules for the ITC, the IRA now allows PTCs to be elected for solar energy projects. PTCs were only available to wind energy projects prior to passage of the IRA. Since PTCs can be more efficiently monetized by the utility, customers will directly benefit in lower LCOEs than would have previously been possible. Battery Energy Storage Systems now also qualify directly for an investment tax credit without the need for a directly connected solar site. The ITC for batteries is also not subject to normalization for utilities which is very helpful for customer economics.

The IRA restores the PTC and ITC tax benefits back to their historical maximum percentage value assuming some Prevailing Wage and Apprenticeship requirements are met throughout the project construction and at least the first five years of operation. This means that there will be opportunity for renewable projects to qualify for 100% PTC, or an ITC equal to 30% of the project's qualified capital costs. A high-level, representative matrix view of the tax provisions is found below. For the purposes of the 2023 IRP the projects were studied with a 100% PTC qualified strategy which assumes that wage and apprenticeship requirements were met for the project. Battery storage options included 30% values.

Table 52: Summary of IRA Tax Benefits

Qualification Criteria	ITC Value (% of qualified project cost)	PTC Value (% of historical maximum)
IRA Baseline tax incentive	6% of qualified spend	20% PTC/MWh ($5.20/MWh)
Prevailing Wages & Apprenticeship	5x ITC multiplier (30% ITC on qualified spend)	5x PTC multiplier (100% PTC) ($26/MWh)
Domestic Content	+10% ITC Bonus	+10% PTC Bonus
Energy Communities	+10% ITC Bonus	+10% PTC Bonus

In addition to the tax incentives for the projects directly, tax attribute transferability was also included in the legislation. In cases where the project owner lacks sufficient cash tax appetite to efficiently monetize the credits, the transferability provisions will allow the entity generating the tax credits through the renewable energy project to monetize those credits more efficiently by selling them to an entity with a tax appetite. For scenarios where it makes sense and items like tax depreciation are not at the core of the business case, the transferability provisions allow for significantly less complexity and expense of an equity stake in the project. As it pertains to energy efficiency and demand response programs analyzed in the DSM potential study (see Section 5), it was not possible to account for any changes due to the IRA. The DOE is presently drafting the program requirements with an expected release date of third quarter 2023. Subsequent to the release of the DOE guidance, the state energy office will administer how funds from these rebate programs may be coordinated with other new and existing programs and incentives. Therefore, at the time the potential study was performed, there was not sufficient detail to be able to incorporate. Evergy continues to evaluate the impact of the IRA and is collaborating with industry professionals and stakeholders through discussions and workshops. Evergy will incorporate new information into its programs as it becomes available.

9.6 VOLTAGE OPTIMIZATION

Update its analysis and planning activities regarding actions necessary for system-wide voltage optimization analysis of its distribution system.

Response:

Evergy is currently reviewing our existing assets as well as adding communication as required to ready them for use by Voltage and Var Optimization (VVO). Also, Evergy is reviewing the data required to support VVO. This data will come from multiple systems and asset types, (Reclosers, Voltage Regulators, DSCADA, Capacitors, and Breakers). The next steps are to check these data sources for quality and begin data clean-up to prepare for future VVO implementation. In parallel with DSCADA implementation, we will be evaluating available VVO software capabilities in the market to prepare for future implementation.

9.7 CUSTOMER CLEAN ENERGY GOALS

Analyze the impact resulting from satisfaction of the clean energy goals of large customers in general, and Kansas City's municipal clean energy goals in particular.

Response:

Evergy met with the City of Kansas City (KCMO) and the Climate Protection Steering Committee to review KCMO's goals. Evergy also presented on the status of the Integrated Resource Planning process and discussed the approaches considered in solving for many disparate objectives and the requirements of the Missouri integrated resource planning rules while balancing Evergy's three core tenets of affordability, reliability, and sustainability.

Kansas City's clean energy goals as they relate to supply-side resources are incredibly aggressive. The requested scenarios included 1) the retirement of Hawthorn Unit 5 by 2025 with only non-emitting replacement resources and 2) the retirement of all Evergy coal units (approximately 6,000 MW) by 2030 with only non-emitting replacement resources. The results of these scenarios, as compared to all other modeled Evergy plans, are below. Ultimately, these scenarios are ranked as two of the three highest-cost modeled plans, with Scenario 2 exceeding the cost of the lowest-cost plan by over $3.5 billion. In summary, this analysis showed that satisfying KCMO's clean energy goals would dramatically increase costs compared to the Preferred Plan, based on current assumptions for renewable and energy storage costs and accreditation, as well as the expected cost of continuing to operate Evergy's coal plants. It is very possible that these key inputs will continue to change over time, ultimately making KCMO's goals more achievable, but at this time they are not economic. Evergy believes a measured pace to transitioning its fleet over time provides the best balance of affordability, reliability, and sustainability – allowing time for technology to improve so that current fossil assets can be replaced at a reasonable cost and while maintaining reliability for Evergy's customers.

It is also important to note that, given ongoing economic development activity in the KCMO area, Evergy must maintain sufficient accredited capacity to serve new customer loads in a timely fashion. If Evergy moves too quickly to retire existing assets and is unable to replace them with sufficient accredited capacity quickly, serving new large customers in the area would be severely challenged.

Related to Hawthorn Unit 5, in particular, Evergy modeled a slightly delayed retirement of that unit compared to KCMO's goal in Scenario 1 (2027 versus 2025). This is because Hawthorn Unit 5 sits in a critical place on the local transmission system – providing necessary counterflow to manage transmission congestion in the KCMO area. Delaying a potential retirement until 2027 allows time for the transmission system to be reinforced to mitigate the congestion impacts of its retirement. If the unit was retired without those transmission system changes, the impact on wholesale energy costs in the Metro area would be significant. It is also important to note that Hawthorn Unit 5 is one of the most efficient units in Evergy's fleet and is fully retrofitted with the Best Available Control Technology which significantly reduces the ambient air impacts from the unit. While Evergy understands the need to retire units which are close to population centers to manage the impact on nearby areas over time (as it understands the need to transition its entire fossil fleet over time), it also is required to rely on the Clean Air Act to assess its fleet's ambient air impacts and to maintain ongoing ambient air compliance. At this time, based on previous ambient air quality analyses, Hawthorn Unit 5 does not cause or contribute to a violation of any National Ambient Air Quality Standard. The Clean Air Act requires the Environmental Protection Agency to establish the National Ambient Air Quality Standards to protect the public health and welfare including the areas near Hawthorn Unit 5. Taking into consideration these Standards, the Evergy units which are identified for earlier retirement (Lawrence Energy Center, Jeffrey Units 2 and 3) have been identified as economic retirement options largely because they do not yet have Best Available Control Technology installed, in addition to being less efficient than Hawthorn Unit 5. Beyond those units, Evergy cannot economically replace additional coal units in the near-term, as the analysis provided in this Annual Update supports.

As noted above, this analysis is based on current technology and regulations which are likely to continue changing over time. Evergy looks forward to continuing to work with KCMO and to continue supporting its clean energy goals using its large existing fleet of renewable resources, but, at this time, is not able to select a Preferred Plan which aligns with KCMO's aggressive near-term goals for coal retirements.

Figure 26: Scenario 1 – Hawthorn 5 Retired in 2027 (All Other Retirements Aligned with Preferred Plans)
Supply-Side Additions Selected by Capacity Expansion – Renewables and Storage Only

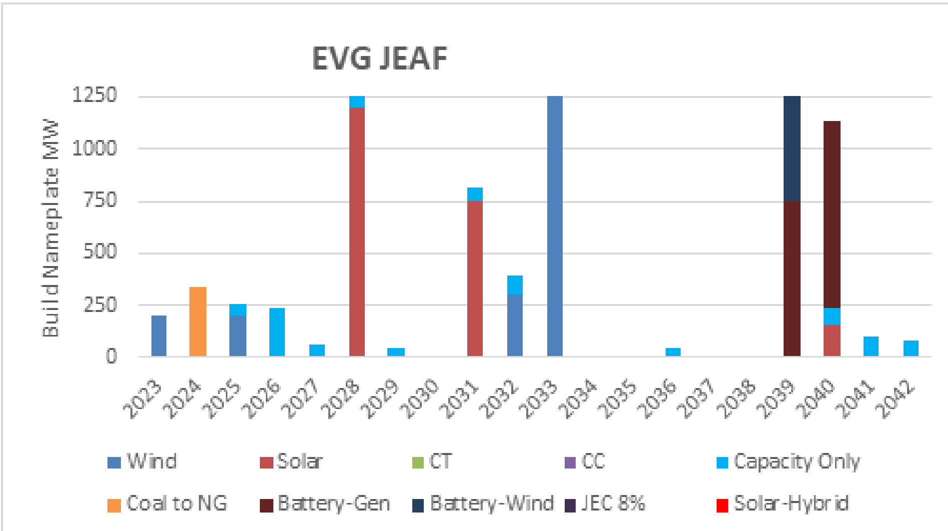


Figure 27: Scenario 2 – All Evergy Coal Retired by 2030
Supply-Side Additions Selected by Capacity Expansion – Renewables and Storage Only

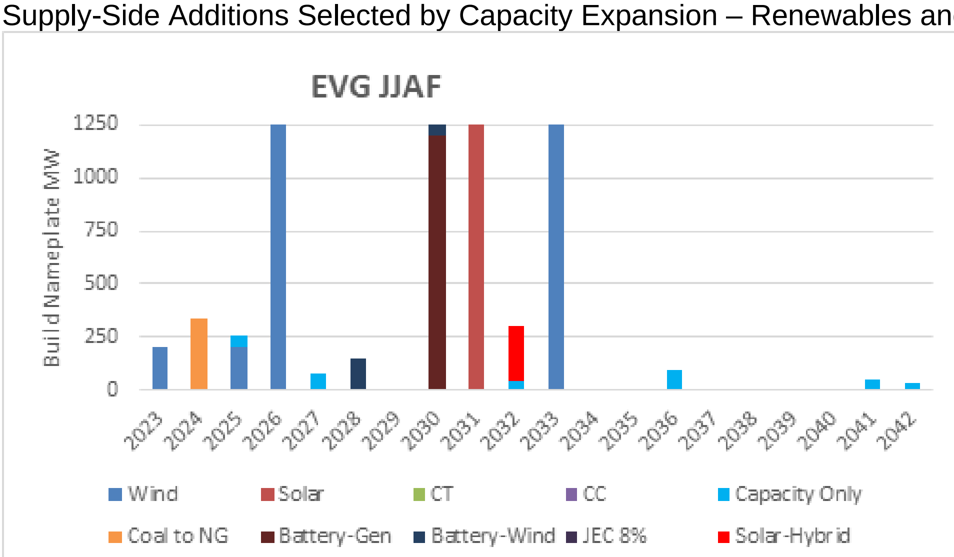


Table 53: Evergy Plan Ranking Including KCMO Scenarios

Rank	Plan	NPVRR ($M)	Difference	Description
1	BIBA	62,248		Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030
2	BCAA	62,295	47	Jeffrey 2 Retires 2030
3	BBBA	62,382	135	Extend Lawrence 4 & 5 to 2028
4	BAAA	62,430	182	2021/22 Preferred Plan
5	BIBD	62,449	201	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; High/High
6	BDAA	62,604	356	Iatan 1 Retires 2030
7	BGAA	62,608	360	Jeffrey 1 & 2 Retire 2030
8	BFAA	62,631	384	LaCygne 2 Retires 2032
9	BADA	62,707	459	Jeffrey 3 to NG 2030
10	BACA	62,742	494	Hawthorn 5 to NG 2027
11	BAEA	62,753	505	Jeffrey 3 to NG 2030, Jeffrey 2 to NG 2039
12	BEAA	62,757	510	Hawthorn 5 Retires 2027
13	BHAA	62,778	531	Extend Lawrence 4 & 5 to 2028, Extend all others past 2042
15	JEAF	63,319	1,071	KCMO Scenario 1
14	BIBE	64,405	2,157	Extend Lawrence 4 & 5 to 2028, Jeffrey 2 Retires 2030; Low/Low
16	JJAF	65,812	3,564	KCMO Scenario 2

As it pertains to energy efficiency and demand response programs, KCMO's goals included addressing energy burden, maximizing the use of energy efficiency, and expanding access to renewable energy for large customers.

Evergy's Heating, Cooling & Home Comfort and Energy Savings Products programs assist residential customers in reducing their energy burdens. Further, Evergy designs Income-Eligible Single-Family and Multi-Family programs specifically targeted to address the more acute needs of those who may experience the highest energy burden. While also supporting the DOE Income-Eligible Weatherization Program.

Also, Evergy provides a suite of programmatic opportunities to support energy efficiency for all sizes of business customers, including the ownership and delivery of aggregated customer usage reports for the KCMO's benchmarking initiative.

Evergy's DSM Potential Study (see Appendix C) addresses KCMO's interest in maximizing the use of energy efficiency. The objective of this study is to develop multiple scenarios that offer programs to all customer market segments while achieving the ultimate goal of all cost-effective demand-side savings. These tools enable Evergy to identify the demand-side programs that provide the most benefit to customers while reducing the revenue requirement.

More generally related to customer sustainability goals, Evergy tariffs are available to help customers meet these goals. Specifically, the Company offers a offers Renewables Direct program. The program provides clean energy access, long term price certainty, additionality at an economic rate delivered through the participant's bill. KCMO enrolled in the program for a 15-year term in 2019 offsetting 18 MW of their load with wind energy.

9.8 BTM DEMAND REDUCTION

Study and/or model various technologies and programs designed to reduce demand on the customer side of the meter, including but not limited to: 1) Residential demand response programs, pairing increased rebates for web-enabled or "smart" thermostats with demand response program participation; 2) Increased rebates for residential electric vehicle charging units paired with customer agreements to participate in a program allowing the Company's use of electricity from a customer's connected electric vehicle at times of high demand; 3) New rebates for residential battery storage units paired with customer agreements to participate in a program allowing the Company's use of batteries at times of high demand; 4) A program offering free installation of utility-owned battery storage units in exchange for customer agreements to allow the Company to use batteries at times of high demand.

Response:

1. The Company has historically as well as currently offers a residential demand response program that provides a customer rebate for the purchase and enrollment of a "smart" thermostat for inclusion in it's peak reduction program.

In addition, the Company regularly reevaluates the appropriate level of rebate as part of the DSM Potential Study, during program planning, and throughout the program implementation. The results of the potential study inform the Company's subsequent MEEIA application. Please refer to Volume 5 for the most recent study.

2. This SCI implicitly references both V1G and V2X.

V1G refers to varying the timing and/or rate of electric vehicle (EV) charging. The flow of energy for V1G is unidirectional, from source to vehicle. V2X primarily refers to energy flow from an EV. The "X" in V2X is a generic placeholder that can refer to a variety of destinations, the most common being a building (V2B), home (V2H), load (V2L), or the distribution grid (V2G).

Evergy performed an industry and technology canvass of V1G approaches during 2022. From this study, Evergy concluded that while utility V1G programs are likely to be ubiquitous within the next five years, the current technologies and implementations thereof are rather immature. Consequently, Evergy believes the best approach for its customers is to monitor the maturation of V1G alternatives and associated utility pilots, then pursue a V1G program once a solution is available that seamlessly integrates with Evergy's distribution grid management platform. In the interim, Evergy will continue to employ time-of-use rates and customer messaging to encourage EV customers to charge off-peak.

In addition to V1G, Evergy recognizes the potential for electric vehicles to benefit grid operation through V2G energy transfer. To that end, Evergy and the Electric Power Research Institute (EPRI) are completing an analysis that summarizes the status of V2G implementation nationally, details the technical and non-technical challenges presented by V2G, and identifies Evergy-specific considerations. This whitepaper will be completed this year and will inform Evergy's expansion of demand response programs to include electric vehicles.

3. The Company as part of its 2022 Missouri Rate case proposed and received approval to launch a residential battery energy storage pilot program. The program will provide participants with the use of a utility owned battery storage system and free installation of the unit in exchange for the Company to utilize the battery at times of high demand to research grid impacts. The Company will evaluate findings over the duration of the pilot through its impact and process evaluation studies that will be finalized in 2025 at the conclusion of the pilot. Based on the findings from the pilot the Company will evaluate and explore potential options for new rebate offerings for residential battery storage units in future filings.

4. The Company as part of its 2022 Missouri Rate case proposed and received approval to launch a residential battery energy storage pilot program. The program will provide participants with the use of a utility owned battery storage system and free installation of the unit in exchange for the Company to utilize the battery at times of high demand to research grid impacts. The Company will outline learning objectives and provide a literature review prior to deployment of the pilot and at the conclusion evaluate findings over the duration of the pilot through its impact and process evaluation studies that will be finalized in 2025 at the conclusion of the pilot. Based on the findings from the pilot the Company will evaluate and explore potential options for new rebate offerings for residential battery storage units in future filings.

9.9 UTILITY-SCALE BATTERY STORAGE

Study and/or model the potential for utility-scale battery storage to meet current and future demand, including: 1) Consideration of the range of potential price reductions in these technologies over the coming two decades; 2) Consideration of pumped hydro, stacked blocks, liquid air, above-ground and underground compressed air, and flow battery technologies in addition to lithium-ion battery technologies; 3) Pairing mid-scale deployments of battery storage technologies with current and future utility-scale solar generation sites; and 4) Offering free installation of utility-

owned battery storage systems to large commercial and industrial customers in exchange for the Company's use of systems at times of high peak demand.

Response:

1. Utility scale battery energy storage systems were included in the solicitation for proposals that Evergy conducted in its 2023 All-Source Request for Proposal (RFP). The responses to this RFP set the baseline for the pricing used to evaluate projects as part of this IRP. From there publicly available cost curves were used to appropriately scale the pricing throughout the 20-year period analyzed in the IRP.

2. In the 2023 All-Source RFP all proven generation technologies were welcomed to be bid into the RFP. No proposals for storage technologies outside of standalone battery energy storage systems were offered. Evergy will stay abreast of developments in these technologies but to the Company's knowledge as of the Spring of 2023 there have been no proposed SPP interconnection requests for these alternative storage technologies and at this time they are not cost or reliability competitive with lithium-ion based systems.

   The company has applied for a DOE grant for a Long-Duration Energy Storage pilot as part of the IIJA through the DOE. Here the company seeks to learn more about long-duration storage technologies and how they may be additive and beneficial for Evergy's customers. As these technologies further develop and become more cost-competitive, they are likely to become a candidate resource option in future Evergy IRPs.

3. The 2023 All-Source Request for Proposal also received bids for Hybrid resources (storage co-located with solar). These resources were included as candidate resource options in Integrated Analysis for this Annual Update. Neither hybrid nor stand-alone storage projects were selected by capacity expansion modeling as part of the lowest-cost resource plan.

4. Please refer to the response in Section 9.8 #4.

9.10 <u>STAND-ALONE AND HYBRID BATTERY STORAGE</u>

Model stand-alone or hybrid battery storage resources

Response:

Stand-alone and hybrid battery storage resources were a candidate resource option in all capacity expansion modeling performed for the 2023 Annual Update.