Evergy Metro

Volume 4

<u>Supply-Side Resource Analysis</u>

Integrated Resource Plan

20 CSR 4240-22.040

April 2024

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Volume 4: Supply-Side Resource Analysis

Highlights

- Energy market forecasts were developed based on the expected resource transition in SPP over the 20-year planning period, with sensitivities for natural gas price changes and future carbon dioxide emissions restrictions.
- Resource adequacy needs and SPP capacity requirements are projected to increase due to weather-related risk and changes to the resource mix.
- Existing power plant efficiency improvements have been an ongoing initiative at Evergy Metro generating units.
- Future power plant efficiency projects have been identified and expected to be completed in upcoming years.
- Existing generation resources have been studied to determine future environmental retrofit requirements and expected maintenance needs.
- Solar, wind, and battery storage resources were identified as new resource candidates based on responses to an all-source RFP held in 2023; all are expected to be eligible for Inflation Reduction Act tax credits.
- Combined-cycle and combustion-turbine resources were identified as self-build options for new firm-dispatchable resources.
- Nuclear SMR and combined cycle with carbon capture were also considered in scenarios with high carbon dioxide restrictions.

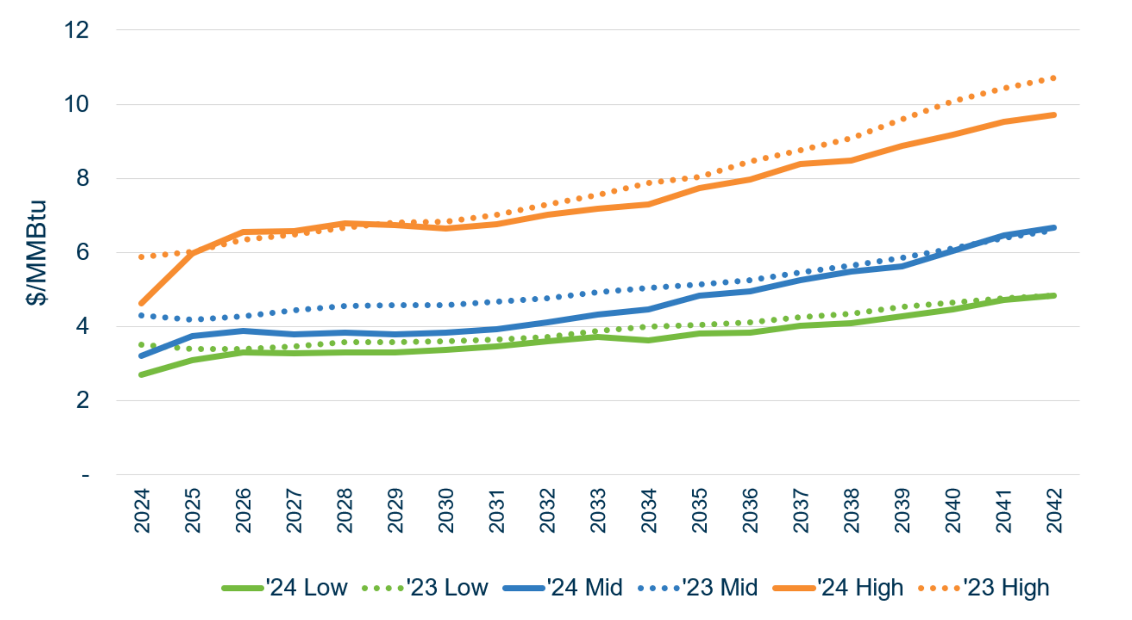
Section 1: Market Conditions Affecting Supply-Side Analysis

1.1 Fuel Price Forecasts[1]

1.1.1 Natural Gas

Evergy updates the IRP natural gas forecast annually based on the forecast used for internal budgeting, which is developed from vendor forecasts and forward markets.[2] The 2024 IRP forecast decreased from the 2023 IRP. Natural Gas prices were identified as a critical uncertain factor, consistent with the 2021 Triennial IRP and the 2022 and 2023 IRPs. High, mid (base) and low forecasts are also used in the development of resource plans and evaluation of plan economics.

Figure 1: Natural Gas Price Forecasts 2024 IRP and 2023 IRP

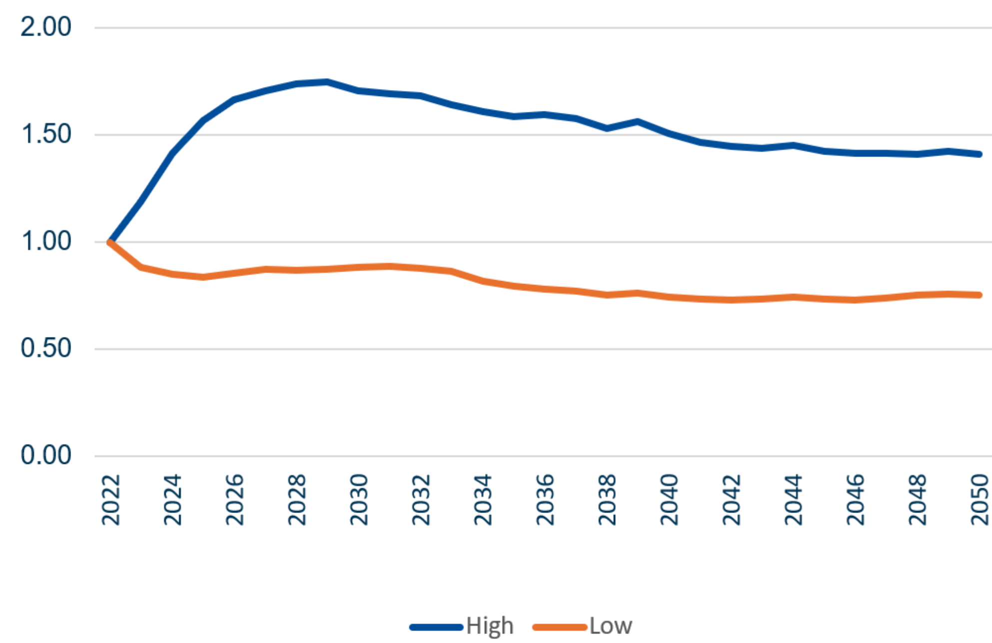


Prices and price expectations for the next few years have fallen from the higher levels that were seen in last year's forecast which was thought to be driven by the Ukraine War, supply chain pressures, global demand, and inflation.

[1] 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(A)
[2] Third party sources include IHS Markit, Energy Information Administration, S&P Global Platts, Energy Ventures Analysis, CME Futures, and ICE.

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.[3]

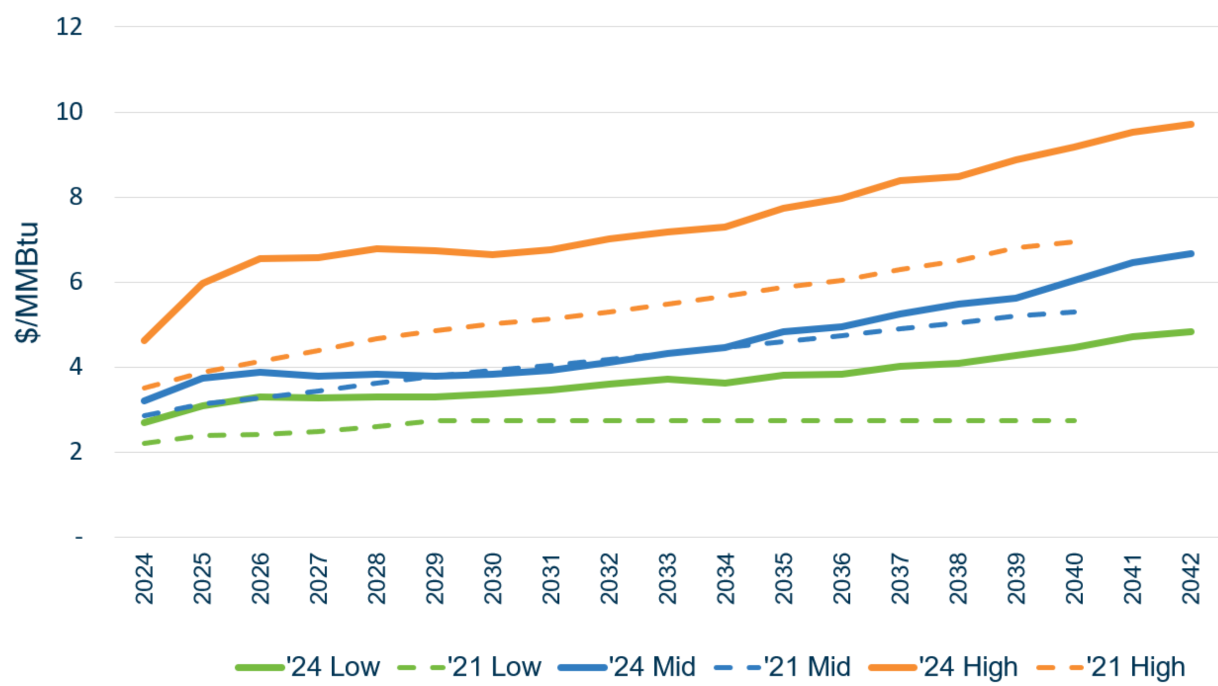
Figure 2: Henry Hub Natural Gas Scalar



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

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 Triennial 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. All forecasts for the 2024 IRP are higher than the 2021 Triennial IRP forecasts.

Figure 3: Natural Gas Price Forecasts 2024 IRP and 2021 IRP



1.1.2 Coal

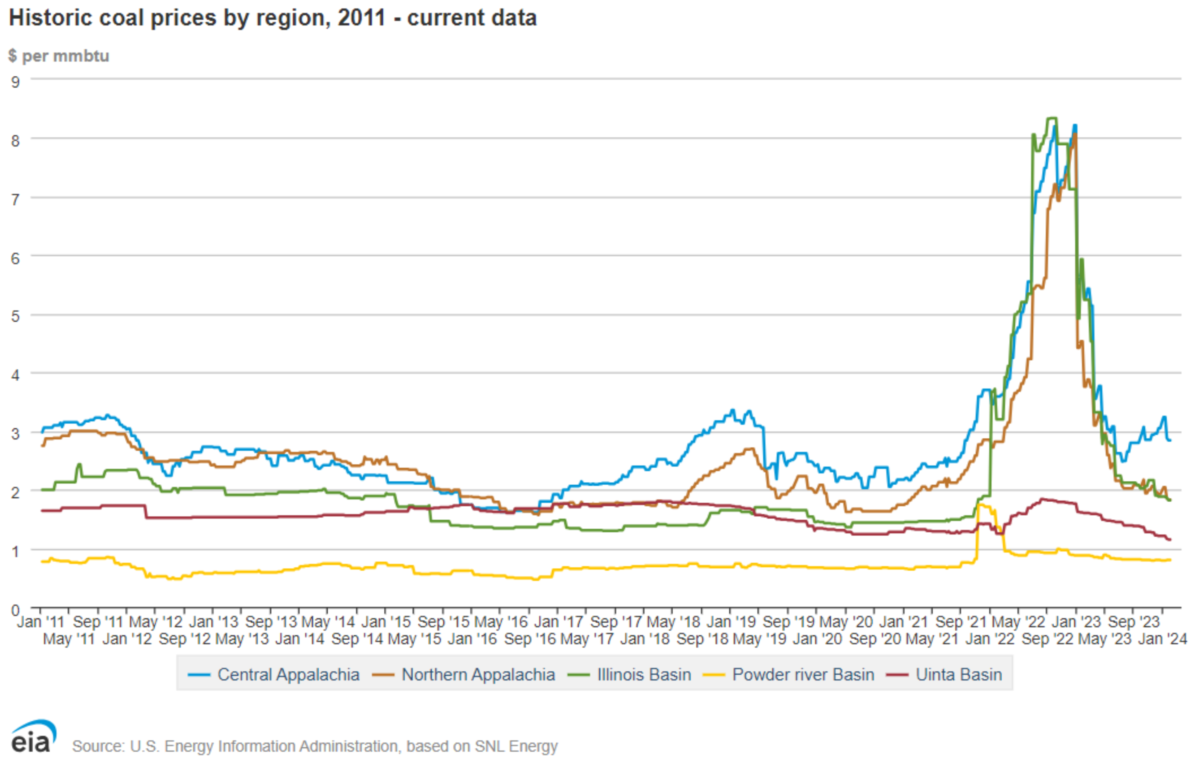
Evergy negotiates coal and rail delivery contracts with suppliers. The coal price forecast was developed using contract prices for the duration that they are in place. Prices for contracted coal volumes were supplemented with prices from Coaldesk's latest available forward market valuation for all uncontracted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

Figure 4: IRP 2024 Metro Coal Price Forecast **Confidential**

[redacted]

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

Figure 5: Historic Coal Prices[4]

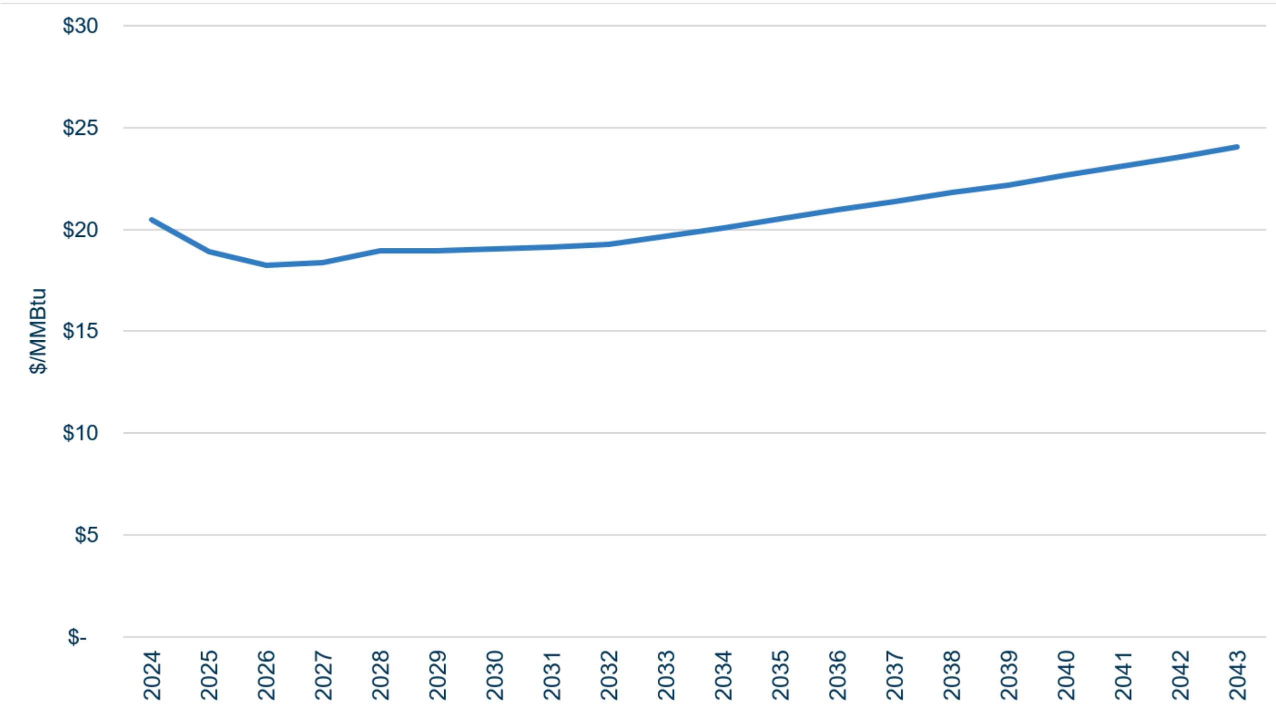


1.1.3 Fuel Oil

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

[4] (EIA. Historical Coal Prices by Region, 2011-Current Data. https://www.eia.gov/coal/markets/includes/archive2.php#tabs-prices-2.)

Figure 6: IRP 2024 Fuel Oil Price Forecast



1.2 Market Price Forecasts[5]

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

[5] 20 CSR 4240-22.040(3)(A); 20 CSR 4240-22.040(3)(A)(1); 20 CSR 4240-22.040(3)(A)(2); 20 CSR 4240-22.040(3)(A)(3); 20 CSR 4240-22.040(3)(A)(4); 20 CSR 4240-22.040(3)(A)(5); 20 CSR 4240-22.040(3)(A)(6)

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 2024 IRP, 1898&Co. used the 2023 ITP models to produce market prices using Evergy's load and fuel price assumptions, including high, mid, and low natural gas price scenarios. This ITP included forecasting models for years 2, 5, 10 and 20. The 2023 ITP models were also used for the 2023 IRP, however for the 2024 IRP, 1898&Co. updated the natural gas prices for Evergy's updated 2024 forecast, included expected transmission upgrades that were approved as part of the 2023 ITP process that had not been completed as of the 2023 IRP filing, and included expected near-term combined-cycle builds that were in Evergy's preferred plans in the 2023 IRP.

1.2.1 SPP ITP Futures

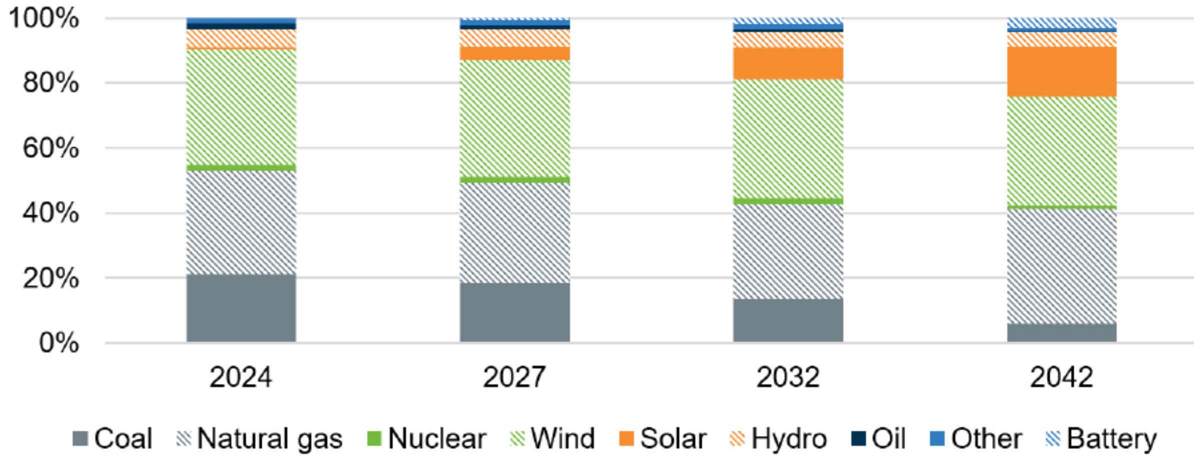
The SPP Future 1 case represents a "business as usual" case with longer retention of existing resources, assuming by 2042 coal resources 56 years and older as well as natural gas and oil generators 50 years and older will retire. The 2024 planning model reflects near-term transmission upgrades and resource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

Table 1: SPP Future 1 Overview

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.

Figure 7: SPP Future 1 Overview



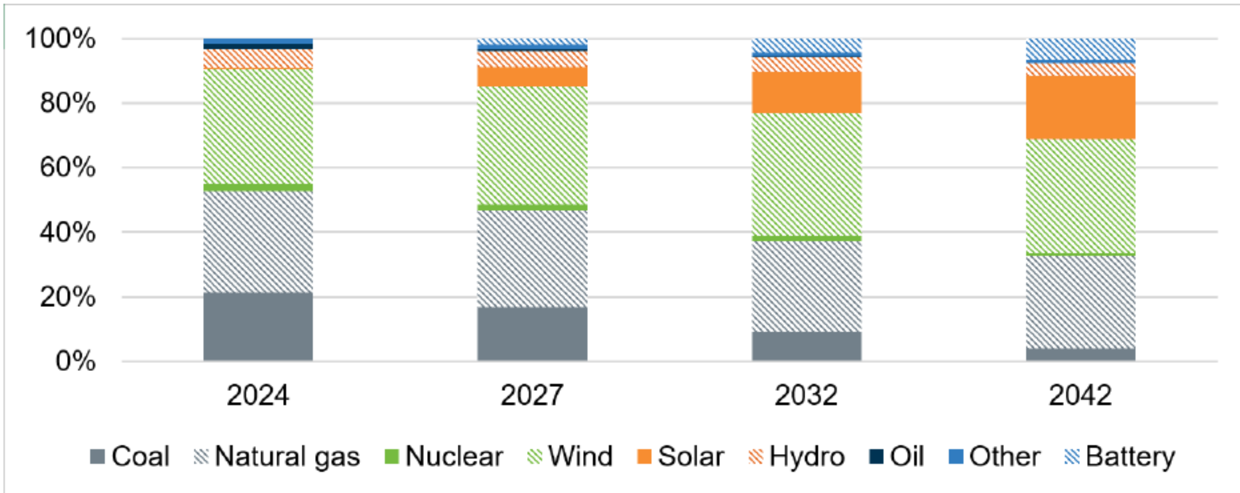
The SPP Future 2 case is an emerging technologies scenario, incorporating growth of electric vehicles and distributed generation as well as higher penetration of renewables and earlier retirement of existing generation. The ages for retirements are reduced to 52 years for coal units and 48 years for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

Table 2: SPP Future 2 Overview

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.

Figure 8: SPP Future 2 Overview



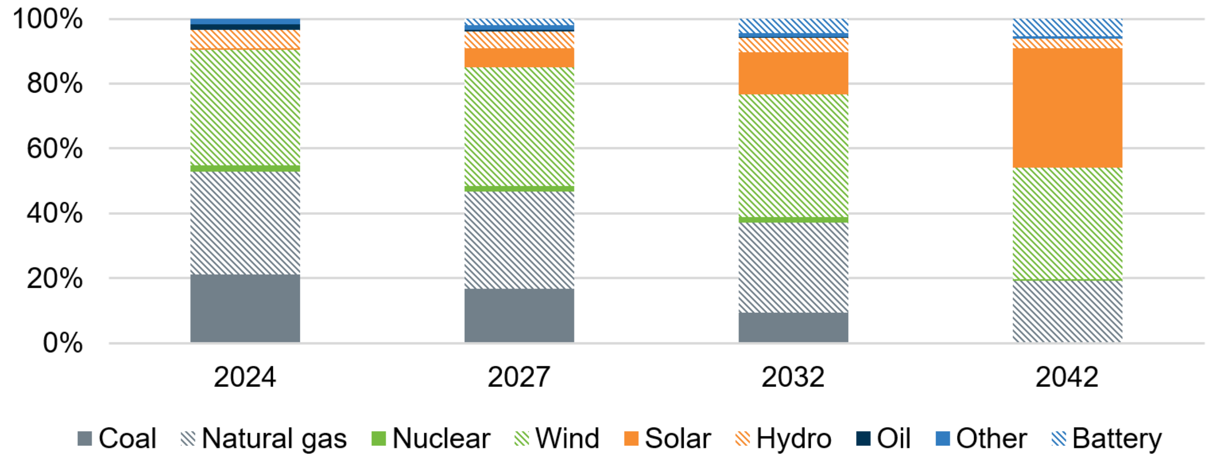
The SPP Future 3 case models accelerated decarbonization. All coal and oil resources are retired by 2042 and new resource build is driven by targeted emissions reductions of approximately 95% from 2017 by 2042. Future 3 is only modeled for 2042, so years 5 and 10 (2027 and 2032) reflect Future 2 models.

Table 3: SPP Future 3 Overview

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.

Figure 9: SPP Future 3 Overview



Consistent with the 2023 IRP, the Evergy market price forecasts for the 2024 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.

1.2.2 Congestion and Nodal Pricing

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. This historical use of a single zonal price reflected the availability of Transmission Congestion Rights (TCRs) which enable basis differential (i.e., congestion) between different nodes to be hedged. Due to increasing penetration of renewables and increasing basis differential between nodes, particularly between resources in the western portion of SPP's territory and Evergy's load nodes, Evergy began incorporating different nodal prices in IRP modeling in 2022. TCRs are still available to mitigate the impact of congestion and will continue to be a part of Evergy's strategy for optimizing its fleet, but utilizing more granular nodal pricing enables a more conservative assessment of resource economics in the context of an IRP. This is most relevant for wind resources which typically see greater basis differential compared to load than other resource types.

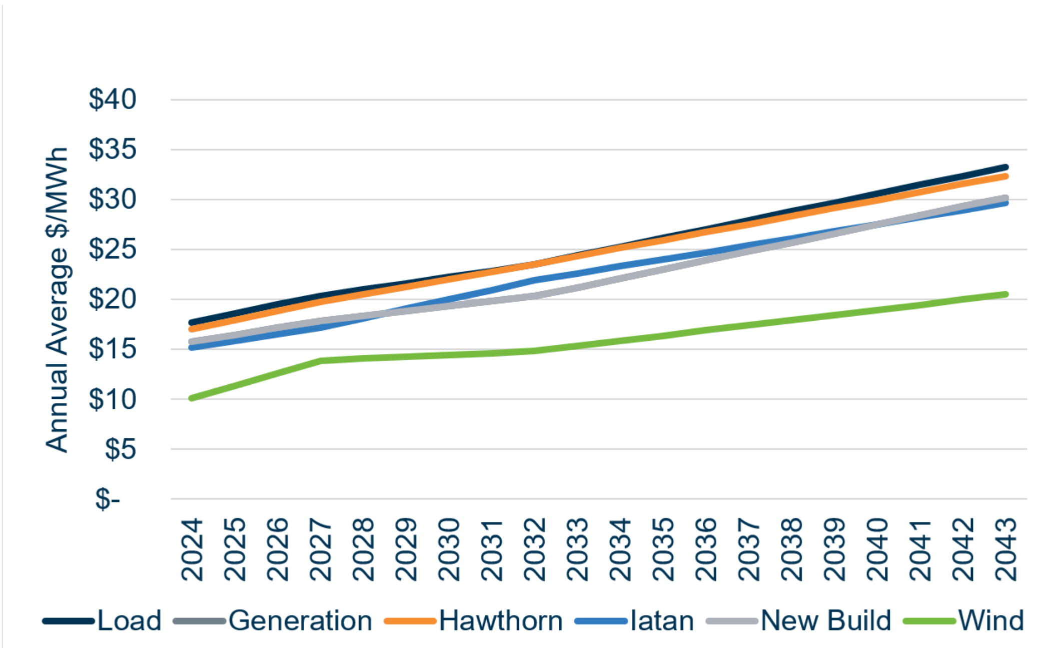
The 2024 IRP pricing models, based on the finalized 2023 SPP ITP models, reflect current transmission topology and near-term transmission upgrades, including those approved by the SPP Board of Directors to resolve new constraints identified in the 2023 ITP process. The models use economic dispatch, considering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

- Load zones for each utility: used for load and DSM
- Coal resource locations for each coal site
- Wind location: used for all new and existing wind and wind PPAs
- Generation zones for each utility: used for existing generators; Metro location used for all non-wind new resources

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 expected build-out of renewable resources between 2032 and 2042, which is not accompanied by forecasted 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.

Consistent with the 2023 IRP, the 2024 IRP Future 2 prices (used in the low and mid carbon restriction scenarios) have slowly rising prices over time. The 2024 IRP market price forecasts are lower, due to lower natural gas price forecasts. Eastern locations are generally slightly higher priced than western locations within Evergy, and the wind location is the lowest priced due to congestion.

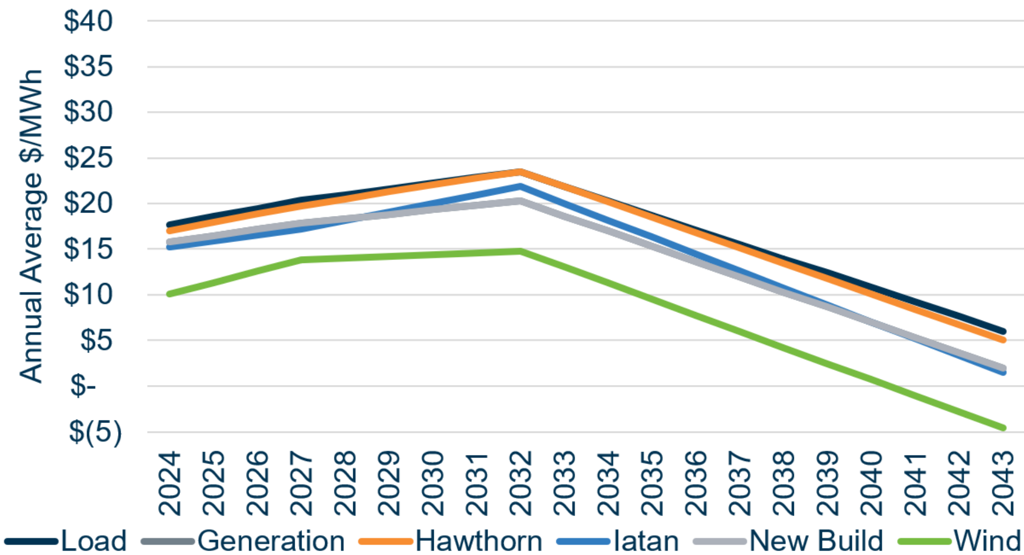
Figure 10: IRP 2024 Metro Market Prices Mid NG Future 2



Note: "New Build" node is equivalent to Metro Generation load. As a result, Metro generation is not visible on chart.

Future 3, used for the high carbon restriction scenarios in IRP 2024, 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 11: IRP 2024 Metro Market Prices Mid NG Future 3



Note: "New Build" node is equivalent to Metro Generation load. As a result, Metro generation is not visible on chart.

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 resulting 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.

1.2.3 Negative Prices

The market price forecasts reflect the negative pricing that has been observed in SPP and predict that the number of negative-priced hours in SPP will continue to grow. 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 and 2024 IRP market price forecasts have more up-to-date planning assumptions and align more closely with recent SPP experience.

Figure 12: Actual Day Ahead Negative Prices at Load (% of Annual Hours)

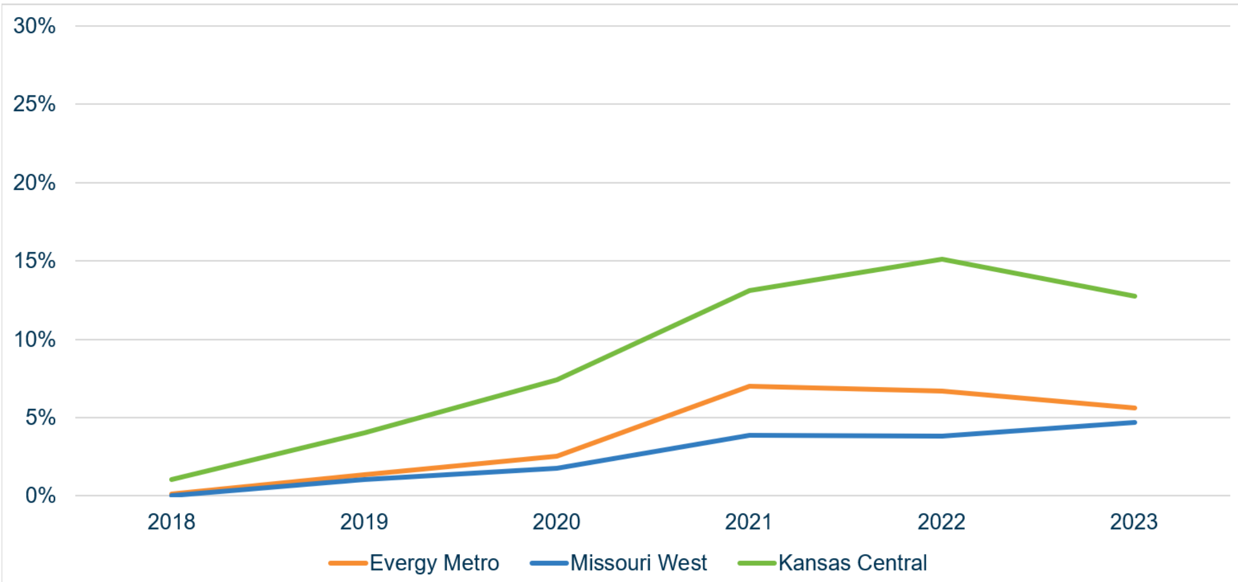


Figure 13: 2024 IRP Modeled Negative Prices at Load (Metro)

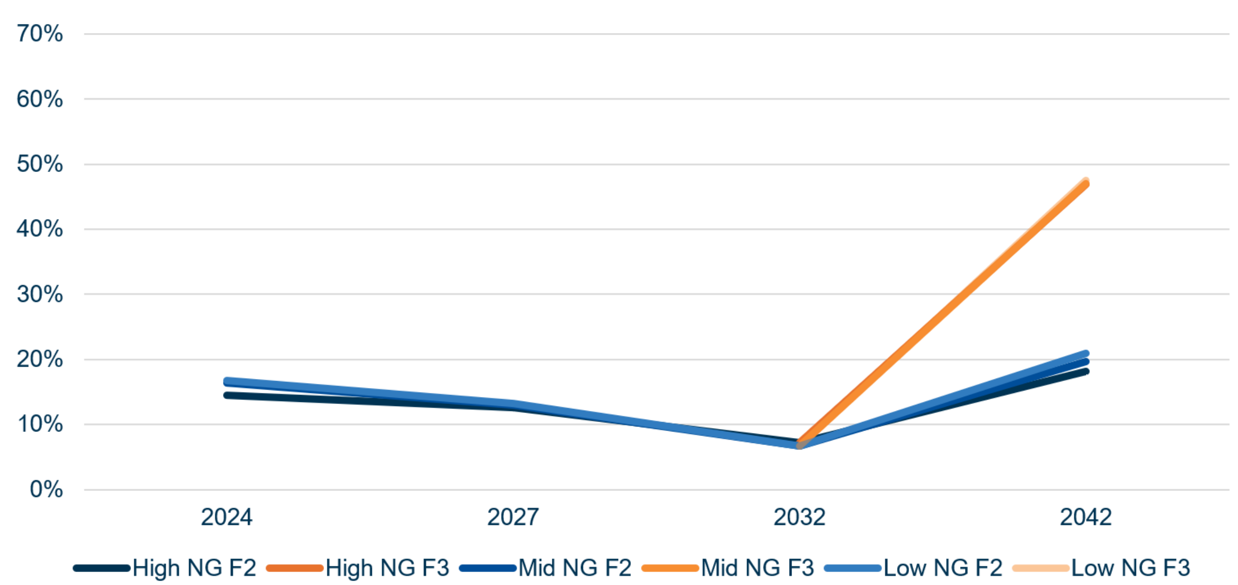


Figure 14: Actual Day Ahead Negative Prices at Generator Nodes (% of Annual Hours)

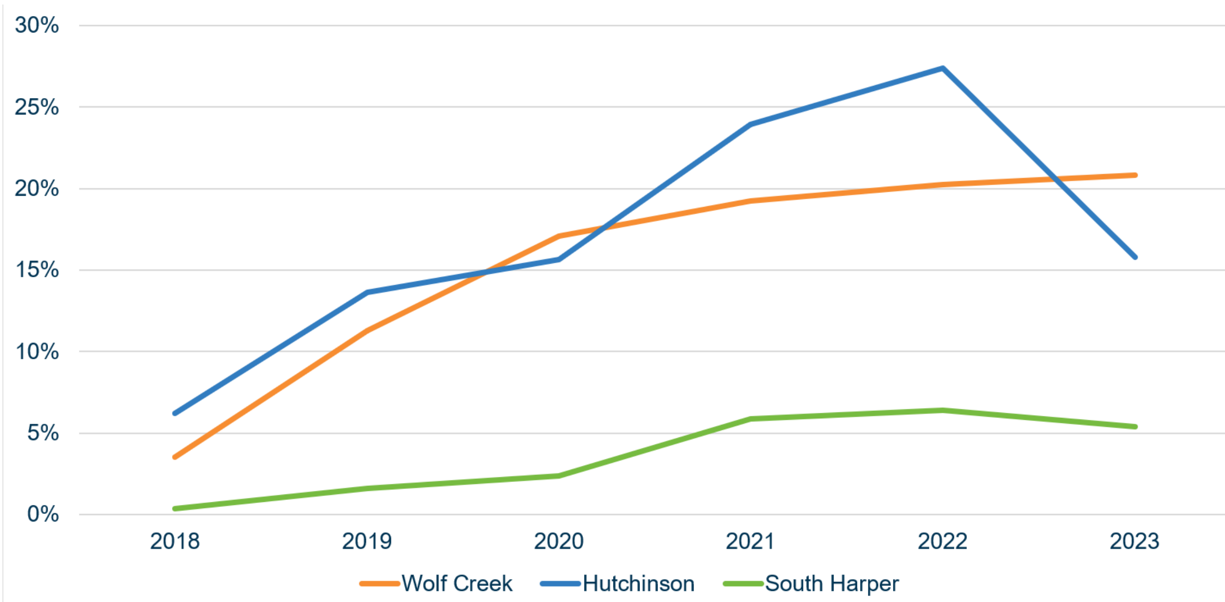


Figure 15: 2024 IRP Modeled Negative Prices at Generator Nodes (Metro)

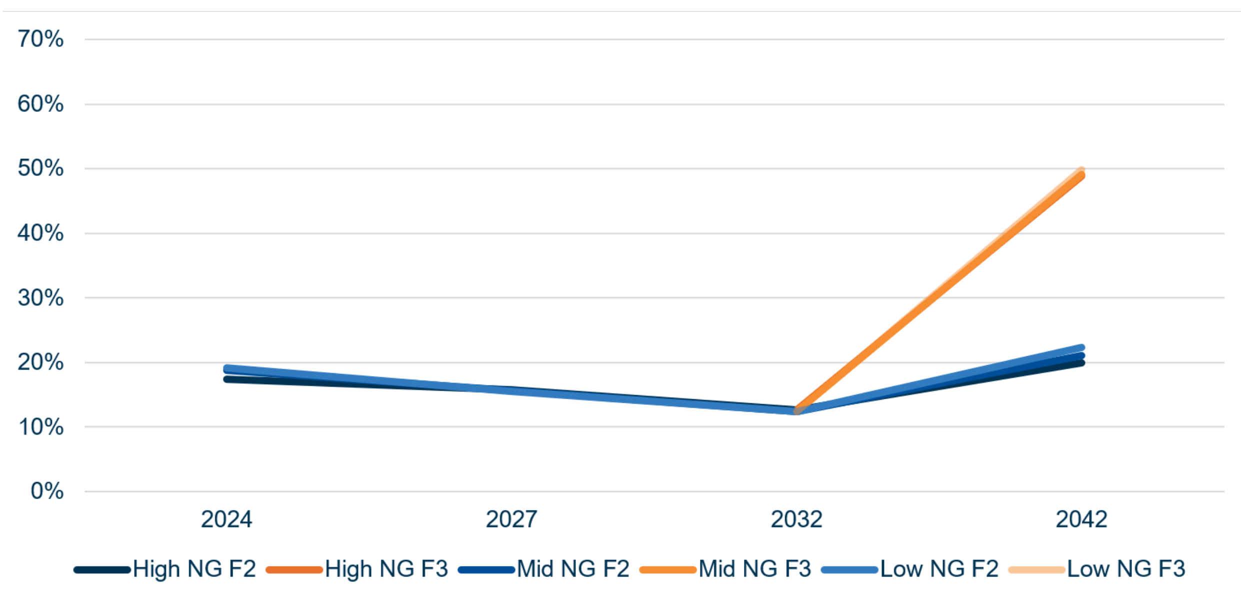


Figure 16: Actual Day Ahead Negative Prices at Wind Nodes (% of Annual Hours)

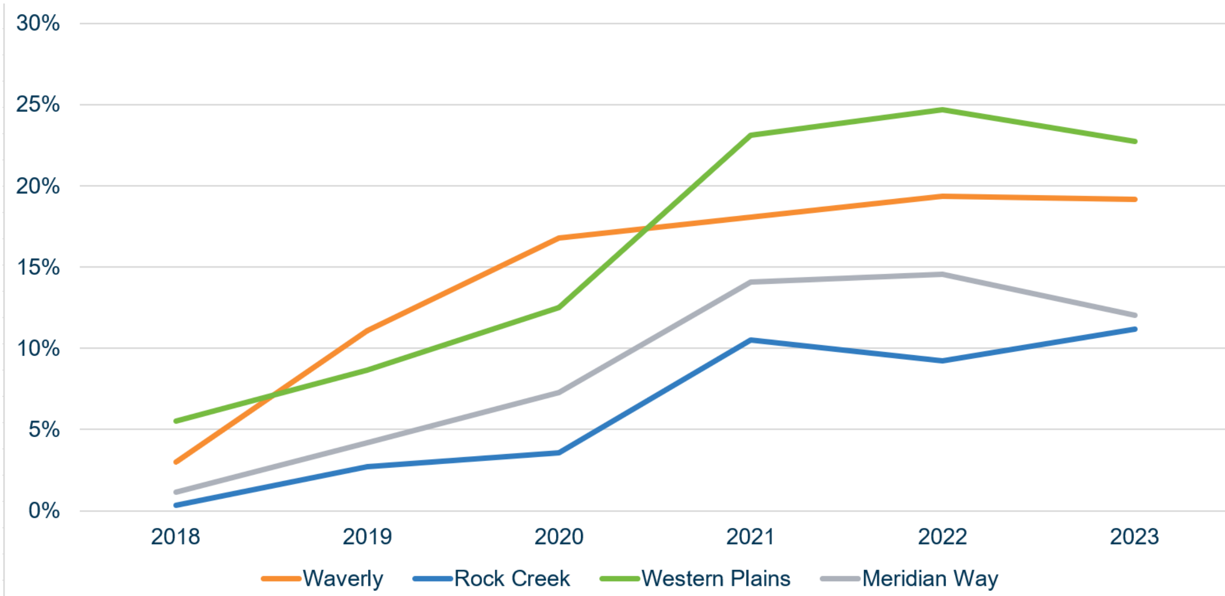
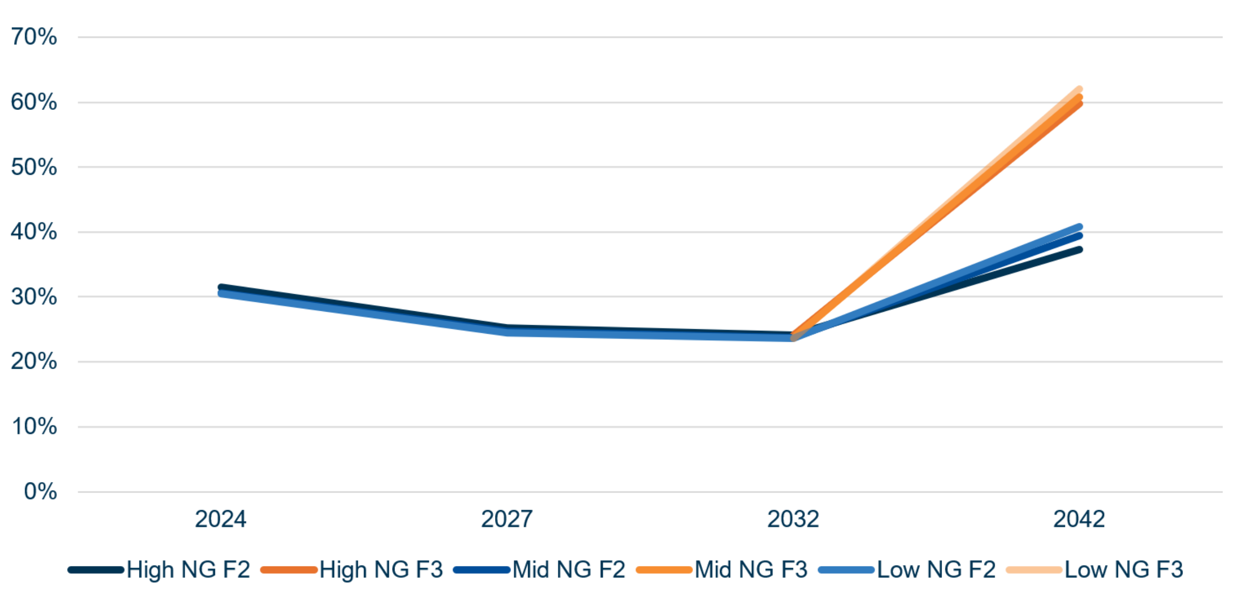


Figure 17: 2023 IRP Modeled Negative Prices at Wind Nodes



1.3 Carbon Restrictions[6]

Carbon emissions policy was identified as a critical uncertain factor, consistent with the 2021 Triennial IRP, and subsequent updates. 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 and 2024 IRPs they were modeled with both restrictions on carbon emissions production and carbon emissions taxes.

Figure 18: CO_2 Emissions Tax Forecasts in IRP 2021 & 2022 **Confidential**

[redacted]

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 Inflation Reduction Act or IRA), or requirements for physical emissions reductions, rather than carbon taxes.

[6] 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(D)

The low forecast for the 2024 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 Evergy's carbon emissions in 2042, the carbon restriction applied in the IRP dispatch model for 2042 is 70%). The high forecast is consistent with the assumptions in the SPP Future 3 model which was engineered with an explicit carbon reduction goal of an approximately 95% reduction in CO_2 production from 2017 levels. Evergy used the same logic to ratably restrict emissions from historic 2017 CO_2 production levels to culminate 2042 with a 95% reduction. The high forecast also incorporates a carbon tax which ramps to $25/ton by the end of the twenty-year horizon, consistent with Future 3.

Figure 19: Metro CO_2 Emission Constraint

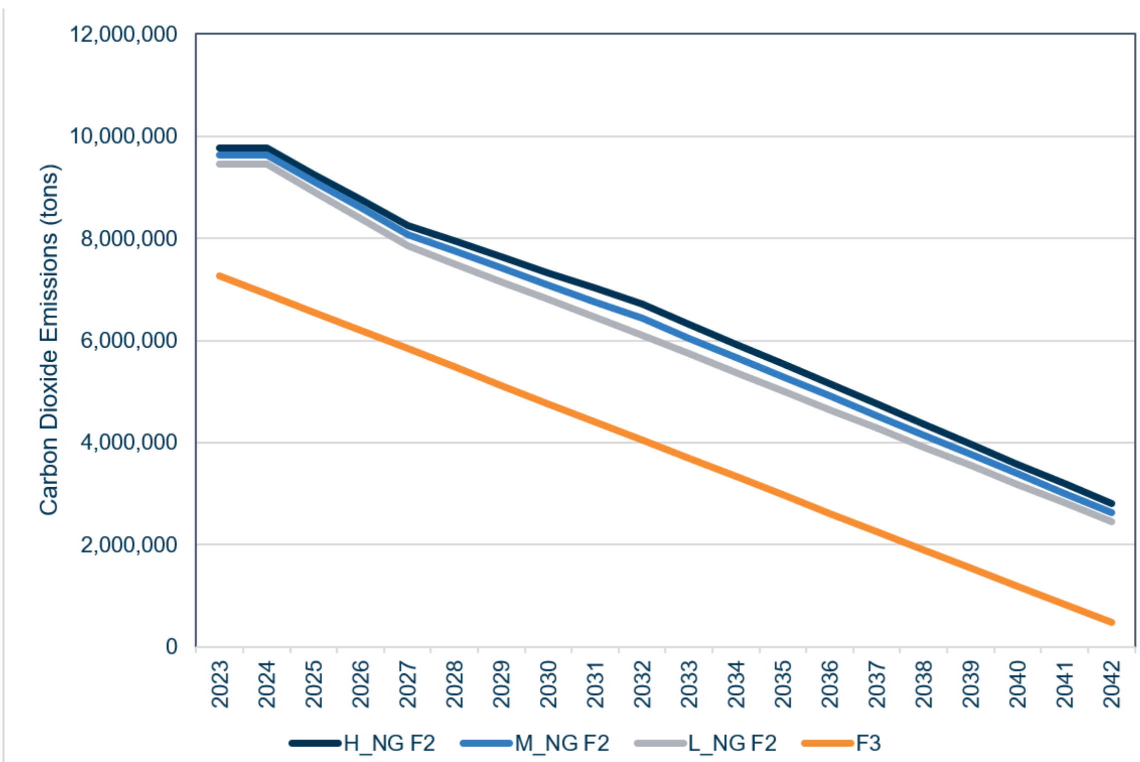


Table 4: Future 3 CO_2 Emission Tax ($/ton)

Year(s)	Price
2024-2032	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
2043	25

In order to achieve SPP Future 3 emissions goals, breakthroughs would be needed in dispatchable carbon-emissions-free technology. Newer combined cycles and combustion turbines are engineered to burn cleaner fuels including hydrogen or ammonia blends. However, production and transport of these fuels is still cost prohibitive. Improvements in carbon capture and sequestration technologies are another option for reducing or eliminating emissions. US government subsidies are encouraging innovation in these areas. In the 2023 IRP, new combined cycles and combustion turbines were assumed to have zero emissions beginning in 2036, at no cost, for Future 3 models, representing the necessary technological breakthroughs. In the 2024 IRP, costs associated with carbon capture and storage were applied to new combined cycles beginning in 2035 in Future 3, reflecting an assumed cost associated with mitigating carbon emissions from these new resources. Additionally, carbon-free energy was assumed to be available in all models for $300/MWh in case the fleet was unable to generate enough energy, or carbon-free energy to serve load. This price point is based on the current typical price of fuel oil-fired peaking units which, although clearly not representative of actual carbon-free energy, provides a “scarcity price” proxy for the cases when Evergy is unable to meet its own load.

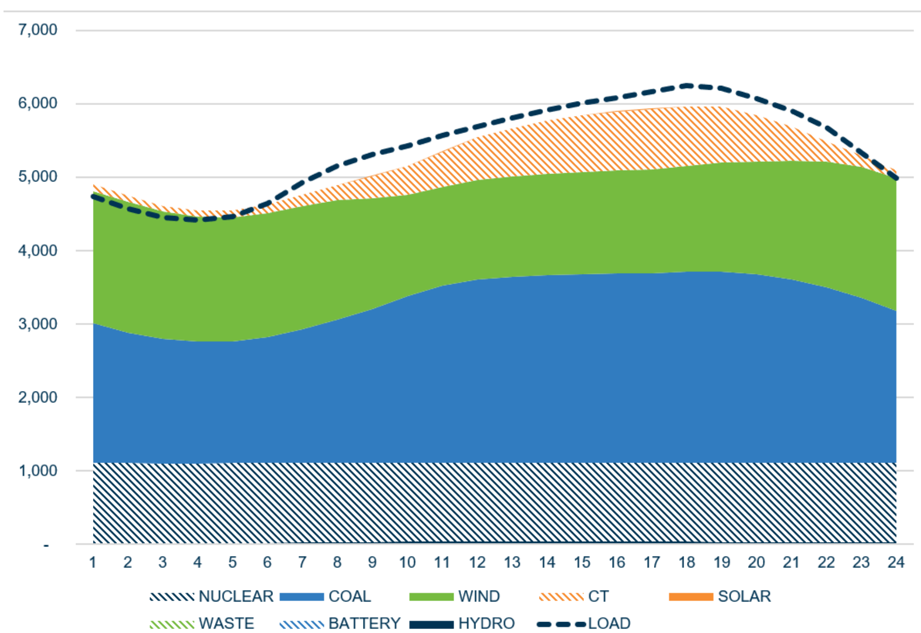
1.3.1 Other Emissions Costs or Restrictions[7]

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

1.4 Market Dependence

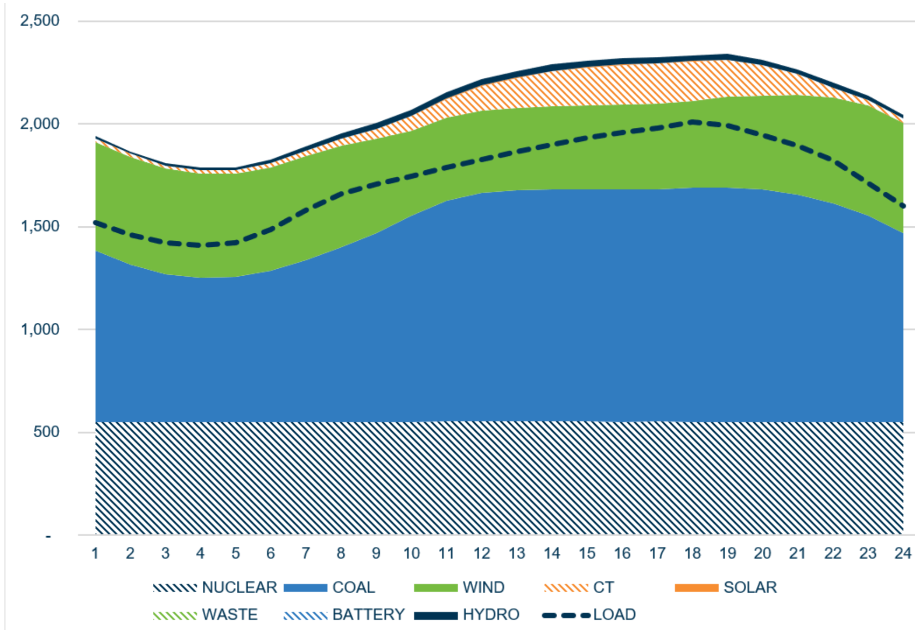
Evergy benefits from participation in the SPP energy markets because it can sell energy when prices are higher than production costs and buy energy when prices are lower than production costs. Currently, aggregated Evergy supply and demand (including Evergy Metro, Missouri West, and Kansas Central) is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

Figure 20: 2023 Annual Evergy Load and Generation Balance by Hour of Day



[7] 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(D)

Figure 21: 2023 Annual Metro Load and Generation Balance by Hour of Day



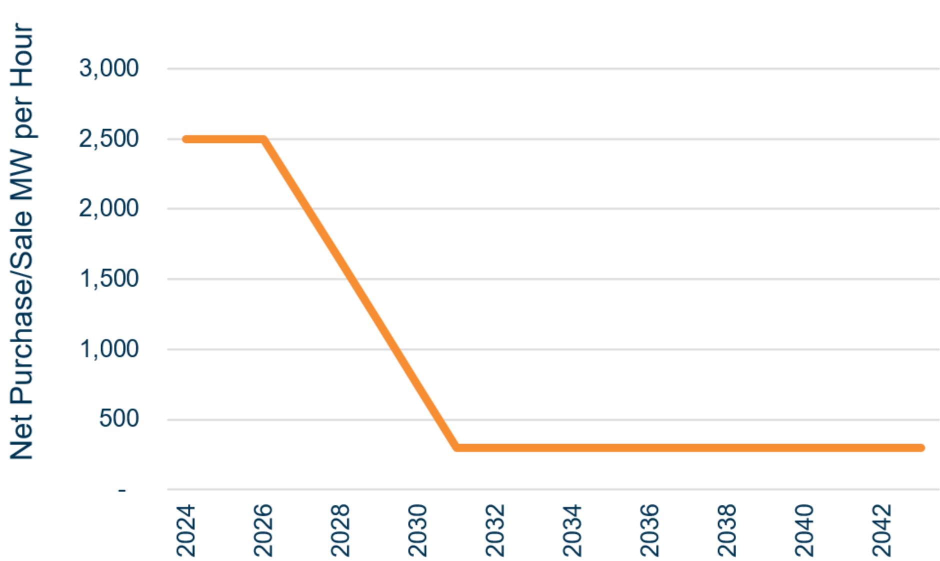
Evergy has incorporated market prices in its resource planning decisions to assist in the valuation of asset economics, particularly to incorporate expected transmission congestion. Evergy also expects to benefit from production cost savings in the future as SPP continues to transition to a low variable cost resource mix.

As this transition occurs, Evergy expects coal generation, a substantial source of energy supply to load, to decline due to economics, environmental restrictions, and retirements. In addition, most of Evergy's wind supply is Power Purchase Agreements (PPAs) which will roll off in the 20-year time horizon.

Evergy does not expect other utilities in SPP to build generation that will replace all of the energy it currently supplies to the market. In addition to meeting SPP Resource Adequacy Requirements, Evergy also aligns its future plans with meeting hourly customer energy needs in the lowest cost manner, by limiting net sales and purchases from the market to design a future portfolio that provides an economic and reliability hedge.

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

Figure 22: Limit on Market Dependence in Resource Planning (Metro)



1.5 Resource Adequacy Requirements

SPP requires all load-serving entities to meet Resource Adequacy Requirements based on forecasted peak load plus planning reserve margins. SPP conducts a LOLE (loss of load expectation) study at least every two years, setting the planning reserve margin based on a LOLE of less than one day in ten years.[8] Evergy plans to have sufficient capacity to meet SPP requirements in every planning year. Evergy submits planning data, including load forecasts and resource accreditation to SPP annually to confirm it has met the requirements prior to the summer season.

Evergy expects significant changes to Resource Adequacy Requirements in the future. There are numerous components of resource adequacy planning that are working through the stakeholder process. Evergy expects SPP to file tariff changes to implement winter Resource Adequacy Requirements, performance-based accreditation, and Effective Load Carrying Capability (ELCC). However, there are many interrelated issues to work through which could influence future requirements – including LOLE study assumptions and variations on accreditation calculations.

1.5.1 Winter Reserve Margin Requirement

The Federal Energy Regulatory Commission (FERC) rejected SPP's tariff change to implement a winter reserve margin requirement beginning in 2024/25 Winter, based on the impression that it was not strict enough in ensuring capacity resources would be available.[9] Evergy expects SPP to submit a revised tariff filing. The initial winter reserve margin for winter 24/25 was 15%, however SPP studies have indicated potential dramatic increases in future winter requirements. There is still uncertainty in predicting what the winter reserve margins will be as stakeholders need to work through LOLE study assumptions that may show greater risks in winter such as higher forced outage rates in extreme cold weather, balance of when loss-of-load events occur between summer and winter in modeling, and planned outages scheduled in winter months.

[8] SPP OATT Attachment AA, Section 4.0 Planning Reserve Margin
[9] *Sw. Power Pool, Inc.*, 185 FERC ¶ 61,159, at P 38 (2023).

1.5.2 LOLE Study Results and Reserve Margin Expectations

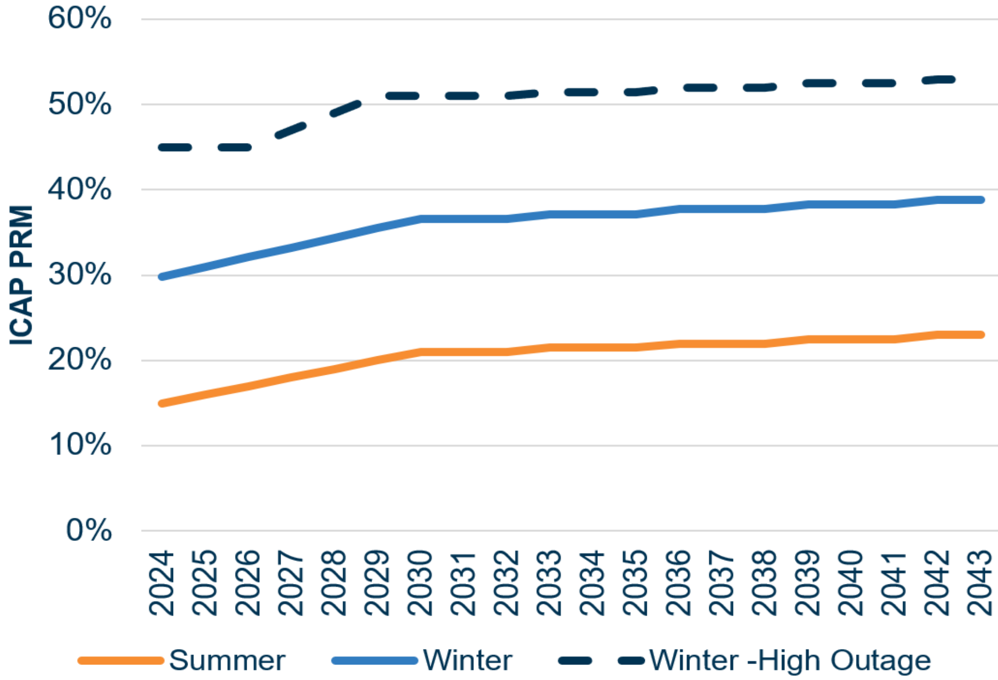
Evergy incorporated a 12% summer reserve margin in its resource plans for the 2021 and 2022 IRPs, consistent with SPP requirements. In July 2022, the SPP board approved an increase in the summer reserve margin to 15% beginning in summer 2023, and Evergy's 2023 IRP met that minimum value for the 20-year planning horizon. The required reserve margin for summer 2024 has been set at 15%, and no winter requirement is in effect for winter 2024/2025. However, SPP's draft LOLE study results anticipate higher reserve margins in future years.

The draft 2023 LOLE study results for the 2026 planning year show a 16% summer reserve margin and a 27%-46% winter reserve margin, depending on the level of cold-weather correlated outages assumed.[10] For planning year 2029, the summer reserve margin rises to 21.4%, and the winter reserve margin rises to 50.7% with full cold-weather outages assumed.[11] The rise in reserve margins from 2026 to 2029 in the study is attributed to changes in the resource mix, planned outage scheduling overlaps with high need hours in winter, increase in load, shift in risk hours, and allocation of most LOLE risk to winter.[12]

Based on these results, Evergy has revised its planning assumptions to anticipate a higher initial winter reserve margin and higher reserve margins for both summer and winter over the planning horizon. The summer base assumption is that the reserve margin of 15% in 2024 will increase by 1% per year through 2030 and then stabilize, rising 0.5% every three years. The winter base assumption is that the same amount of capacity is needed in both seasons, despite the lower winter load. SPP winter peak is approximately 89% of summer peak, implying an initial reserve margin of 30% and rising as the summer reserve margin increases. As a high case, the winter reserve margin starts at 45%, reflecting full cold weather correlated outage risk.

[10] SPP, 2023 Loss of Load Expectation (LOLE) Study Draft Results, December 2023 SAWG Meeting, Slide 19 (assuming 50% split between summer and winter LOLE allocation). ("LOLE Draft Results")
[11] Id., Slide 22. (Assumes 97% of LOLE in winter, 3% in summer).
[12] Id., Slide 22.

Figure 23: SPP Reserve Margin Assumptions IRP 2024



The draft study results and future LOLE study assumptions are still being vetted in the stakeholder process. Some of the primary focus areas for refinement may be[13]:

- **Future Weather Expectations:** The 2023 draft LOLE study uses 43 years of historical weather data to model load, wind, and solar patterns.[14] The Monte Carlo approach runs thousands of models with these weather-patterned loads, and varying resource availability based on historical outage distributions. The summer 2026 LOLE events occurred in 10 different weather years, with the most events, 33%, in the 1980 models.[15] The winter 2026 LOLE events occurred in only four different weather years, with 72% of events in the 2021 model which had the winter storm Uri.[16] Stakeholders may consider whether a Uri-type event is likely to occur again and how much weight it should carry in the modeling.

[13] Id., Slide 18.
[14] Id., Slide 7.
[15] Id., Slide 14.
[16] Id., Slide 14.

- **Cold-Weather Correlated Outages:** Historical analysis shows a large increase in forced outages when temperatures are below zero in SPP.[17] When the LOLE study considers historical cold-weather outage correlation, more LOLE events occur in winter, increasing the reserve margin needed to lower the number of events back to the 1-in-10 years standard. Stakeholders may consider whether cold weather issues are expected to persist in the future or may have been remedied by better practices in the natural gas industry, winterization, and incorporation of lessons learned.
- **Seasonal Balance of Risk:** The allocation of events to summer and winter changes the reserve margin for each season. For example, allowing more events to occur in winter raises the summer reserve margin and lowers the winter reserve margin. This may affect utilities that are summer and winter peaking differently.
- **Scheduling of Maintenance Outages:** The modeling accounts for some scheduled outages in winter, consistent with historical scheduling practices. The presence of scheduled outages in winter increases the need for other resources to be available, raising the winter reserve margin.

1.5.3 Performance-Based Accreditation

Performance-based accreditation is a metric to redistribute accreditation based on historical availability at peak times. SPP currently accredits thermal resources based on their tested summer capacity, through 3-hour capability tests every three years, supplemented by 1-hour operational tests annually. The new method proposed in the stakeholder process reduces accreditation based on each resource's seasonal (winter or summer) forced outage rate. Seven-year average seasonal forced outage rates will be used. However, until SPP collects seven years of data, class average outage rates will substitute for resource-specific forced outage rates as part of the calculation. All resources lose accreditation under PBA, however the SPP reserve margin will also decrease to reflect the system need for unforced capacity. Therefore, resource portfolios with higher outages than average, will get less relative accreditation and will need more

[17] Id., Slide 8.

capacity to meet requirements and portfolios with lower outages than average, will get more relative accreditation and will need less capacity. For the 2024 IRP, Evergy has incorporated the expected change in accreditation in its resource planning beginning summer 2026.

1.5.4 Effective Load Carrying Capability (ELCC)

ELCC is a method to measure the contribution a resource makes to meeting load, taking into account fuel supply and duration limitations (for example, solar resources cannot serve load at night). SPP is working toward implementing ELCC for renewable and storage resources. FERC rejected SPP's tariff change to implement ELCC before summer 2023, due to deficient tariff language.[18] SPP stakeholders were concerned that if SPP were to correct the deficiency, FERC might still reject ELCC due to concerns about whether renewables and storage would be unfairly accredited more stringently than thermal resources. Evergy expects SPP to couple ELCC with performance-based accreditation for thermal resources in a future filing to address these concerns. For the 2024 IRP, Evergy is factoring in expected ELCC values for renewable and battery resources in its resource planning beginning in summer 2026.

1.5.5 Accredited Capacity (ACAP) Reserve Margin

As SPP moves to performance-based accreditation and ELCC it will be measuring the unforced capacity of resources rather than the installed capacity. ACAP reserve margins will reflect the need for resource capacity that has already been adjusted for ELCC and performance-based accreditation. In the 2024 IRP, Evergy includes this beginning in summer 2026 as part of the adjustment to the capacity need for performance-based accreditation.

1.5.6 Demand Response Accreditation

Demand response resources are currently netted against peak load based on their tested capabilities. Stakeholders have discussed whether these resources should be accredited using an ELCC construct to reflect their availability limitations – such as number and

[18] *Sw. Power Pool, Inc.*, 182 FERC ¶ 61,100 at P 25 (2023).

duration of events. The 2024 IRP incorporates an assumption that demand response receives accreditation up to its expected tested capacity. This is lower than the past IRP assumption that demand response would continue to be treated as a net to load, which gave it a capacity value equivalent to its tested capacity plus the reserve margin. Updated policy related to Demand Resource is still in very early stages of development, but this change in assumption allows for a slightly more conservative assessment of accreditation in expectation of potential future changes.

1.5.7 Other Possible Policy Changes

SPP stakeholders have discussed other possible policy changes, that Evergy is monitoring, but has not included in the 2024 IRP analysis, including:

- Potential incorporation of on-site fuel or firm fuel requirements or changes to accreditation calculations based on fuel supply. At this time, the incorporation of a specific fuel supply requirement is considered unlikely, but considerations specific to fuel supply are being assessed in the evaluation of peak hours (next bullet).
- Possible incorporation of a calculation to assess resource availability in peak load hours (i.e. top 3% of load hours or reliability event hours) as a refinement to performance-based accreditation.
- Outage scheduling requirements, possibility needed to ensure adequate energy supplies throughout the planning year, including spring and fall. This could potentially affect winter and summer capacity accreditation if resources need to shift planned outages to those seasons.

1.5.8 Resource Adequacy Requirement Uncertainty

Evergy is not specifically treating Resource Adequacy Requirements as a Critical Uncertain Factor in the 2024 IRP. While uncertainty in Resource Adequacy Requirements can certainly impact the amount of capacity Evergy must procure to meet requirements, it does not specifically impact the relative performance of different resource plans (i.e., because if requirements increase, more capacity is necessary; if requirements decrease, less capacity is necessary). In this way, Resource Adequacy Requirements are very similar to Load because they both define the amount of capacity each Evergy utility must maintain to meet customer needs. As a result, for the 2024 IRP, Evergy is considering the Load critical uncertain factor sufficient to capture both Load and Resource Adequacy Requirement uncertainty. Particularly because the High Electrification Load scenario includes a very large amount of load growth based on an assumption of policy changes that support economy-wide electrification, Evergy believes it is also sufficient to capture a more moderate level of load growth combined with even larger increases in Resource Adequacy Requirements. This High Load case, along with the Low Load case, has been assessed to develop contingency plans which would reflect either higher or lower Load / Resource Adequacy Requirements for each utility compared to its base case.

Section 2: Existing Resources

2.1 Fuel Mix Summary

Evergy Metro has gradually shifted its generating fleet, which historically consisted of primarily coal and gas generation, to a more diversified and balanced fuel mix. More than a decade ago, Evergy Metro began increasing its renewable generation resources while retiring older, end of life generators. In 2007, less than 3% of Evergy Metro's total nameplate capacity was sourced from renewable resources, whereas by 2023, 25% of total capacity is sourced from renewable resources. The table below reflects Evergy Metro's generation assets operating in 2023.

Table 5: Metro Capacity and Energy by Resource Type

Capacity by Fuel Type	Capacity (MW)	Capacity (%)	Energy (MWh)	Energy (%)
Coal	2,258	41.8%	8,521,370	46.2%
Nuclear	553	10.2%	4,842,090	26.3%
Nat. Gas	791	14.7%	738,661	4.0%
Oil	394	7.3%	25,537	0.1%
Wind*	1,331	24.7%	4,090,868	22.2%
Hydro	66	1.2%	197,865	1.1%
Solar	7	0.1%	11,506	0.1%
Total	5,400	100.0%	18,427,897	100.0%

*Nameplate Wind Capacity

2.2 Thermal Fleet Efficiency Improvements[19]

Evergy works to proactively improve plant efficiency across the entire generation fleet. In addition to reducing production costs, improved plant efficiency also effectively improves air quality-related emissions. Large baseload coal units produce the largest share of MWhs, so they are the natural priority of plant efficiency improvements and the focus of this section.

[19] 20 CSR 4240-22.040(1)

Plant efficiency is influenced by many different factors including operational issues, maintenance, and equipment degradation. Evergy employs a variety of resources to proactively improve plant efficiency:

2.2.1 Software

- **EtaPRO©** - Performance monitoring software from GP Strategies that performs real-time and continuous performance calculations to monitor equipment degradation. Platform also employs Advanced Pattern Recognition (APR) models to monitor equipment health. Software is implemented on the following units:
  - Hawthorn Unit 5, 6&9
  - Iatan Units 1 & 2
  - La Cygne Units 1 & 2
- **Power BI** – Plant Efficiency data is visualized using software from Microsoft, increasing real-time, awareness of plant performance issues on a mobile platform.
- **P3000** – Closed Loop Optimization software from Siemens monitors unit processes and makes real-time changes to operating parameters based on expert rules and advanced algorithms. Evergy has (or is in progress) implemented optimization on the following units:
  - Hawthorn Unit 5
  - La Cygne Units 1 & 2
  - Iatan Units 1 & 2

2.2.2 Personnel

- **Engineering** – positions dedicated to Plant Efficiency are staffed as follows:
  - Performance Engineer Manager - Fleet Performance
  - Central Performance Engineer - Fleet
  - Hawthorn Performance/Combustion Engineer
  - Iatan Performance/Combustion Engineer
  - La Cygne Performance/Combustion Engineer
- **Remote Monitoring & Diagnostics (M&D Center)** – the M&D Center supports continuous online monitoring (a service formerly contracted through GP

Strategies), including plant efficiency and equipment performance/reliability issues.

- Generation M&D Center is staffed with a Manager, Engineer, and 2 Analysts

2.2.3 O&M Practices

- Top tier plant efficiency requires conscientious Operations and Maintenance strategies. Plant efficiency is always a key consideration of regular operator rounds and preventative maintenance. In addition, cleaning/maintenance of certain equipment is critical – and this often requires special equipment and/or vendors. This maintenance is typically performed on an ‘as needed’ basis and is typically guided by equipment performance monitoring. The following are examples of recent ‘major’ O&M-related efforts performed by specialty contractors that have direct plant efficiency benefits:
  - Condenser & Heat Exchanger Tube Cleaning (darting)
  - Condenser Air In-leakage testing (online helium or offline flood test)
  - Steam Turbine Open/Inspect/Clean (media blasting)
  - Air Heater Element Cleaning (wash, vacuum, or media/chem clean)
  - Boiler Chemical Clean (to remove internal scale/deposits)
  - Boiler & Flue Cleaning (vacuum, explosive cleaning, or media blasting)
  - Feedwater Heater Tube Leak Repair (explosive plugs)

2.2.4 Capital

Evergy invests significant capital on projects to maintain or improve plant efficiency. Examples of these projects are listed in Table 6 below.

In addition to the resources listed in Table 6, Evergy is planning to invest in additional wireless sensors for Continuous On-line Monitoring (COLM). This equipment will allow more robust identification of equipment degradation, including performance issues – especially on medium-to-high value assets. Several trial/demonstration projects are in progress.

Evergy's performance efforts have resulted in the following key accomplishments:

- Evergy Coal Fleet benchmarks top quartile (tier 1) on efficiency
- Iatan Unit 2 continues to be one the most efficient plants in the U.S.
    - Consistently the top plant burning sub-bituminous Powder River Basin (PRB) coal.
- Industry leader in Optimization
    - Evergy has optimized Sootblowing and Combustion processes on several units. These efforts were featured in POWER magazine articles.

Table 6: Power Plant Efficiency Projects

Project Description	Unit	Year	Performance Impact
Iatan Station			
Replace Air Heater Cold End Baskets	Iatan 1	2015	Nominal
Traveling Screen Upgrade	Iatan 1	2015	Moderate
Burner Replacement	Iatan 2	2016	Nominal
Online Air In-Leakage Monitor	Iatan 2	2017	Nominal
Replace LP Rotors (w/enhanced performance option)	Iatan 1	2017	Significant
Combustion Air Inlet Screens	Both	2017	Nominal
Mill Throat Upgrade	Iatan 1	2017	Nominal
Turbine Overhaul	Iatan 2	2018	Nominal
Replace Cold End APH Baskets	Iatan 2	2018	Nominal
Mill Overhauls	Iatan 2	2018	Nominal
Mill Outlet Diffuser Upgrade	Iatan 1	2019	Nominal
Replace Air Heater Cold End Seals	Iatan 2	2020	Nominal
Intelligent Sootblowing	Iatan 1	2021	Nominal
Combustion Optimizer	Iatan 2	2021	Nominal
Replace Condenser Exhausters	Iatan 1	2021	Nominal
Water Lance Addition	Iatan 2	2021	Nominal
Intelligent Sootblowing	Iatan 2	2022	Moderate
Cooling Tower Fill Replacement	Iatan 2	2024	Nominal
LP Turbine L-0 Replacement	Iatan 2	2024	Nominal
Major Turbine Overhaul and New IP Rotor	Iatan 1	2025	Moderate
HP Turbine Bucket Repalcement	Iatan 2	2026	Nominal
Air Heater Basket Replacement	Iatan 2	2026	Nominal

Hawthorn Station			
Automated Overfire Air Dampers	Hawthorn 5	2015	Nominal
Combustion Air Inlet Screens	Hawthorn 5	2015	Nominal
Air Heater Basket/Seal Replacement	Hawthorn 5	2016	Nominal
Condenser Rebundle	Hawthorn 5	2016	Nominal
HP #1 FWH Replacement	Hawthorn 5	2016	Nominal
HP/IP and LP Turbine Overhaul	Hawthorn 9	2017	Nominal
Gas Turbine Blade and Vane Replacement	Hawthorn 6	2018	Nominal
Automate Burner Total Air Registers	Hawthorn 5	2018	Nominal
Boiler Blowdown Recovery Flash Tank	Hawthorn 5	2019	Moderate
Classifier Replacement	Hawthorn 5	2020	Moderate
LP Turbine Overhaul	Hawthorn 5	2020	Nominal
HP/IP Turbine Overhaul	Hawthorn 5	2023	Moderate
BFP Runner Repl	Hawthorn 5	2023	Nominal
Combustion Turbine Overhaul	Hawthorn 6	2023	Moderate
LP Turbine Overhaul	Hawthorn 9	2027	Nominal
LaCygne Station			
Startup System Valve Replacement	LaCygne 1	2017	Moderate
Pulverizer Classifiers	LaCygne 2	2017	Nominal
Boiler Blowdown Recovery Flash Tank	LaCygne 2	2018	Moderate
BFP Runner Replacement	LaCygne 1	2018	Nominal
BFP Runner Replacement	LaCygne 2	2018	Nominal
Startup Boiler Feed Pump	LaCygne 1	2019	Nominal
Vacuum Priming System Replacement	LaCygne 1	2019	Nominal
Air Heater Baskets Repl	LaCygne 1	2020	Nominal
BFP Recirc Valves Replacement	LaCygne 1	2020	Nominal
BFP Runner Replacement	LaCygne 1	2020	Nominal
Sec Air Flow Controls Replacement	LaCygne 1	2021	Nominal
Turbine Overhaul	LaCygne 1	2024	Moderate
Hydrogen Cooler Upgrade	LaCygne 1	2024	Nominal
Air Heater Basket Replacement	LaCygne 1	2024	Nominal
Turbine Overhaul	LaCygne 2	2025	Moderate
IP Turbine Upgrade	LaCygne 1	2025	Significant
Primary AH Baskets Repl	LaCygne 2	2025	Nominal
Estimated Performance Impact: Nominal - Less than 0.1% efficiency improvement; Moderate - 0.1 - 0.5% improvement; Significant - Greater than 0.5% improvement			

2.3 Air Emission Impacts[20]

Environmental laws or regulations that may be imposed at some point within the planning horizon may impact air emissions, water discharges, or waste material disposal. Following is a brief discussion of each of these pollutants that could result in compliance costs that may have a significant impact on utility rates.

2.3.1 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.

2.3.2 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 February 2024, the EPA finalized a rule strengthening the primary annual PM2.5 (particulate matter less than 2.5 microns in diameter) NAAQS. The EPA is lowering the primary annual PM2.5 NAAQS from 9 to 12.0 µg /m3 (micrograms per cubic meter). Future non-attainment of revised standards could require additional reduction technologies, emission limits, or both on fossil-fueled units.

2.3.3 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. Future non-attainment of revised standards could result in regulations

[20] 20 CSR 4240-22.040(2); 20 CSR 4240-22.040(2)(B)

requiring additional nitrogen oxides (NO_x) reduction technologies, emission limits or both on fossil-fueled units. NO_x is considered a precursor pollutant for ozone formation.

2.3.4 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 attaining 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.

2.3.5 Nitrogen Dioxide

In 2010, the EPA strengthened the NAAQS for NO_2. The Kansas City area is currently in attainment of the NO_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 NO_2 reduction technologies, emission limits or both on fossil-fueled units.

2.3.6 Carbon Monoxide

In 2011, the EPA maintained the existing 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.

2.3.7 Lead

In 2016, the EPA strengthened the NAAQS for 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.

2.3.8 Cross-State Air Pollution Rule

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 and Missouri, 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. This FIP would establish a revised CSAPR ozone season NO_x emissions trading program for electric generating units, a new daily backstop NO_x limit for applicable coal-fired units larger than 100MW, and unit-specific NO_x emission rate limits for certain industrial emissions units. The proposed FIP includes reductions to the state ozone season NO_x allowance allocations for Missouri beginning in 2023 with additional reductions in future years. In February 2023, the EPA published a final rule disapproving the ITSIPs submitted by 19 states, including the final disapproval of the Missouri ITSIP. In March 2023, the EPA issued the final ITFIP for twenty-three states, including Missouri. In April 2023, the

Attorney General of Missouri filed a Petition for Review in the U.S. Courts of Appeals for the Eighth Circuit challenging the EPA's disapproval. In May 2023, the Eighth Circuit granted a stay of the EPA's disapproval of the Missouri ITSIP. As a result of the judicial stays of the EPA's disapproval of the Missouri ITSIP, the EPA issued interim final rules staying the effectiveness of the ITFIP in Missouri while the stay issued by the Eighth Circuit in the ITSIP disapproval case remains in place. Missouri will continue operating under the existing CSAPR program.

In January 2024, the EPA proposed to disapprove the ITSIP for Kansas and four other states. The Kansas ITSIP was previously approved in April 2022. While Kansas was not originally included in the ITFIP, in January 2024, the EPA issued a proposal to include Kansas in the ITFIP. If finalized, the ITFIP for Kansas would become effective for the 2025 ozone season beginning in May 2025.Evergy Missouri Metro currently complies with the existing CSAPR program 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.

2.3.9 Regional Haze

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 PM2.5, and compounds which contribute to PM2.5 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 or “planning period” was due in 2007. For the second ten-year planning period, the EPA issued a final rule revision in 2017 that allowed states to submit their SIP revisions by July 31, 2021, and further extended the deadline a second time to August 15, 2022. Evergy collaborated 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, including Evergy Missouri Metro, based on the significant reductions that were achieved during the first implementation period. KDHE submitted the Kansas SIP revision in July 2021. On January 2, 2024, EPA proposed to disapprove the Kansas SIP revision. The EPA indicated its proposed disapproval was based on the lack of at least two four-factor analyses being conducted for Kansas emission sources. If a Kansas generating unit of Evergy Missouri Metro is selected for additional analysis, the possibility exists that the state or the EPA, through a revised SIP or a FIP, could determine that additional operational or physical modifications are required on the generating unit to further reduce emissions. At this time, given the uncertainty of which two of the hundreds of Kansas based emission sources may be chosen for further analyses and considering neither state is looking for additional reduction from Evergy Missouri Metro sources, Evergy Missouri

Metro is not considering any additional control requirements for the Regional Haze Rule planning period.

Evergy Missouri Metro's existing emission controls at its La Cygne, Iatan and Hawthorn Generating Stations maintain compliance with these requirements. Future visibility progress goals could result in additional SO_2, NO_x and PM controls or reduction technologies on fossil-fired units.

2.3.10 Carbon Dioxide

In May 2023, the EPA proposed CO_2 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.

2.3.11 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 comments 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 anticipated to comply with the current or proposed standards.

2.4 Water Emission Impacts[21]

2.4.1 Effluent Limitation Guidelines (ELG)

In 2015, EPA updated the effluent limitations guidelines (ELG) and standards for wastewater discharges from steam electric sources, including new limits on the amount of 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 that adjusts numeric limits for flue gas desulfurization (FGD) wastewater and adds a 10% volumetric purge limit for bottom ash transport water in addition to extending the FGD compliance date to no later than December 31, 2025

Due to the April 2019 ruling, the EPA announced a plan in July 2021 to issue a proposed rule in the fall of 2022 to address the vacated limitations for legacy wastewater and landfill leachate. In March 2023, the EPA published a proposed update to the ELG to address the vacated limitations and prior reviews of the existing rule by the current administration. Flue Gas Desulfurization (FGD) wastewater, bottom ash transport wastewater, coal residual leachate, and legacy wastewater are addressed in the proposal.

Evergy Metro is currently in compliance with this regulation, but future strengthening of the rule could require additional reduction technologies, on coal and oil-fired units.

2.4.2 Clean Water Act Section 316(A)

Evergy's river plants comply with the calculated limits defined in the current permits. Future regulations could be issued that would restrict the thermal discharges and 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.

[21] 20 CSR 4240-22.040(2); 20 CSR 4240-22.040(2)(B)

2.4.3 Clean Water Act Section 316(B)

In May 2014, the EPA finalized standards to reduce the injury and death of fish and other aquatic life caused by cooling water intake structures at power plants and factories. The rule could require modifications to cooling water inlet screens and fish return systems.

2.4.4 Zebra Mussel Infestation

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

2.4.5 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.

2.5 Waste Material Impacts[22]

2.5.1 Coal Combustion Residuals (CCR's)

The EPA published a rule to regulate CCRs in April 2015 that requires additional CCR handling, processing and storage equipment and closure of certain ash disposal units. In January 2022, the 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, more stringent remediation requirements for units that are in corrective action or forced to go into corrective action are possible. In April 2022, the Utility Solid Waste Activities Group (USWAG) and other interested parties filed similar petitions in the D.C. Circuit challenging the EPA's legal positions regarding the CCR rule determinations proposed in January 2022.

[22] 20 CSR 4240-22.040(2); 20 CSR 4240-22.040(2)(B)

In May 2023, the EPA published a proposed expansion to the CCR regulation focused on legacy surface impoundments. This regulation expands applicability of the 2015 CCR regulation to two newly defined types of CCR disposal units. If finalized, the Evergy Companies anticipate having additional CCR units requiring evaluation and potential remediation.

The finalization of the CCR legacy rulemaking and future rule modification 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.

For the purposes of ranking the supply-side resource options, the subjective probabilities assigned to comply with future environmental laws or regulations are listed as follows:

- CO_2 emissions restrictions = probability based on scenario endpoints as described in Volume 6
- Closure of CCR surface impoundments and additional more stringent requirements on CCR landfills. = 100% probability

2.6 Uprates

Evergy has ongoing capital and O&M projects that will improve the summer performance of some of its generating resources. Types of projects include evaporative cooling, which lowers the temperature and increases the density of air to the turbines. Forecasts of the increase in expected tested summer capacity value due these projects were included in calculating the future summer capacity position. Projects occurring in 2025-2027 are anticipated to increase Metro's summer capacity by 87 MW by 2027.

2.7 Winter Capacity

Since SPP currently does not have a binding winter capacity requirement, Evergy accounts for its winter capacity based on tests performed for summer capacity. Evergy plans to test all of its natural gas resources based on winter conditions prior to winter requirements, which it forecasts to begin in winter 2026/2027.

Evergy expects to be able to get more capacity accreditation in winter, particularly for natural gas combustion turbines, which operate at higher levels in colder weather because the air is denser, increasing mass and power flow through the turbines. For the 2024 IRP, Evergy added 10% to the tested summer capacity of its combustion turbines to approximate winter test performance.

For the 2024 IRP, Evergy also assumes that resources without firm natural gas supply will receive winter accreditation. Currently performance-based accreditation is expected to reduce the value of these resources in winter, as forced outages due to lack of natural gas supply would be counted against performance. If resource adequacy rules evolve to require firm fuel, Evergy may be able to buy additional long term firm transport.

2.8 PBA Impacts

Evergy calculated the expected performance-based accreditation impacts to summer and winter capacity needs and incorporated them into the resource plan. Evergy used SPP data to apply forced outage rate calculations and class averages as applicable to resources, and reductions in reserve margins for load to each of the first five years as the rule is expected to phase in. After year 5, the accreditation impact was assumed to remain constant through the planning horizon.

Table 7: Equivalent Gain or Loss of Capacity from PBA (MW)

Metro	2026	2027	2028	2029	2030
Summer	(59)	(73)	(86)	(85)	(84)
Winter	(45)	(59)	(74)	(69)	(92)

2.9 Plant Modifications

Evergy conducted high-level analysis of potential compliance paths if the GHG rule or similar carbon emissions reductions policies were to go in effect in the future. For a prescriptive GHG compliance path, Evergy developed representative costs for existing coal units to co-fire with coal and natural gas.

Table 8: Natural Gas Co-Firing Assumptions **Confidential**

[redacted]

2.10 Retirement Evaluation

Evergy evaluates retirements based on fixed and production cost economics. Evergy considers the going forward costs of keeping a resource in operation versus the cost of replacing the resource as needed in the resource plan. In addition to go-forward cost savings associated with avoided capital and O&M costs, evaluation of retirements also includes an estimate of the cost required for transmission upgrades to maintain the reliability of the transmission system post-retirement.

Table 9: Metro Coal Resources

Resource	Share of Capacity	Energy	Capacity Factor	In-Service Year	Planned Retirement Year
LAC 1	50%	2,069,823	62%	1973	2032
LAC 2	50%	1,566,723	54%	1977	2039
Iatan 1	70%	1,665,807	39%	1980	2039
Iatan 2	54.71%	1,633,983	38%	2010	-
Hawthorn 5	100%	2,384,689	48%	1969	-

2.11 Renewables

2.11.1 Wind

Evergy has a considerable energy supply from wind and wind PPAs. Evergy has forecasted the transition to ELCC for the past few years of IRPs and planned for its impacts on capacity accreditation. ELCC was expected to be in effect by summer 2023, but due to delays in implementation, the 2024 IRP forecasts will begin in summer 2026.

Table 10: Metro Wind Accreditation

Wind PPA	Nameplate MW	2024 Capacity	ELCC
Cimarron-II	131	54	36
Spearville-3	101	38	23
Slate Creek	150	67	38
Waverly	200	62	40
Osborn	120	21	23
Rock Creek	180	31	40
Prairie Queen	90	26	19
Ponderosa	100	62	15
Pratt	110	70	33
Total	**1182**	**431**	**267**

Many of these wind resources were procured through PPAs which have finite contract terms, with most contracts expiring in the 2030s. The IRP model assumes these contracts expire based on current contract terms and the capacity / energy that they provide will need to be replaced. In reality, renegotiation of these contracts for an extended term or purchase of the assets could be evaluated as an alternative to a replacement resource addition based on economics closer to the time of contract expiration. Within the IRP, Evergy does not make assumptions about what renegotiation opportunities may be available 10-15 years in the future due to uncertainty around PPA market conditions and counterparty interest.

Figure 24: Metro Wind PPA Nameplate

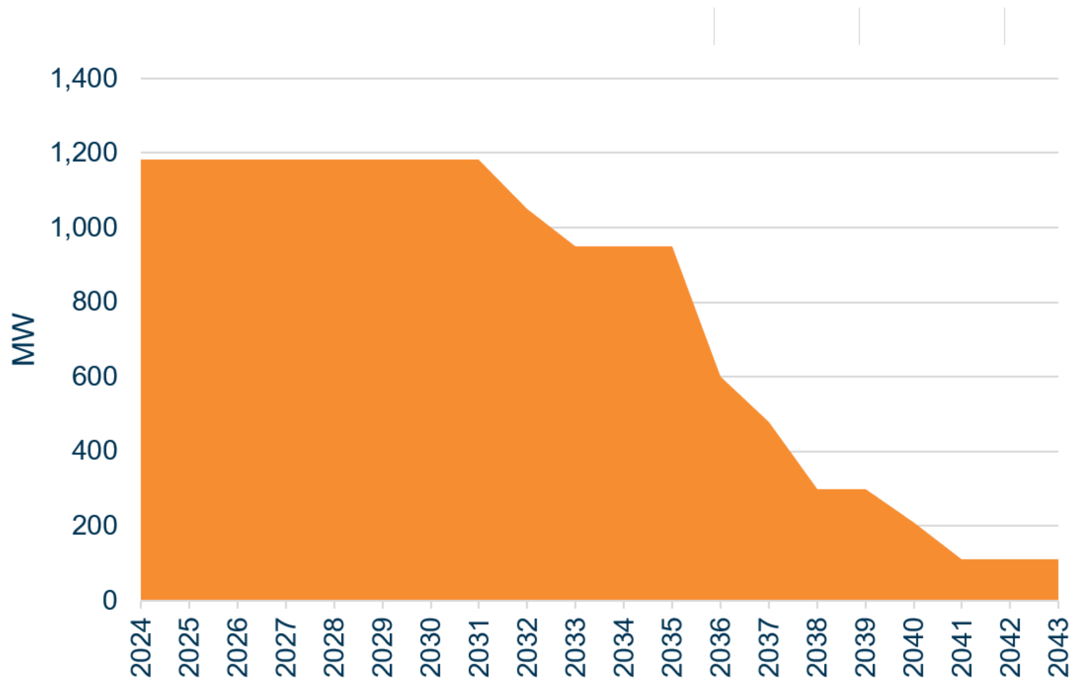
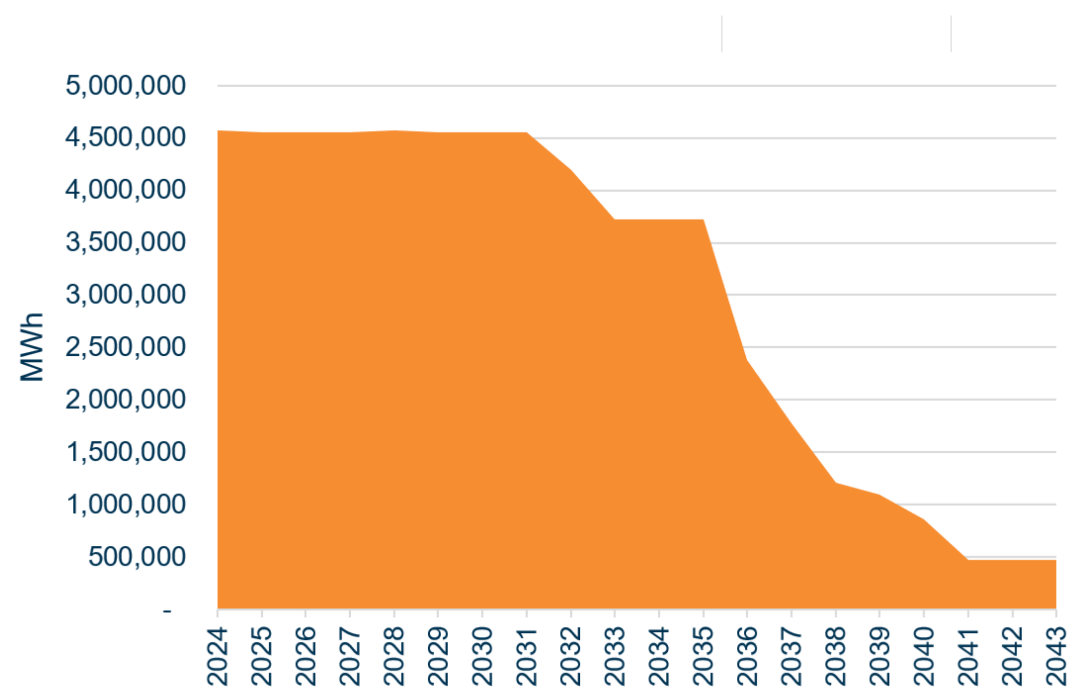


Figure 25: Metro Wind PPA Energy



Section 3: New Resources[23]

3.1 Selection of Resource Candidates[24]

In January 2023, Evergy issued an all-source request for proposals (RFP) 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.

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.

Table 11: Primary Resource Options **Confidential[25]**

[redacted]

[23] 20 CSR 4240-22.040(1)
[24] 20 CSR 4240-22.040(4); 20 CSR 4240-22.040(4)(A)
[25] 20 CSR 4240-22.040(4);20 CSR 4240-22.040(4)(C); 20 CSR 4240-22.040(5)(B); 20 CSR 4240-22.040(5)(F); 20 CSR 4240-22.040(2)(C); 20 CSR 4240-22.040(2)(C)(1) wind and solar are considered renewable resources, and cost information for all resources includes expected compliance with all environmental regulations, except future carbon dioxide restrictions which are modeled as scenarios.

Table 12: Primary Resource Costs in First Year of Operation **Confidential[26]**

[redacted]

Table 13: New Resource Emissions Rates (lb/MWh)

Resource Type	NO_x	SO_2	CO_2
Solar	-	-	-
Wind	-	-	-
Battery	-	-	-
Combustion Turbine	0.036	0.017	1,051
Combined Cycle	0.023	0.006	759
Half Combined Cycle	0.023	0.006	759

Based on stakeholder feedback, Evergy also considered Combined Cycles with Carbon Capture and Nuclear SMR as resources that could be deployed to enable future emissions reductions. While these technologies are not currently operating, and cost data is more speculative, they may assist in the analysis of tradeoffs in a low-carbon future.

Table 14: Future Low Emissions Options **Confidential**

[redacted]

Table 15: Future Low Emissions Costs in First Year of Operation **Confidential**

[redacted]

[26] 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(C); 20 CSR 4240-22.040(5)(E)

Table 16: Future Low Emissions Resource Emissions Rates (lb/MWh)

Resource Type	NO_x	SO_2	CO_2
Combined Cycle CCS	0.027	0.007	43.0
Nuclear	-	-	-

3.2 Renewable and Storage Resources

3.2.1 Tax Incentives

In August 2022, Congress passed the Inflation Reduction Act (IRA) and it was signed into law by President Biden. The IRA includes availability of production tax credits (PTC) and investment tax credits (ITC). Evergy assumes that new wind and solar will receive PTC and new battery resources will receive ITC. New wind and solar resources can select either the PTC or ITC. New wind resources are expected to have high capacity factors, making the PTC advantageous. Solar resources have lower capacity factors, however the PTC is still expected to be the most economic option for Evergy customers, because of the expected capacity factor and the requirement for utilities to amortize the ITC over the life of the asset. New battery resources are only able to use the ITC and utilities are able to take the credit upfront (rather than amortizing it) as part of the IRA guidelines.

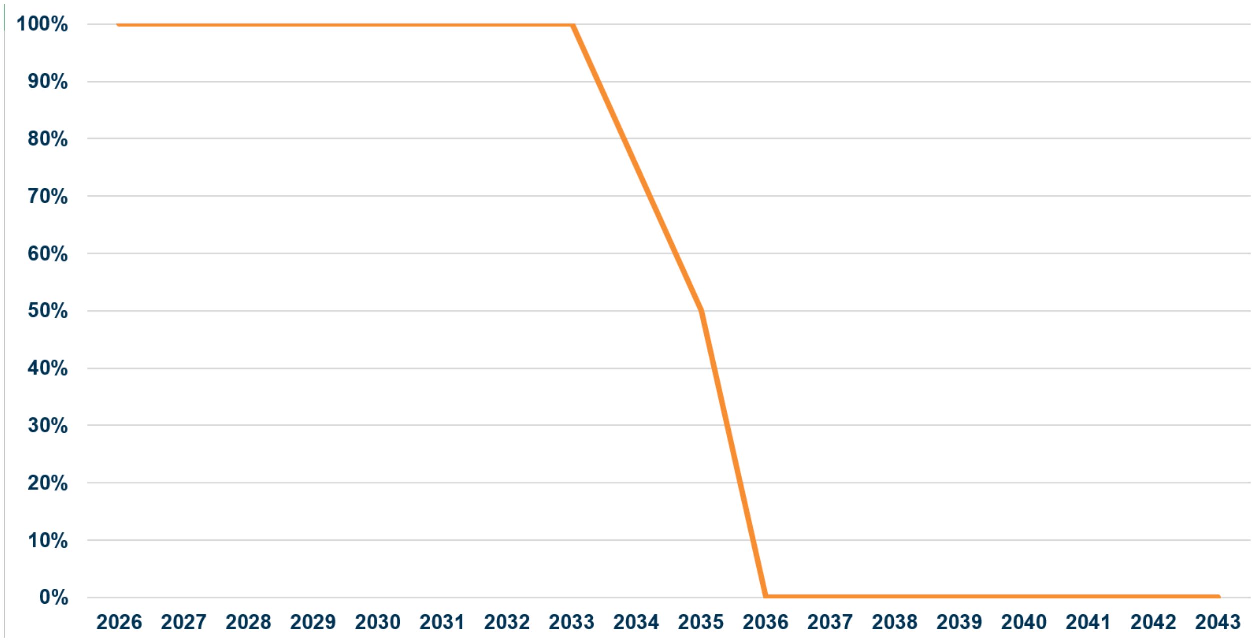
Table 17: Production Tax Credit Assumptions

Year	PTC	PTC 75% PTC	PTC 50% PTC	Before Tax PTC	Before Tax PTC 75% PTC	Before Tax PTC 50% PTC
2022	$ 27.50			$ 34.81		
2023	$ 28.19			$ 35.68		
2024	$ 28.89			$ 36.57		
2025	$ 29.61			$ 37.49		
2026	$ 30.35			$ 38.42		
2027	$ 31.11			$ 39.38		
2028	$ 31.89			$ 40.37		
2029	$ 32.69			$ 41.38		
2030	$ 33.51			$ 42.41		
2031	$ 34.34			$ 43.47		
2032	$ 35.20			$ 44.56		
2033	$ 36.08			$ 45.67		
2034	$ 36.98	$ 27.74		$ 46.82	$ 35.11	
2035	$ 37.91	$ 28.43	$ 18.95	$ 47.99	$ 35.99	$ 23.99
2036	$ 38.86	$ 29.14	$ 19.43	$ 49.19	$ 36.89	$ 24.59
2037	$ 39.83	$ 29.87	$ 19.91	$ 50.42	$ 37.81	$ 25.21
2038	$ 40.82	$ 30.62	$ 20.41	$ 51.68	$ 38.76	$ 25.84
2039	$ 41.84	$ 31.38	$ 20.92	$ 52.97	$ 39.73	$ 26.48
2040	$ 42.89	$ 32.17	$ 21.45	$ 54.29	$ 40.72	$ 27.15
2041	$ 43.96	$ 32.97	$ 21.98	$ 55.65	$ 41.74	$ 27.82
2042	$ 45.06	$ 33.80	$ 22.53	$ 57.04	$ 42.78	$ 28.52
2043		$ 34.64	$ 23.09		$ 43.85	$ 29.23

The Internal Revenue Service (IRS) released the PTC value for 2022 and guidelines for calculating future amounts.[27] Evergy incorporated the IRS guidance and information from other sources in evaluating the future PTC forecast. The benefit of the PTC is equivalent to the credit grossed up for federal taxes (before tax value).

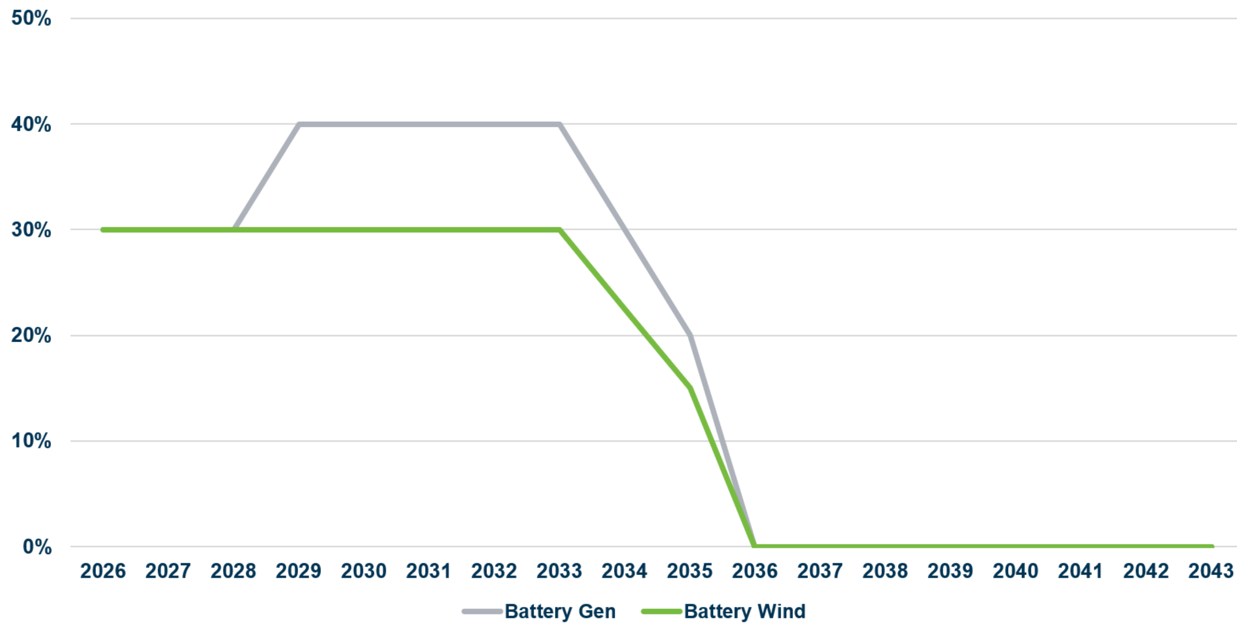
[27] Renewable Electricity Production Credit Amounts for Calendar Year 2022. https://www.irs.gov/pub/irs-drop/a-22-23.pdf.

Figure 26: PTC Values and Phase Out for Wind and Solar



Evergy expects new wind and solar projects to meet the eligibility criteria for 100% PTC, with a PTC earned for every MWh of production for the first 10-years of operation. Consistent with IRA provisions, production tax credit eligibility for new projects phases out as the US meets its GHG emissions reduction goals. Projects beginning operation in 2034 and 2035 are eligible for 75% PTC and 50% PTC, respectively, before the credit ceases for projects after 2035.

Figure 27: ITC Values and Phase Out for Batteries



Evergy expects new battery projects to meet the eligibility criteria for 30% ITC, with the benefit received upfront in the first year of operation. The IRA allows additional bonus credit eligibility for projects located in "energy communities".[28] Evergy is modeling additional bonus credit eligibility for a total of 40% ITC, beginning in 2029, after the scheduled retirement of Lawrence 4. As the credit phases out, projects beginning operation in 2034 and 2035 are eligible for 75% and 50% of the expected credits, respectively, before the credit ceases for projects after 2035.

3.2.2 Solar

Currently, solar accounts for only 0.3% of nameplate capacity and 0.2% of generation for SPP[29], but there are many potential future projects in the interconnection queue. According to the US EIA, solar is projected to be the fastest growing utility power source in the next two years, with installed nameplate expected to grow from 95 GW at the end of 2023 to 131 GW at the end of 2024.[30] Solar production is greatest during summer

[28] IRS. Energy Community Bonus Credit Amounts under the Inflation Reduction Act of 2022 Notice 2023-29. https://www.irs.gov/irb/2023-29_IRB#NOT-2023-29.
[29] SPP. Fast Facts. https://www.spp.org/about-us/fast-facts/.
[30] EIA. Solar and wind to lead growth of U.S. power generation for the next two years. https://www.eia.gov/todayinenergy/detail.php?id=61242.

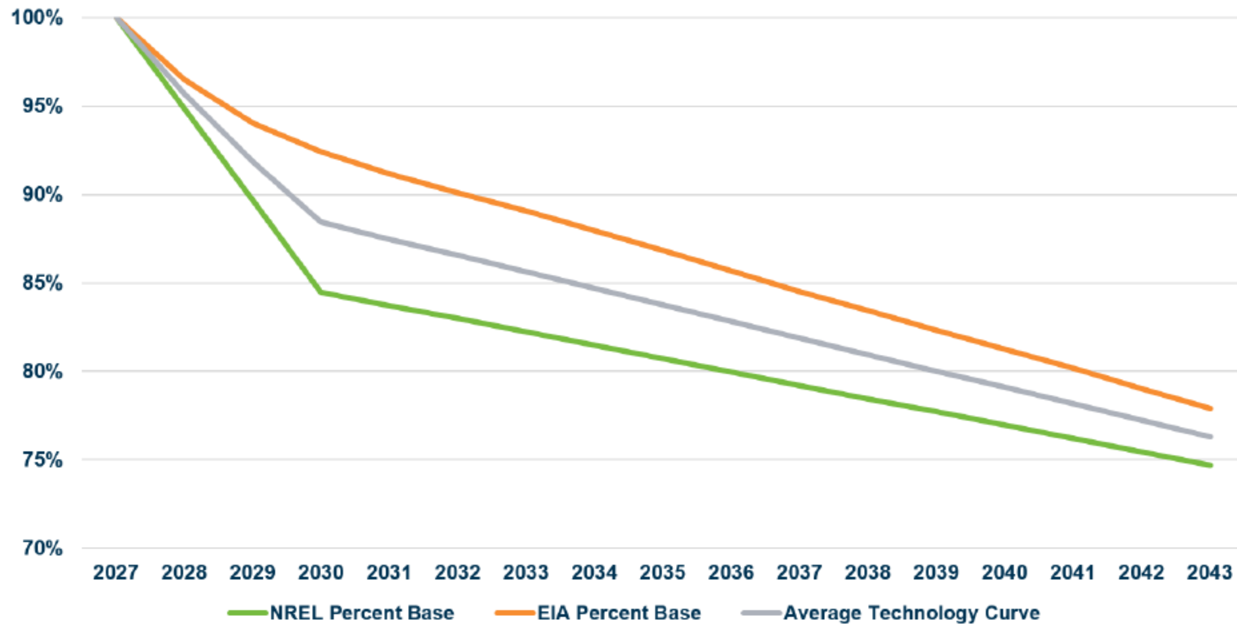
daylight hours, which typically correspond to high load and high system energy needs in SPP. New solar is expected to have high summer capacity value in SPP due to its ability to operate during peak conditions. Generally solar irradiance is better the further south and west in and outside of Evergy's service territory. The solar projects Evergy is considering benefit from being closer to load and are expected to be less transmission constrained than wind projects.

Evergy received multiple offers for solar resources in its 2023 RFP. These resources have interconnection queue positions and other milestones, however the earliest delivery dates are for 2027 summer capacity. In the past few years there have been many issues causing cost increases and delays in solar projects. Pandemic-related global price increases and supply chain issues compounded with US government action preventing import of materials made with forced labor, and threats of high tariffs for dumping and penalties for tariff circumvention delayed the import of solar panels. Installed cost estimates for solar projects increased 62% between the 2021 and 2023 IRPs. With some supply chain pressures easing and temporary suspension of US enforcement of tariffs, costs are stabilizing for solar projects. Evergy has refreshed offers for its short-listed solar projects from the RFP and determined that costs are the same as forecasted in the 2023 IRP.

Evergy is also pursuing self-build options for solar, and hoped to have one potential project available for 2026 summer capacity. However, some local opposition is likely to delay the project, eliminating 2026 delivery of a solar resource as a possible option for the resource plan.

For 2027 solar, Evergy used installed cost estimates based on RFP results. For projects after 2027, Evergy applied a technological improvement factor and inflation to the 2027 installed costs. The technology curve was constructed using EIA and NREL estimates of future project costs and averaging the implied cost reduction factors.

Figure 28: Solar Technology Curve



The technology curve declines most steeply through 2030. NREL estimates are more aggressive than EIA, but on average technological improvement outweighs inflation from 2027-2030, reducing expected nominal costs each year, and after 2030 costs rise annually.

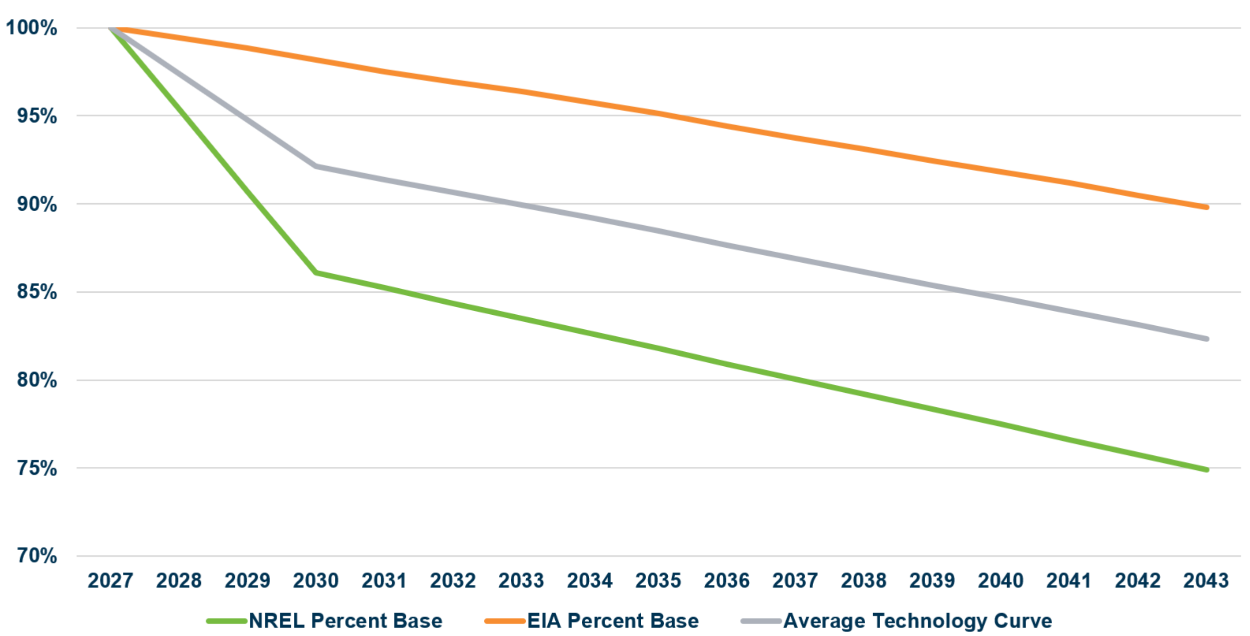
Figure 29: Annual Solar Build Costs ($/kw) **Confidential**

[redacted]

3.2.3 Wind

Evergy received offers for existing and new build wind projects in its 2023 RFP. New projects had significantly higher installed costs than operating projects but will have a full 10 years of PTC eligibility when constructed. Cost estimates, based on these RFP results, rose significantly from the 2022 IRP assumptions. However, based on the most recent information, including offer refreshes from the RFP short list cost estimates have remained steady from 2023 IRP assumptions to the 2024 IRP.

Figure 30: Wind Technology Curve



The technology curve declines most steeply through 2030. However, the average technology curve is similar to the inflation rate, keeping costs relatively flat from 2027-2030. After 2030 costs rise annually.

Figure 31: Annual Wind Build Costs **Confidential**

[redacted]

A recent NREL analysis cited design innovations which may improve wind performance in the future, including taller towers, longer blades, larger rotors, and improved steering controls and cost reducing innovations including on-site manufacturing, and climbing cranes.[31]

Some asset owners are considering repowering older wind resources to take advantage of IRA incentives. A repowered facility becomes eligible for the 10-years of PTC again. Evergy did not receive any repowering offers in the RFP and did not specifically consider repowering in the IRP analysis. Costs to repower are likely similar to the estimates for new installations because of the 80/20 rule established by IRS guidance that the cost of adding the new components of the project must account for at least 80% of its value to qualify as a new installation eligible for tax credits. Most of Evergy's current wind is in PPAs, and Evergy will evaluate offers to extend or repower these PPAs as they arise.

[31] NREL. Technology Advancements Could Unlock 80% More Wind Energy Potential During This Decade. September 22, 2023. https://www.nrel.gov/news/program/2023/technology-advancements-could-unlock-80-more-wind-energy-potential-during-this-decade.html.

3.2.4 Battery

Utility-scale battery storage capacity for electricity has been growing in recent years. Based on reporting to EIA, 16 GW of installed capacity was expected in the US by the end of 2023, up from less than 2 GW in 2020.[32] The majority of battery capacity as of November 2023 was located in California, which had 7.3 GW and Texas which had 3.2 GW. There is currently very little battery storage in SPP. Evergy operates a 1 MW battery pilot project connected at distribution voltage in the Wichita area which is providing experience navigating SPP market nuances that impact a battery resource, but SPP rules related to batteries still need to be further developed for larger utility-scale facilities.

The predominant battery technology used in power system operations is Lithium-ion batteries.[33] Batteries do not produce energy, but store energy for future use. Batteries can be a useful addition to the resource mix because they can store energy produced at low-need or low-priced times and release it at high-need or high-priced times, providing reliability value as capacity, and economic arbitrage value. Batteries lose some energy in the charging process and are limited by the duration of energy supply (4 hours) before needing to be recharged.

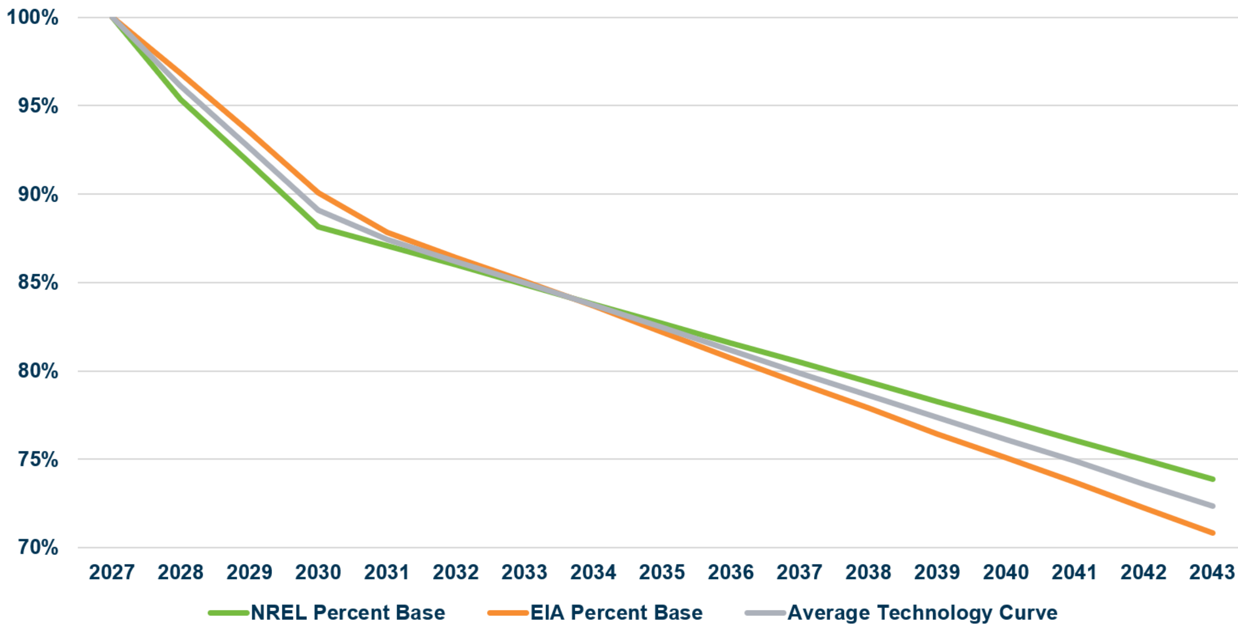
Evergy received offers for 4-hour Lithium-Ion batteries in its all-source RFP for delivery in time for summer 2026 and summer 2027 capacity needs. These offers are for battery projects in the SPP interconnection queue. Evergy also believes it could procure batteries for self-build options. In early years, these batteries could use surplus interconnection, particularly at wind sites. Evergy would need to enter the interconnection queue to self-build at new locations.

For 2026 and 2027 Battery projects, Evergy used installed cost estimates based on RFP results. For projects after 2027, Evergy applied a technological improvement factor and

[32] US EIA, Today in Energy. "US Battery Storage Capacity Expected to Nearly Double in 2024." January 9, 2024. https://www.eia.gov/todayinenergy/detail.php?id=61202.
[33] US EIA, Electricity Explained, Energy Storage for Electricity Generation. https://www.eia.gov/energyexplained/electricity/energy-storage-for-electricity-generation.php.

inflation to the 2027 installed costs. The technology curve was constructed using EIA and NREL estimates of future project costs and averaging the implied cost reduction factors.

Figure 32: Battery Technology Curve



The technology curve steeply declines through 2030, implying rapid cost reductions. Technological improvement outweighs inflation from 2027-2030, reducing expected nominal costs each year, and after 2030 costs rise annually.

Figure 33: Battery Build Costs (Excluding ITC) ($/kw) **Confidential**

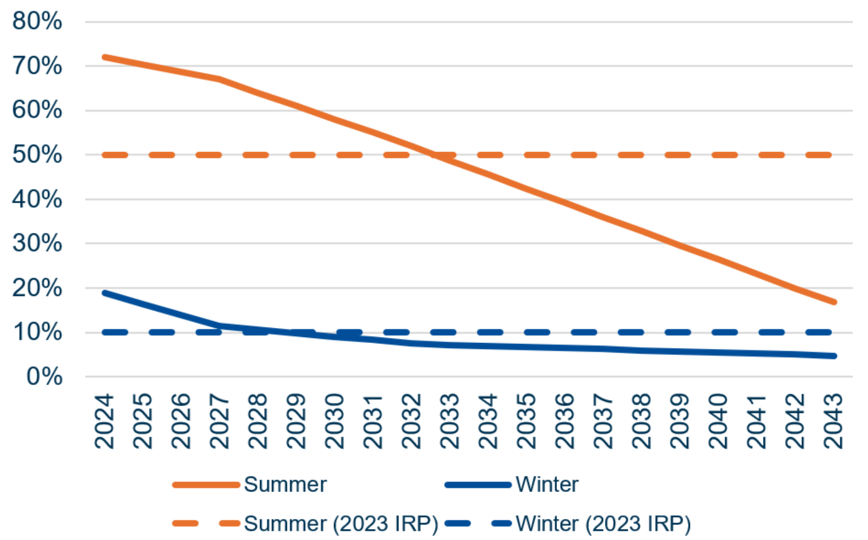
[redacted]

3.2.5 ELCC

Evergy expects new renewable and battery resources to be subject to ELCC capacity accreditation rules beginning in summer 2026. ELCC measures the effectiveness of the resource to produce energy at times needed to meet load. Generally, as the saturation of the resource type increases in the market, each resource is less effective at meeting load requirements. SPP has conducted studies to estimate the relationship between increasing amounts of resources and ELCC value. Evergy used the study results in conjunction with the ITP futures expectations of resource penetration in order to develop a forecast of how ELCC accreditation will vary over the 20-year planning horizon.

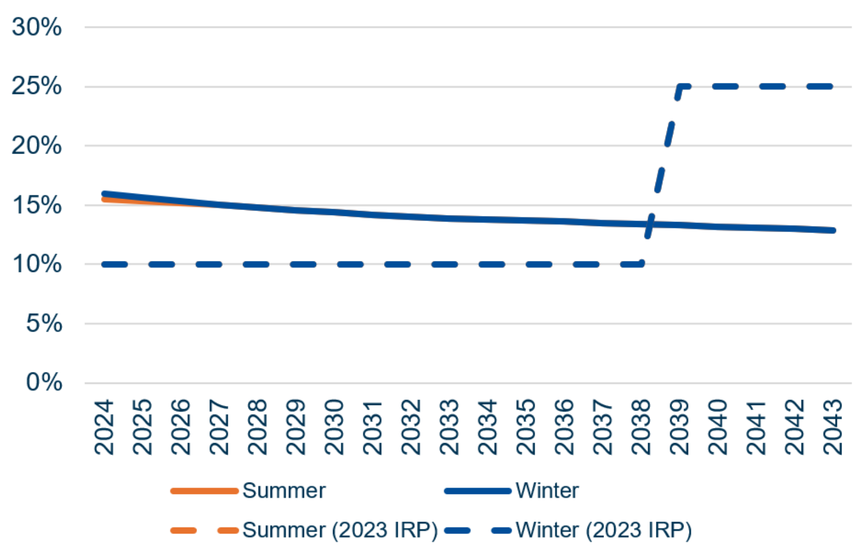
The forecasts differ from 2023 IRP assumptions because SPP stakeholders have modified some of the proposed implementation of ELCC. For the 2023 IRP, Evergy assumed that renewable resources would be allocated ELCC according to tiers based on share of load. In particular, solar nameplate equivalent to 20% of load (2,000 MW for Evergy) would receive higher summer accreditation (50%), and incremental solar would receive lower accreditation (10%). This construct is no longer part of the proposed method for implementing ELCC. Evergy expects some variation in ELCC based on whether resources procure network transmission service to ensure capacity deliverability. However, Evergy expects that new resources will pursue network transmission service.

Figure 34: New Solar ELCC Assumptions



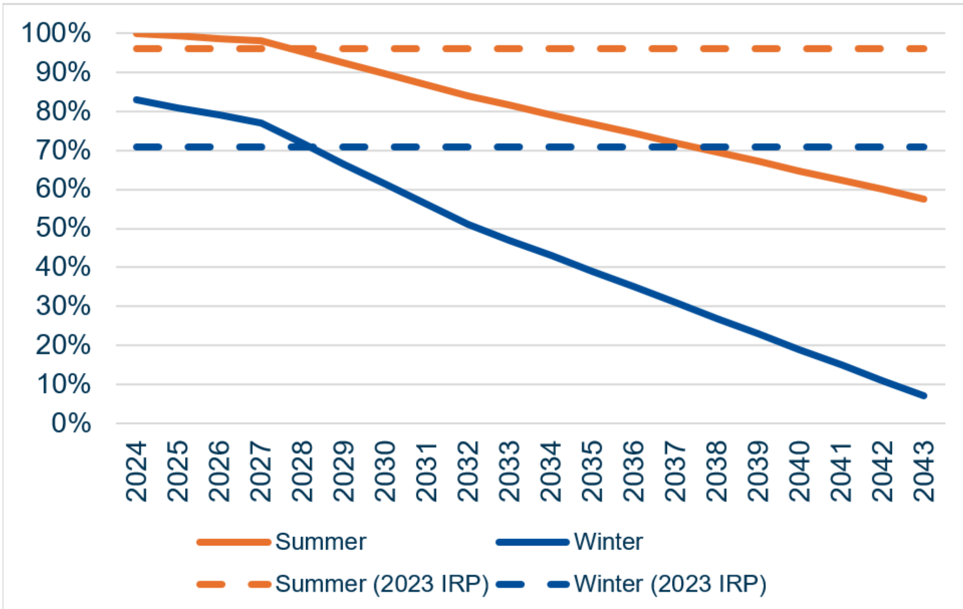
Solar resources are projected to have higher ELCC values in the first half of the time horizon, and lower values as more solar resources enter the market in the second half of the planning horizon.

Figure 35: New Wind ELCC Assumptions



New wind ELCC assumptions increased slightly for most of the planning horizon, but are lower at the end. Evergy previously assumed that it had exhausted its load-ratio share of wind under the tier system, but would get higher accreditation as wind PPAs rolled off at the end of the planning horizon.

Figure 36: New Battery ELCC Assumptions



In the 2023 IRP, Evergy assumed that new battery ELCC would be consistent with an SPP build out of 3,000 MW batteries. However, the 2024 IRP aligns ELCC with the 2023 ITP forecast which assumes much higher build out of batteries in future years.

3.3 Thermal Resources

3.3.1 Combined Cycle

Evergy did not receive any offers for thermal resources in its 2023 RFP and developers are not pursuing speculative thermal resource projects in SPP. The need for firm dispatchable generation beginning in the late 2020's to early 2030's was identified in the 2023 IRP. Evergy expects to self-develop these resources and has undertaken studies to determine the appropriate generator technology and sites with favorable characteristics (interconnection, gas supply, etc.) to locate them. Cost estimates for the 2023 IRP were based on engineering estimates and recently completed projects, however inflationary pressures have increased projected costs based on engineering estimates, newly announced projects and publicly available information. Evergy still estimates that the earliest available combined cycle build would be for commercial operation by summer 2028.

Costs for future years were estimated by scaling the 2028 cost estimate by inflation and the average of the NREL and EIA technology curves. Inflation exceeds technological innovation, resulting in higher nominal costs each year.

Figure 37: Combined Cycle Build Costs ($/kw) **Confidential**

[redacted]

3.3.2 Combustion Turbine

Evergy also expects to self-develop combustion turbines if needed. Cost estimates for the 2024 IRP were based updated engineering estimates, newly announced projects and publicly available information. Evergy still estimates that the earliest available combined turbine build would be for commercial operation by summer 2028.

Costs for future years were estimated by scaling the 2028 cost estimate by inflation and the average of the NREL and EIA technology curves. Inflation exceeds technological innovation, resulting in higher nominal costs each year.

Figure 38: Combustion Turbine Build Costs ($/kw) **Confidential**

[redacted]

3.3.3 PBA Assumptions

Since performance-based accreditation is a reallocation of thermal accreditation, no adjustments were made for new resources under the assumption that they would have forced outage rates consistent with or lower than the broader market.

3.4 Low-Emission Future Resources

3.4.1 Combined Cycle with CCS

Evergy modeled retrofitting new combined cycle builds with CCS, beginning in 2035 as an option for compliance with the strict (high) CO_2 emissions reductions scenarios. Carbon capture facilities have high capital costs, similar to the costs of building the generator. The operation of carbon capture increases fixed and variable costs, and decreases the efficiency (i.e., increases the heat rate) and the net output of the underlying resource. However, the net CO_2 emissions are also reduced by 95%. Plant capital and operating costs were modeled using NREL estimates from the 2023 Annual Technology Baseline (ATB)[34], while the cost of CO_2 transportation and storage was estimated from a 2022 report by the National Energy Technology Laboratory (NETL)[35].

Table 18: Unit Characteristics of Combined Cycle with and without CCS

****Confidential****

[redacted]

3.4.2 Nuclear SMR

Evergy also modeled small modular nuclear reactors as a resource option for high CO_2 emissions reductions scenarios. Evergy expects that the timeline for siting, permitting, and construction of a facility would take at least 10 years due to the intense regulatory requirements for nuclear projects. Small modular reactors are an immature technology, with a lot of research and development activity occurring around the world. There is still significant uncertainty about which technologies will ultimately become operational and their costs. Evergy does not expect to be a first adopter, and the IRP cost and timing assumptions incorporate the expected strategy of building an "nth" of a kind (NOAK) reactor, meaning several resources of the same technology would be in commercial operation first. For planning purposes, the 2024 IRP considers building a nuclear SMR in 2038 or later.

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

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

Table 19: Installed Cost Estimates and Evergy Cost Assumption **Confidential**

[redacted]

Table 20: Levelized Cost Estimates and Evergy Assumption **Confidential**

[redacted]

3.5 Market Capacity

SPP is in the process of significantly tightening resource adequacy requirements, including raising reserve margins, reducing capacity accreditation, and imposing penalties for failing to meet winter requirements. Evergy expects that some utilities will be short capacity beginning in 2026 when new rules are forecasted to be in effect. Evergy has seen evidence that other utilities are looking to procure capacity through RFPs and market activity. Since there is likely to be little excess market capacity, Evergy is planning to meet its expected capacity needs with little reliance on the broader SPP market.

Table 21: Market Capacity Available Metro

	2024	2025	2026	2027+
Market Capacity (MW)	300	300	300	50

In practice, Evergy will continue to look for offers in the market to mitigate the risks associated with the lead time in bringing new resources to commercial operation and changes to capacity needs.

3.6 Leased or Rented Facilities[36]

Evergy does not expect any new resources to be leased or rented.

3.7 Environmental Issues with New Resources

New resources will be subject to different environmental standards depending on the technology. Local, state, and federal permits will be obtained to site, permit, and construct these resources. Evergy plans to do a full permit matrix for each project pursued and has access to expertise internally and externally to support those permitting plans.

Permitting restrictions for future regulation is difficult to predict but it is likely that conventional generation will be subject to air emissions limitations for both traditional controlled emissions such as water effluent, SO_x, NO_x and particulate matter and carbon emissions in the future. Wildlife protection is also a strong consideration when siting a new generating facility.

On the renewables side, solar and wind do not have the traditional or carbon air emissions but do have different impacts on land use. Bat and bird impacts are a strong consideration in the environmental impact of new wind generation and is being evaluated for solar. Recent environmental activity for solar has focused on the impact of materials in the

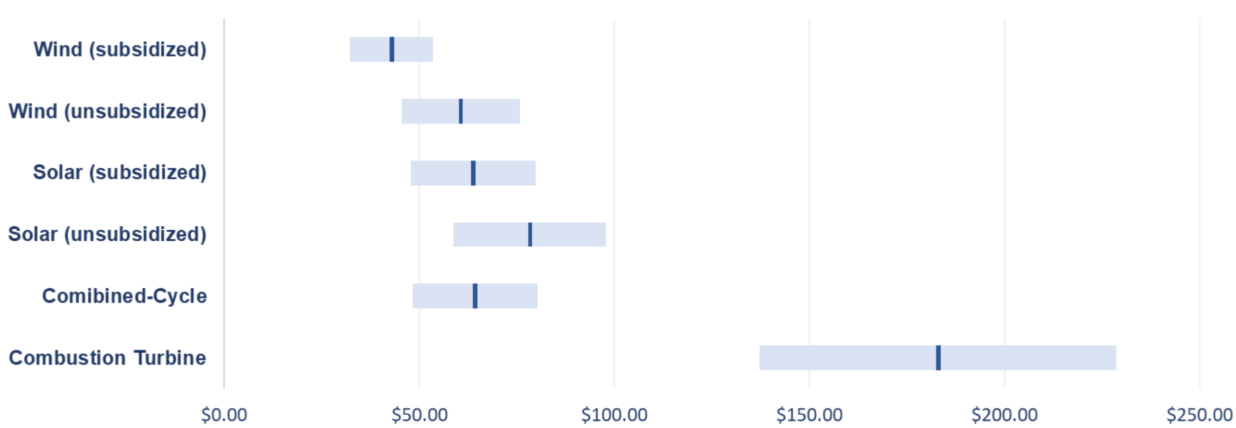
[36] 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(E)

panels on the surrounding environment and the change in groundwater characteristics from having the panels installed above the ground.

3.8 LCOE[37]

The Levelized Cost of Energy (LCOE) is a useful measure to evaluate the costs of different generation resource types. The LCOE values found in the figure below estimate the cost of owning and operating select resource types over the current IRP planning period. While LCOE provides a useful indication of the relative cost of producing energy, it does not capture all the strengths and capabilities of each generating technology required for long-term generation resource planning. Evergy uses the Net Present Value of Revenue Requirement as the financial measure to evaluate and compare the cost-effectiveness of resource plans.

Figure 39: Levelized Cost of Energy ($/MWh)



Note: Ranges represent +/-25% of estimated levelized cost of energy. Wind and solar subsidized categories include PTC.

3.9 Resources Not Selected[38]

Evergy reviewed its supply-side screening from the 2021 Triennial IRP and determined that many of the options screened out continue to be inappropriate for possible inclusion in the resource plan due to geographical unsuitability, high costs, or technological immaturity. Evergy considered variations of natural gas technologies, which may be options in the future, before choosing preferred technologies for the combined cycle and

[37] 20 CSR 4240-22.040(2); 20 CSR 4240-22.040(2)(A)
[38] 20 CSR 4240-22.040(2); 20 CSR 4240-22.040(2)(C);20 CSR 4240-22.040(2)(C)(2)

combustion turbine options. Evergy also considered long-duration storage and advanced geothermal based on stakeholder feedback, before eliminating these options.

3.9.1 Supply-Side Resources Eliminated Consistent with Last Triennial

Evergy eliminated the following resources in the pre-screening for the 2024 Triennial IRP:

- **Central Station Geothermal:** Central US lacks adequate geological resources
- **Municipal Solid Waste**: Developmental phase, environmental concerns concerning delivery of waste
- **Hydrokinetic (Run-of-River):** Environmental/unproven technology and wildlife concerns
- **Animal Waste:** Delivery issues and high moisture content is problematic
- **Advanced Geothermal:** Exploring, discovering, developing, and managing geothermal resources is inherently complex and can have greater risks and upfront costs than other renewable energy technologies. There are not anticipated to be any geothermal resources identified for Kansas and Missouri in the NREL "Enhanced Geothermal Shot Analysis for the Geothermal Technologies Office" report by 2050. [39]

Evergy also eliminated resources in the 2021 Triennial IRP after considering economics, technological maturity and other factors. Evergy believes the same concerns exist for some of these options:

- **Ultra-Supercritical Pulverized Coal with 90% Carbon Capture and Storage:** Cost uncertainty and technological immaturity
- **Combined Heat and Power (CHP):** Uncertainty regarding feasible potential sites and lack of potential partners expressing interest
- **Molten Salt Energy Storage:** Engineering complexity of development and operation and scarcity of operating examples of molten salt energy storage to draw upon

[39] https://www.nrel.gov/docs/fy23osti/84822.pdf Pg 17

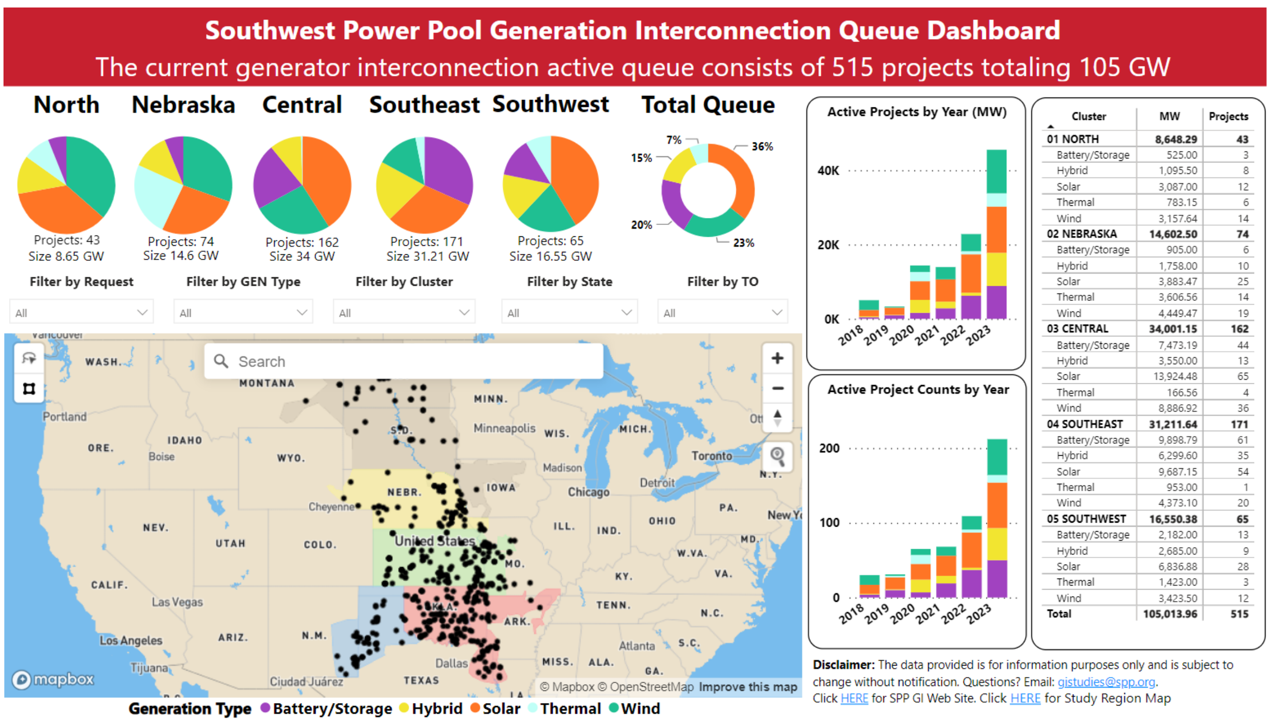
- **Compressed Air Energy Storage:** Engineering complexity of development and operation as well as lack of natural geology
- **Hydroelectric:** Challenges associated with permitting new pumped hydroelectric storage facilities
- **Large-Scale Nuclear:** Permitting, cost and environmental concerns. Evergy is considering SMR as a resource option for the end of the 20-year planning horizon.
- **Biomass:** High cost, lack of fuel, more cost-effective renewable options
- **Fuel Cell:** High cost and technological immaturity
- **Solar Thermal:** High cost, unsuitable geography
- **Long-Duration Battery Storage (Alternative Chemistries**): Eliminated from consideration due to high cost and technological immaturity. Pilot projects are being pursued and could become a resource option in future IRPs.
- **Alternative Natural Gas Technologies:** In 2023, Evergy ran a technology study exploring various simple and combined cycle natural gas technologies. Various technologies were explored including: simple cycle heavy frame E class, heavy frame F class, aeroderivative, and reciprocating engines. Additionally, combined-cycle E class, F class, and advanced class with wet and dry cooling were modeled. The results of that study showed that advanced class units had relatively low construction costs on a per kilowatt basis and comparative heat rate advantages. Due to these characteristics, the team moved forward with advanced class simple and combined cycle as the modeled case for the 2024 triennial IRP.

Section 4: Interconnection and Transmission Requirements

4.1 Interconnection Queue Status[40]

The Southwest Power Pool (SPP) interconnection queue has reached historic levels thanks to the passage of the Inflation Reduction Act and the proliferation of solar and solar plus storage deployment in the SPP after a decade of focus on wind. As of early 2024, as shown the figure below , the Southwest Power Pool queue totaled 515 projects and more than 105 gigawatts of nameplate capacity. For SPP Central, which is the area that encompasses Kansas and Missouri, there are 162 projects and ~34 gigawatts of nameplate capacity in the queue.

Figure 40: SPP GI Queue Status



Cluster	MW	Projects
01 NORTH	**8,648.29**	**43**
Battery/Storage	525.00	3
Hybrid	1,095.50	8
Solar	3,087.00	12
Thermal	783.15	6
Wind	3,157.64	14
02 NEBRASKA	**14,602.50**	**74**
Battery/Storage	905.00	6
Hybrid	1,758.00	10
Solar	3,883.47	25
Thermal	3,606.56	14
Wind	4,449.47	19
03 CENTRAL	**34,001.15**	**162**
Battery/Storage	7,473.19	44
Hybrid	3,550.00	13
Solar	13,924.48	65
Thermal	166.56	4
Wind	8,886.92	36
04 SOUTHEAST	**31,211.64**	**171**
Battery/Storage	9,898.79	61
Hybrid	6,299.60	35
Solar	9,687.15	54
Thermal	953.00	1
Wind	4,373.10	20
05 SOUTHWEST	**16,550.38**	**65**
Battery/Storage	2,182.00	13
Hybrid	2,685.00	9
Solar	6,836.88	28
Thermal	1,423.00	3
Wind	3,423.50	12
Total	**105,013.96**	**515**

Despite the record levels of interconnection requests, the Southwest Power Pool is making progress on their new timelines for Generator Interconnection studies. The 2021 and 2022 DISIS cluster studies were published on time and restudies were completed according to the timeline laid out by the SPP. Evergy will continue to actively engage in this process as both the Transmission Owner in the area as well as a developer. Evergy

[40] 20 CSR 4240-22.040(3); 20 CSR 4240-22.040(3)(B)

did not eliminate any supply-side resource options on the basis of interconnection or transmission concerns.[41]

Table 22: SPP Generation Interconnection Queue Study Schedule

Revision Date: 2/13/2024 9:50 AM   Questions? Email: GIStudies@spp.org   To View Interactive GI Queue Dashboard CLICK HERE   Refer to Notes, Legends and Links at Bottom of Page

SPP Generation Interconnection Queue Study Schedule*

Green shaded cells indicate milestone completion. *Actual Start and Completion dates may vary and are subject to change. **Restudy start dates may change pending the outcome of the previous restudy.

DISIS Cluster	Projects	MWs	*Projected DISIS Study Start	Projected DP 1 Completion	Projected DP2 Completion	**Projected Restudy Start	Projected Restudy Completion	Projected Facilities Studies Start (pending restudy)	Projected GIA Start	Current Status	Postings & Comments
DISIS-2017-002	59	11,727	6/21/2021	3/14/2022	9/20/2022	1/5/2024	3/4/2024	12/29/2022	2/15/2023	Restudy in progress GIA in progress	Restudy #2 started 1/5/24 (all groups)
DISIS-2018-001	32	4,955	3/15/2022	8/23/2022	4/24/2023	None planned	None planned	9/18/2023	11/29/2023	FS in progress GIA in progress	Phase 2 Final re-posted 4/10/2023. DP2 extended 10 BD to 4/24/2023
DISIS-2018-002 & DISIS-2019-001	54	7,298	8/24/2022	12/1/2022	10/13/2023	3/25/2024	5/23/2024	5/24/2024	7/22/2024	Restudy pending	Phase 1 Final re-posted 11/16/2022, Phase 2 Final re-posted 9/14/23
DISIS-2020-001	65	14371	12/2/2022	4/7/2023	3/11/2024	6/14/2024	8/12/2024	8/13/2024	10/11/2024	Phase 2 in progress	Phase 1 Final posted 3/17/2023
DISIS-2021-001	68	13,942	4/10/2023	7/17/2023	7/30/2024	9/2/2024	10/31/2024	11/1/2024	12/30/2024	Phase 1 complete	Phase 1 Final re-posted 6/30/2023
DISIS-2022-001	109	22,824	7/18/2023	11/3/2023	12/19/2024	1/14/2025	3/14/2025	3/17/2025	5/15/2025	Phase 1 complete	Phase 1 Final re-posted 10/20/23
DISIS-2023-001	214	46,517	1/2/2024	3/22/2024	5/9/2025	6/3/2025	8/1/2025	8/4/2025	10/2/2025	Phase 1 in progress	Window closed 10/2/2023
DISIS-2024-001	TBD	TBD	12/2/2024	2/21/2025	9/29/2025	10/22/2025	12/19/2025	12/22/2025	2/19/2026	Window Open	Window opened 12/1/23, closes 10/31/24

4.2 Interconnection Costs and Construction Costs

The SPP interconnection queue has grown in recent years, leading to concerns of potential future cost increases. SPP interconnection cost data compiled by Berkeley Lab was analyzed to assess the impact of interconnection cost variation on build plans and plan NPVRR.

4.3 SPP Interconnection Historical Costs

Berkeley Lab's SPP interconnection cost data provides point of interconnection and broader network upgrade costs for a sample of individual projects with cost data from 2002 to early 2023. The sample represents 47% of all interconnection requests between 2001 and 2022. Berkeley Labs notes several broad conclusions from the historical data.

First, interconnection costs vary widely by type, fuel, year, and location. Solar, wind and storage projects have higher interconnection costs than natural gas plants. Broader transmission system upgrade costs are the primary cost driver and have grown over time. Projects in the northern part of SPP report higher costs than the south.

[41] 20 CSR 4240-22.040(4); 20 CSR 4240-22.040(4)(B)

Second, interconnection costs for projects with completed studies have been relatively stable since 2002. Withdrawn project costs have grown significantly. Projects that withdraw typically have significantly higher costs than completed or currently active projects. Annual cohort average costs tend to lower over time as active projects withdraw from the queue.

Table 23: SPP Average Historical Interconnection Costs (2022 $/kW)

Project Status	2002-2009	2010-2019	2020-2022
Complete	$54	$43	$57
Active			$106
Withdrawn	$22	$247	$304

4.4 Development of Interconnection Cost Forecasts[42]

Since the impact of potential cost increases is the primary concern, total interconnection cost data ($/kW) from 2019-2023 for active and completed projects was analyzed to obtain estimates of high and low interconnection costs by fuel type. Those estimates were used to assess the impact of interconnection cost variation on the 2023 IRP model's capacity expansion plans and NPVRR.

The smallest 5% and largest 5% of observations were dropped from the sample since several fuel types had projects that were extreme outliers (e.g., $0/kW). Solar and wind projects make up the bulk of the sample. Natural gas and hybrid projects have limited observations over the sample period. Active projects consist of 71% of the sample.

Since project costs by fuel type were not normally distributed, the median observation for each fuel type was used as the midpoint estimate. The 25th and 75th percentile of each fuel type was used as the high and low estimated costs.

[42] 20 CSR 4240-22.040(3); 20 CSR 4240-22.040(3)(A); 20 CSR 4240-22.040(3)(A)(1); 20 CSR 4240-22.040(3)(A)(4); 20 CSR 4240-22.040(3)(A)(3); 20 CSR 4240-22.040(3)(A)(4); 20 CSR 4240-22.040(3)(A)(5); 20 CSR 4240-22.040(3)(A)(6)

Table 24: Interconnection Cost Sensitivities (2022 $/kW) **Confidential**

[redacted]

Interconnection costs had a very small impact on build plans in the critical uncertain factor analysis and did not change NPVRR rankings of alternative build plans. Results of the analysis are discussed in more detail in Volume 6.

4.5 Construction and Interconnection Costs as a Critical Uncertain Factor[43]

The SPP interconnection cost data from Berkeley Labs was also used to refine and improve scenario analysis of total build costs. Total build cost values were calculated by combining construction and interconnection estimates costs for each new resource. Due to their relative size difference, construction cost changes for new resources have a larger impact on build plans and NPVRR than interconnection costs in critical uncertain factor scenario analysis. Interconnection cost estimates in the 2024 IRP represent just 3-7% of a resource's total build cost.

Interconnection cost estimates for renewables in the total build cost scenario were based on the 2019-2023 SPP sample of active and completed projects previously discussed. Renewables mid estimates used the median value for each fuel type. The low and high estimates used the 25th and 75th percentile values. CC and CT interconnection cost mid estimates were based on internal estimates due to the small SPP sample. High and low CC and CT interconnection costs estimates vary by 15% from the mid value for the total build scenario.

[43] 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(B); 20 CSR 4240-22.040(5)(F)

Results of the total build cost scenario critical uncertain factor analysis are discussed in Volume 6.

Table 25: Construction and Interconnection Cost Scenario Values ($/kW)

****Confidential****

[redacted]