Evergy Missouri Metro

2026 Annual Update

Integrated Resource Plan

May 2026

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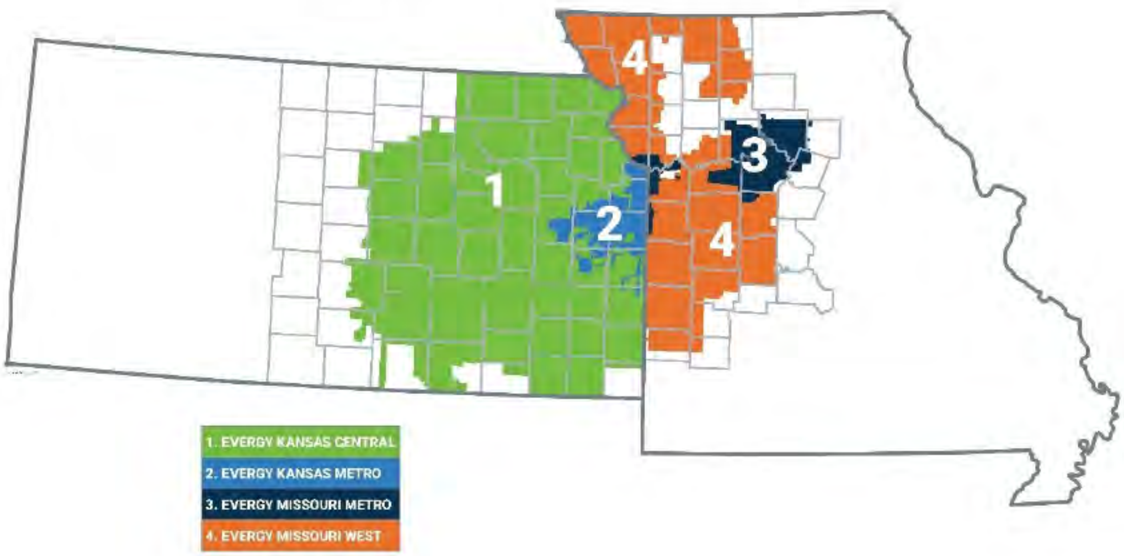
Section 1: Executive Summary

1.1 Utility Introduction

Evergy Metro (or "Company") is an integrated, mid-sized electric utility serving the region in and surrounding the Kansas City, Missouri metropolitan area including customers in Kansas and Missouri. A map of the Evergy service territory, which includes Evergy Metro, is provided in Figure 1 below.

Figure 1: Evergy Service Territory



Evergy Metro is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. The Table below provides a snapshot of the number of customers served, retail sales, and peak demand based upon 2025 data.

Table 1: 2025 Customers, Retail Sales, and Peak Demand

Jurisdiction	Number of Retail Customers	Retail Sales (MWh)	Net Peak Demand (MW)
Evergy Missouri Metro	310,605	8,396,957	1,872
Evergy Kansas Metro	279,835	6,414,535	1,659
Total Evergy Metro	**590,440**	**14,811,492**	**3,531**

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

Table 2: Capacity and Energy by Resource Type

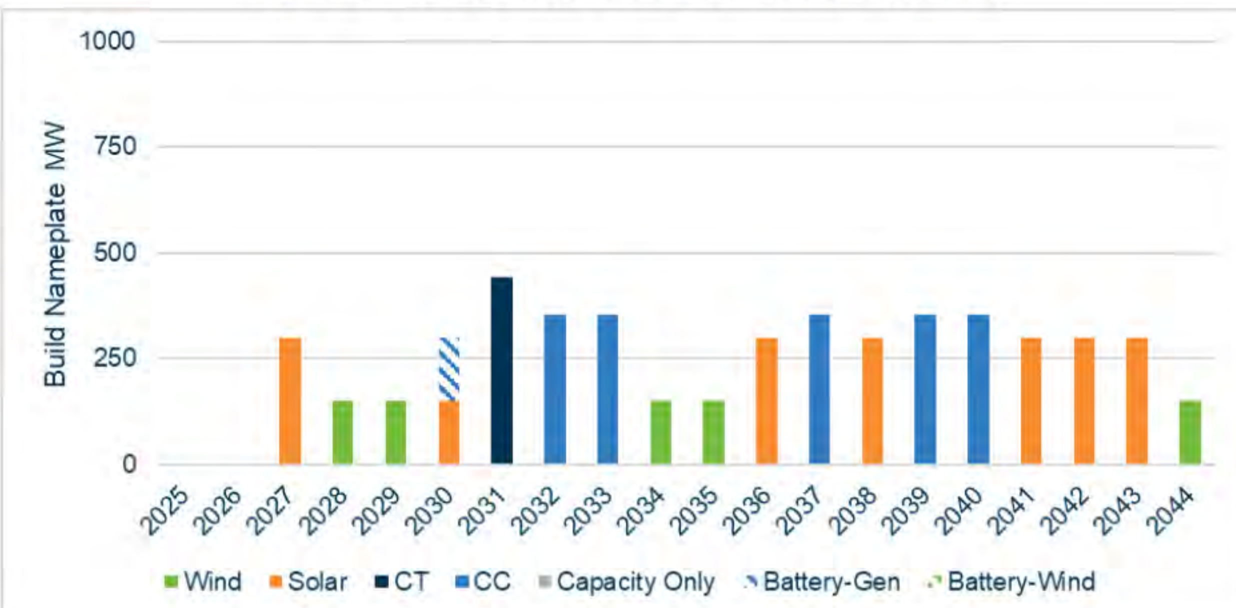
Jurisdiction	Capacity by Fuel Type	Capacity (MW)	Capacity (%)	Energy (MWh)	Energy (%)
Evergy Metro	Coal	2,274	42%	9,365,017	51%
	Nuclear	553	10%	4,356,483	24%
	Natural Gas/Oil	1,208	22%	740,475	4%
	Renewable*	1,337	25%	3,773,494	21%
Total		**5,373**	**100.0%**	**18,235,469**	**100%**

**Nameplate renewables capacity*

1.2 Preferred Plan Filed in the 2025 Annual Update

Evergy Metro submitted its 2025 Annual Update filing on March 13, 2025.[1]

Figure 2: Evergy Metro 2025 Preferred Plan AAAA



[1] EO-2025-0250

The 2025 Preferred Plan called for Evergy Metro to build or acquire new resources including 300 MW of solar in 2027, 150 MW of wind in 2028 and 2029, and 150 MW of solar and 150 MW of storage in 2030 to meet customer needs in the next 5 years, with the first thermal resource build needed in 2031. The Preferred Plan also reflected the demand-side programs consistent with the Missouri Energy Efficiency Investment Act ("MEEIA") Cycle 4 approved programs. In response to federal environmental rules, coal generator retirements were anticipated to occur in March 2033 for La Cygne 1, and in March 2040 for La Cygne 2 and Iatan 1.

1.3 Changes to the Preferred Plan for the 2026 Annual Update

This year's 2026 Annual Update shows increasing needs for Metro inclusive of higher large load customer growth, beginning in 2026 and exceeding 300 MW by 2031. A large load customer included in Metro's 2025 Integrated Resource Plan ("IRP") has signed an Energy Service Agreement ("ESA"), increasing the certainty of large load committed in Metro's forecast.

In addition to large-load customer growth, the changes to Metro's resource needs, as identified in the resource plan, were primarily driven by:

- Alignment with the most recent Southwest Power Pool ("SPP") resource adequacy rules and study results for expected summer and winter reserve margins and capacity accreditation
- Cost and performance characteristics of new thermal resource options consistent with market availability
- Updates to solar, wind, and storage costs based on 2025 all-source Request for Proposal ("RFP") results
- Changes in policy for renewable and storage tax credits and outlook for carbon regulation

The updated 2026 Preferred Plan affirms the need for some of the projects identified in the 2025 Annual Update, including thermal resources in 2031 and 2032 and battery storage in 2030. The 2026 Preferred Plan ACAA, as shown in Figure 3 below and described in Section 10.3 and 10.4 of this IRP, postpones planned retirements relative to the 2025 Preferred Plan and assumes DSM programs continue.

In the near-term, the Preferred Plan calls for 150 MW each of solar and storage qualifying for production tax credits ("PTC") and investment tax credits ("ITC"), respectively, to meet reserve margin needs. The plan adds firm-dispatchable generation including a Simple-Cycle Gas Turbine ("SCGT") in 2031 and ½ Combined-Cycle Gas Turbine ("CCGT") in 2032. Evergy Metro plans to execute on the Mullin Creek #2 project to fill the 2031 need that was identified in the 2025 Annual Update and confirmed in the 2026 Annual Update. Evergy Metro expects to share ownership in the 2032 CCGT with Evergy Missouri West, which also needs ½ CCGT in its 2026 Preferred Plan.

The Preferred Plan delays the La Cygne 1 retirement date to March 2038, from March 2033 in the 2025 Annual Update. Retirement dates for La Cygne 2 and Iatan 1, which were March 2040 in the 2025 Annual Update, are delayed beyond the 20-year planning horizon.

Additional firm-dispatchable resources are selected beginning in 2035. SCGTs are selected in 2035 and 2038, ½ CCGTs are selected in 2040 and 2042, and a Reciprocating Internal Combustion Engine ("RICE") unit is selected in 2044.

New renewable build and long-term ownership economics have become less favorable compared to prior years due to changes in federal tax policy, carbon policy outlook, and higher fixed costs for wind turbines. The 2025 Preferred Plan had significantly more wind and solar generation additions, with 450 MW wind and 1.5 GW solar selected between 2034-2044. The reduction in planned renewable additions in Metro's 2026 IRP Preferred Plan reflects the combined effect of shortened PTC eligibility under the One Big Beautiful Bill Act ("OBBBA"), approximately 30% higher renewable development costs, and local siting and permitting challenges. The Company continues to value an all-of-the-above generation strategy and will pursue renewable opportunities as economics and permitting conditions allow.

While Plan ACAA is not the absolute lowest-cost plan on a probability-weighted net present value revenue requirements ("NPVRR") basis, the cost difference relative to the lowest-ranked plans is less than $15 million — or less than 0.05% of the 20-year revenue requirement. Evergy Metro selected Plan ACAA as the Preferred Plan because it represents the best risk-adjusted portfolio when factoring the practical realities of project execution, including the concentration risk of co-locating two major thermal projects in a single construction year, growing permitting challenges for solar development in Missouri, and the superior winter capacity contribution of battery storage during Evergy Metro's most acute deficit years. The resulting near-term resource mix — solar, battery storage, SCGT, and CCGT — provides technology and fuel diversity that hedges against execution risk in any single resource category and positions the Company to adapt as market conditions, tax policy, and customer commitments evolve.

Figure 3: Evergy Metro 2026 Preferred Plan ACAA

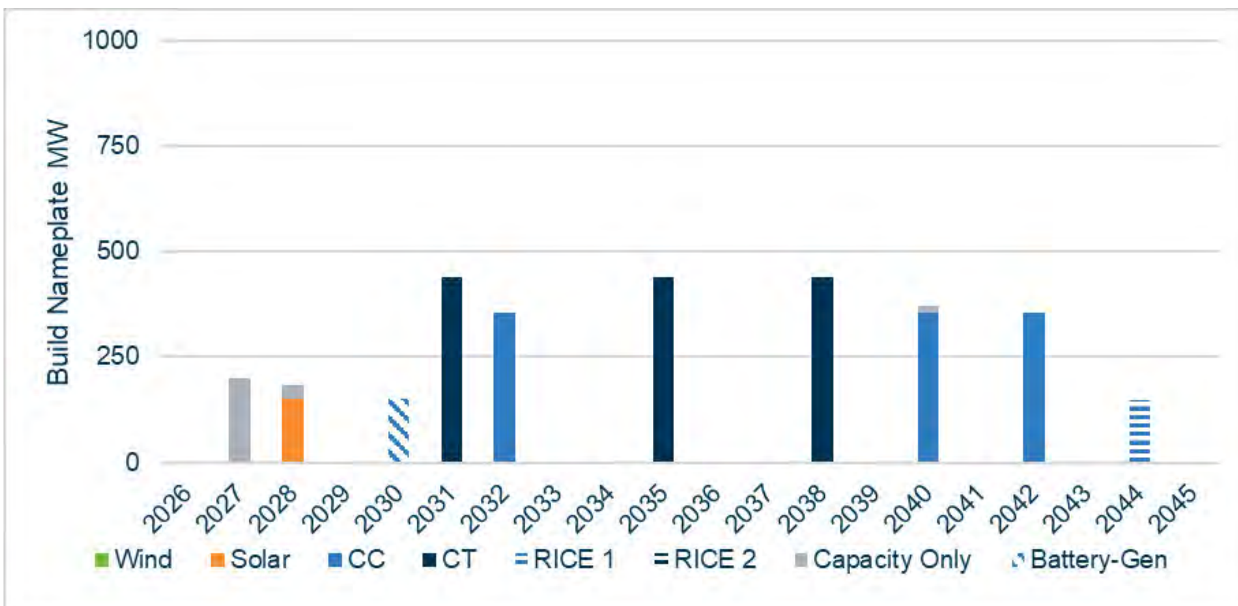


Table 3: Evergy Metro Preferred Plan Comparison

	2025 IRP Annual Update	2026 IRP Annual Update
Retirements	La Cygne 1 March 2033 La Cygne 2 March 2040 Iatan 1 March 2040	La Cygne 1 March 2038
Wind Additions	150 MW in 2028 150 MW in 2029 150 MW in 2034 150 MW in 2035 150 MW in 2044	
Solar Additions	300 MW in 2027 150 MW in 2030 300 MW in 2036 300 MW in 2038 300 MW in 2041 300 MW in 2042 300 MW in 2043	150 MW in 2028
Battery Additions	150 MW in 2030	150 MW in 2030
Thermal Additions	440 MW CT in 2031 355 MW CC in 2032 355 MW CC in 2033 355 MW CC in 2037 355 MW CC in 2039 355 MW CC in 2040	440 MW CT in 2031 355 MW CC in 2032 440 MW CT in 2035 440 MW CT in 2038 355 MW CC in 2040 355 MW CC in 2042 148 MW RICE in 2044
New DSM Programs	MEEIA Cycle 4 Extended Demand Response	Continuation of Demand Response

**CCGT = CC, SCGT = CT, Natural Gas = NG*

1.4 Managing Risk and Investing to Support Regional Growth

This IRP plans for Evergy Metro to grow from a summer peak of 3.7 GW in 2026 to 4.6 GW in 2032, and 5.4 GW by 2045, approximately 24% and 46% of system peak growth, respectively. The base load forecast has increased this year as Evergy Metro has gained commitments from more customers, driven primarily by the datacenter and artificial intelligence ("AI") economy, and facilitated by the approval of a Large-Load Power Service ("LLPS") tariff in Missouri and Kansas.

The increase in committed and prospective load in Evergy Metro, Evergy's other utilities, and SPP will require significant investments in the bulk power system in the next few years. Evergy Metro customers will benefit from expansion and modernization of the transmission system and new sources of supply, including highly efficient, reliable baseload energy resources, to complement the aging fleet.

Evergy Metro must keep pace with rapidly growing generation capacity and energy needs to foster economic development in Missouri and support regional prosperity. Evergy Metro also prioritizes maintaining affordability and minimizing investment risks for its current customers. The Company has taken a balanced approach in planning to grow its fleet in step with customer commitments while ensuring there is sufficient confidence in the load forecast before adding long-life assets to its infrastructure portfolio. With the LLPS tariff, large customers are committed to long-term minimum offtakes and will pay a premium rate that covers their fair share of existing and new system costs to drive affordability benefits for existing customers and enhance economic growth.

Building new generation resources commensurate with new committed load growth is challenging in practice, because the supply and demand forces in the generation development sector have led to rising costs each year for the past few years and longer lead times for project completion.

Options are limited for new generation projects that can be developed and placed into commercial operation prior to 2031. Evergy Metro has explored the possibilities for meeting near-term needs and chosen a Preferred Plan that includes a mix of short-duration market capacity as a bridge and buildable owned resource additions that comprise the least-cost resource portfolio over the planning horizon. In the medium-term (5-7 years out), Evergy Metro has a wider range of planning options and has selected new natural gas-fired resources to meet capacity and energy needs.

The goal of this Preferred Plan is to outline the Company’s current long-term strategy to meet customer energy needs, but also to focus particularly on the robustness and viability of near-term decisions which must be made to begin executing on that strategy. Given the increasing capacity and energy requirements described throughout this filing, there is significant urgency to continue to execute both the supply and demand-side additions outlined in the first 3-6 years of this Preferred Plan. The analysis performed in this IRP will be used to support separate regulatory filings related to these resource additions. These filings must be supported by the whole IRP and not only by resource-specific evaluations because the evaluation of resource decisions cannot be performed in a vacuum. The integrated analysis of risks and resource options, along with customer needs for energy and capacity, is required to reflect the trade-offs inherent in any resource decision. Any resource added (or not added) today has an impact on future resource decisions.

Consistent with Evergy Metro's prior two IRPs, future natural gas commodity prices, carbon dioxide emissions policy, and new resource construction costs are assessed as critical uncertain factors ("CUF") which contribute to the economic evaluation of plans. The 2026 Annual Update includes a refresh of planning cost forecasts consistent with current market conditions and a reassessment of risks based on federal policy changes.

There is strong potential for even greater future load growth than what is laid out in this Preferred Plan, as there is a pipeline of customers interested in locating in Evergy's service territory. This IRP includes alternative resource plans ("ARPs") to determine additional resource additions that can accommodate future committed large load customers in the most cost-effective and reliable manner across the planning horizon.

Section 2: Evolution in the Planning Environment

The planning environment in the United States ("US") electricity sector has been very dynamic since the 2025 Annual Update to the IRP and in the past few years. The 2026 Annual Update incorporates forecast revisions consistent with the most recent expectations of load growth and changes to policy and economics.

2.1 Higher Expected Load Growth

Evergy is planning for additional load growth above the 2025 Annual Update forecast for all three utilities.

Since the 2025 Annual Update, the pathway to integrate large loads has become more certain. In November 2025, Evergy completed the regulatory processes in both Missouri and Kansas to establish plans for LLPS customers.[2] These cases resulted in tariffs requiring long-term commitments from customers with over 75 MW of peak load and include rate structures aligned with their incremental costs to the system.

With these Tariff approvals, Evergy has made more progress finalizing agreements with customers. Evergy's preferred plans reflect a load forecast based on final Energy Service Agreements or near-final negotiations. As Evergy negotiates customer agreements, a primary consideration is ensuring that new load can be supplied with Evergy's existing and planned resources and a realistic level of future resource development and acquisitions, considering availability, cost, and lead time for new projects.

This IRP also considers ARPs that would accommodate additional large-load customers and demand growth. Evergy has a substantial pipeline of prospective customers beyond just the customers included in the Preferred Plan.

[2] The Public Service Commission of the State of Missouri. Report and Order, Case No. EO-2025-0154, November 13, 2025. The State Corporation Commission of the State of Kansas. Order Approving Unanimous Settlement Agreement, Docket No. 25-EKME-315-TAR, November 6, 2025.

From a broader perspective, data centers are driving load growth across the US. S&P Global reports that data center demand was projected to rise by 22% (11.3 GW) year-over-year by the end of 2025.[3] There are strong indications that the nationwide boom in Hyperscaler activity will continue to be a big driver of load growth across the country as technology companies compete to dominate the AI sector. In early 2026, Microsoft, Meta, Alphabet (Google), and Amazon announced a combined total of $650 billion in expected capex spending for 2026, a 60% increase from 2025 (with both Google and Meta further increasing their 2026 capex estimates in late April).[4] Analysts are tracking AI spending, and some forecast that in the coming years, it will exceed historic infrastructure expansions (telecom, railroads, New Deal projects). President Trump has directed an action plan for the US to achieve global dominance in AI, that includes goals to streamline permitting of datacenters and adapt the power grid to meet supply needs.[5]

Currently, forecasts for US datacenter demand vary widely as there are many unknowns. Some recent projections estimate an increase in peak demand from datacenters of 60 GW to 167 GW in 2030.[6] Overall, US peak demand forecasts for 2030 have increased 20% between 2022 and 2025 forecast updates, and the SPP forecast has increased almost 42%.[7]

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[3] Hering, Garrett and Dlin, Susan. S&P Global. "Data Center Grid-Power Demand to Rise 22% in 2025, Nearly Triple by 2030". October 14, 2025.
[4] Day, Matt and Bang, Annie. Bloomberg. "Big Tech to Spend $650 Billion This Year as AI Race Intensifies." February 6, 2026. https://finance.yahoo.com/news/big-tech-spend-650-billion-012716850.html
[5] Executive Office of the President of the United States, Office of Science and Technology Policy. Winning the Race America's AI Action Plan. July 2025.
[6] Grid Strategies deconstructed forecasts submitted to FERC in 2025 from the planning entities and determined 90 GW of the projected 166 MW of load growth by 2030 could be attributed to datacenters. They compared this estimate to the Cleanview database tracking datacenters which estimated 60 GW by 2029, and a TD Cowen projection of 65 GW based on shipments of processing chips. Grid Strategies. Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers. Slide 10. November 2025. High end estimate based on 451 Research. Datacenter Services & Infrastructure Market Monitor & Forecast, December 2025.
[7] Grid Strategies. Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers. Slide 22. November 2025. It is likely that some of the SPP increase is due to efforts to electrify the Permian Basin and Bakken.

While data center demand presents significant growth opportunities, Evergy recognizes the importance of ensuring that the pace of resource development in the Preferred Plan aligns with customer commitments and that existing customers are not exposed to stranded asset risk from speculative load growth.

2.2 Continued Focus on Reliability

Evergy's preferred and alternative resource plans are developed to meet expected reliability needs in every year of the planning horizon. Evergy follows and participates in resource adequacy policy development at SPP. The IRP reflects the most up-to-date expectations for capacity needs, resource accreditation, and timelines for development and interconnection. SPP and stakeholders acknowledge challenges with resource adequacy and continue to work through policy and process changes. In the past year, SPP finalized the seasonal reserve margin construct, conducted more reserve margin studies, and established a cadence for informational studies. SPP also created a one-time pathway to resolve imminent resource adequacy shortfalls due to interconnection queue delays. Evergy expects continued focus on resource adequacy in SPP with future rules focusing on forecast accuracy of load and demand response. The State of Missouri also passed Senate Bill 4 during the 2025 legislative session to address resource adequacy concerns which also included incentives for new gas generation and requirements for replacing dispatchable resources one-for-one with dispatchable capacity.[8] Other provisions include a reliability mechanism with annual reporting by utilities and accounting changes to promote construction of natural gas-fired power plants and grid upgrades.

In 2025, the Federal Energy Regulatory Commission ("FERC") accepted SPP's proposed tariff change to establish separate planning reserve margins for winter and summer seasons.[9] SPP refreshed its Loss of Load Expectation ("LOLE") study with updated

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[8] Mike Kehoe, Missouri Governor. "Governor Kehoe Signs SB 4 Into Law, Securing Missouri's Energy Future and Economic Growth." April 9, 2025. https://governor.mo.gov/press-releases/archive/governor-kehoe-signs-sb-4-law-securing-missouris-energy-future-and-economic

[9] *Sw. Power Pool, Inc.*, 192 FERC ¶ 61,161. August 19, 2025. The Order also approved SPP's proposal to consider length and duration of loss of load events in setting reserve margin requirements.

planning information from load-serving entities and set the 2029 installed capacity planning reserve margins, which increased from 16% in summer 2026 to 17% for summer 2029, and from 36% to 38% in winters 2026/27 to 2029/30. Evergy's 2025 Annual Update and capacity planning had anticipated these changes. SPP has instituted a new process for periodic LOLE studies, including informational studies of future years to better anticipate planning needs. The preliminary results from LOLE studies for 2030 and 2032 indicate that reserve margins will remain stable or increase slightly if the load and resource mix planned by SPP load-serving entities materialize.[10]

Recognizing a potential reliability challenge due to rapidly increasing load forecasts, higher reserve margin requirements, and long lead times in the interconnection queue, SPP stakeholders proposed a process to quickly enable generators, needed for resource adequacy, to connect to the grid by 2030. In July 2025, FERC approved SPP's Expedited Resource Adequacy Study ("ERAS") process.[11] ERAS created a one-time interconnection queue process for resources needed to meet capacity needs. Evergy submitted four thermal resources consistent with its 2025 Annual Update to ensure firm-dispatchable capacity is online to meet the needs identified in its resource plan.[12]

The next emerging issue related to SPP's resource adequacy is forecast accuracy. SPP has suggested assessing compliance with reserve margin requirements on an ex-post basis after the season concludes. Load-serving entities would be accountable for actual net peak needs (including load and demand response), rather than pre-season forecasted net peak needs and subject to penalties if accredited capacity is insufficient.[13] The potential change in the framework illustrates the importance of having sufficient capacity to meet forecasted peak load.

[10] SPP. 2025 LOLE Study Results and PRM Recommendation. January 2026 SAWG.
[11] *Sw. Power Pool, Inc.*, 192 FERC ¶ 61,062. July 21, 2025.
[12] Evergy resources in the ERAS queue include Viola and McNew combined-cycle gas turbine projects jointly owned by Evergy Missouri West and Evergy Kansas Central, Mullin Creek #1 simple-cycle gas turbine owned by Evergy Missouri West and Mullin Creek #2 simple cycle gas turbine for Evergy Metro.
[13] *See* SPP Revision Request RR703.

2.3 Changes in Environmental Policy and Decarbonization Outlook

In the past year, there have been several changes to policy and market fundamentals that reduce Evergy's expectations for the pace of decarbonization in the US electric sector, including for the Evergy generating fleet and SPP more broadly. Evergy has adjusted its future carbon-reduction-risk CUF values, updated its future SPP resource mix assumptions for market pricing, and reassessed coal plant retirement risks due to the following changes:

- Federal implementation of greenhouse gas emissions ("GHG") rules being postponed and potentially eliminated,
- Timeline for required investment in Jeffrey Energy Center nitrogen-oxide ("NO_X") emissions controls being extended,
- PTC eligibility for new renewable resources ending earlier,
- Load growth and reliability needs driving resource plans toward retaining and adding new firm-dispatchable resources; and,
- Availability of carbon-free dispatchable options remaining limited

2.3.1 GHG Rule

For the 2025 Annual Update, Evergy included ARPs to comply with the Environmental Protection Agency's ("EPA") GHG Final Rule which was issued in May 2024.[14] Evergy Metro developed GHG Rule compliance options for its coal fleet, including high-level cost estimates for retrofitting coal resources to co-fire or fully operate with natural gas. The Company also engaged with natural gas pipelines to estimate the costs of adding infrastructure to deliver natural gas to the sites. A compliance plan was not chosen as the Preferred Plan because of higher expected costs and uncertainty of enforcement of the rule due to the change in presidential administration prior to the IRP.

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

In March 2025, the EPA publicly announced reconsideration of the GHG Rule.[15] In June 2025, EPA proposed a rule to repeal all GHG emissions standards for fossil fuel-fired plants, or in the alternative, to repeal the standards created in the GHG Rule.[16] As of the 2026 Annual Update, a final rule has not been issued.

2.3.2 Production Tax Credits and Investment Tax Credits

PTCs and ITCs provide customer benefit for eligible resources as the tax attributes are flowed back to the customers. Recent federal law changes have shortened the eligibility timeline for PTCs for wind and solar resources, thereby increasing the expected net costs for solar and wind additions beginning operation in 2030 and beyond. There are also stricter project qualification requirements for production or investment tax credits, which may affect the viability and cost of new resource builds.

In August 2022, Congress passed the Inflation Reduction Act (“IRA”), and it was signed into law by President Biden. The IRA increased and extended availability of PTC and ITC. Evergy’s IRPs in 2023, 2024, and 2025 assumed that new wind and solar resources would receive PTC and new battery resources would receive ITC. The IRA included a phase-out of eligibility for tax credits as the US meets its GHG emissions reduction goals. Projects beginning operation before 2034 were forecast to receive 100% of credits, with the credits phasing down to 75% and 50% for projects beginning operation in 2034 and 2035 and ceasing for projects after 2035.

In July 2025, Congress passed the OBBBA and it was signed into law by President Trump. The OBBBA shortened the eligibility window for new projects to qualify for PTC. New wind and solar resources must begin operation before 2028, or begin construction by July 4, 2026, and begin operation before 2030. In addition, resource developers will

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[15] EPA Press Office. “Trump EPA Announces Reconsideration of Biden-Harris Rule, ‘Clean Power Plan 2.0’, That Priotized Shutting Down Power Plants While Raising Costs on American Families.” March 12, 2025. https://www.epa.gov/newsreleases/trump-epa-announces-reconsideration-biden-harris-rule-clean-power-plan-20-prioritized

[16] Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units. 90 FR 25752.

be subject to stricter criteria to meet the definition of beginning construction[17] and to qualify projects that source parts and components from Foreign Entities of Concern ("FEOC").[18] Storage resources maintain their eligibility for ITC within the same time horizon expected under the IRA rules but will also be subject to FEOC rules.

2.3.3 Pace of Resource Mix Change

For the 2026 Annual Update, Evergy continues to consider carbon policy as a CUF and has updated market pricing based on updated ITP supply and demand forecasts (see Appendix B Evergy Market Prices 2025 Refresh). Evergy is no longer using the 95% carbon reduction resource mix as a scenario because it does not seem plausible, even in a "high" case based on the current fundamental and policy drivers.

For the 2024 and 2025 IRPs, Evergy used two different future resource mix scenarios for market pricing, based on the SPP Integrated Transmission Planning ("ITP") process assumptions which project the system supply and demand 2, 5, 10 and 20 years into the future. The scenario, including a moderate level of renewable and storage resource additions, was used for the "low" (no) and "mid" carbon policy risk models. The scenario used for Evergy's "high" carbon policy risk was based on high levels of renewable and storage buildout as well as earlier retirement assumptions for emitting resources to achieve a 95% carbon reduction from 2017 levels by 2040. Evergy analysis found that this reduction was fairly consistent with the EPA GHG rule goals. The resulting market price forecast declined over time, consistent with a high fixed cost, low variable cost supply mix, including negative production costs due to tax credits.

[17] The IRS has issued a notice with guidance on establishing beginning of construction to meet OBBBA requirements. The standard is a Physical Work Test with a Continuity Requirement. See IRS Notice 2025-42, Beginning of Construction Requirements for Purposes of the Termination of Clean Electricity Production Credits and Clean Electricity Investment Credits for Applicable Wind and Solar Facilities. https://www.irs.gov/pub/irs-drop/n-25-42.pdf
[18] The US Treasury has not finalized FEOC guidance.

2.3.4 Enabling Technologies

Dispatchable, carbon-free energy sources will be needed to achieve decarbonization while meeting load growth and reliability needs. Commercially viable options are not expected to be available in the near term as AI and datacenter load ramps up. There is some optimism that US government and tech company support may help accelerate nuclear development. Evergy plans to continue monitoring the progress of nuclear generation technology and study it within the IRP when it becomes technologically and economically viable.

In the past few years, some pathways to decarbonization began to gain traction, including using hydrogen as an alternative fuel, carbon emissions capture, and development of Small Modular Reactors ("SMRs"). However, none of these options are economically viable without advances in technology. Hydrogen fuel is created by using other energy sources to break up water molecules. The process uses more energy than can be created and can be cost-prohibitive. Naturally occurring geologic hydrogen has been identified,[19] but mining and extraction methods have not been developed. There are also cost and logistical challenges in storing and transporting hydrogen for power production. Carbon capture technology has been in existence for many years but requires significant and expensive infrastructure to complete chemical processes to separate the carbon. Post separation, the carbon then must be stored in a geologically appropriate location or transported for off-site storage. Evergy considered carbon capture at coal plants to comply with the GHG Rule but found that storage would likely be physically impractical, in addition to being extremely costly. In the past few years, SMR technology appeared to be making gains in viability. However, in late 2023, Utah Associated Municipal Power Systems cancelled its SMR project with NuScale after 8 years of development due to rising costs, exceeding three times the initial estimate.[20]

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[19] See Section 14.4 for discussion of geologic hydrogen in our area.

[20] Day, Paul. Cancelled NuScale Contract Weighs Heavy on New Nuclear. Reuters. January 10, 2024. https://www.reuters.com/business/energy/cancelled-nuscale-contract-weighs-heavy-new-nuclear-2024-01-10/ . Ramana, M.V. The Collapse of NuScale's Project Should Spell the End for Small Modular Nuclear Reactors (Opinion). Utility Dive. January 31, 2024. https://www.utilitydive.com/news/nuscale-uamps-project-small-modular-reactor-ramanasmr-/705717/

In September 2025, Evergy, TerraPower, a nuclear innovation company, and the Kansas Department of Commerce, announced the signing of a memorandum of understanding ("MOU") to explore siting TerraPower's flagship technology, the Natrium® reactor[21] and energy storage system, within Evergy's service territory in Kansas. This agreement enables collaboration between the entities to evaluate site-specific characteristics for a potential advanced nuclear power plant, as well as explore the Natrium plant's technical design and ability to support Evergy's customers. While the agreement to search for a site has no financial commitment for Evergy or its customers, the MOU does provide an avenue for Evergy to monitor closely the landscape of this emerging SMR technology. This allows Evergy to be poised to evaluate inclusion in future IRPs when it is reasonably demonstrated to be operationally and economically viable for customers.

Some of the largest datacenter end-users have carbon-free energy goals. Their financial backing, as well as support from US government programs and policies, may help accelerate nuclear development. In mid-2025, Google and Kairos Power announced the development of a 50 MW advanced nuclear reactor that will supply Tennessee Valley Authority beginning in 2030.[22] Google has a partnership with Kairos Power to financially support the development of the first-of-a-kind technology and enable progress to commercial viability.

Building a new large-scale nuclear resource requires about 10 years of lead time.[23] Large-scale nuclear development in the US has been deterred by safety concerns resulting from the Fukushima nuclear accident in Japan, the bankruptcy of Westinghouse, and the long delays and large cost overruns in building the Vogle units in Georgia. Some electricity suppliers are looking at restarting retired nuclear reactors to serve datacenter

[21] The Natrium is a TerraPower and GE Vernova Hitachi Nuclear Energy technology.
[22] Kimball, Spencer. Google, Kairos Power Plan Advanced Nuclear Plant for Tennessee Valley Authority Grid by 2030. CNBC. August 18, 2025. https://www.cnbc.com/2025/08/18/google-kairos-nuclear-smr-tennessee-valley-authority-tva-data-center-ai.html
[23] See later discussion on nuclear timelines in Section 14.1

customers.[24] The US government has also announced goals, policy reforms, and financing to boost nuclear power development including improving supply chains for nuclear fuel, advancing reactor technology, and restarting closed reactors.[25]

2.4 Continued Increase in New Build Costs, Long Lead Times for Development

The 2026 Annual Update includes cost increases for most new resource options and updates to the expected availability and lead times for new resources. Evergy's planning options for the 2026 Annual Update are informed by offers received in the 2025 all-source RFP, continued discussions with RFP project sponsors, and knowledge gained through self-development research.

Costs for new gas turbines have increased since the 2025 Annual Update due to supply and demand forces including supply chain issues, inflation, prices of metals and other components, limited manufacturing capabilities, and expectations for strong demand growth across the country and internationally due to advanced manufacturing, AI, and datacenter investment. In 2025, S&P Global reported long wait times of 5-7 years for gas-turbine orders and cost increases of over 200% compared to a few years ago.[26] It also noted high increases in development costs for engineering and construction of all types of projects. Evergy received some offers for gas-fired projects in its 2025 RFP and has continued to advance thermal self-development activity based on needs identified in the 2025 Annual Update. These options allow Evergy to add natural gas resources in the early 2030's. Evergy also forecasts increases in development costs and firm natural gas delivery contracts. Total costs for new natural gas-fired additions are expected to be about 20-25% higher than forecasted in the 2025 Annual Update.

[24] In late 2024, Microsoft signed a deal with Constellation to restart Three Mile Island, which closed in 2019. In late 2025, NextEra Energy and Google announced an agreement to restart Duane Arnold which closed in 2020.

[25] US Department of Energy. Fact Sheet: The Energy Department is Delivering on Accelerating the Deployment of Nuclear Power. January 19, 2026. https://www.energy.gov/articles/fact-sheet-energy-department-delivering-accelerating-deployment-nuclear-power

[26] Anderson, Jared. Wait Times for US Gas-Fired Turbines Averaging 5-7 Years, Costs Up Sharply. S&P Capital IQ. May 25, 2025.

Relative to the 2025 forecast, costs for developing new wind and solar projects have increased by about 30%, while storage project costs have increased by about half as much. Renewable and storage projects have a quicker development timeline than new natural gas-fired resources and can help accommodate load growth while diversifying Evergy's energy and capacity mix. Based on RFP offers and self-development options analysis, Evergy has few options for near-term wind or solar additions, particularly options that would be eligible for PTCs. Solar project viability and timing have been challenged by local opposition in some counties in both Kansas and Missouri, which has stalled or prevented permitting. There is also a threat that solar development could be restricted or delayed on a state-wide basis in Missouri, based on bills introduced in the 2026 legislative session. Evergy has more viable storage options, including adding surplus to existing sites or executing on RFP projects. Storage costs are affected by sourcing options, which must avoid FEOC restrictions. Development timelines are also impacted by availability of substation and transmission equipment, which can have significant procurement lead times by 2-3 years.

2.5 Delay of Coal Retirements Relative to Prior Forecasts

Evergy's 2025 and prior IRPs recognized that the coal fleet is aging, and its performance has a significant impact on meeting SPP's resource adequacy requirements ("RARs"). Additionally, the coal fleet has been and continues to be at risk of tightening environmental regulations. Evergy continues to plan for the measured retirement of the coal fleet over time and the replacement of its capacity and energy. However, the risk balance has shifted due to the fundamental drivers discussed previously, including rapid load growth, need for reliable dispatchable capacity, higher development costs, and slowing of decarbonization and environmental restrictions. Given these broader market dynamic changes and outlook for federal policy, the 2026 Annual Update delays planned retirement dates relative to the 2025 Annual Update.

Section 3: Load Analysis and Load Forecasting Update

3.1 Changes from the 2025 Annual Update

Several inputs to the load forecasting models were updated for this filing compared to the 2025 Annual Update:

- Historical data for customers, kWh and $/kWh: ending May 2025 vs ending June 2024.
- DOE forecasts of Residential appliance and equipment saturations and kWh/unit are from the Energy Information Administration (“EIA”) 2025 Annual Energy Outlook (“AEO”), while non-Residential equipment saturations and efficiency forecasts are from the 2023 AEO. See below for additional descriptions.
- Economic forecasts from Moody’s Analytics: May 2025 vs June 2024.
- Class models in the 2026 Evergy Metro Annual Update filing are the same as the 2025 Annual Update filing: residential, small commercial, big commercial (medium, large, large power) and industrial.
- The elasticities inherent to the end-use structured variables were evaluated for model fit and minor adjustments were made as necessary. A summary of elasticity values is included in the Load Forecasting workpapers.
- The Company utilized an Electric Power Research Institute (“EPRI”) electric vehicle study within its modeling for the 2026 Annual Update filing.
- The Company utilized Google Mobility Reports data through October of 2022 (Google stopped reporting the mobility data publicly October 15, 2022) to account for load pattern changes resulting from geolocation behaviors induced by the COVID19 pandemic.

Table 4, Figure 4, and Figure 5 below show a higher forecast for both peak and energy for the 2026 Annual Update compared to the 2025 Annual Update. Below are the primary reasons for the change in forecast:

- The EIA produced an updated AEO for 2025. Evergy’s 2026 Annual Update utilizes end-use forecasts from the 2025 AEO for the Residential class. However, the 2023 AEO was used to support Commercial and Industrial classes because the data was not available for sufficient review prior to the forecast timeline.

- There are some changes from the Moody's Analytics Economic forecasts from 2024 to 2025. Economic forecasts for Population, Households, Employment and Non-Manufacturing Gross Product show a stronger growth trajectory throughout the forecast period, while Manufacturing Gross Product shows a weaker forecast compared to 2024.
- The growth trajectory of Evergy Metro Commercial load since the 2025 Annual Update forecast contributes to a higher forecast trajectory, while Residential and Industrial load since the 2025 Annual Update forecast contributes to a lower forecast trajectory.
- New large load customer forecasts have been incorporated into the Evergy Metro energy and peak forecasts for all scenarios. Figures 6 and 7 show how new large load customers influence load growth trajectory of the mid-case forecast during the 2026-2036 timeframe.
- A new electric vehicle forecast in partnership with EPRI results in lower growth in passenger electric vehicle adoption but higher non-passenger electric vehicle growth. Additionally, charging profile estimates result in a MW peak forecast in the High Electrification scenario that is reduced compared to the 2025 Annual Update forecast. Much of this effect is due to the timing of electric vehicle charging occurring outside of typical peak hours.

Table 4: Evergy Metro Mid-Case Annual Forecast **Confidential**

[redacted]

Figure 4: Peak Forecasts - 2026 Annual Update vs. 2025 Annual Update

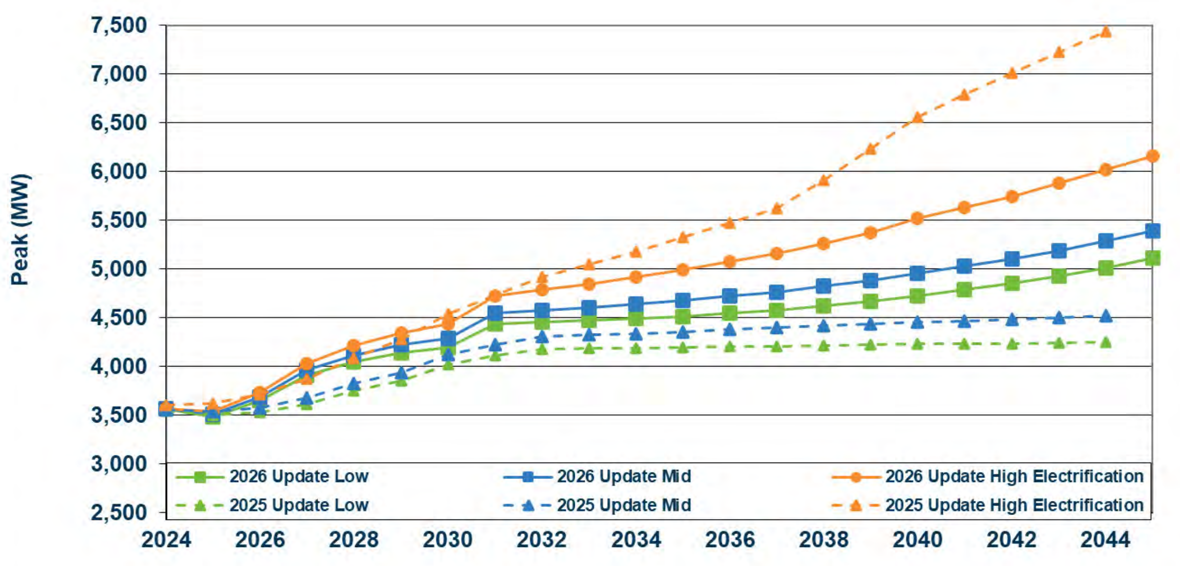
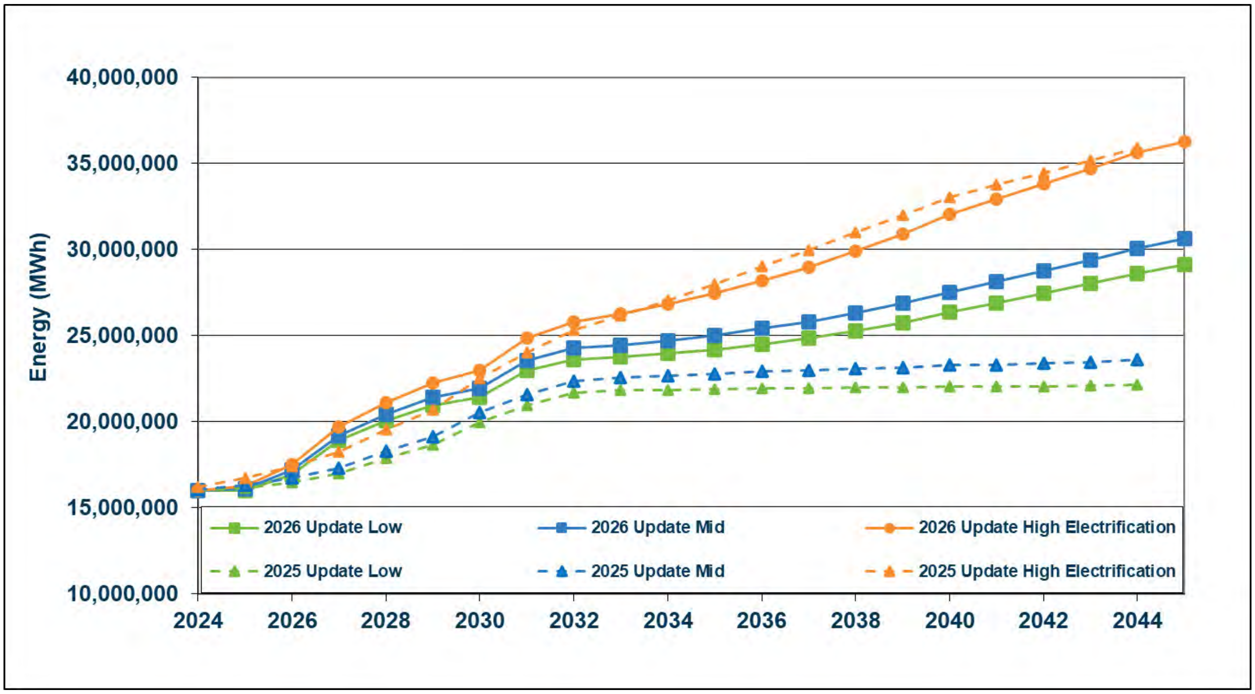


Figure 5: Energy Forecasts - 2026 Annual Update vs. 2025 Annual Update



While Evergy has a robust pipeline of prospective large load customers, only customers who meet critical criteria and milestones within Evergy's established review process are included in base load planning to avoid exposing our Preferred Plan to unnecessary risks. Generally, for a large load to be included into base load IRP planning, Evergy expects that a large load customer project have met at least one of the following criteria: recently commenced electric service from Evergy, an executed ESA under the LLPS tariff, or have a finalized SPP load addition study (typically Attachment AQ) and expect to have an executed LLPS ESA within the next 3-6 months. Evergy Metro has three specific large load customers that meet the criteria for base load planning and have been incorporated in all load forecast scenarios (low, mid, high) for the 2026 Annual Update.

The total combined peak of these three large load customers is projected to be approximately 900 MW at steady state. The largest of the three customers is located in Evergy Missouri Metro's ("EMM") service territory. This project is currently using electricity for active site construction, executed an LLPS ESA in the first quarter of 2026, and was previously incorporated in Metro's 2025 Annual Update Preferred Plan load forecast. Additionally, there is a second, smaller project that is included in the EMM territory that is also already online and receiving service under an existing Large Power Service tariff due to the current peak MW being projected below the 75 MW threshold for LLPS qualification. When and if this project further develops to exceed the 75 MW threshold, Evergy will work with the customer to transition them to the LLPS tariff. Combined, these two EMM customers account for nearly 90% of the total large load incorporated into Metro's 2026 IRP base load forecast.

Lastly, the third large load is in Evergy Kansas Metro's ("EKM") territory and accounts for the remaining 10% of the total large load included in the 2026 IRP load forecast. This project is not yet online but has fully completed the required SPP load addition study (Attachment AQ) and has nearly completed Evergy's large load process as the project is in the final commercial negotiation stage. The customer qualifies for the LLPS tariff and is expected to have an ESA executed by later in 2026.

To explain how the large load drives Metro's 2026 IRP mid-case load forecast, Figures 6 and 7 show the peak MW and MWh impact over the next decade of adding the new large load profiles to the native demand. Each of the base planning scenarios studied in this 2026 IRP (low, mid, high) includes the new large loads starting to ramp in 2026, reaching peaks by 2032, and continuing at those levels through the end of the 20-year planning period.

Figure 6: Evergy Metro Peak MW Load Forecast Including New Large Load

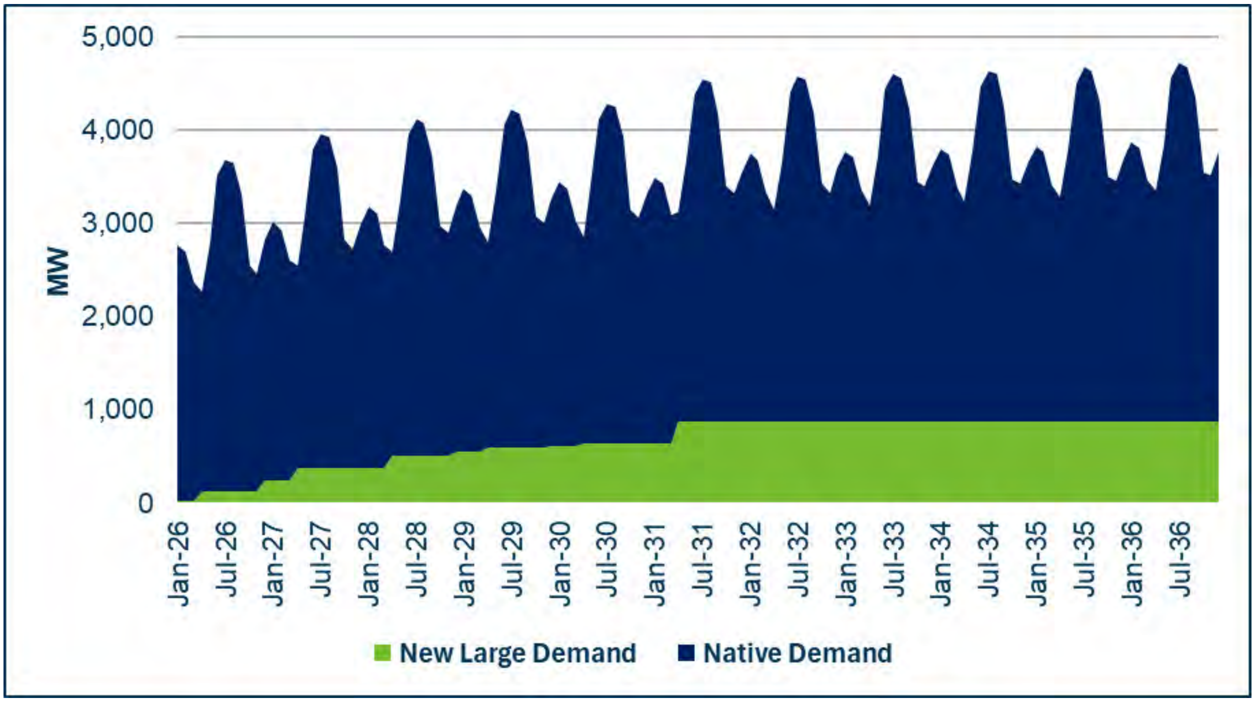
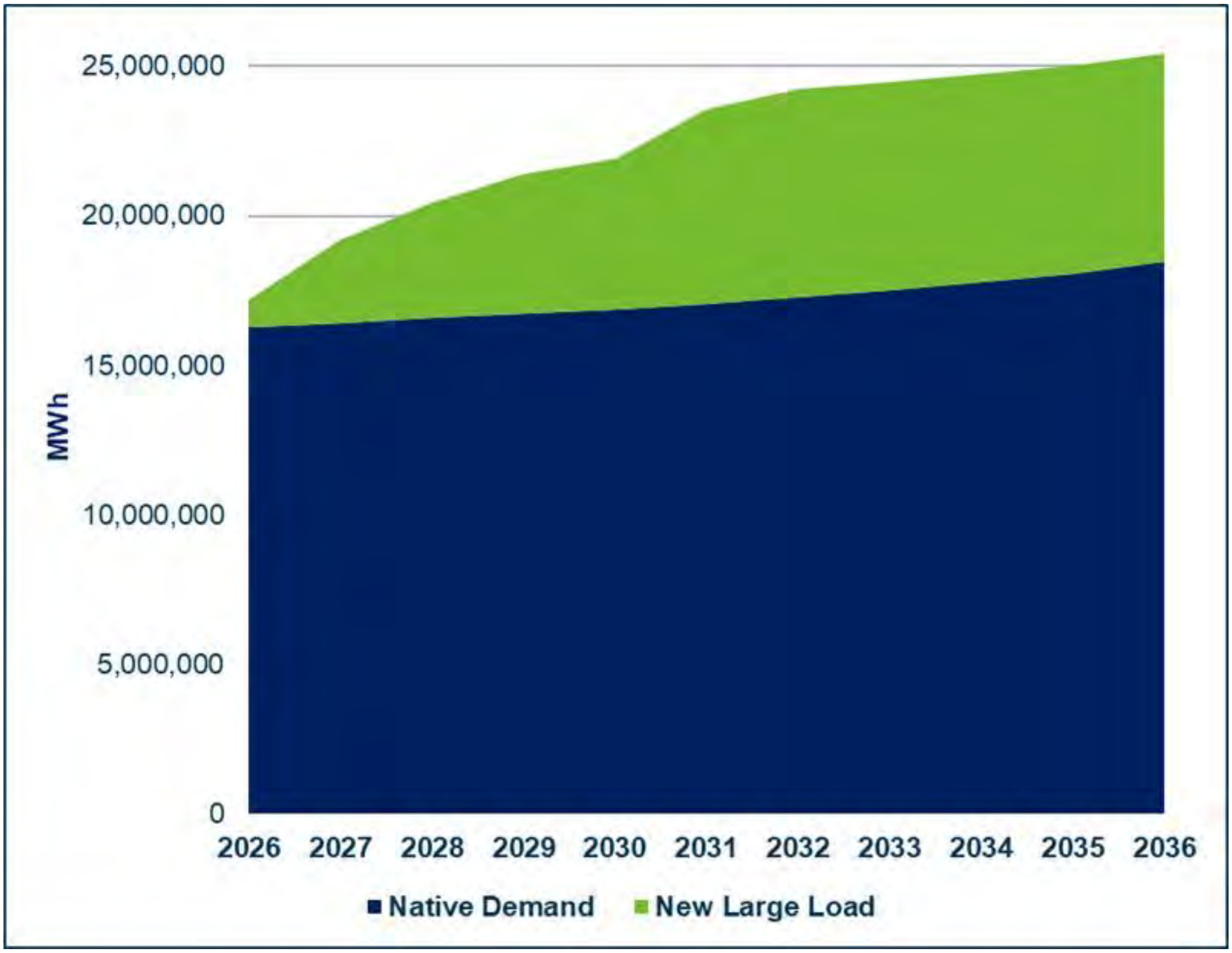


Figure 7: Evergy Metro Peak MWh Load Forecast Including New Large Load



Section 4: Market Fundamentals Update

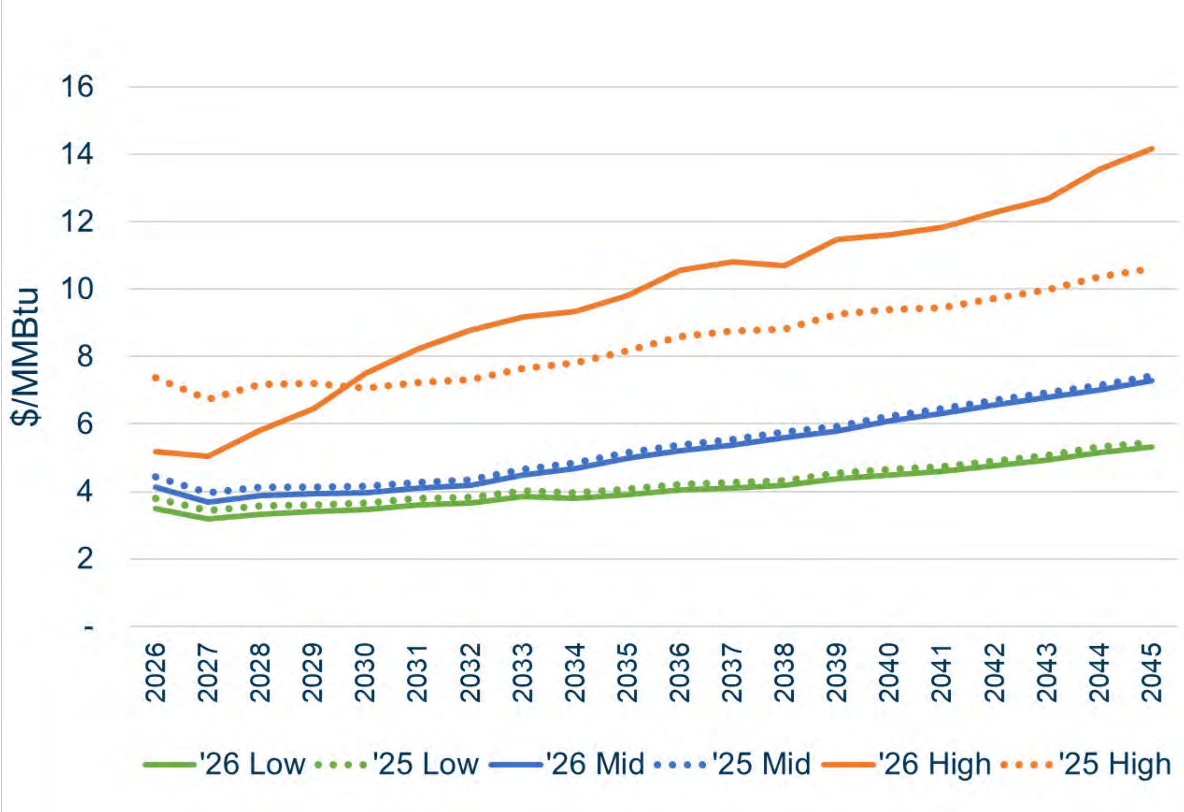
4.1 Fuel Price Forecasts [27]

4.1.1 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.[28] The internal forecast is then scaled by EIA's fundamental supply and demand forecasts to produce high and low estimates. EIA released new fundamental forecasts in the 2025 AEO. EIA's low and mid natural gas supply cases were consistent with the previous 2023 forecasts; however, the high case significantly increased from the 2023 outlook. The 2025 high case was incorporated into this year's IRP modeling to better capture natural gas sensitivity with anticipated industry-wide load growth and natural gas build out. Natural gas prices were identified as a CUF, consistent with the 2024 Triennial IRP. High, mid (base), and low forecasts are used in the development of resource plans and evaluation of plan economics.

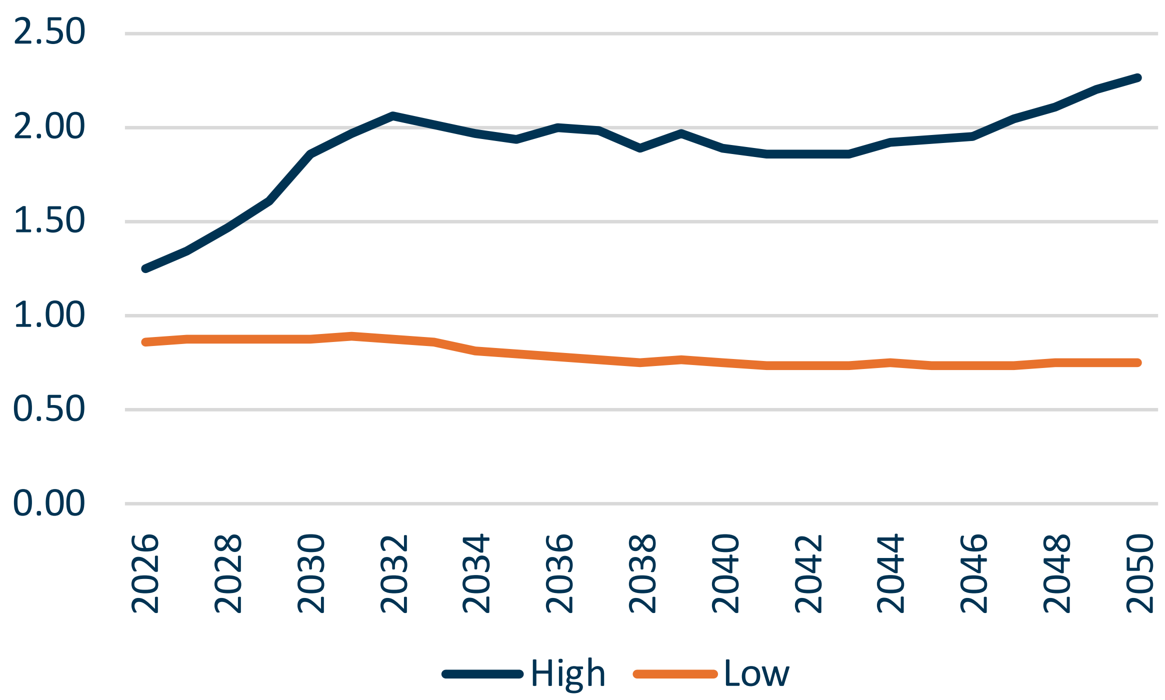
[27] 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(A)
[28] Third party sources include IHS Markit, Energy Information Administration, S&P Global Platts, Energy Ventures Analysis, CME Futures, and ICE.

Figure 8: Natural Gas Price Forecasts 2026 IRP vs 2025 IRP



The high and low forecasts were developed by scaling the mid forecast based on the fundamental supply and demand forecasts in the EIA AEO 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 Liquefied Natural Gas ("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.

Figure 9: Henry Hub Natural Gas Scalar



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

4.1.2 Coal

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

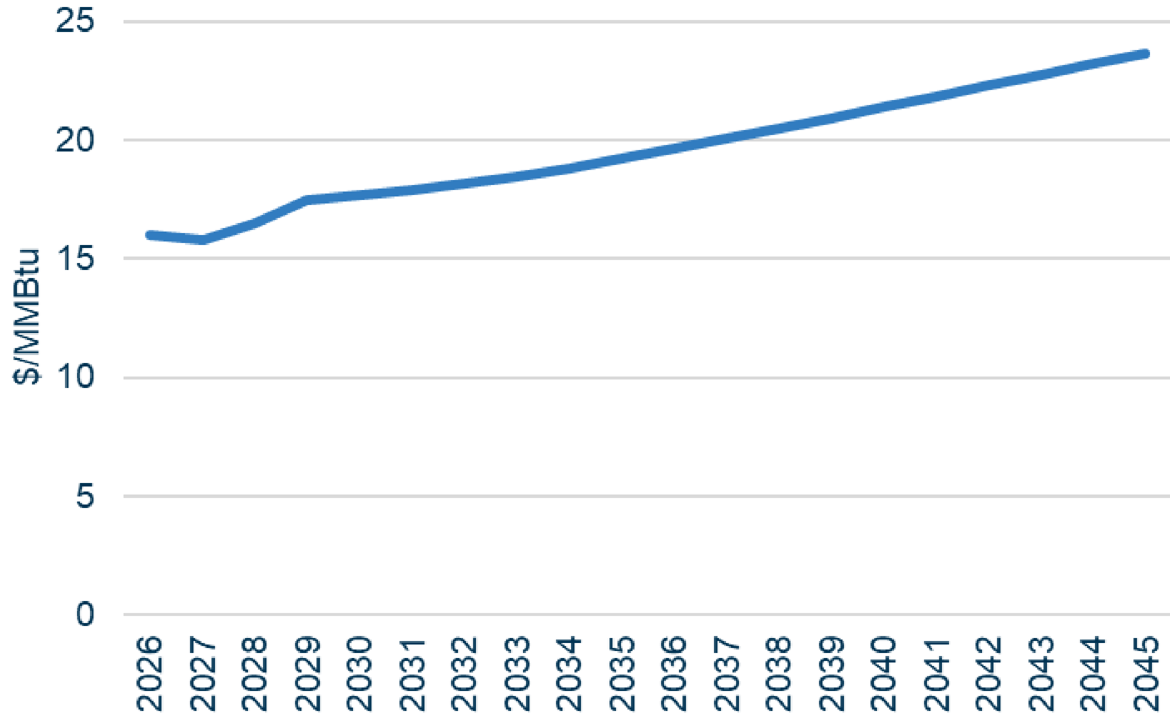
Figure 10: 2026 IRP Metro Coal Price Forecast **Confidential**

[redacted]

4.1.3 Fuel Oil

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

Figure 11: 2026 IRP Fuel Oil Price Forecast



4.2 Carbon Emissions Policy

Evergy identified carbon emissions policy as a CUF through model scenario analysis in the 2024 Triennial IRP, consistent with the 2021 Triennial IRP, and has included it in the economic analysis of resource plans for at least the past 5 years. It is challenging to accurately forecast the impact of carbon emissions policy on utility financial performance because future market conditions, regulations, and compliance options are highly uncertain.

For the 2021 and 2022 IRPs, Evergy incorporated future carbon taxes, beginning to take effect in 2026 for its “mid” and “high” scenarios. The mid was based on an average of vendor forecasts, while the high was based on one vendor forecast which estimated the expected costs of economy-wide carbon reductions. For the 2023-2025 IRPs, Evergy found that vendor forecasts had been discontinued or were outdated given recent policy changes including the IRA incentives for renewables and expected regulations on GHG emissions. Evergy modeled the impacts of carbon policy through physical emissions reductions in the mid and high cases and also included a carbon tax in the high case. The mid case for the 2023-2025 IRPs was consistent with an emissions reduction trend seen in the SPP ITP models over the 20-year planning horizon, which included increasing penetration of renewables in the supply mix, retirements of older coal, natural gas, and oil plants, and modest load growth in Evergy's service area. The high case was based on SPP modeling of an explicit carbon reduction goal of an approximately 95% reduction in carbon dioxide ("CO_2") production from 2017 levels, which resembles the expected emissions reductions contemplated in GHG Rule issued in 2024.

Evergy has reassessed its carbon policy risks for the 2026 Annual Update based on announced policy changes including reconsideration of the GHG Rule and curtailment of IRA incentives under the OBBBA, as well as changes in market conditions including expectations of substantial load growth, and rebalancing of the future supply mix towards firm dispatchable resources. The 2026 Annual Update employs a carbon tax (rather than physical reduction) for the mid and high carbon policy risk scenarios. The low scenario, consistent with past IRPs, has no tax.

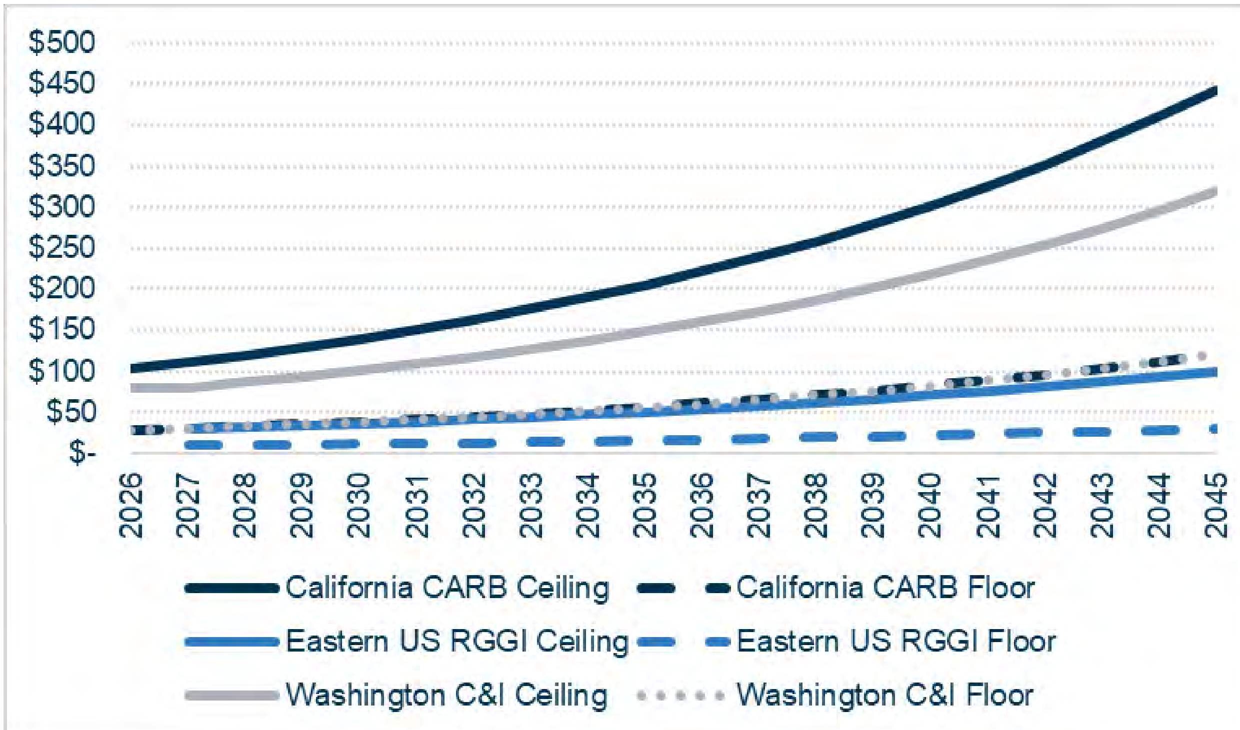
Evergy researched existing carbon reduction pricing mechanisms and other utility IRPs to determine appropriate economic risk levels for a future carbon tax.

There are three current cap and trade programs in the United States, including state-level programs in California and Washington, and the multi-state[29] Regional Greenhouse Gas Initiative ("RGGI") program in the Eastern US.[30] All three programs require emitting resources to hold an allowance for each ton of CO_2 emitted. The number of allowances available declines over time to achieve emissions reductions. Each program has a minimum (floor) allowance price and pricing tiers for issuing additional allowances up to

[29] Since 2012, RGGI has had 9, 10, or 11 states participating each year.
[30] For program information, see https://ww2.arb.ca.gov/our-work/programs/cap-and-invest-program/about, https://ecology.wa.gov/air-climate/climate-commitment-act/cap-and-invest, https://www.rggi.org/program-overview-and-design/elements

a maximum (ceiling price). These prices escalate each year. California and Washington have price ranges approximately three times higher than RGGI.[31]

Figure 12: US Emissions Cap and Trade Program CO_2 Allowance Prices ($/ton)

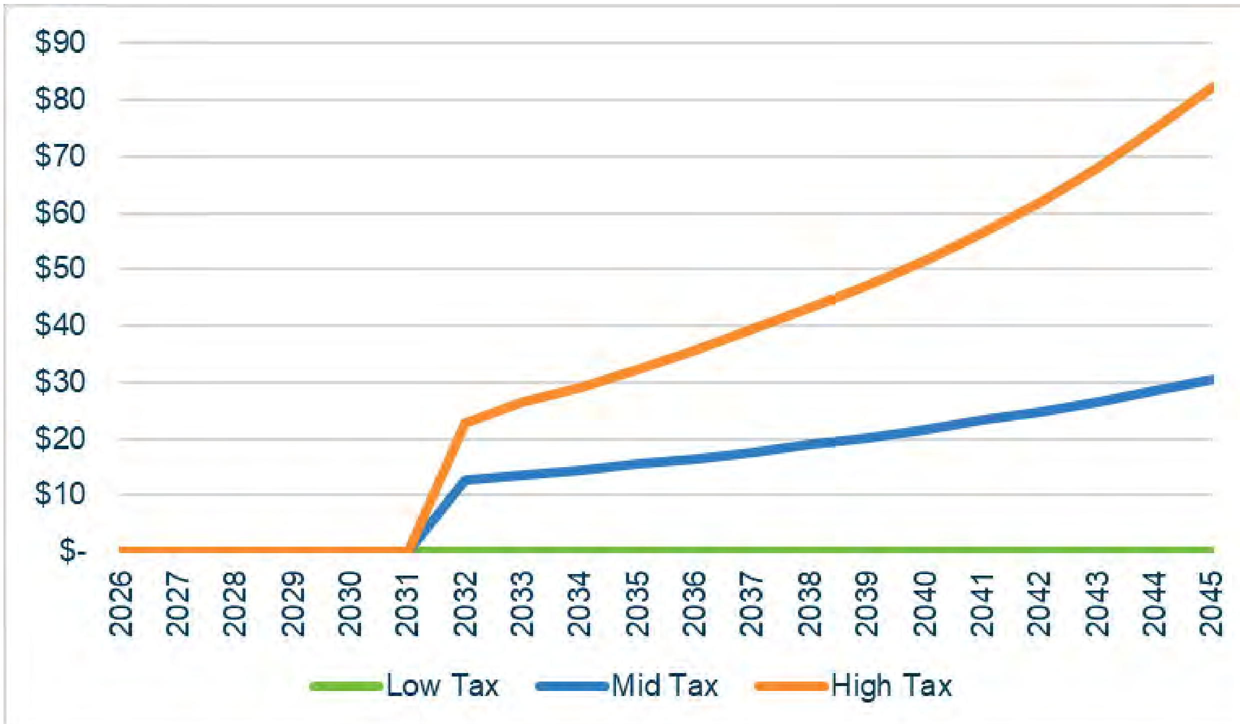


Evergy is using carbon tax assumptions informed by the RGGI Cap and Trade program in the Eastern US. The mid tax is based on the price floor for the program, and the high tax is based on the weighted-average price expected if the ceiling amount of allowances are used. The mid and high taxes are modeled to begin in 2032, which Evergy believes is a plausible start time for regulatory action on carbon emissions. Evergy selected RGGI-based assumptions as the most plausible reference for potential carbon regulation applicable to the SPP region, given that California and Washington programs reflect more aggressive state-level climate policies. However, Evergy's probability-weighted analysis

[31] See Workpaper, or https://ww2.arb.ca.gov/sites/default/files/2025-12/nc-2026_annual_reserve_price_notice_joint_auction.pdf, https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/cost-containment-information, https://apps.ecology.wa.gov/publications/documents/2514102.pdf, https://apps.ecology.wa.gov/publications/documents/2514103.pdf, https://www.rggi.org/program-overview-and-design/program-review

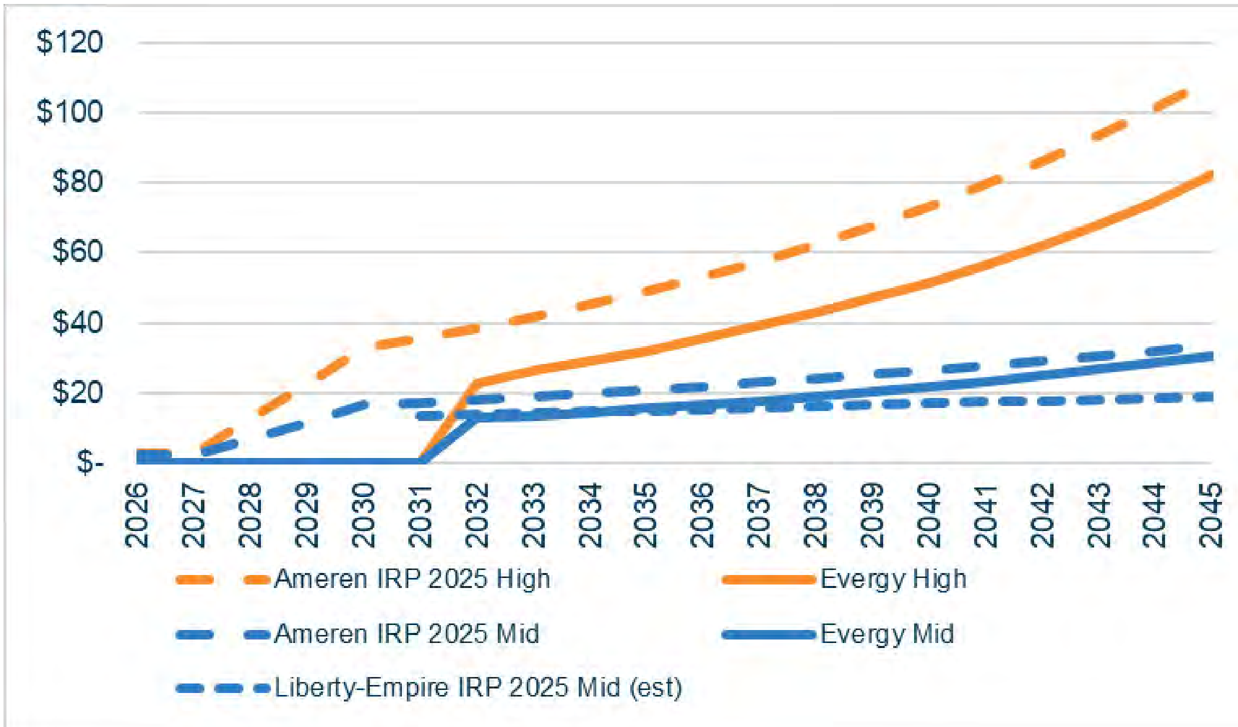
ensures that plans are tested against a range of outcomes, including high carbon restriction futures where renewable-heavy plans outperform. Further strengthening this selection, Evergy's assumptions appear to be similar to the values used by Ameren and Liberty-Empire in their 2025 IRPs. [32]

Figure 13: CO_2 Emission Tax ($/ton)



[32] The Liberty-Empire IRP cites a $13-$14/short ton price beginning in 2031. The annual forecast was marked confidential, so Evergy assumes a 2.5% inflation rate in future years.

Figure 14: Evergy and Missouri Utility CO_2 Tax Scenarios



4.3 Market Price Forecasts

Evergy considers current and future market conditions in developing its 20-year forward looking forecasts for the IRP. Starting with the 2022 IRP Annual Update, Evergy contracted with 1898&Co. to produce 20-year market price forecasts using SPP's transmission planning models as a baseline. As mentioned in Section 2.3.3, Evergy has updated its market price forecast from the 2024 and 2025 IRPs.

The 2026 Annual Update pricing models, based on the finalized 2025 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 2025 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

Market pricing was calculated for three different natural gas price futures, based on the values used for the natural gas CUF forecasts. After the pricing was completed, EIA issued a new AEO for 2025. Evergy updated natural gas price assumptions based on the new data and found that while its new low and mid natural gas price forecasts were substantially unchanged, the new high price forecast was much higher. To align with this higher forecast, Evergy scaled up the high natural gas market price series.

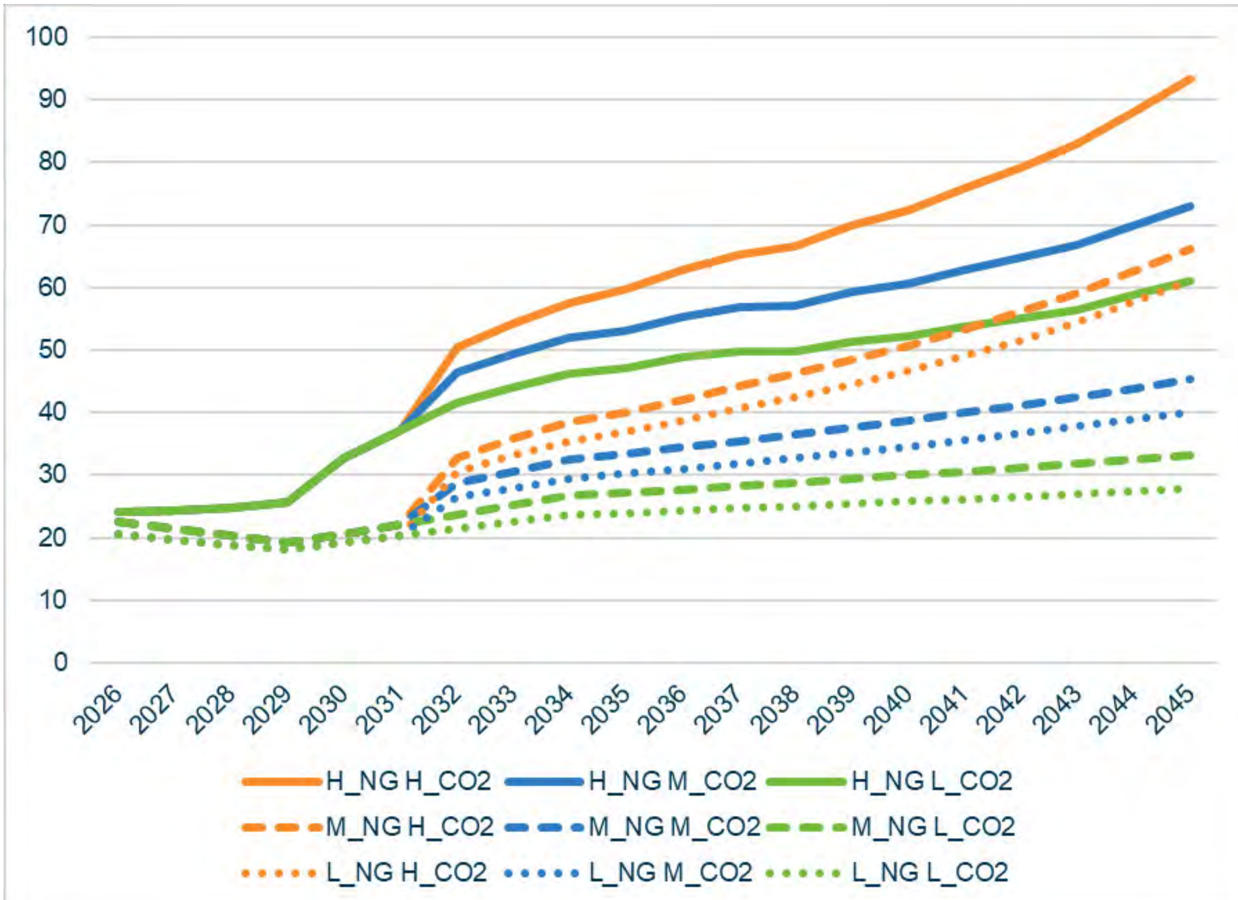
The base market price forecasts did not include carbon taxes. Evergy adjusted market prices to incorporate the expected impact of the taxes for the mid and high CO_2 tax futures, beginning in 2032.[33]

Overall, nine price series, incorporating the different values of the high, mid, and low natural gas and CO_2 tax futures, were used to model future production costs and to calculate expected NPVRR of resource plans.

The "Build Gen" node represents a central generation location in Evergy's system (Metro Generation Hub) and is used to represent the siting of generic resource additions, other than wind. Price series across the nine endpoints show that the highest prices over the 20-year horizon are seen in the high natural gas price, high CO_2 tax market price series. The high natural gas price with mid CO_2 tax is the second highest. The high natural gas price with low (no) CO_2 tax is the third highest until the last few years of the planning horizon when it is exceeded by the mid natural gas price, high CO_2 tax scenario, and equals the low natural gas, high CO_2 tax scenario in 2045. The rest of the price series from highest to lowest are mid natural gas with mid CO_2 tax, low natural gas with mid CO_2 tax, mid natural gas with low CO_2 tax, low natural gas with low CO_2 tax.

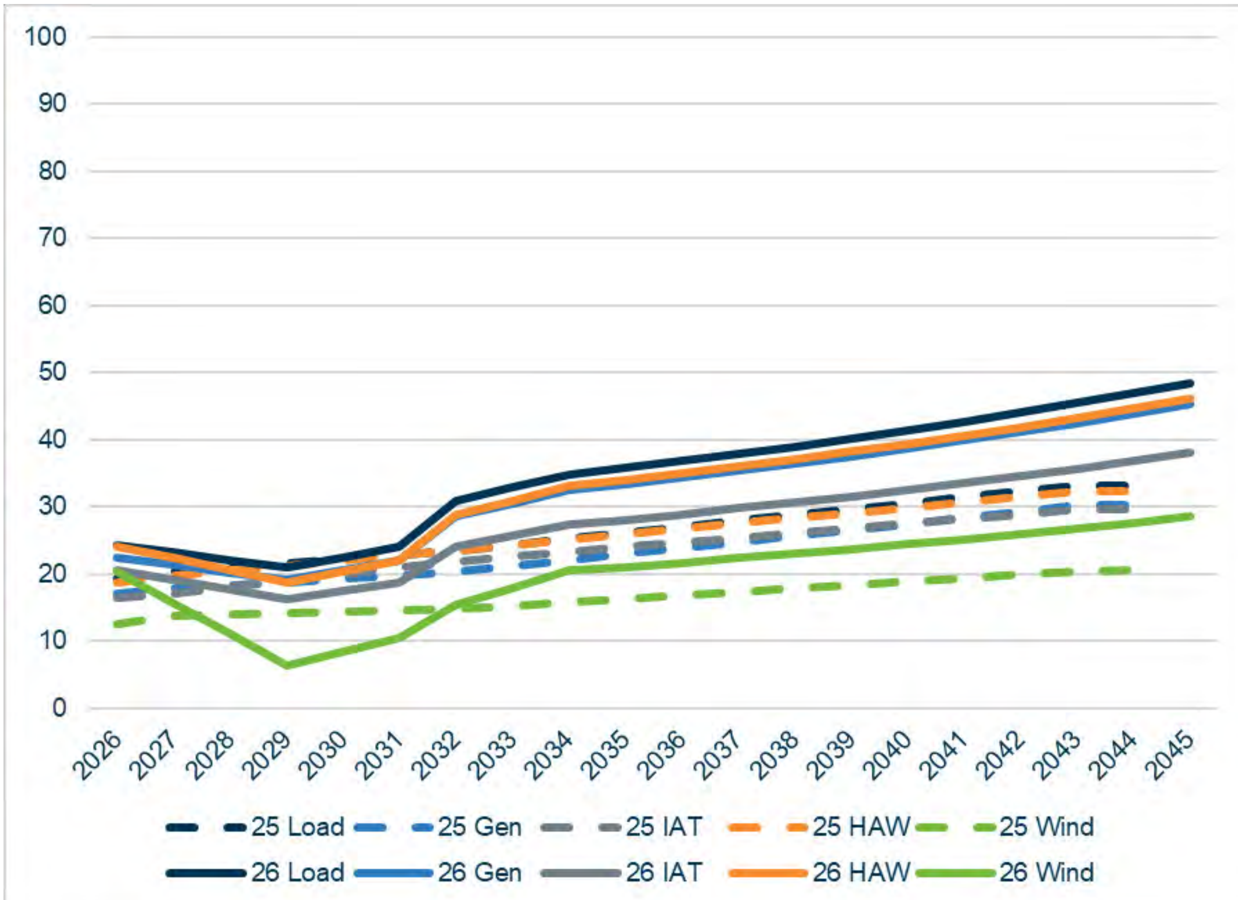
[33] See Carbon Tax Workpaper. Taxes were incorporated into future prices based on expectations of the percentage of hours emitting resources are on the margin to set price.

Figure 15: Build Gen Node Market Prices ($/MWh)



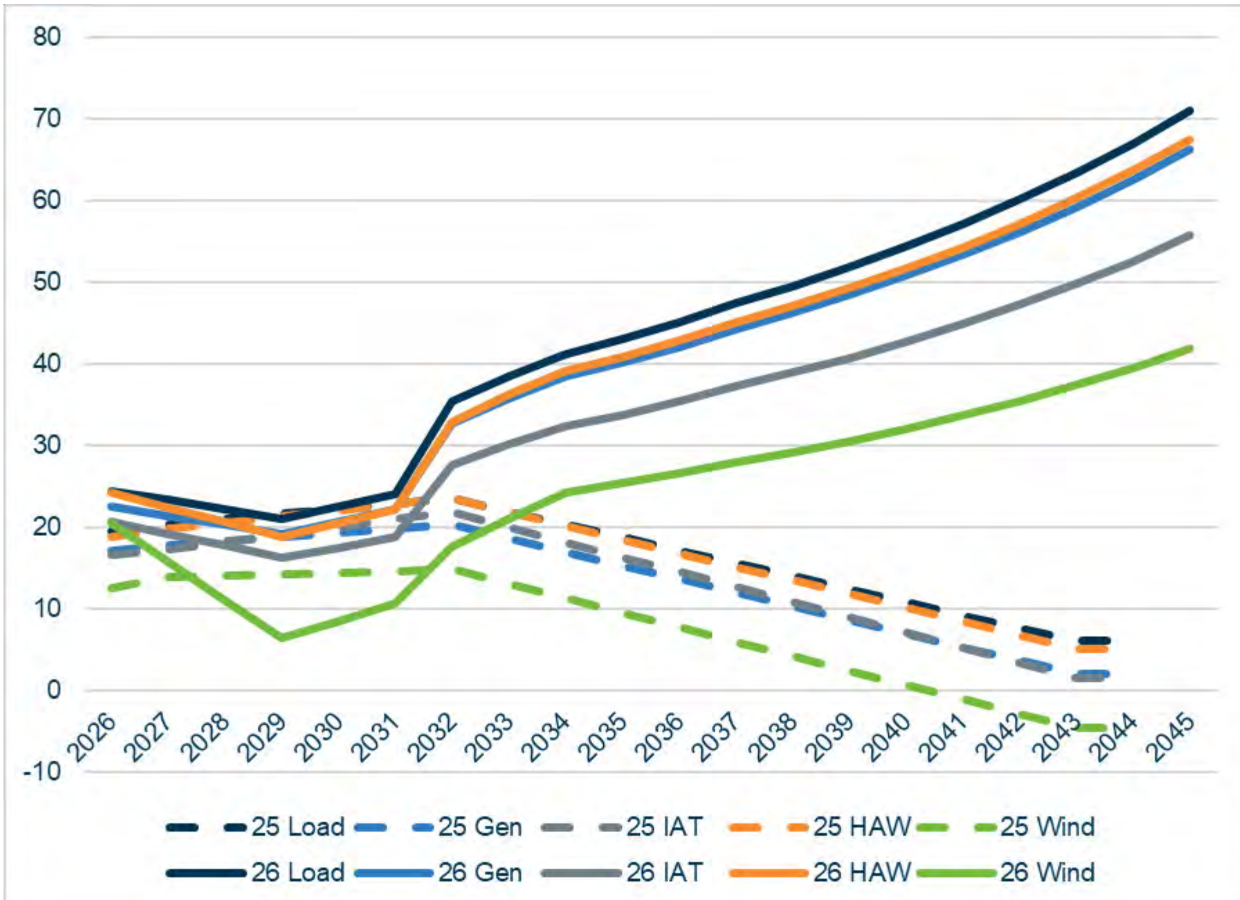
Compared to prices in the 2025 IRP, the 2026 IRP prices are higher in most years for the mid natural gas with mid CO_2 tax price series. For the Metro load and generation nodes, 2026 IRP prices are generally higher throughout the time horizon. For the coal and wind nodes, prices are generally lower in 2027-2031 before climbing higher for the rest of the planning period.

Figure 16: 2026 IRP vs. 2025 IRP Mid NG Mid CO_2 Market Prices ($/MWh)



For the mid natural gas high CO_2 tax price series, the increase in prices between the 2026 and 2025 IRPs is more substantial. The 2025 IRP scenario for high CO_2 policy used a high-renewables resource mix and redispatch to achieve carbon reductions. High renewable investment drives a high fixed cost, low variable cost system, with low production costs and market prices. Prices in the 2025 IRP declined over time. Updated assumptions for the 2026 IRP no longer use this future resource mix, and implement carbon policy through a tax on emissions, which raises prices.

Figure 17: 2026 IRP vs. 2025 IRP Mid NG High CO_2 Market Prices ($/MWh)



4.3.1 Other Emissions Costs or Restrictions

Evergy does not expect to incur costs for emissions allowances for sulfur dioxide ("SO_2") or NO_x and does not expect future restrictions to limit generation operations.

4.4 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) are well-matched in SPP.

With high load growth expected over the next few years, planned retirements, and expiration of wind PPA contracts, Evergy does not expect other utilities in SPP to build generation to serve the needs of Evergy customers. In addition to meeting SPP RARs, Evergy aligns its future plans with meeting hourly customer energy needs in the lowest cost manner, by limiting net sales and purchases from the market to design a future portfolio that provides an economic and reliability hedge. Beginning in 2030, market purchases and sales are limited to 200 MW per hour.

Allowing market purchases does not mean that a utility (e.g., Metro) is physically incapable of meeting 100% of customer energy needs. RARs 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 RARs, but also because it is the lowest-cost way to produce energy which aligns closely 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.

Section 5: Resource Adequacy Requirements Update

SPP requires all Load Responsible Entities ("LREs") to maintain sufficient accredited capacity to meet both summer and winter RARs. These requirements are established by combining each LRE's forecasted seasonal peak load with the applicable Planning Reserve Margin ("PRM"), which is informed by SPP's biennial LOLE studies. As SPP transitions to performance-based and effective load carrying capability-based accreditation methodologies, Evergy continues to update its planning assumptions to reflect the evolving accreditation rules, PRM levels, and expected resource performance.

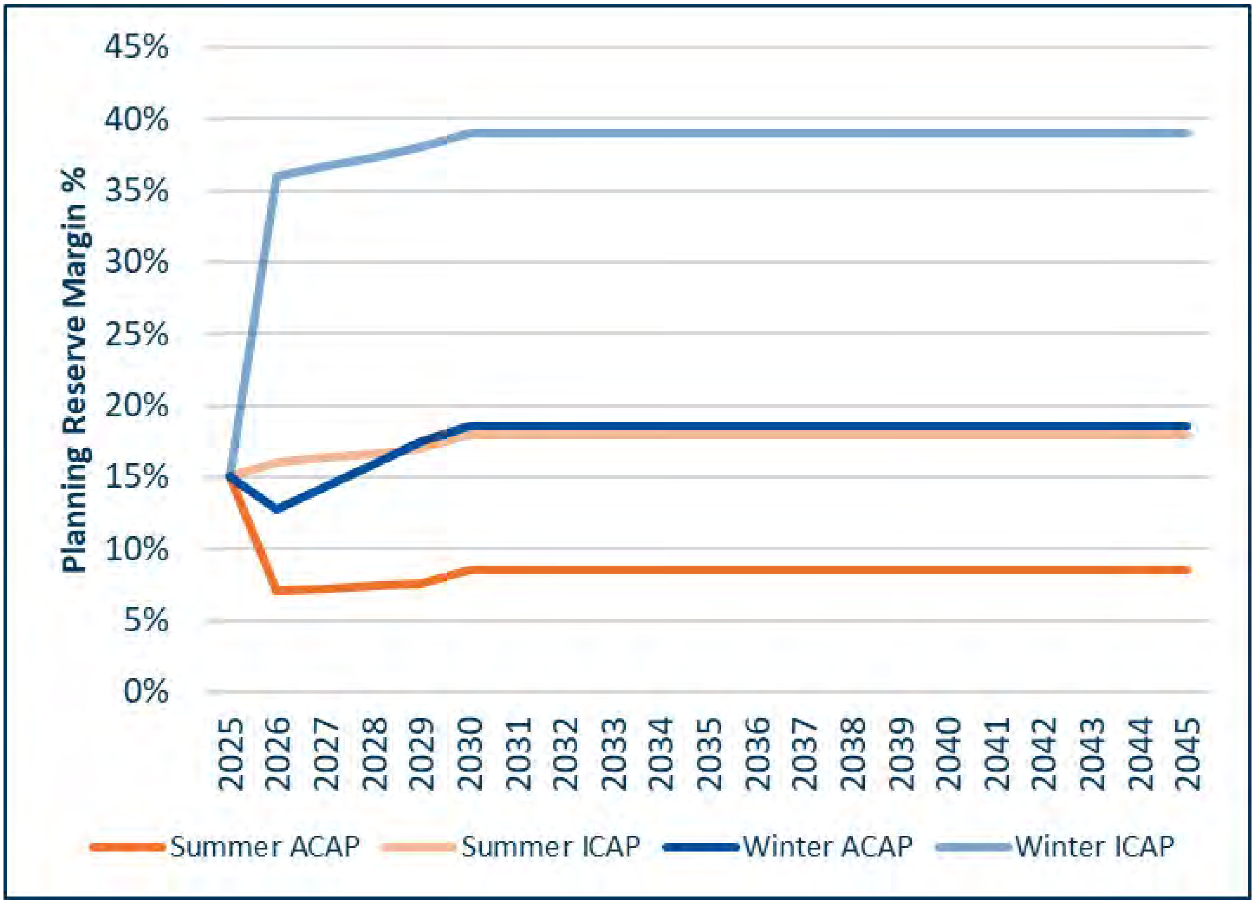
5.1 Winter Resource Adequacy Requirement

SPP implemented a Winter RAR beginning with the 2025–26 winter season, applying a structure parallel to the summer requirement but reflecting winter-specific risks, outage patterns, and accreditation values. LREs must demonstrate sufficient accredited winter capacity and are subject to deficiency payments if requirements are not met. While the initial winter PRM began at 15%, SPP's recent LOLE analyses indicate that larger winter reserve margins will be needed in future years due to increased cold-weather outage, winter peak load variability, and planned outage overlaps. Evergy's IRP modeling reflects these expanding winter needs and ensures the portfolio maintains adequate accredited capacity in both seasons.

5.2 LOLE Study Results and Reserve Margin Expectations

Recent LOLE study results show that SPP's historical reserve margin levels will not meet future reliability needs without adjustments. Planning years beginning in 2026 require higher summer and significantly higher winter PRMs due to cold-weather correlated outages, changes in the regional resource mix, increased load growth, and the shifting seasonal balance of LOLE events toward winter conditions. Evergy's IRP incorporates these emerging requirements by adopting higher assumed reserve margins for both summer and winter across the planning horizon. Summer PRMs are modeled to gradually increase, while winter PRMs are modeled to rise sharply beginning in 2026 and remain elevated thereafter, ensuring resource portfolios remain resilient to future LOLE-driven reserve margin requirements. Figure 18 details the IRP assumption for PRM over the next 20 years and the difference between installed capacity based ("ICAP") PRM and accredited capacity based ("ACAP") PRM.

Figure 18: 2026 IRP Planning Reserve Margin Assumptions



5.3 Performance-Based Accreditation

SPP's Performance-Based Accreditation ("PBA") methodology replaces historic test-based thermal capacity accreditation with performance-driven measures tied to seasonal forced outage behavior. Under PBA, a resource's accredited capacity reflects its availability during peak-risk hours, based on multi-year seasonal forced outage rates and other performance indicators. As SPP transitions toward PBA beginning in summer 2026, Evergy incorporates these changes into its IRP by applying updated accreditation assumptions for all thermal resources. Winter accreditation also includes a forced outage factor ("EFOF") representing cold-weather and fuel-assurance risks, consistent with the methodology applied beginning in Evergy's 2025 Annual Update and continued in the 2026 Annual Update with updated data.

5.4 Effective Load Carrying Capability

SPP is implementing Effective Load Carrying Capability ("ELCC") for wind, solar, and storage resources as part of its unified accreditation framework. ELCC quantifies a resource's contribution to meeting load by accounting for variability, duration limitations, and availability constraints. Beginning in summer 2026, renewable and storage resources' accredited capacity will be determined through ELCC, while thermal resources will be accredited through PBA. Evergy applies expected ELCC values in its IRP to reflect the evolving contribution of renewable and battery resources to meet resource adequacy obligations under SPP's accreditation approach.

5.5 Accredited Capacity Reserve Margin

With the implementation of PBA and ELCC, SPP is transitioning from an ICAP PRM to an ACAP PRM. Under this approach, the reserve margin represents the amount of accredited capacity—already adjusted for ELCC and PBA—needed to satisfy RARs. Evergy adopted ACAP-based planning beginning in summer 2026 in the 2025 IRP and continues applying it in the 2026 IRP to ensure alignment with SPP's accreditation transition.

5.6 Demand Response Accreditation

Demand response resources are currently credited against load based on their tested performance, but SPP stakeholders are evaluating whether future accreditation should account for availability constraints such as event frequency, duration, and seasonal limitations. To avoid overstating the resource adequacy contribution of these resources and to prepare for potential future policy changes, Evergy's 2026 Annual Update continues to assume that demand response receives accredited capacity equal only to its expected tested capability rather than receiving credit as a full net reduction to load. This conservative approach ensures that Evergy's resource plans remain robust and appropriately reflect the evolving accreditation landscape for demand-side resources.

Section 6: Supply-Side Resource Options

Combined cycle (“CC”) and combustion turbine (“CT”) installed costs and resource characteristics were updated for the 2026 Annual Update based on recent Evergy development experience. Updates were made to battery, wind, and solar resource costs based on Evergy’s 2025 RFP and updated EIA and National Renewable Energy Laboratory (“NREL”) future resource cost forecasts. Additionally, two thermal options for RICE were added using developer information from the 2025 RFP. PTCs were updated based on recent published guidance. Resource availability was also updated based on expected lead time.

Table 5: Primary Resource Options **Confidential**

[redacted]

Evergy continues to consider construction costs a CUF in resource planning. Evergy modeled installed cost increases by 25% for the high construction cost scenarios, and cost decreases by 25% for the low construction cost scenarios. Installed costs in Table 5 include estimated interconnection costs.

Table 6: Primary Resource Costs in First Year of Operation **Confidential**

[redacted]

Table 7: New Resource Emissions Rates (lb/MWh)

Resource Type	NO_x	SO_2	CO_2
Solar	-	-	-
Wind	-	-	-
Battery	-	-	-
Reciprocating Internal Combustion Engine	0.032	0.008	927.9
Combustion Turbine	0.045	0.009	1,064
Combined Cycle	0.026	0.006	754
Half Combined Cycle	0.026	0.006	754

6.1 Renewable and Storage Resources

Renewable and storage resource costs and characteristics have been updated to reflect Evergy's 2025 RFP. Resource costs have increased compared to Evergy's 2023 RFP (which helped inform resource costs for the prior two IRPs), as depicted in the next graph. As to be discussed in section 6.2, changes to federal policy have materially changed the economics of renewable and storage resources. Cost increases in the 2026 Annual Update reflect both current marketplace pricing and updated future resource cost forecasts. Cost estimates from Evergy's 2025 RFP responses reflect marketplace offers made after the passage of the OBBBA. Consistent with prior IRPs, future year costs incorporate inflation and updated resource cost forecasts from the EIA and NREL.

Figure 19: Annual Renewable and Storage Build Costs ($/kW) **Confidential**

[redacted]

Battery costs depicted above exclude ITCs.

6.2 Tax Incentives

The OBBBA substantially accelerated the phase-out of PTC and ITC eligibility for wind and solar facilities. Under the new law, wind and solar facilities that begin construction on or before July 4, 2026, remain eligible for the full credit and are not subject to the accelerated placed-in-service deadline, provided they satisfy the continuity safe harbor by being placed in service within four calendar years of when construction began. For the 2026 Annual Update, Evergy assumes that the 150 MW solar resource planned for 2028 will qualify for 100% PTC. Evergy's development team has taken steps to establish beginning of construction for this project consistent with the Physical Work Test IRS requirements. The PTC value used in the IRP is based on the most recent IRS annual inflation adjustment. Wind and solar resources planned for operation in 2029 and beyond are not assumed to receive PTC or ITC, as they are not expected to meet the beginning of construction deadline under current law.

Battery energy storage systems are eligible for the clean electricity ITC under Section 48E. Unlike wind and solar, storage resources were not subject to the OBBBA's accelerated phase-out. Storage facilities that begin construction before 2034 remain eligible for the full ITC. The credit phases down to 75% for facilities beginning construction in 2034, 50% in 2035, and is eliminated for projects beginning construction in 2036 or later. Evergy assumes that the 150 MW battery storage resource planned for 2030 will qualify for a 40% ITC, reflecting the base 30% credit plus a 10% bonus for either domestic content or location in an energy community, consistent with IRA provisions. The ITC benefit is received upfront in the first year of operation.

The combined effect of the OBBBA's accelerated PTC phase-out for wind and solar, the tightened beginning of construction requirements, and the new FEOC restrictions has materially changed the economics of renewable and storage resource additions compared to prior IRPs. The loss of PTC eligibility for wind and solar resources beginning operation after 2029–2030 increases the expected levelized cost of these resources by the value of the forgone credits. This change is a driver of the reduction in renewable resource selections in the 2026 Preferred Plan relative to the 2025 Preferred Plan, as discussed in Section 1.3.

6.3 New Renewable and Battery ELCC

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

Evergy has updated ELCC assumptions from the 2025 Annual Update using reported data from SPP's 2024 ELCC Study and 2025 LOLE Study. In addition to these studies, Evergy tweaked its previous degradation curves that were based on SPP's 2022 ELCC Study. This tweak lessened the overall degradation of renewable and storage resources to coincide with more recent market and policy dynamics surrounding the preference for thermal resources to meet the level of load growth seen across the nation (refer to Section 2.3 for more context).

The differences from the 2026 Annual Update and the prior two IRPs, for both summer and winter ELCC, are depicted in the next couple of graphs. Overall, both new renewable and storage resources have better accreditation in the winter compared to previous ELCC degradation curves. In terms of summer accreditation, both new solar and battery resources are seeing worse accreditation in the early years, while the later years are showing more favorable ELCCs.

Figure 20: Renewable and Storage New Build ELCC (Summer)

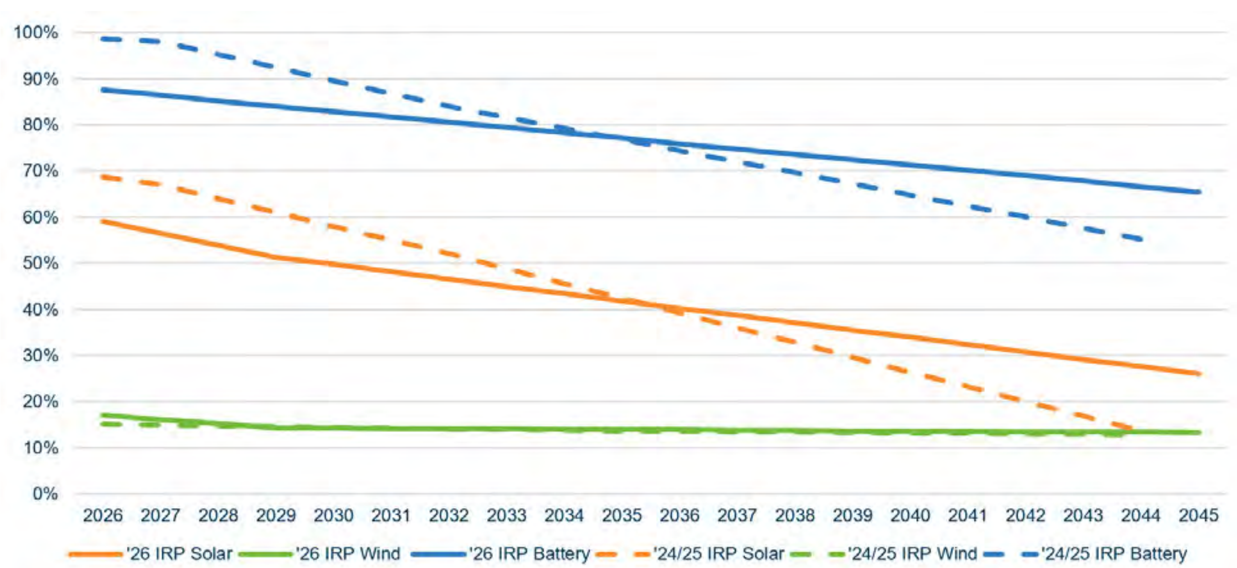
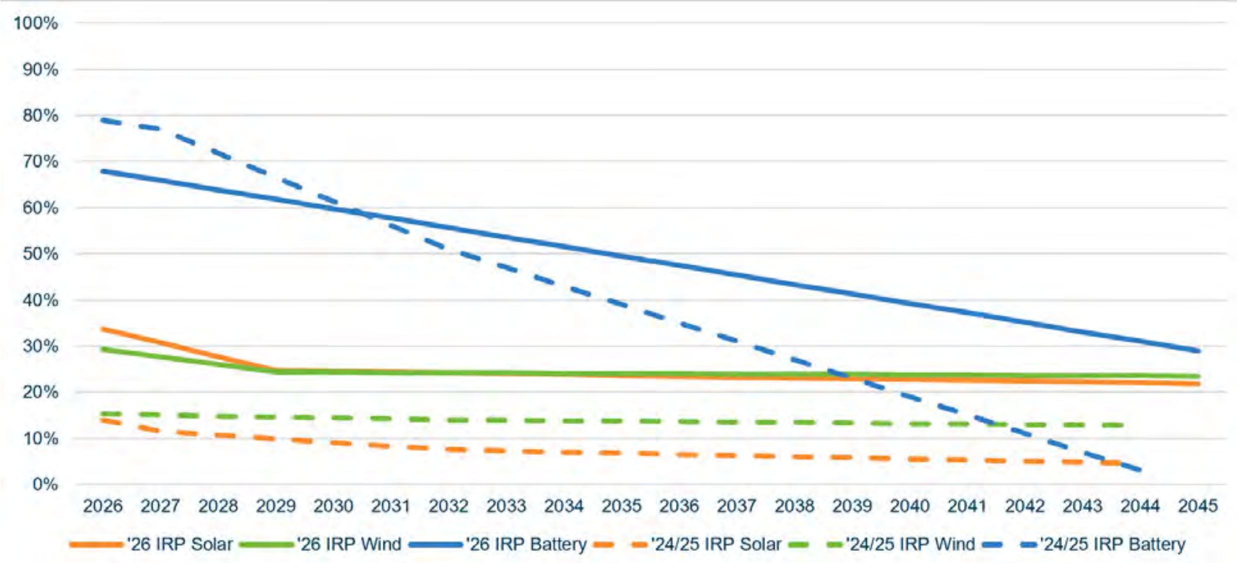


Figure 21: Renewable and Storage New Build ELCC (Winter)



6.4 Thermal Resources

6.4.1 Cost and Availability

The need for firm dispatchable generation beginning in the late 2020's to early 2030's was identified in prior IRPs. Evergy expects to self-develop the majority of these resources, while also evaluating thermal offers from the 2025 RFP. Cost estimates were based on both recent development experience surrounding the approved natural gas CCN resources and manufacturer information from the 2025 RFP.

Evergy's development team has taken steps to execute on the resource plan and has received updated cost estimates from suppliers. Cost estimates have risen significantly from the 2025 Annual Update. This is partly attributable to broad inflation in the economy, but also likely the result of the strong supply and demand forces for natural gas-fired generation. Utilities across the US are forecasting unprecedented load growth from economic development, datacenters, and other large-load customers. Many utilities have announced intentions to build new natural gas projects to meet their growing needs.

2029 and 2030 thermal costs reflect the approved natural gas CCN resource costs. Costs for future years were estimated by scaling cost estimates for 2031 and 2032 self-developed combined cycle and combustion turbine projects by inflation and the average of the NREL and EIA technology curves. Inflation exceeds technological innovation, resulting in higher nominal costs each year.

Figure 22: Thermal Installed Costs ($/kW) **<u>Confidential</u>****

[redacted]

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

6.4.2 PBA Assumptions

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

6.5 Market Capacity

Evergy has been actively pursuing market capacity purchases to meet short term reliability needs prior to thermal resource construction. This near-term bridge strategy is necessary due to the lead time required to develop new generation resources. The Company recognizes that market capacity availability beyond current commitments is uncertain and has limited its reliance to conservative levels. Based on ongoing negotiations with counterparties, Evergy believes it can secure some market capacity in the 2026 – 2031 time horizon.

Because SPP is in the process of significantly tightening RARs, including raising reserve margins, reducing capacity accreditation, and imposing penalties for failing to meet winter requirements, Evergy expects market capacity to be higher-priced and scarce relative to recent history of market capacity in SPP. 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.

Section 7: Environmental Regulation Update

7.1 Air Emission Impacts

7.1.1 Particulate Matter National Ambient Air Quality Standards

In March 2024, the EPA published in the Federal Register a final rule which strengthens the primary annual particulate matter less than 2.5 microns in diameter (“$PM_{2.5}$”) National Ambient Air Quality Standard (“NAAQS”). The EPA lowered the primary annual $PM_{2.5}$ NAAQS from 12.0 µg/m^3 (micrograms per cubic meter) to 9.0 µg/m^3. The final rule took effect in May 2024. In March 2024, a coalition of 24 states, including Kansas and Missouri, filed a challenge to the final 2024 $PM_{2.5}$ NAAQS regulation, claiming the final rule exceeded EPA’s statutory authority by failing to conduct a full analysis before revising the NAAQS. In February 2025, with the change in presidential administrations, the D.C. Circuit Court agreed to hold in abeyance all challenges to this final rule pending EPA’s reconsideration of the final 2024 $PM_{2.5}$ NAAQS. In November 2025, EPA filed a motion requesting that the DC Circuit Court vacate the 2024 $PM_{2.5}$ NAAQS, asserting that the Biden Administration’s EPA failed to consider costs during its revision process and therefore did not conduct a thorough review, as required.

Depending on the outcome of these court challenges, future non-attainment designation for this revised standard could require additional emission reduction technologies on existing fossil-fueled units.

7.1.2 Cross-State Air Pollution Rule

Ozone Interstate Transport State Implementation Plans (“ITSIP”)

In 2015, the EPA lowered the Ozone NAAQS from 75 ppb to 70 ppb. States were required to submit ITSIPs in 2018 to comply with the "Good Neighbor Provision" of the Clean Air Act (“CAA”) as it applies to the revised NAAQS. The EPA did not act on these ITSIP submissions by the deadline established in the CAA and entered consent decrees establishing deadlines to take final action on various ITSIPs. In February 2022, the EPA published a proposed rule to disapprove the ITSIPs submitted by nineteen states including Missouri and Oklahoma. In April 2022, the EPA published an approval of the Kansas ITSIP in the Federal Register. The Missouri Department of Natural Resources

(“MDNR”) submitted a supplemental ITSIP to the EPA in November 2022. In February 2023, the EPA published a final rule disapproving the ITSIPs submitted by 19 states, including the final disapproval of the Missouri and Oklahoma ITSIPs. In April 2023, the Attorneys General of Missouri and Oklahoma filed Petitions for Review in the U.S. Court of Appeals for the Eighth Circuit (Eighth Circuit) and the U.S. Court of Appeals for the Tenth Circuit (Tenth Circuit), respectively, challenging the EPA's disapproval. In May 2023, the Eighth Circuit granted a stay of the EPA's disapproval of the Missouri ITSIP. Similarly, in July 2023, the Tenth Circuit granted a stay of the EPA's disapproval of the Oklahoma ITSIP. In August 2024, the EPA published in the Federal Register a proposed rule to disapprove the supplemental ITSIP that Missouri submitted in November 2022. In January 2024, the EPA proposed to disapprove the ITSIP for Kansas and four other states. As described below, in January 2026, EPA proposed to re-evaluate and approve previously disapproved ITSIP submissions for five states including Kansas.

Ozone Interstate Transport Federal Implementation Plans (“ITFIP”)

In April 2022, the EPA published in the Federal Register the proposed ITFIP to resolve outstanding "Good Neighbor" obligations with respect to the 2015 Ozone NAAQS for 26 states including Missouri and Oklahoma. This ITFIP would establish a revised Cross-State Air Pollution Rule (“CSAPR”) ozone season NO_x emissions trading program for electric generating units (“EGUs”) beginning in 2023 and would limit ozone season NO_x emissions from certain industrial stationary sources beginning in 2026. The proposed rule would also establish a new daily backstop NO_x emissions rate limit for applicable coal-fired units larger than 100 MW, as well as unit-specific NO_x emission rate limits for certain industrial emission units and would feature "dynamic" adjustments of emission budgets for EGUs beginning with ozone season 2025. The proposed ITFIP included reductions to the state ozone season NO_x budgets for Missouri and Oklahoma beginning in 2023 with additional reductions in future years. Evergy Metro provided formal comments as part of the rulemaking process. In March 2023, the EPA issued the final ITFIPs for 23 states, including Missouri and Oklahoma, which included reduced ozone season NO_x budgets for EGUs in Missouri, Oklahoma and other states, and included other features and requirements that were in the proposed version of the rule. Because the EPA's authority to impose an ITFIP for a state is triggered by the state's failure to submit an ITSIP addressing NAAQS by the statutory deadline or disapproval of an ITSIP, the EPA lacks authority under the CAA to impose an ITFIP on a state for which state implementation plan ("SIP") disapprovals have been stayed by the courts. Accordingly, the EPA issued interim final rules staying the effectiveness of the ITFIP in both Missouri and Oklahoma while the stays issued by the Eighth and Tenth Circuits in the ITSIP disapproval cases remain in place. During this time, both states will continue to operate under the existing CSAPR program. While Kansas was not originally included in the ITFIP, in January 2024, the EPA issued a proposal to include Kansas in the ITFIP. In June 2024, the U.S. Supreme Court issued an order granting emergency motions for stay filed by state and industry petitioners of the final ITFIP pending further review of the ITFIP by the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit). In March 2025, EPA announced that they plan to eliminate the requirements of the ITFIP. EPA has not provided details regarding how they plan to rescind the applicable ITFIP. Regardless, EPA never finalized the ITFIP for Kansas. Missouri submitted a supplemental ITSIP to EPA. In January 2026, EPA published in the Federal Register, a proposed "Phase 1" reconsideration rule addressing interstate transport requirements for six states including Kansas. EPA indicated they intend to address additional states, including Missouri in a separate action. The Phase 1 proposal would reevaluate and approve previously disapproved ITSIP submissions for five states including Kansas; thus, Kansas would no longer be subject to the ITFIP if this rule is finalized.

Evergy Metro currently complies with the existing CSAPR rule through a combination of trading allowances within or outside its system in addition to changes in operations as necessary. Future, strengthened ozone, particulate matter ("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.

7.1.3 Regional Haze

In 1999, the EPA finalized the Regional Haze Rule, which aims to restore national parks and wilderness areas to pristine conditions. The rule requires states in coordination with the EPA, the National Park Service, the U.S. Fish and Wildlife Service, the U.S. Forest Service, and other interested parties to develop and implement air quality protection plans to reduce the pollution that causes visibility impairment. There are 156 "Class I" areas across the U.S. that must be restored to pristine conditions by the year 2064. There are no Class I areas in Kansas, whereas Missouri has two: the Hercules-Glades Wilderness Area and the Mingo Wilderness Area. States must submit revisions to their Regional Haze Rule SIPs every ten years, and the first round was due in 2007. For the second ten-year implementation period, the EPA issued a final rule revision in 2017 that allowed states to submit their SIP revisions by July 2021. In December 2025, EPA issued a final rule extending the SIP revision deadline for the third ten-year implementation period to from July 2028 to July 2031.

The Missouri SIP revision does not require any additional reductions from the Evergy Companies' generating units in the state. MDNR submitted the Missouri SIP revision to the EPA in August 2022; however, they failed to do so by the EPA's revised submittal deadline in August 2022. As a result, in August 2022, the EPA published "finding of failure" with respect to Missouri and fourteen other states for failing to submit their Regional Haze SIP revisions by the applicable deadline. This finding of failure established a two-year deadline for the EPA to issue a Regional Haze federal implementation plan (“FIP”) for each state unless the state submits, and the EPA approves a revised SIP that meets all applicable requirements before the EPA issues the FIP. In July 2024, the EPA published in the Federal Register a proposal to partially approve and partially disapprove Missouri's Regional Haze SIP revision.

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

SIP or a FIP, could determine that additional operational or physical modifications are required on the generating unit to further reduce emissions. In January 2026, KDHE submitted a supplemental Kansas SIP revision to EPA for approval. The supplement includes a KDHE analysis for two Kansas emissions sources, one of which is Evergy's La Cygne Generating Station, demonstrating both emission sources do not require additional emission reductions. If EPA approves this supplement, no emission reductions will be required for any Kansas emissions sources, including Evergy Metro sources, during the second ten-year implementation period.

7.1.4 Greenhouse Gases

In April 2024, EPA finalized the GHG regulations and guidelines that apply to new and existing fossil fuel fired EGUs.

In June 2025, EPA published in the Federal Register a proposed rule to repeal and/or revise the GHG regulation and guidelines. EPA is proposing both a primary and alternative proposal. The primary proposal would repeal all GHG emission standards for the power sector promulgated in both 2015 and 2024. The alternative proposal would repeal specific portions of the 2024 final rule based on revised best system of emission reduction ("BSER") determinations for existing coal-fired units and new combustion turbines. EPA is proposing to repeal the requirement to add carbon capture and sequestration ("CCS") to existing coal-fired units retiring on or after January 1, 2039, and new combustion turbines units. EPA is also proposing to repeal the requirement to conduct natural gas co-firing for existing coal-fired units retiring between 2032 and 2039. This proposal would eliminate all GHG requirements for existing coal-fired units.

In July 2025, EPA proposed a repeal of the GHG 2009 endangerment finding as well as GHG emission standards for motor vehicles. Specifically, EPA proposed to repeal all GHG emissions standards for motor vehicles and repeal the Endangerment finding because EPA had no authority to establish GHG emissions standards. The previous EPA unreasonably analyzed the scientific record and failed to determine that GHG reduction technology poses greater harm to public health and welfare.

Evergy Metro awaits EPA's finalization of these regulations to determine the full impact on our operations.

7.1.5 Mercury and Air Toxics Standards

In April 2024, the EPA finalized a rule to tighten certain aspects of the Mercury and Air Toxics Standards ("MATS") rule. The EPA lowered the emission limit for PM and required the use of PM continuous emissions monitors ("CEMs") for coal-fired units.

In February 2026, EPA issued a final regulation repealing the April 2024 regulation. This repeal eliminated the proposed reduction in the PM limitation and the requirement for PM CEMs on all coal units. In March 2026, a coalition comprising environmental organizations, states, and cities petitioned the DC Circuit Court to review and challenge the EPA's final rule.

7.2 Water Emission Impacts

7.2.1 Effluent Limitation Guidelines

The Evergy Companies discharge some of the water used in generation and other operations containing substances deemed to be pollutants. In April 2024 and December 2025, the EPA finalized updates to the Effluent Limitation Guidelines ("ELGs") for steam electric power generating facilities to address the vacated limitations, deadlines, and prior reviews of the existing rule. Flue Gas Desulfurization ("FGD") wastewater, bottom ash transport wastewater ("BATW"), coal residual leachate ("CRL"), and legacy wastewater are addressed in the rulemaking. FGD, BATW, and CRL at operating facilities are required to achieve zero liquid discharge as soon as feasible and no later than December 2034. The Evergy Companies have reviewed the modifications to limitations on FGD wastewater and bottom ash transport water and the Evergy Companies do not believe the impact to be material. The Evergy Companies are reviewing the limitations on CRL, its impact on their operations and financial results and believe the cost to comply will not be material. In June 2024, multiple legal challenges to the ELG were consolidated in the Eighth Circuit. In October 2024, the Eighth Circuit denied a motion to stay the ELG.

Additional litigation and regulatory review by EPA is ongoing that could impact the timing or cost to comply.

7.2.2 Clean Water Act Section 316(A)

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

7.2.3 Clean Water Act Section 316(B)

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

7.2.4 Zebra Mussel Infestation

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

7.2.5 Total Maximum Daily Loads

A Total Maximum Daily Load ("TMDL") is a calculation of the maximum amount of a given pollutant that a body of water can absorb before its quality is impacted. A stream is considered impaired if it fails to meet Water Quality Standards established by the Clean

Water Commission. Future TMDL standards could restrict discharges and require equipment to be installed to minimize or control the discharge.

7.3 Waste Material Impact

7.3.1 Coal Combustion Residuals ("CCRs")

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

In April 2024 and February 2026, the EPA finalized an expansion and deadline extension to the CCR regulations focused on legacy surface impoundments and historic placements of CCR. This regulation expands the applicability of the 2015 CCR regulation to inactive landfills and beneficial use sites not previously regulated. Additional litigation and announced reconsiderations from EPA could impact the timing or cost to comply.

Section 8: Transmission and Distribution Update

8.1 Changes from the 2025 Annual Update

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

8.1.1 RTO Expansion Planning

Evergy Metro assessment of regional transmission organization ("RTO") expansion plans is an ongoing process that occurs through the various regional planning processes conducted by SPP. These assessments include review and approval of plan scope documents, review and approval of plan input assumptions, review of plan study analysis and results with feedback from Evergy Metro staff, and review and approval of final plan reports. All transmission projects identified by SPP for the Evergy Metro service territory are included in SPP's annual Transmission Expansion Plan Report and Project List, posted publicly on SPP's website. By meeting the performance standards established for transmission planning, the assessment ensures that adequate transmission is available in the near term and long term to meet the firm load and transmission service requirements included in the SPP Regional Plan for Evergy Metro.

8.1.2 Advanced Distribution Technologies

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

- Advanced Distribution Management Systems ("ADMS")
- Communicating Faulted Circuit Indicators ("CFCIs")
- Reclosers with communication
- Regulators and Capacitors with Communication
- Load Tap Changers with Communication
- Private Long-Term Evolution ("PLTE") Cellular

ADMS

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

- Outage Management System (“OMS”)
- FLISR
- Advanced Fault Location Functionality Utilization
- Distribution Supervisory Control and Data Acquisition (“D-SCADA”)
- Distributed Energy Resource Management System (“DERMS”)
- Power Flow Optimization
- Volt/Var Optimization (“VVO”)
- State Estimation

FLISR

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

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

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

Fault Location Analysis Functionality ("FLA")

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

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

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

The Company intends to further expand FLA solutions beyond the current state by fully configuring the system impedance model within the OMS application and aggregating in the required field data as a parallel FLA effort, which will enable further validation and model calibration of the two FLA systems in contrast to one another. Success of this planned effort is dependent on OMS system capability plus successful integration and testing of model comparisons and prescribed event solutions.

CFCI

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

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

Reclosers with Communication

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

Regulators and Capacitors with Communication

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

Load Tap Changers with Communication

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

PLTE Cellular

Evergy is deploying a PLTE communications network as a foundational element of grid modernization. This dedicated wireless network provides secure broadband connectivity to field devices, substations, and grid automation equipment, enabling faster data transfer, improved situational awareness, and more reliable remote operations.

This reduces reliance on leased public carrier networks and legacy narrowband systems. In addition, PLTE improves cybersecurity posture, network performance, and long-term cost stability.

8.1.3 Advanced Transmission Technologies Discussion

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

Advanced Assessment Methods

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

New Transmission Technologies

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

- **STATCOM** – a sub-division of a group of devices known as Flexible Alternating Current Transmission System ("FACTS") devices. A STATCOM uses a voltage source converter ("VSC") to match or produce a voltage wave and can react to large changes nearly instantaneously.
- **E-STATCOM** – a STATCOM with added super-capacitor to enable primary frequency response and enhance grid-support capability.
- **SynCon** – a synchronous generator connected to a motor. SynCons provide nearly identical system support characteristics in terms of voltage and frequency as a traditional synchronous generator. However, since they are connected via a motor to the transmission system, they are unable to produce real-power output (i.e., Megawatts).

Section 9: Demand-Side Resource Analysis Update

After the 2024 Triennial IRP filing, Evergy Metro filed its proposal for future demand-side programs in its MEEIA Cycle 4 application on April 29, 2024.[34] The parties to the case reached a joint agreement and the Commission issued its order approving the agreement and tariffs on December 11, 2024, with an effective date of January 1, 2025.

EMM approved MEEIA Cycle 4 programs will deliver a lower capacity accreditation as compared to the realistic achievable potential plus ("RAP+") DSM portfolio that was selected in EMM's 2024 Triennial IRP and subsequently filed in EMM's MEEIA Cycle 4 proposed plan in Case No. EO-2023-0369/0370. Additionally, the approved MEEIA Cycle 4 programs were shorter in duration than the proposed programs in Case No. EO-2023-0369/0370. EMM had filed and proposed a 4-year cycle for its energy efficiency programs concurrent with a 4-year cycle for its demand response programs. However, the Stipulation and Agreement approved in Case No. EO-2023-0369/0370 included reduced energy efficiency programs for two years (2025-2026) and demand response programs for three years (2025-2027). These changes result in a lower total cost-effective capacity reduction than what could be achieved through the demand-side programs modeled in EMM's 2024 Triennial IRP.

As a result, EMM modified its 2026 Annual Update IRP DSM planning profile to reflect:

- the lower, approved MEEIA Cycle 4 portfolio (budget, energy, demand and cycle duration)
- the uncertainty of future MEEIA programs given the tenor of Staff, OPC, and Commission comments during the filing, as well as the terms of the Stipulation and Agreement

Therefore, EMM did not model any additional energy efficiency programs after the approved cycle ends in 2026. It also modeled a continuation of the approved MEEIA Cycle 4 level of demand response programs through the end of the IRP planning horizon.

[34] EO-2023-0369/0370

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

For EKM, no new DSM potential forecast is included in this 2026 Annual Update. However, Evergy’s base case includes impacts of Kansas Energy Efficiency Investment Act (“KEEIA”) Cycle 1 programs approved in 22-EKME-254 with adjustments to reflect actual achievement from the recent year.

9.1 Changes from the 2025 Annual Update

Evergy's base case includes impacts of MEEIA Cycle 4 energy efficiency and demand response programs as approved by the Commission in EO-2023-0369/0370 with adjustments for demand response impacts to reflect the actual achievements from the recent year.

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

Table 8 shows the total energy and demand savings included in EMM's base case.

Table 8: Base Case DSM Impacts – EMM

Year	MWh	MW-Summer	MW-Winter
2027	18,940	118	35
2028	18,776	134	41
2029	18,156	104	34
2030	17,364	106	36
2031	16,543	107	36
2032	15,393	107	37
2033	14,675	107	37
2034	14,531	108	38
2035	14,195	109	39
2036	13,312	110	40
2037	12,407	109	39
2038	11,921	109	39
2039	11,766	108	39
2040	9,998	108	39
2041	4,894	107	39
2042	1,614	107	38
2043	1,339	107	38
2044	1,099	107	38

Table 9 shows the total energy and demand savings included in EKM's base case.

Table 9: Base Case DSM Impacts – EKM

Year	MWh	MW-Summer	MW-Winter
2027	44,205	56	17
2028	50,744	66	23
2029	47,971	58	21
2030	47,444	58	20
2031	46,845	57	20
2032	45,466	56	20
2033	43,455	55	20
2034	42,254	54	19
2035	41,611	54	19
2036	38,528	53	19
2037	30,431	51	18
2038	19,639	47	16
2039	13,609	45	14
2040	12,600	44	13
2041	11,528	44	13
2042	8,441	43	13
2043	4,279	43	13
2044	1,857	42	12

Table 10 shows the total energy and demand savings included in Evergy Metro's base case.

Table 10: Base Case DSM Impacts – EMM & EKM

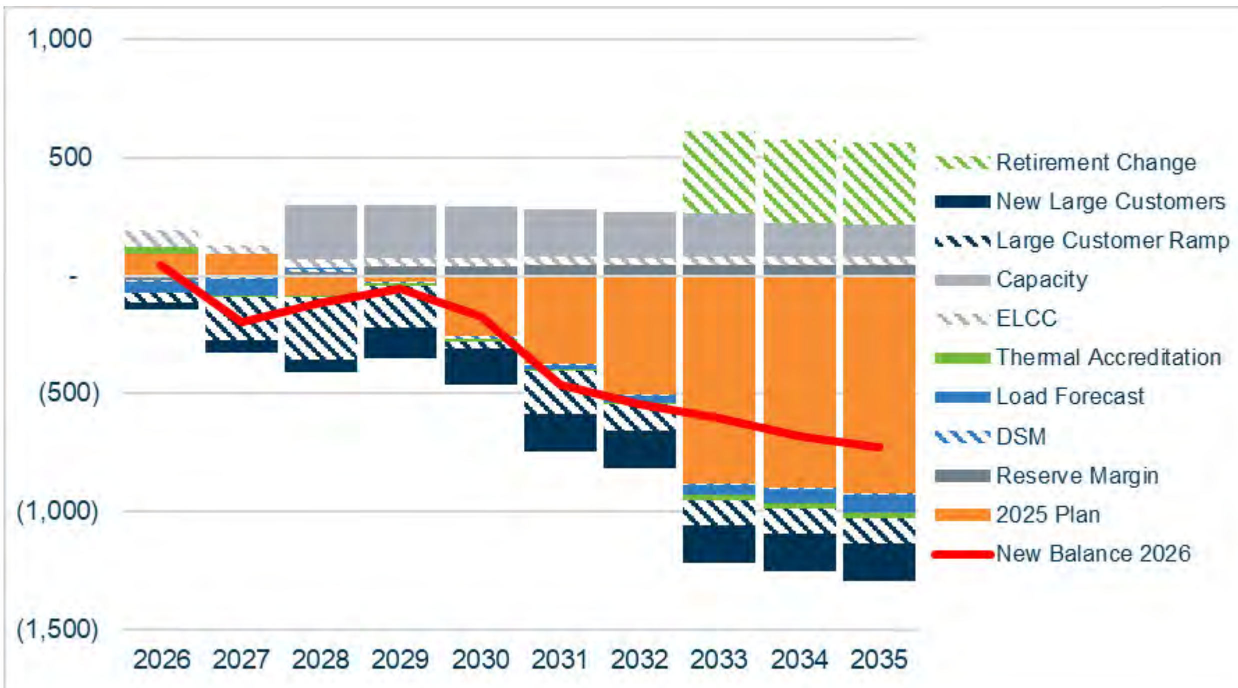
Year	MWh	MW-Summer	MW-Winter
2027	63,145	173	52
2028	69,520	200	63
2029	66,126	162	55
2030	64,808	164	56
2031	63,389	164	57
2032	60,859	163	57
2033	58,130	162	57
2034	56,784	162	57
2035	55,807	163	58
2036	51,840	163	59
2037	42,838	160	57
2038	31,560	156	55
2039	25,375	153	53
2040	22,598	152	52
2041	16,422	151	52
2042	10,055	150	51
2043	5,618	150	51
2044	2,956	149	50

Section 10: Resource Plan Analysis

10.1 Changes to Expected Capacity Needs

Evergy Metro's 2025 Annual Update forecasted that without adding resources, Evergy Metro would have some summer capacity length above reserve margin requirements in 2026 and 2027, followed by small additional summer capacity deficits in 2028 and 2029 and a summer deficit position of about 300 MW in 2030. These near-term capacity needs were expected to be met by additions of 450 MW of solar, 300 MW of wind and 150 MW of battery storage by 2030. After 2030, with additional load growth, Evergy Metro was projected to need greater amounts of summer capacity, rising to over 700 MW in the early 2030s. Evergy Metro's 2025 Preferred Plan included a 410 MW SCGT and two half CCGTs totaling 710 MW to meet summer and winter capacity needs.

Figure 23: Changes to Evergy Metro Summer Capacity Balance

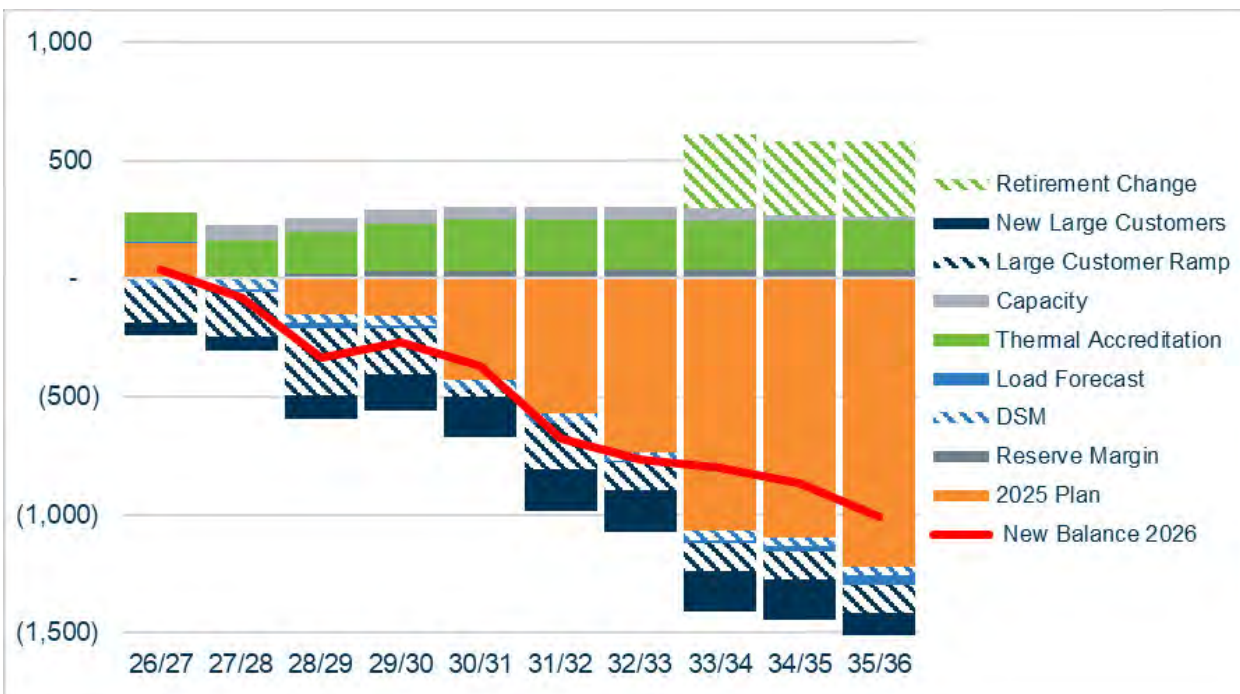


Since the 2025 Annual Update, there have been a few forecast changes that have improved Evergy Metro's expected summer capacity position before resource additions. In conjunction with a large customer agreement, it has secured market capacity from the customer. It also has procured a small amount of additional market capacity. Revised

ELCC calculations for existing renewable resources and PPAs show a small increase in forecasted summer capacity accreditation. There is also a small increase in the capacity balance attributable to slightly lower reserve margin requirements than forecasted in the 2025 Annual Update. Evergy Metro's 2026 Preferred Plan delays the retirement of La Cygne 1 from March 2033 to March 2038, increasing the accredited capacity available during those years (other retirement delays improve capacity balances in later years in the planning horizon).

The updated 2026 capacity balance shows that Evergy Metro continues to need additional summer capacity beginning in 2027. The need increases in 2030-2032 consistent with the 2025 Annual Update forecast and then levels off when La Cygne 1 capacity is added to the forecast beginning in 2033 due to the extension of its anticipated retirement date.

Figure 24: Changes to Evergy Metro Winter Capacity Balance



Evergy Metro's 2025 Annual Update forecast showed greater needs for winter capacity than summer capacity, and this continues to be true with the 2026 Annual Update forecast. Evergy Metro's revised winter capacity balance reflects gains from increased accreditation from existing thermal resources – primarily due to firming of natural gas supply which is expected to reduce outage risk. Evergy Metro's winter capacity position benefitted from the executed market-capacity purchases, however the contribution to winter capacity was lower than summer due to ties to solar resource accreditation. Higher large load forecasts outweighed these capacity additions, leaving Evergy Metro shorter winter capacity in most years through winter 32/33. The later modeled retirement date for La Cygne 1 added capacity to the forecast beginning in winter 33/34, improving Evergy Metro's capacity balance relative to the 2025 Annual Update forecast. The 2026 Annual Update forecast shows winter capacity needs of over 300 MW in winter 28/29 increasing to almost 700 MW by winter 31/32 and 800 MW by winter 33/34.

10.2 Base Planning Options

10.2.1 Resource Availability

Evergy Metro's base planning assumptions consider the availability of viable projects from the RFP and self-development options that can be executed in the near-term window. In future years, the number of project additions is limited each year to ensure the company continues to meet financial metrics and maintain an investment-grade credit rating.

Table 11: Base Build Limit Assumptions

Year	Solar	Wind	Battery	CC	CT	RICE
2027	n/a	n/a	n/a	n/a	n/a	n/a
2028	150 MW PTC	n/a	n/a	n/a	n/a	n/a
2029	150 MW	n/a	150 MW	n/a	n/a	n/a
2030	150 MW	150 MW	150 MW	n/a	n/a	n/a
2031	150 MW	150 MW	150 MW	710 MW	Mullin Creek #2	373 MW
2032	300 MW	150 MW	300 MW	710 MW	n/a	373 MW
2033+	300 MW	150 MW	300 MW	355 MW	440 MW	373 MW

10.2.2 Retirements

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

The 2025 Preferred Plan included the retirement of La Cygne 1 in March 2033, La Cygne 2 in March 2040, and Iatan 1 in March 2040. The 2026 Annual Update tests extending the life of these units with later retirement dates:

- La Cygne 1 retires March 2038
- Iatan 1 retires after 2045
- La Cygne 2 retires after 2045

The 2025 Preferred Plan projected retirement dates for Iatan 2 and Hawthorn 5 are beyond the planning horizon. These coal resources are modeled as operating through the whole planning horizon (2026-2045) in all 2026 Annual Update ARPs.

10.3 ARP Testing

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

- Testing the economics of plans with variations in near-term resource build decisions
- Testing plans with different future CUF expectations
- Testing plan variations for meeting the minimum requirements for Missouri Renewable Energy Standards ("RES")

Table 12: Plan Key for Retirement/Build Options

Load	Retirements	Build Options	Other
A- Base Load	A - 2025 PP Retirement Dates	A- Base	A- Base (Mid/Mid/Mid)
	B- Extend La Cygne 1 to March 2038	B- No 2028 Solar	K- RES Solar Additions
	C- Extend La Cygne 1 to March 2038, Extend La Cygne 2 and Iatan 1 to Beyond 2045	C- No 2030 Storage	L- RES Wind Additions
		D- No Mullin Creek #2	
		E- No 2032 CCGT	

Table 13: Plan Key for Futures Testing

Load	Retirements	Build Options	Other
A- Base Load	C- Extend La Cygne 1 to March 2038, Extend La Cygne 2 and Iatan 1 to Beyond 2045	A- Base	C- Low CO_2, Low NG
			D- High CO_2
			E- Low CO_2
			F- High CO_2, High NG
			G- High Construction Cost
			H- Low Construction Cost
			I- High NG
			J- Low NG

Table 14: Base Plan Descriptions

Plan Name	Description
AAAA	2025 PP Retirement Dates
ABAA	Extend La Cygne 1 to March 2038
ACAA	Extend La Cygne 1 to March 2038, Extend La Cygne 2 and Iatan 1 to Beyond 2045
ACBA	No 2028 Solar
ACCA	No 2030 Storage
ACDA	No Mullin Creek #2
ACEA	No 2032 CCGT
ACAC	Low CO_2, Low NG
ACAD	High CO_2
ACAE	Low CO_2
ACAF	High CO_2, High NG
ACAG	High Build Cost
ACAH	Low Build Cost
ACAI	High NG
ACAJ	Low NG
ACAK	RES Solar Additions
ACAL	RES Wind Additions

The ARPs generated through this process were tested in each endpoint (future with varied CUFs) and rankings were developed based on the probability-weighted NPVRR, consistent with the 2024 Triennial IRP and the Missouri IRP process.

Table 15: CUF Probabilities

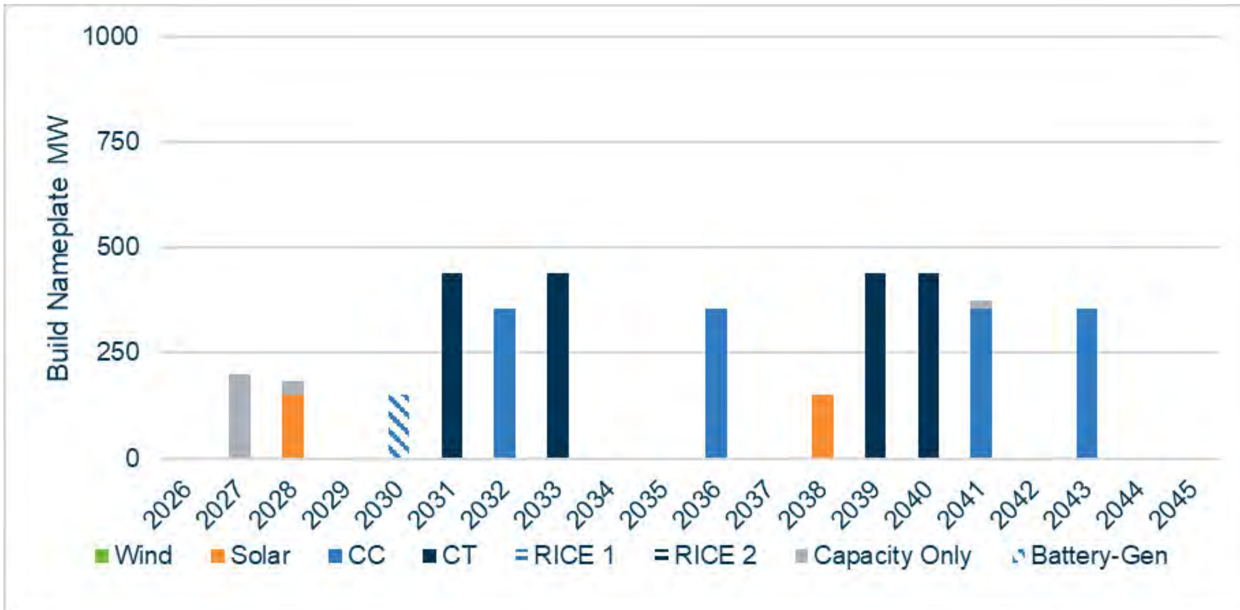
	Natural Gas Price	CO_2 Emissions Restrictions	Construction Cost
Low	35%	25%	25%
Mid	50%	60%	50%
High	15%	15%	25%

10.4 Plans Testing Retirements

Retirement decisions were tested using capacity expansion and base planning assumptions, including the updated load, MEEIA and KEEIA demand-side programs and resource adequacy forecasts. Plan AAAA uses retirement dates identified in the 2025 Annual Update Preferred Plan. Plans ABAA and ACAA use the same base assumptions but vary the retirement dates. Plan ABAA moves the La Cygne 1 retirement from March 2033 to March 2038. Plan ACAA also moves the Iatan 1 and La Cygne 2 retirements from March 2040 to beyond 2045 (the last year in the IRP 20-year window).

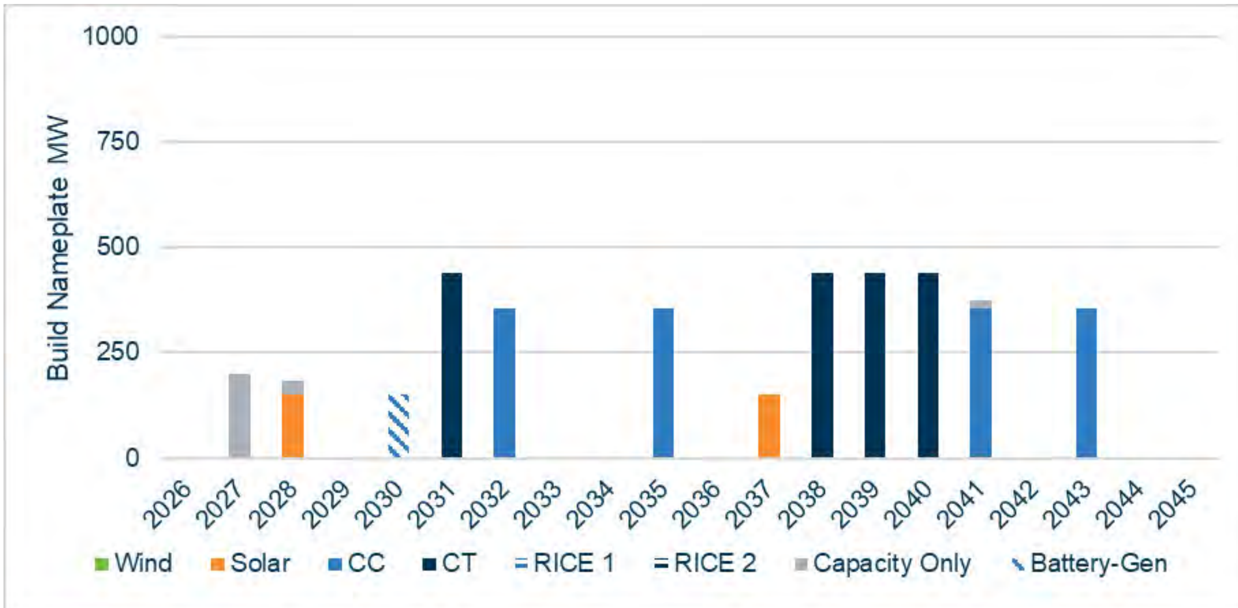
Plan AAAA selects 150 MW solar in 2028, 150 MW storage in 2030, the Mullin Creek #2 CT in 2031, and ½ CCGT in 2032. It then selects another CT in 2033, likely to replace the 375 MW La Cygne 2 retirement in March 2033. The plan requires further builds beginning in 2036, including ½ CCGT in 2036, 150 MW of solar in 2038, CTs in 2039 and 2040, and ½ CCGTs in 2041 and 2043.

Figure 25: Base Planning Assumptions and 2025 PP Retirements Plan AAAA



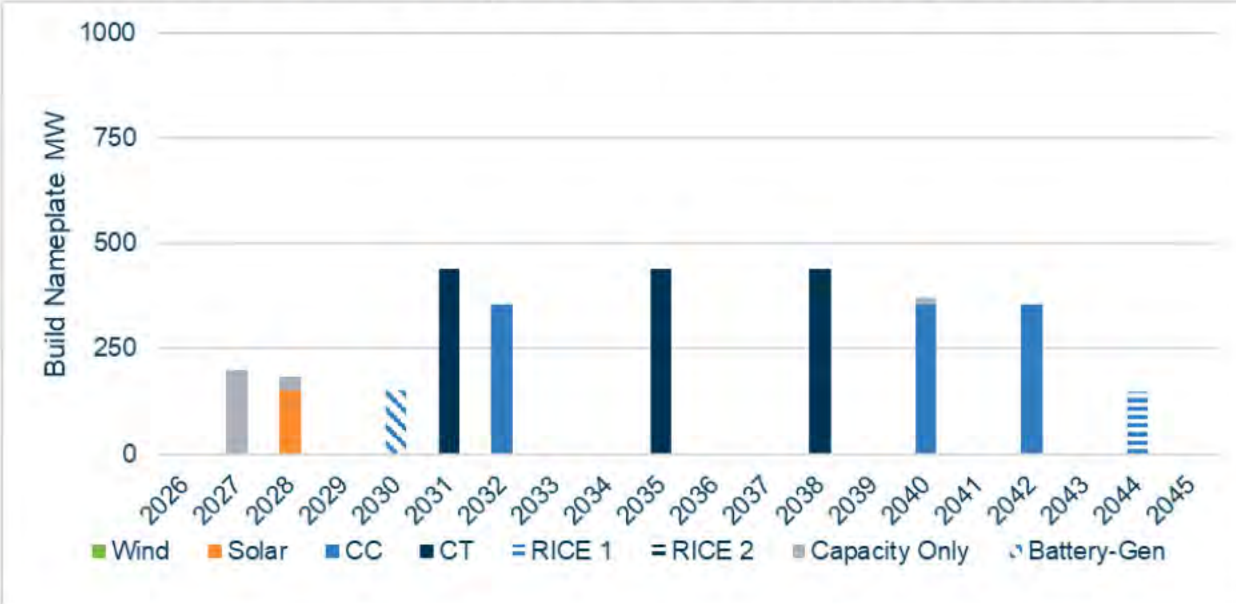
Plan ABAA selects the same early resources as the Plan AAAA, including 150 MW solar in 2028, 150 MW storage in 2030, the Mullin Creek #2 CT in 2031, and ½ CCGT in 2032. It does not select a 2033 resource, and pushes the next build to 2035, selecting ½ CCGT in 2035, 150 MW of solar in 2037, CTs in 2038, 2039 and 2040, and ½ CCGTs in 2041 and 2043.

Figure 26: Extend La Cygne 1 to March 2038 Plan ABAA



Plan ACAA selects the same early resources as Plans AAAA and ABAA, including 150 MW solar in 2028, 150 MW storage in 2030, the Mullin Creek #2 CT in 2031, and ½ CCGT in 2032. Consistent with Plan ABAA, it does not select a 2033 resource and pushes the next build to 2035. Plan ACAA selects a CT in 2035 and 2038, ½ CCGTs in 2040 and 2042, and a RICE unit in 2044.

Figure 27: Extend La Cygne 1, Iatan 1, and La Cygne 2 Plan ACAA



The plan extending all retirement decisions, Plan ACAA, is the least cost plan considered. The 2025 Preferred Plan retirements increase NPVRR by $624 million, due to the need to replace retiring resources with earlier capacity additions. Plan ABAA, which postpones the La Cygne 1 retirement to March 2038 but continues to retire Iatan 1 and La Cygne 2 in March 2040 increases NPVRR by $468 million.

Table 16: Coal Retirement Plan Rankings

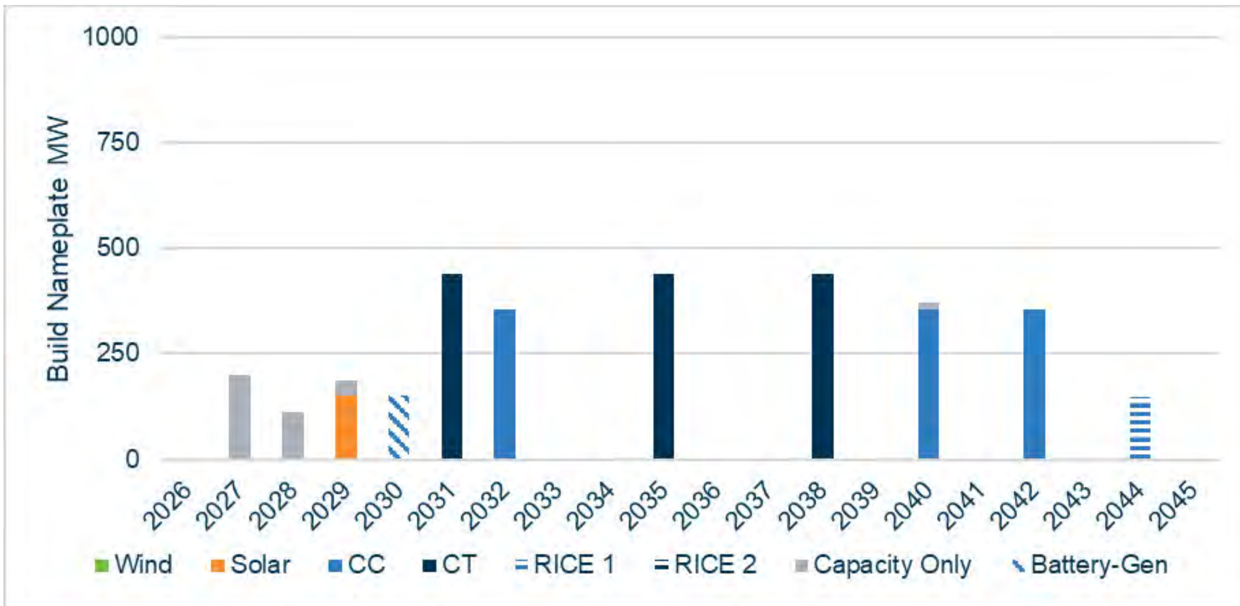
Rank	Plan	NPVRR	Difference	Description
1	ACAA	32,839		Extend La Cygne 1 to March 2038, Extend La Cygne 2 and Iatan 1 to Beyond 2045
2	ABAA	33,307	468	Extend La Cygne 1 to March 2038
3	AAAA	33,463	624	2025 PP Retirement Dates

10.5 Plans Testing Near-Term Options

All ARPs testing retirement dates selected the same early build options, including 150 MW solar in 2028, 150 MW storage in 2030, the Mullin Creek #2 CT in 2031, and ½ CCGT in 2032. Plans ACBA, ACCA, ACDA, and ACEA test the tradeoffs of these early build decisions by removing the option of one resource selection at a time and using capacity expansion to develop an ARP and testing the economics of that ARP. All of these plans include the extended retirement dates and base planning assumptions.

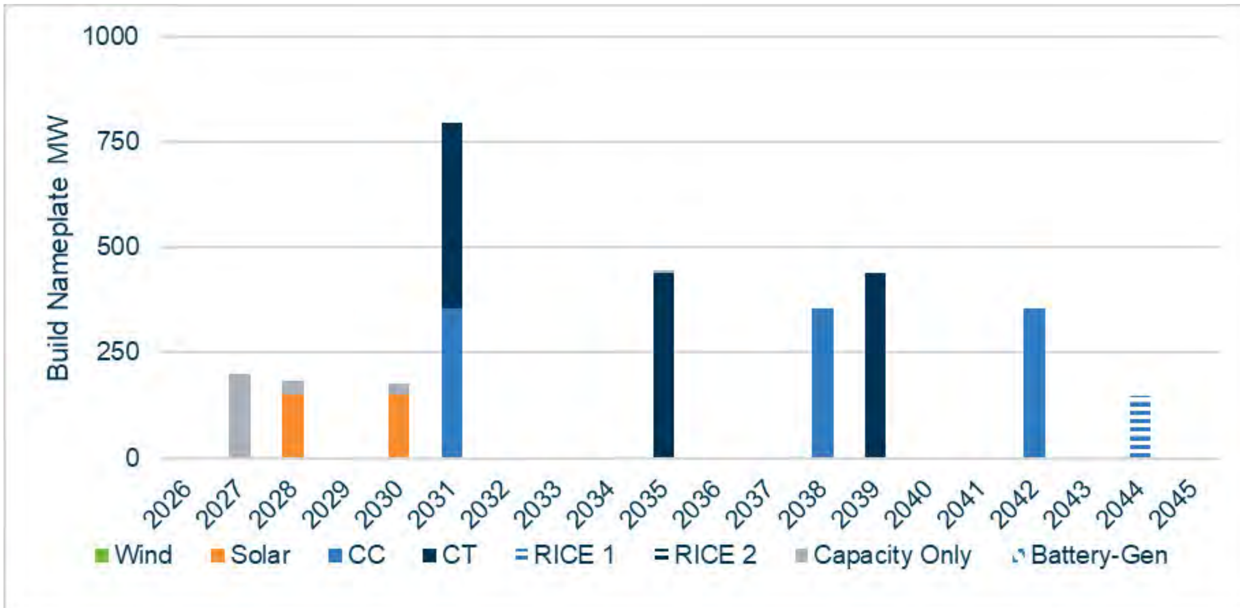
Plan ACBA removes 2028 solar as a resource option for capacity expansion. The plan continues to pick 150 MW of solar, moving it to 2029. The plan also continues to select the rest of the early resources through 2032, including 150 MW storage in 2030, Mullin Creek #2 in 2031, and ½ CCGT in 2032. The plan is identical to Plan ACAA throughout the entire planning horizon, except for the solar move from 2028 to 2029.

Figure 28: No 2028 Solar Plan ACBA



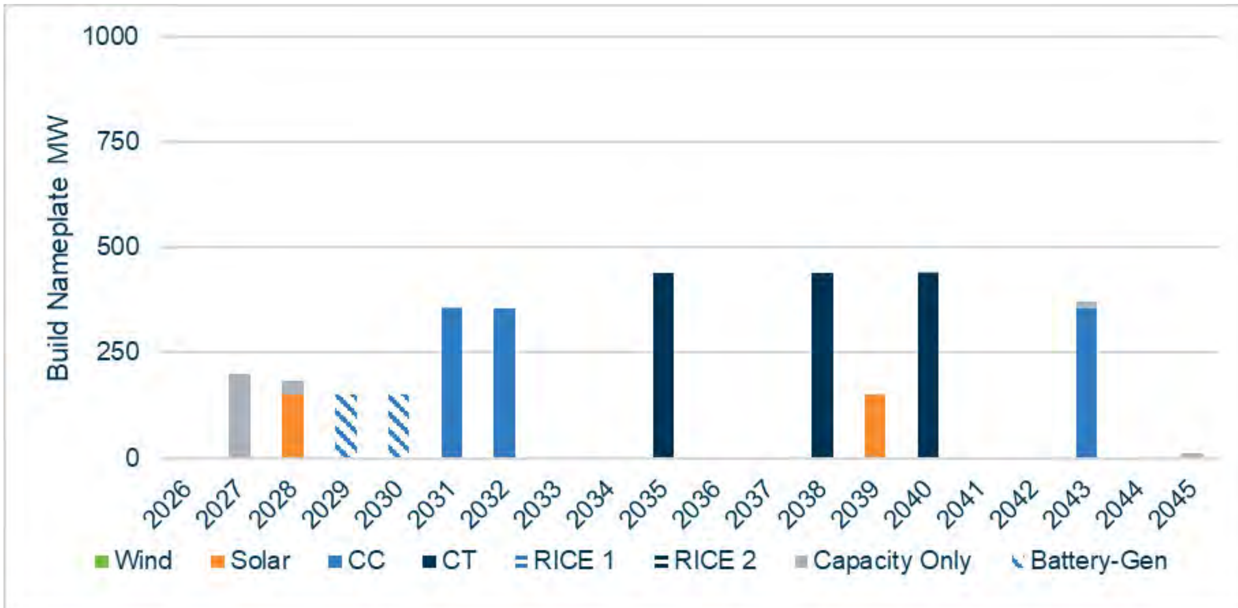
Plan ACCA removes 2030 storage as a resource option for capacity expansion. The plan continues to pick 150 MW of solar in 2028. It adds another 150 MW of solar in 2030 in place of the 2030 storage. The plan also selects Mullin Creek #2 in 2031, and moves forward the ½ CCGT to 2031 from 2032. The plan continues to build two CTs, two ½ CCGTs, and a RICE unit after 2034, however there are some timing changes with one ½ CCGT moved forward to 2038 from 2040, and one CT moved back to 2039 from 2038.

Figure 29: No 2030 Storage Plan ACCA



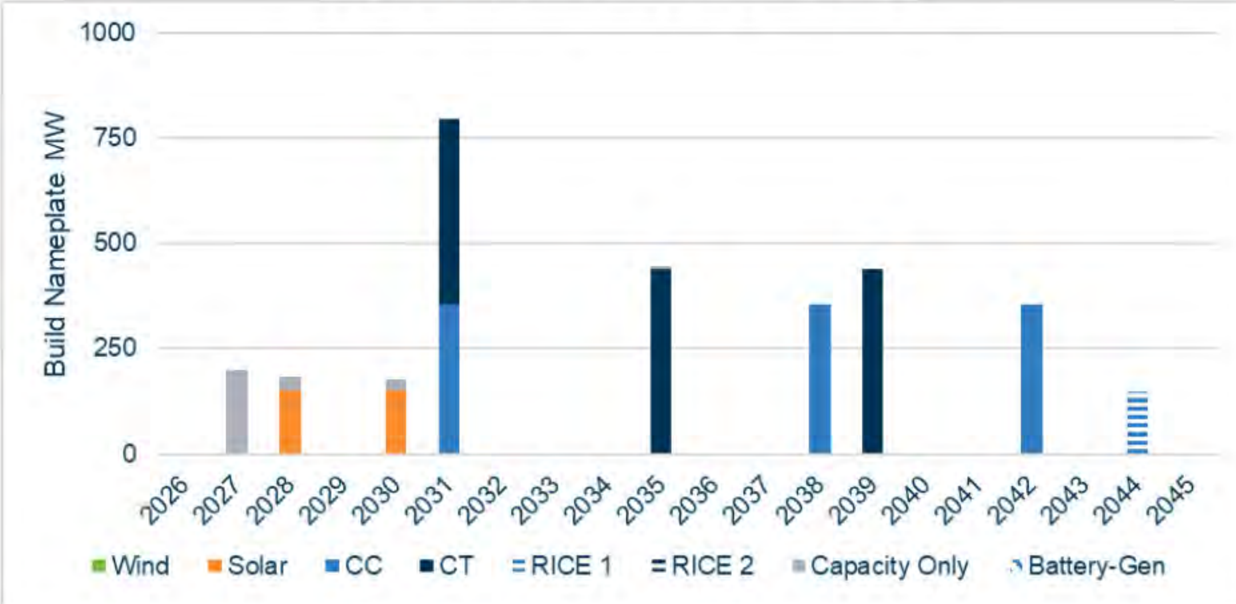
Plan ACDA removes Mullin Creek #2 in 2031 as a resource option for capacity expansion. The plan continues to pick 150 MW of solar in 2028, 150 MW of storage in 2030 and ½ CCGT in 2032. However, it adds an additional 150 MW of storage in 2029 and selects ½ CCGT in 2031. The plan selects 2035 and 2038 CTs consistent with Plan ACAA but varies in the later years with 150 MW of solar in 2039, a CT in 2040 and a ½ CCGT in 2043.

Figure 30: No Mullin Creek #2 Plan ACDA



Plan ACEA removes the ½ CCGT in 2032 as a resource option for capacity expansion. The plan continues to pick 150 MW of solar in 2028 and Mullin Creek #2 in 2031. However, it substitutes 150 MW of solar for 150 MW of storage in 2030 and selects ½ CCGT in 2031, moving the resource up one year. Plan ACEA is identical to Plan ACCA which removes the 2030 storage option. The plan selects a 2035 CT consistent with Plan ACAA, but varies in the later years with ½ CCGT in 2038, a CT in 2039, ½ CCGT in 2042, and a RICE unit in 2044.

Figure 31: No 2032 ½ CCGT Plan ACEA



All of the near-term build tests show the need for 4-5 new resources between 2028 and 2032. Plans ACEA and ACCA are identical, and their near-term selections include two solar resources in 2028 and 2030 and both Mullin Creek #2 and the ½ CCGT in 2031. Plan ACAA is $15 million more expensive in the rankings, with the 2030 storage resource and the ½ CCGT in 2032. The ACBA Plan, which did not allow 2028 solar, is $105 million more expensive, with the solar moved one year later in 2029. Finally, the plan which does not allow Mullin Creek #2, and adds extra storage and a ½ CCGT instead, is the most expensive, increasing the NPVRR by $245 million.

Table 17: Rankings for Near-Term Build Decisions

Rank	Plan	NPVRR	Difference	Description
1	ACEA	32,824		No 2032 CCGT
2	ACCA	32,824	0	No 2030 Storage
3	ACAA	32,839	15	Base Builds
4	ACBA	32,929	105	No 2028 Solar
5	ACDA	33,069	245	No Mullin Creek #2

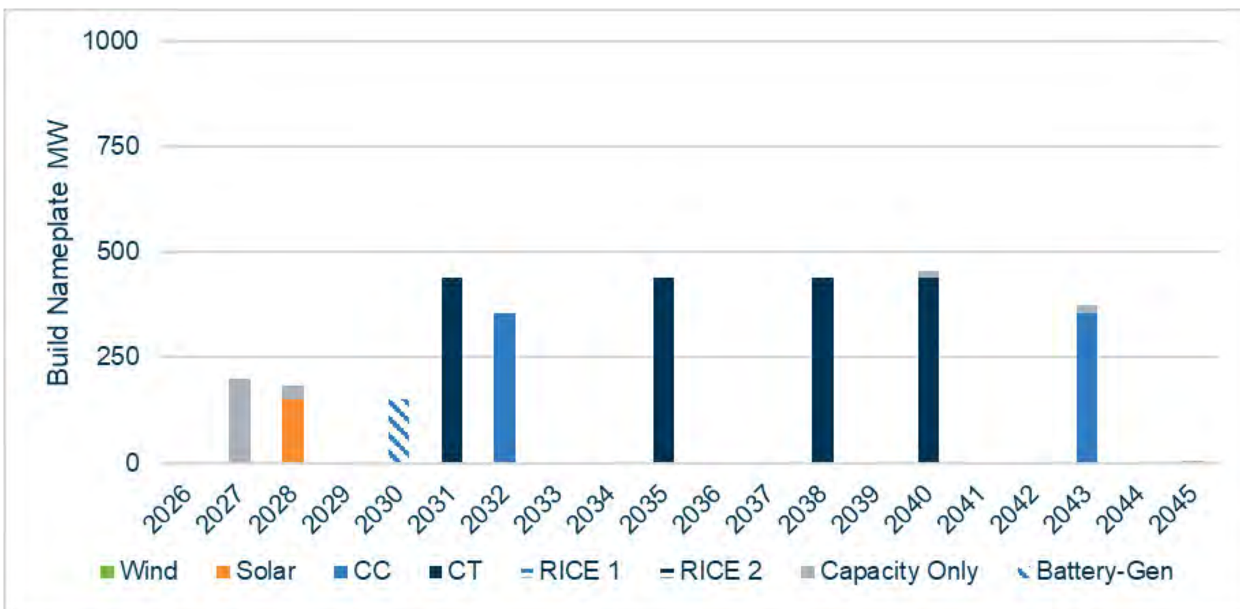
10.6 Plans Testing Optimal Builds for Varying Futures

All ARPs testing retirement dates and early build decisions were based on the optimal build decisions at the “mid” level of each CUF. Additional ARPs were created by varying the CUF level. These plans show the optimal build decisions if future forecasts were expected to be at the “low” or “high” levels.

Capacity expansion plans were developed to test how build decisions would change if the expectation was no future CO_2 regulation/costs in the planning horizon (Low CO_2 scenario), or high CO_2 taxes.

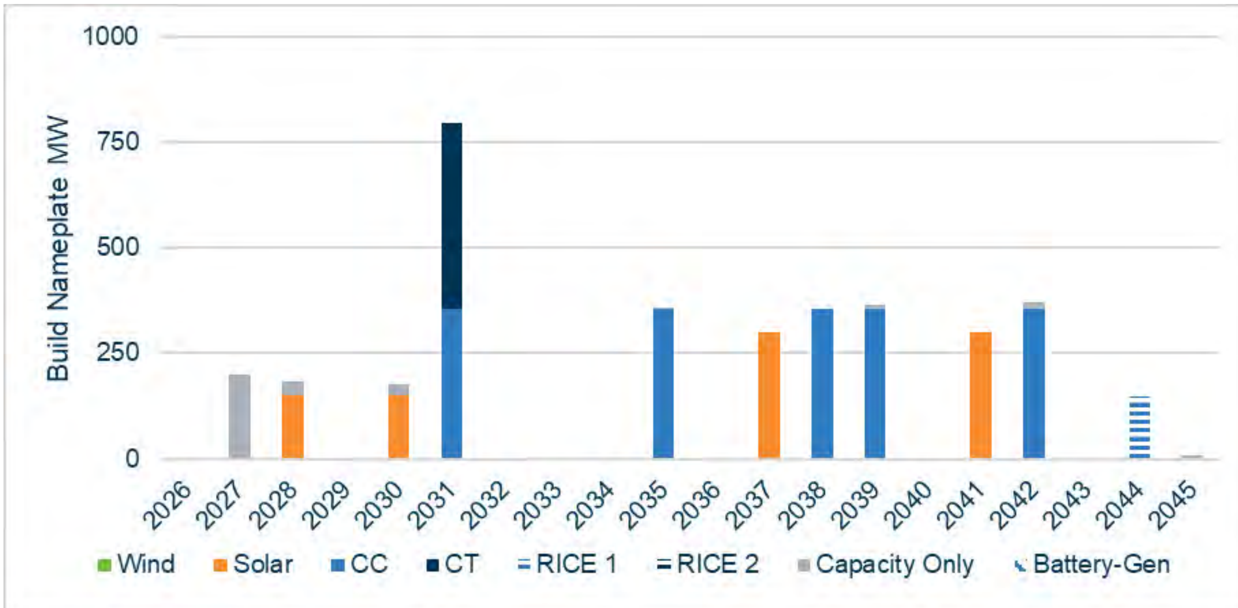
Plan ACAE assumes no future CO_2 taxes. The near-term resources match Plan ACAA, including 2028 solar, 2030 storage, 2031 Mullin Creek #2, and 2032 ½ CCGT. The later year resources are slightly different, preferring an additional CT over ½ CCGT and a RICE.

Figure 32: Low CO_2 Future Plan ACAE



Plan ACAD uses the High CO_2 tax future. Relative to Plan ACAA, it continues to build 2028 solar and Mullin Creek #2 in 2031. It substitutes 2030 storage with solar and moves the ½ CCGT forward to 2031. Beginning in 2035, it selects ½ CCGTs in four planning years, 600 MW of solar, and a RICE. The High CO_2 tax encourages additional builds of non-emitting solar resources and preference for more efficient and lower emitting CCGTs over SCGTs later in the planning horizon.

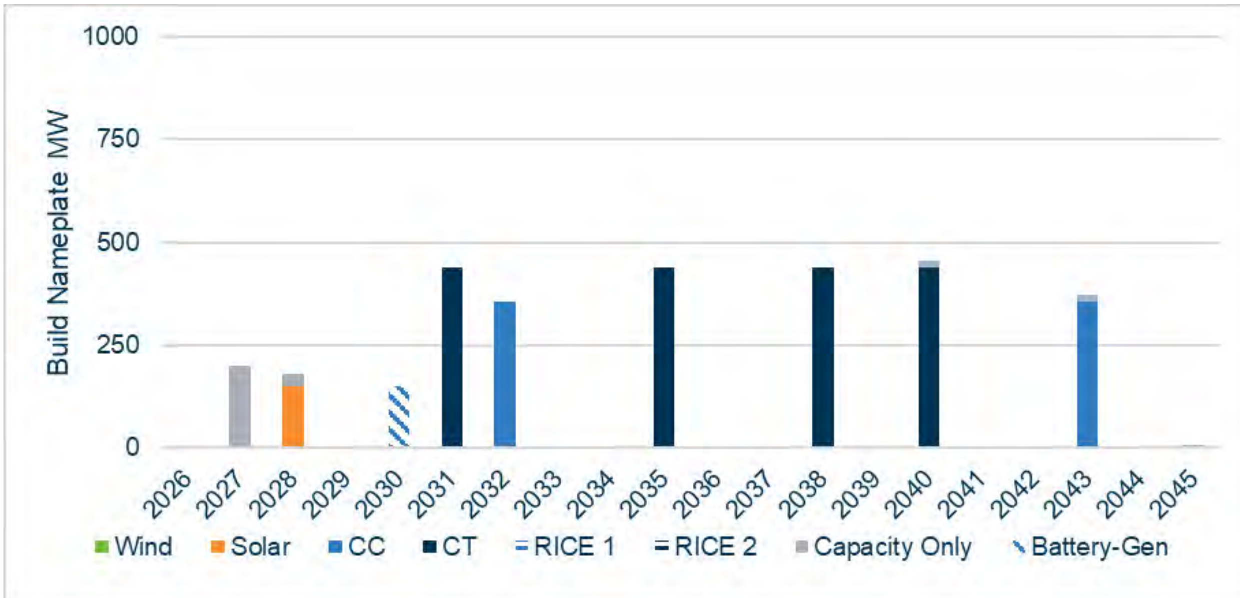
Figure 33: High CO_2 Future Plan ACAD



Two ARPs were to optimize the build decisions with varied future construction cost assumptions. Plan ACAG includes the High Construction Cost forecast, and Plan ACAH includes the Low Construction Cost forecast.

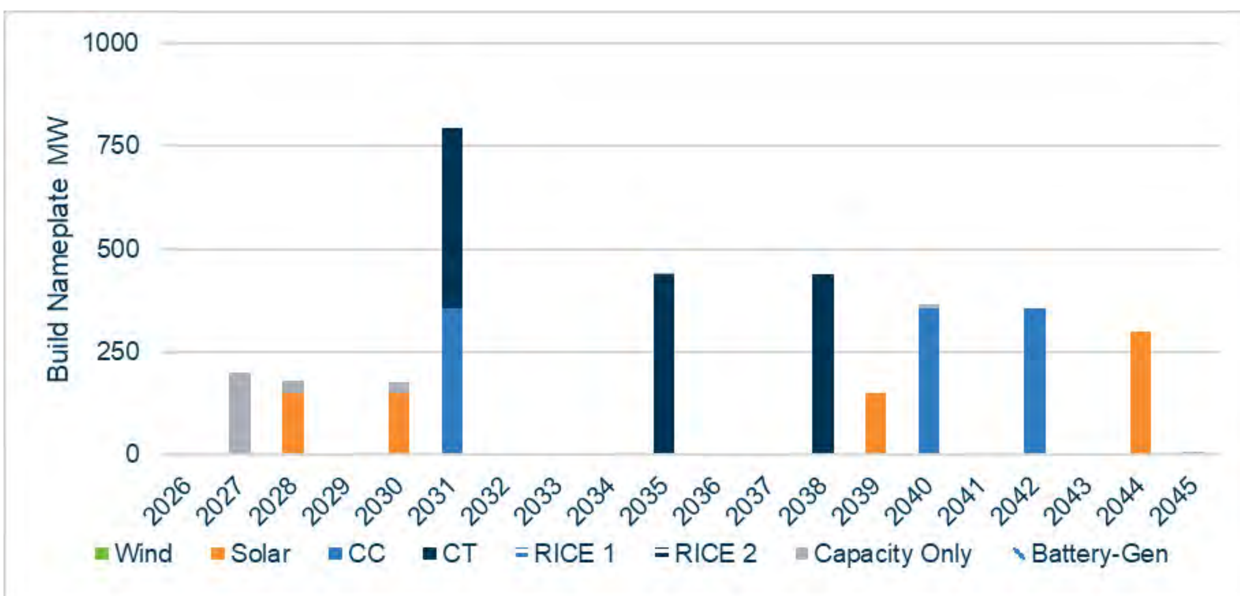
The High Construction Cost Plan ACAG resembles Plan ACAA through 2038. At the end of the planning horizon, Plan ACAG selects an SCGT in 2040 and a ½ CCGT in 2043, in contrast to Plan ACAA which selects ½ CCGTs in 2040 and 2042 and a RICE in 2044. SCGTs have lower fixed costs and higher production costs than CCGTs, so it makes sense that this substitution may be marginal in a high fixed cost future.

Figure 34: High Construction Cost Future Plan ACAG



In comparison with Plan ACAA, the Low Construction Cost Plan ACAH moves up development timing and increases the number of resources. Plan ACAH substitutes solar for storage in 2030, pulls forward the 2032 ½ CCGT to 2031, adds 450 MW of solar in 2039 and 2044, and removes the RICE.

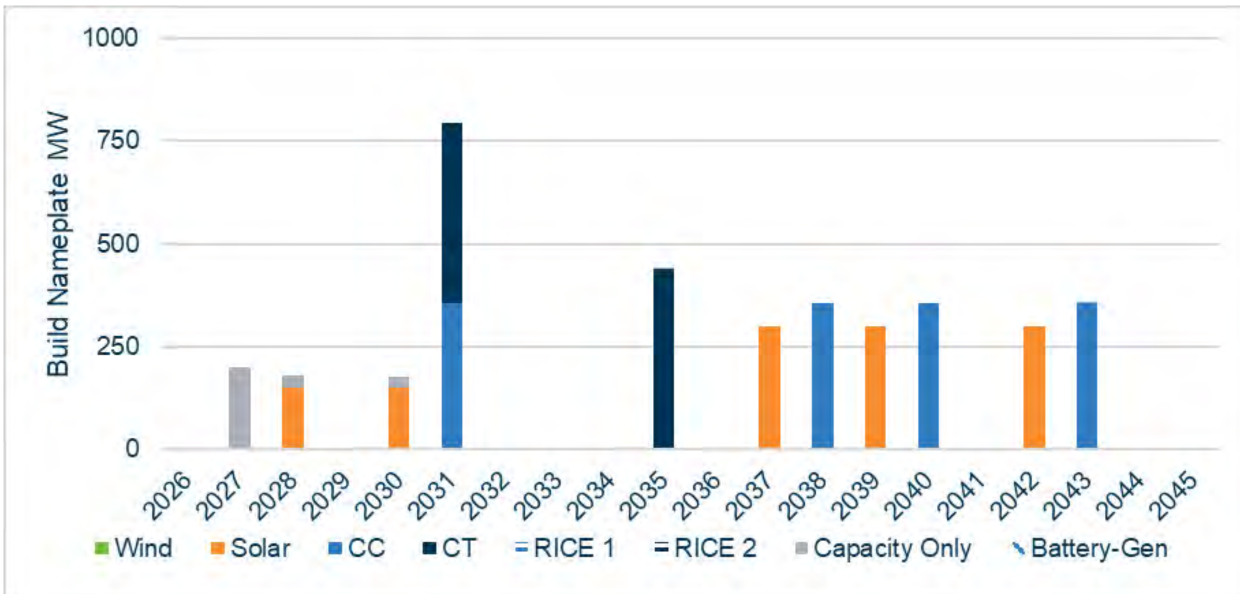
Figure 35: Low Construction Cost Future Plan ACAH



Plans ACAI and ACAJ isolate the effects of the natural gas price forecasts on the optimal build decisions.

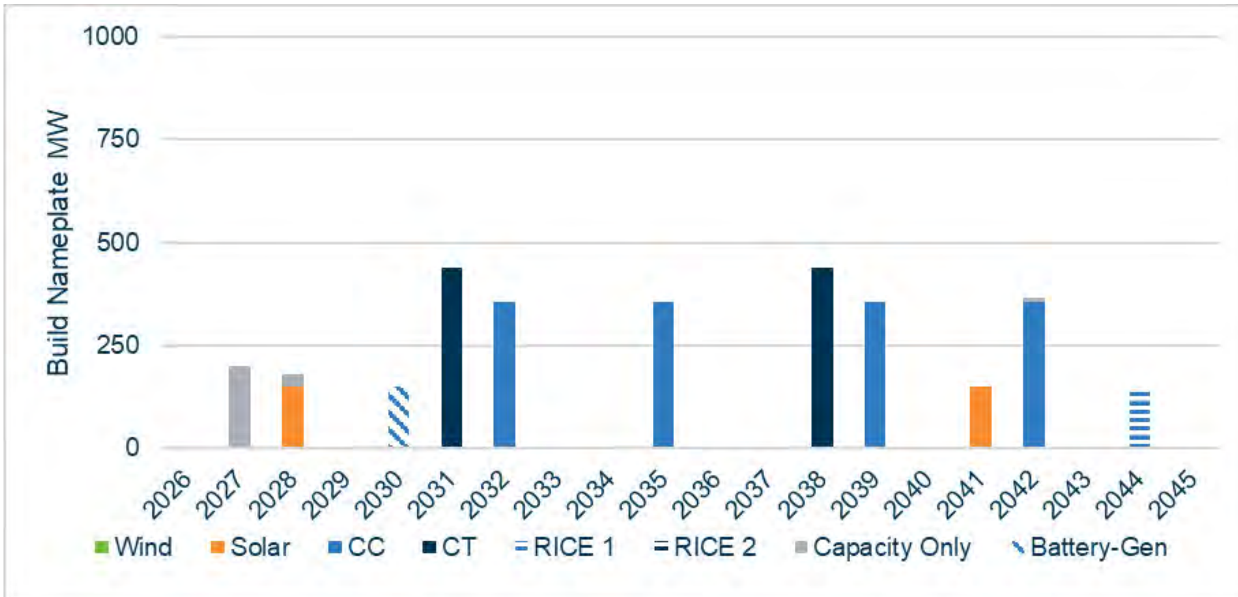
Plan ACAI uses the high NG price forecast. In the near term, it selects 150 MW of solar rather than storage in 2030 and moves up the ½ CCGT to 2031. It continues to select the 2035 SCGT but substitutes the 2038 SCGT for ½ CCGT. It selects two additional ½ CCGTs and does not select a RICE. It also selects 900 MW of solar spread in planning years 2037, 2039, and 2042. The high natural gas price forecast encourages the addition of zero production cost solar resources, and substitution of more efficient natural gas resources.

Figure 36: High NG Price Forecast Plan ACAI



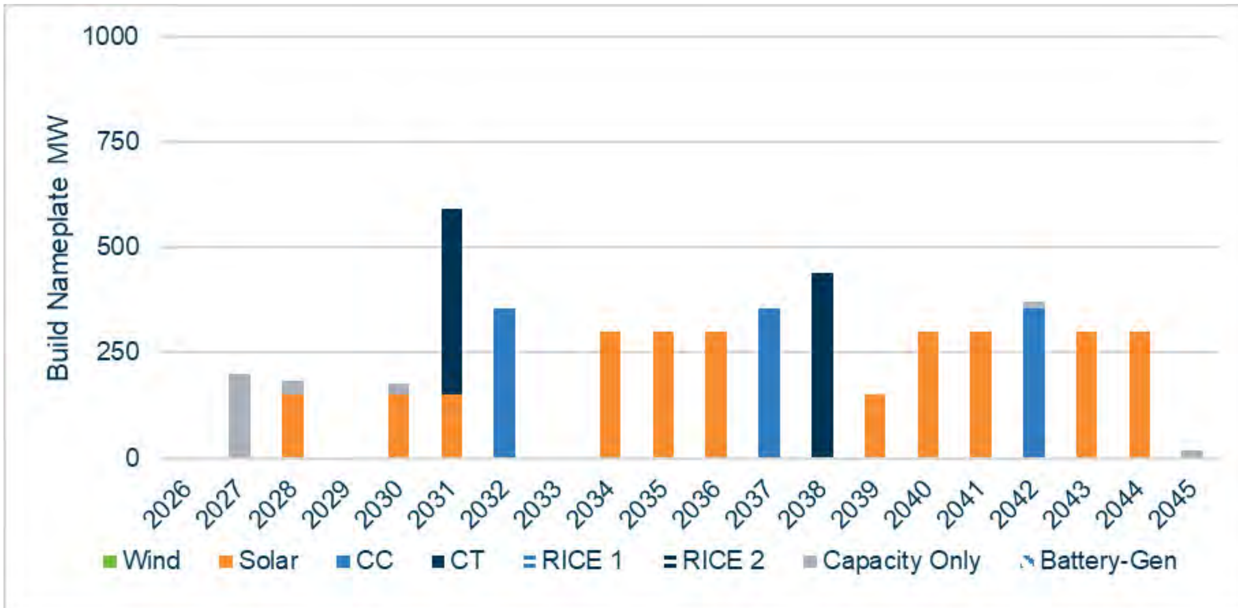
Plan ACAJ uses the low NG price forecast. In the near term, it selects the same resource plan as Plan ACAA through 2032. In 2035, it substitutes the SCGT for a ½ CCGT, likely due to production costs benefits with lower NG prices. It continues to select the 2038 SCGT, moves forward the 2040 ½ CCGT to 2039 and continues to select the ½ CCGT in 2042 and RICE in 2044. It adds 150 MW solar in 2041.

Figure 37: Low NG Price Forecast Plan ACAJ



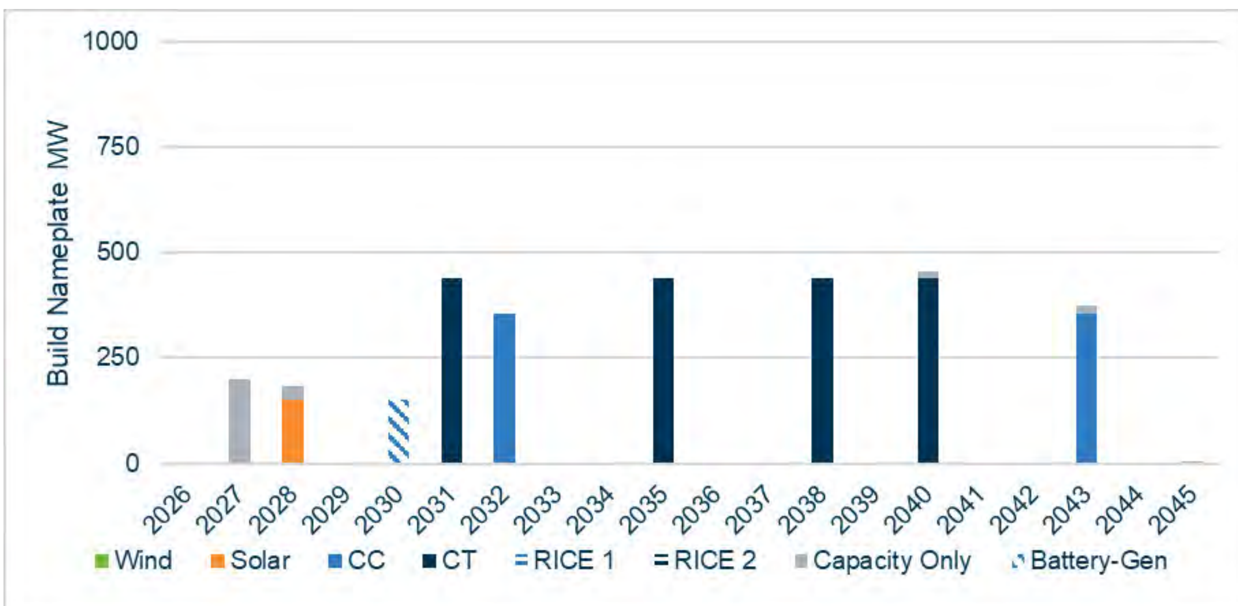
Plan ACAF, which couples High NG prices with High CO_2 taxes continues to build 2028 solar, Mullin Creek #2 in 2031, and ½ CCGT in 2032. It substitutes 2030 storage with solar and adds a solar in 2031. Beginning in 2034, it selects significantly more solar, and less thermal resources than the plan with the Mid/Mid forecasts. Plan ACAF has 2,250 MW of solar. The high natural gas price/high CO_2 tax forecast drives a substantial increase in solar additions, totaling 2,250 MW. This plan shows that with very high natural gas prices and emissions taxes, there are economic benefits to adding a large quantity of zero production cost, non-emitting solar resources, despite the increase in fixed costs.

Figure 38: High NG/High CO_2 Future Plan ACAF



Plan ACAC which couples the Low CO_2 tax with the Low NG forecast is identical to Plan ACAE which Low CO_2 tax with the Mid NG forecast.

Figure 39: Low NG/Low CO_2 Future Plan ACAC



All of the ARPs optimized for different futures make similar near-term selections, each chooses 150 MW solar in 2028, Mullin Creek #2, and a ½ CCGT by 2032. For 2030, five plans pick 150 MW storage – Plans ACAA, ACAJ, ACAE, ACAC, and ACAG. The other four plans pick 150 MW solar. The plans that pick solar move forward the 2032 ½ CCGT to 2031, except for Plan ACAF which adds an additional 150 MW solar in 2031.

The lowest cost plan, Plan ACAJ was optimized for the low natural gas future. It has the same near-term execution resources as the Preferred Plan ACAA, however, it begins to differ in 2035.

The highest cost plans are the plans optimized for High CO_2 tax and High NG futures. These ARPs include additional solar resources for energy production cost and emissions tax savings which perform well in the high futures but not as well in other futures.

Table 18: Rankings of Plans Optimized for Different Futures

Rank	Plan	NPVRR	Difference	Description
1	ACAJ	32,825		Low NG
2	ACAH	32,831	6	Low Construction Cost
3	ACAA	32,839	14	Base
4	ACAE	32,845	20	Low CO_2
5	ACAC	32,845	20	Low CO_2, Low NG
6	ACAG	32,845	20	High Construction Cost
7	ACAD	32,924	99	High CO_2
8	ACAI	32,926	101	High NG
9	ACAF	33,236	410	High CO_2, High NG

10.7 Rankings of Base Plans

10.7.1 Risk-Weighted Rankings

Table 19: Overall Plan Rankings

Rank	Plan	NPVRR	Difference	Description
1	ACCA	32,824		No 2030 Storage
2	ACEA	32,824	0	No 2032 CCGT
3	ACAJ	32,825	1	Low NG
4	ACAH	32,831	7	Low Construction Cost
5	ACAA	32,839	15	Base Assumptions, Extended Retirements
6	ACAG	32,845	21	High Construction Cost
7	ACAC	32,845	21	Low CO_2, Low NG
8	ACAE	32,845	21	Low CO_2
9	ACAD	32,924	100	High CO_2
10	ACAI	32,926	102	High NG
11	ACBA	32,929	105	No 2028 Solar
12	ACDA	33,069	245	No Mullin Creek #2
13	ACAF	33,236	412	High CO_2, High NG
14	ABAA	33,307	483	Extend La Cygne 1 to March 2038
15	AAAA	33,463	639	2025 PP Retirement Dates

10.7.2 Carbon Restriction Rankings

Table 20: Rankings for High Carbon Tax Future

Rank	Plan	NPVRR	Difference	Description
1	ACAD	35,202		High CO_2
2	ACAJ	35,296	94	Low NG
3	ACAI	35,296	95	High NG
4	ACAH	35,350	149	Low Construction Cost
5	ACCA	35,356	154	No 2030 Storage
6	ACEA	35,356	154	No 2032 CCGT
7	ACAF	35,415	213	High CO_2, High NG
8	ACAA	35,428	227	Base Assumptions, Extended Retirements
9	ACAC	35,491	289	Low CO_2, Low NG
10	ACAE	35,491	289	Low CO_2
11	ACAG	35,491	289	High Construction Cost
12	ACBA	35,518	316	No 2028 Solar
13	ACDA	35,592	390	No Mullin Creek #2
14	ABAA	35,642	440	Extend La Cygne 1 to March 2038
15	AAAA	35,776	574	2025 PP Retirement Dates

Table 21: Rankings for Mid Carbon Tax Future

Rank	Plan	NPVRR	Difference	Description
1	ACCA	32,963		No 2030 Storage
2	ACEA	32,963	0	No 2032 CCGT
3	ACAJ	32,967	4	Low NG
4	ACAH	32,970	7	Low Construction Cost
5	ACAA	32,979	17	Base Assumptions, Extended Retirements
6	ACAG	32,984	21	High Construction Cost
7	ACAC	32,984	21	Low CO_2, Low NG
8	ACAE	32,984	21	Low CO_2
9	ACAI	33,066	103	High NG
10	ACAD	33,069	106	High CO_2
11	ACBA	33,069	106	No 2028 Solar
12	ACDA	33,207	245	No Mullin Creek #2
13	ACAF	33,368	406	High CO_2, High NG
14	ABAA	33,432	470	Extend La Cygne 1 to March 2038
15	AAAA	33,584	621	2025 PP Retirement Dates

Table 22: Rankings for Low (No) Carbon Tax Future

Rank	Plan	NPVRR	Difference	Description
1	ACAG	30,925		High Construction Cost
2	ACAC	30,925	0	Low CO_2, Low NG
3	ACAE	30,925	0	Low CO_2
4	ACAA	30,951	25	Base Assumptions, Extended Retirements
5	ACCA	30,973	47	No 2030 Storage
6	ACEA	30,973	47	No 2032 CCGT
7	ACAH	30,988	63	Low Construction Cost
8	ACAJ	31,003	78	Low NG
9	ACBA	31,040	115	No 2028 Solar
10	ACAI	31,169	243	High NG
11	ACAD	31,212	286	High CO_2
12	ACDA	31,223	297	No Mullin Creek #2
13	ABAA	31,606	680	Extend La Cygne 1 to March 2038
14	ACAF	31,610	684	High CO_2, High NG
15	AAAA	31,786	861	2025 PP Retirement Dates

10.7.3 Natural Gas Price Rankings

Table 23: Rankings for High Natural Gas Price Future

Rank	Plan	NPVRR	Difference	Description
1	ACAI	34,667		High NG
2	ACAH	34,699	32	Low Construction Cost
3	ACAD	34,721	55	High CO_2
4	ACCA	34,724	58	No 2030 Storage
5	ACEA	34,724	58	No 2032 CCGT
6	ACAJ	34,734	67	Low NG
7	ACAF	34,753	87	High CO_2, High NG
8	ACAA	34,795	128	Base Assumptions, Extended Retirements
9	ACAC	34,856	189	Low CO_2, Low NG
10	ACAE	34,856	189	Low CO_2
11	ACAG	34,856	189	High Construction Cost
12	ACBA	34,886	219	No 2028 Solar
13	ACDA	34,990	324	No Mullin Creek #2
14	ABAA	35,654	987	Extend La Cygne 1 to March 2038
15	AAAA	35,963	1,296	2025 PP Retirement Dates

Table 24: Rankings for Mid Natural Gas Price Future

Rank	Plan	NPVRR	Difference	Description
1	ACCA	32,703		No 2030 Storage
2	ACEA	32,703	0	No 2032 CCGT
3	ACAJ	32,708	5	Low NG
4	ACAH	32,711	8	Low Construction Cost
5	ACAA	32,713	10	Base Assumptions, Extended Retirements
6	ACAC	32,714	11	Low CO_2, Low NG
7	ACAE	32,714	11	Low CO_2
8	ACAG	32,714	11	High Construction Cost
9	ACBA	32,802	99	No 2028 Solar
10	ACAI	32,818	115	High NG
11	ACAD	32,824	121	High CO_2
12	ACDA	32,949	246	No Mullin Creek #2
13	ACAF	33,141	438	High CO_2, High NG
14	ABAA	33,157	454	Extend La Cygne 1 to March 2038
15	AAAA	33,298	595	2025 PP Retirement Dates

Table 25: Rankings for Low Natural Gas Price Future

Rank	Plan	NPVRR	Difference	Description
1	ACAG	32,172		High Construction Cost
2	ACAC	32,172	0	Low CO_2, Low NG
3	ACAE	32,172	0	Low CO_2
4	ACAJ	32,175	3	Low NG
5	ACCA	32,182	11	No 2030 Storage
6	ACEA	32,182	11	No 2032 CCGT
7	ACAA	32,183	11	Base Assumptions, Extended Retirements
8	ACAH	32,202	31	Low Construction Cost
9	ACBA	32,272	100	No 2028 Solar
10	ACAD	32,298	126	High CO_2
11	ACAI	32,334	162	High NG
12	ACDA	32,416	244	No Mullin Creek #2
13	ABAA	32,515	343	Extend La Cygne 1 to March 2038
14	AAAA	32,628	457	2025 PP Retirement Dates
15	ACAF	32,720	548	High CO_2, High NG

10.7.4 Construction Cost Rankings

Table 26: Rankings for High Construction Cost Future

Rank	Plan	NPVRR	Difference	Description
1	ACAG	33,617		High Construction Cost
2	ACAC	33,617	0	Low CO_2, Low NG
3	ACAE	33,617	0	Low CO_2
4	ACAA	33,631	14	Base Assumptions, Extended Retirements
5	ACAJ	33,642	25	Low NG
6	ACCA	33,671	54	No 2030 Storage
7	ACEA	33,671	54	No 2032 CCGT
8	ACAH	33,696	78	Low Construction Cost
9	ACBA	33,716	99	No 2028 Solar
10	ACAD	33,864	247	High CO_2
11	ACAI	33,879	261	High NG
12	ACDA	33,905	288	No Mullin Creek #2
13	ABAA	34,238	620	Extend La Cygne 1 to March 2038
14	ACAF	34,393	776	High CO_2, High NG
15	AAAA	34,442	825	2025 PP Retirement Dates

Table 27: Rankings for Mid Construction Cost Future

Rank	Plan	NPVRR	Difference	Description
1	ACCA	32,822		No 2030 Storage
2	ACEA	32,822	0	No 2032 CCGT
3	ACAJ	32,824	2	Low NG
4	ACAH	32,829	7	Low Construction Cost
5	ACAA	32,839	16	Base Assumptions, Extended Retirements
6	ACAC	32,844	22	Low CO_2, Low NG
7	ACAE	32,844	22	Low CO_2
8	ACAG	32,844	22	High Construction Cost
9	ACAD	32,921	99	High CO_2
10	ACAI	32,922	100	High NG
11	ACBA	32,928	106	No 2028 Solar
12	ACDA	33,068	245	No Mullin Creek #2
13	ACAF	33,227	405	High CO_2, High NG
14	ABAA	33,306	483	Extend La Cygne 1 to March 2038
15	AAAA	33,462	640	2025 PP Retirement Dates

Table 28: Rankings for Low Construction Cost Future

Rank	Plan	NPVRR	Difference	Description
1	ACAH	31,972		Low Construction Cost
2	ACCA	31,980	8	No 2030 Storage
3	ACEA	31,980	8	No 2032 CCGT
4	ACAI	31,981	9	High NG
5	ACAD	31,991	19	High CO_2
6	ACAJ	32,011	39	Low NG
7	ACAA	32,050	78	Base Assumptions, Extended Retirements
8	ACAC	32,075	103	Low CO_2, Low NG
9	ACAE	32,075	103	Low CO_2
10	ACAG	32,075	103	High Construction Cost
11	ACAF	32,095	123	High CO_2, High NG
12	ACBA	32,144	172	No 2028 Solar
13	ACDA	32,235	263	No Mullin Creek #2
14	ABAA	32,379	407	Extend La Cygne 1 to March 2038
15	AAAA	32,487	515	2025 PP Retirement Dates

10.8 Plans to Comply with RES Requirements

The Missouri RES requirements include 14.7% of retail sales to be served by non-solar renewables and 0.3% by solar renewables.

Table 29: Missouri Metro RES Requirements

Year	Retail Electric Sales (MWh)	Missouri RES Non-Solar Requirement	Non-Solar RES Requirement (MWh)	Missouri RES Solar Requirement	Solar RES Requirement (MWh)
2026	9,377,875	14.7%	1,378,548	0.30%	28,134
2027	11,315,359	14.7%	1,663,358	0.30%	33,946
2028	12,454,823	14.7%	1,830,859	0.30%	37,364
2029	13,351,467	14.7%	1,962,666	0.30%	40,054
2030	13,791,523	14.7%	2,027,354	0.30%	41,375
2031	15,332,862	14.7%	2,253,931	0.30%	45,999
2032	15,894,693	14.7%	2,336,520	0.30%	47,684
2033	15,976,018	14.7%	2,348,475	0.30%	47,928
2034	16,088,310	14.7%	2,364,982	0.30%	48,265
2035	16,222,198	14.7%	2,384,663	0.30%	48,667
2036	16,404,707	14.7%	2,411,492	0.30%	49,214
2037	16,582,040	14.7%	2,437,560	0.30%	49,746
2038	16,815,442	14.7%	2,471,870	0.30%	50,446
2039	17,077,200	14.7%	2,510,348	0.30%	51,232
2040	17,383,904	14.7%	2,555,434	0.30%	52,152
2041	17,660,467	14.7%	2,596,089	0.30%	52,981
2042	17,949,007	14.7%	2,638,504	0.30%	53,847
2043	18,242,589	14.7%	2,681,661	0.30%	54,728
2044	18,555,252	14.7%	2,727,622	0.30%	55,666
2045	18,822,902	14.7%	2,766,967	0.30%	56,469

Plan ACAA includes 150 MW of solar in 2028, which will supply enough solar energy to meet the solar requirement throughout the planning horizon. However, beginning in 2036, Evergy Metro's planned renewable generation falls short of the total target amount. Since renewable credits can be banked and used up to 3 years later, Evergy Metro would need a source of renewable energy by 2037 to continue to meet the standard. Given this runway, Evergy Metro has nearly a decade to monitor and reassess the timing and magnitude of RES compliance requirements in future IRPs. The RES compliance gap may narrow or widen depending on retail sales volumes and any future changes to RES compliance requirements. Evergy Metro could purchase renewable energy credits (REC) or procure additional renewable resources. Market REC purchases provide a flexible, lower-capital compliance mechanism that does not require Evergy to commit to long-lived generating assets solely for compliance purposes. Evergy has utilized market REC purchases as part of its compliance strategy in prior years and will continue to evaluate market REC pricing relative to the cost of owned renewable generation.

Plans ACAK and ACAL test meeting the standard with new owned or contracted resources.

Figure 40: Solar Generation Compared to RES Target for Plan ACAA

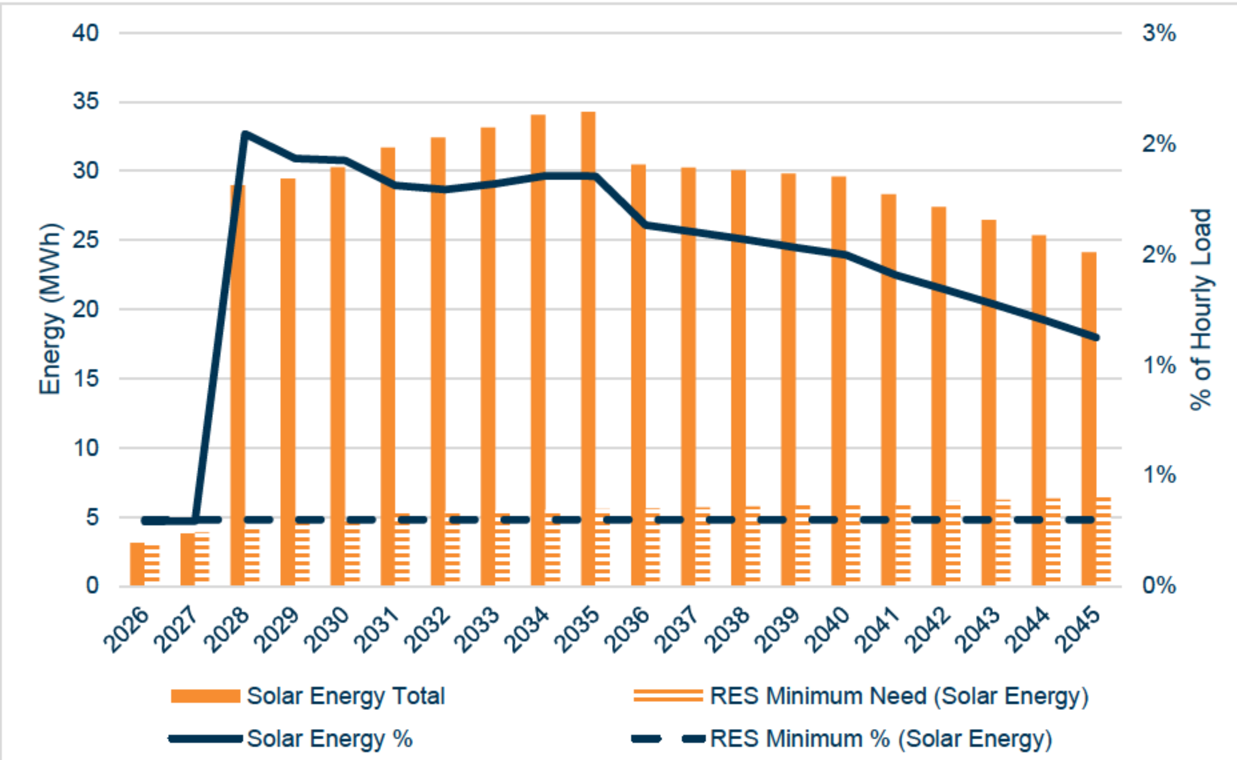
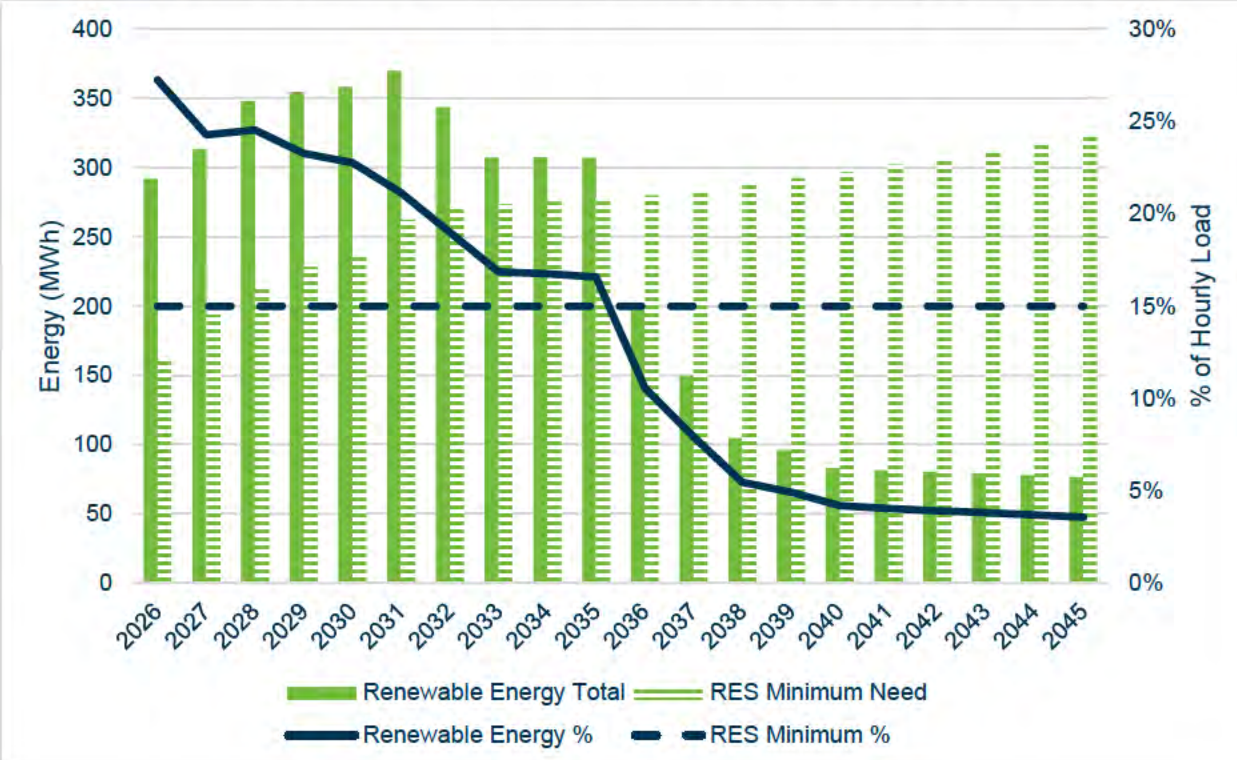
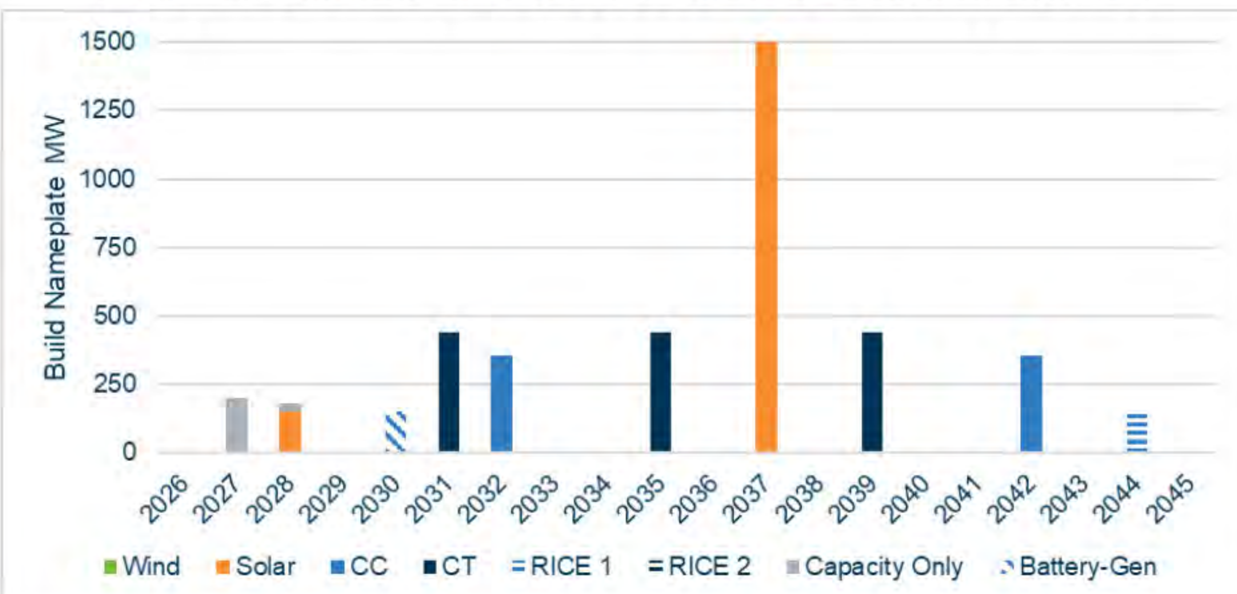


Figure 41: Renewable Generation Compared to RES Target for Plan ACAA



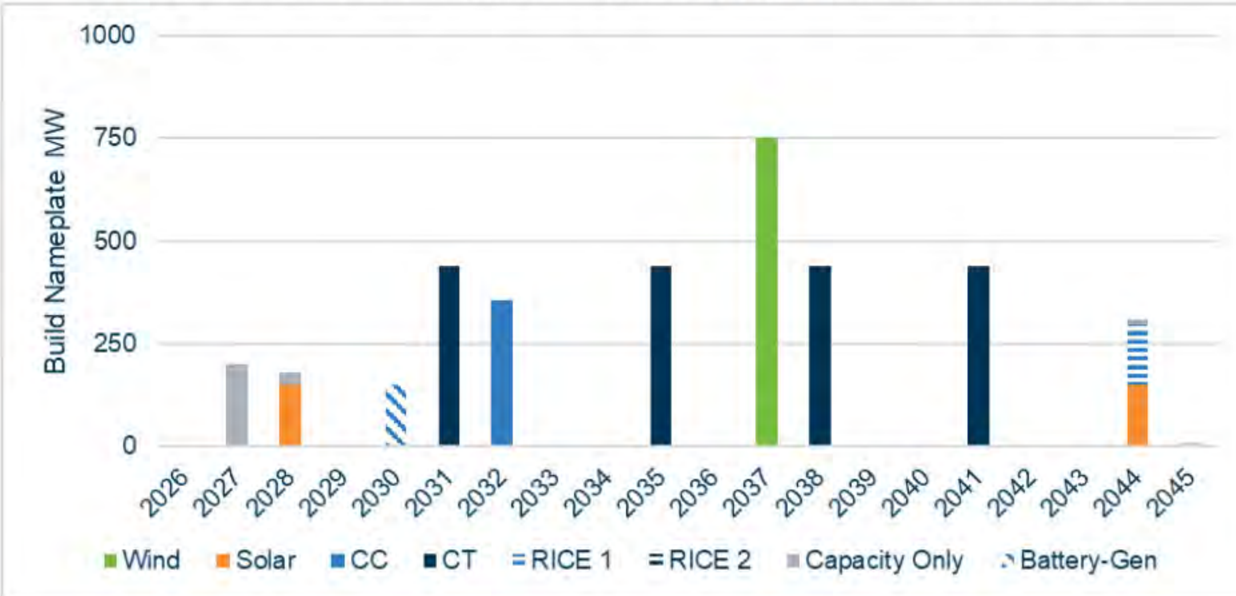
Plan ACAK tests meeting the requirement with 1.5 GW of solar in 2037. This level of solar additions would produce enough energy through 2045 to meet RES needs each year.

Figure 42: Compliance with RES through Solar Additions Plan ACAK



Plan ACAL tests meeting the requirement with 750 MW of wind in 2037. This level of wind additions would produce enough energy through 2045 to meet RES needs each year.

Figure 43: Compliance with RES through Wind Additions Plan ACAL



The economic analysis of the two options shows that procuring solar additions would be a lower cost option for meeting the RES requirements than wind. Evergy Metro does not plan to execute on 2037 resources this early in the planning process but will continue to monitor the RES compliance needs and sources in future IRPs.

Table 30: RES Plan Compliance Options Comparison

Rank	Plan	NPVRR	Difference	Description
1	ACAA	32,839		Base
2	ACAK	34,805	1,966	RES Solar Additions
3	ACAL	34,924	2,084	RES Wind Additions

Section 11: Resource Plan Contingency Analysis

Evergy Metro also developed several contingency plans to determine the optimal plans for differing load forecasts:

- Large load customers
    - Large loads of varying sizes 500 MW – 1,500 MW beginning service in 2031
- Other retail forecast drivers
    - High electrification
    - Low load growth

Table 31: Plan Key for Load Contingency Analysis

Load	Retirements	Build Options	Other
A- Base Load	C- Extend La Cygne 1 to March 2038, Extend La Cygne 2 and Iatan 1 to beyond 2045	A- Base	A- Base
B- Additional 500 MW Load			
C- Additional 750 MW Load			
D- Additional 1,000 MW Load			
E- Additional 1,500 MW Load			
F- High Electrification Load			
G- Low Load			

Table 32: Contingency Plan Descriptions

Plan Name	Description
ACAA	Base Load
BCAA	Additional 500 MW Load
CCAA	Additional 750 MW Load
DCAA	Additional 1,000 MW Load
ECAA	Additional 1,500 MW Load
FCAA	High Electrification Load
GCAA	Low Load

11.1 Large Customer Growth

Evergy Metro developed ARPs to determine how additional large customers could be served.

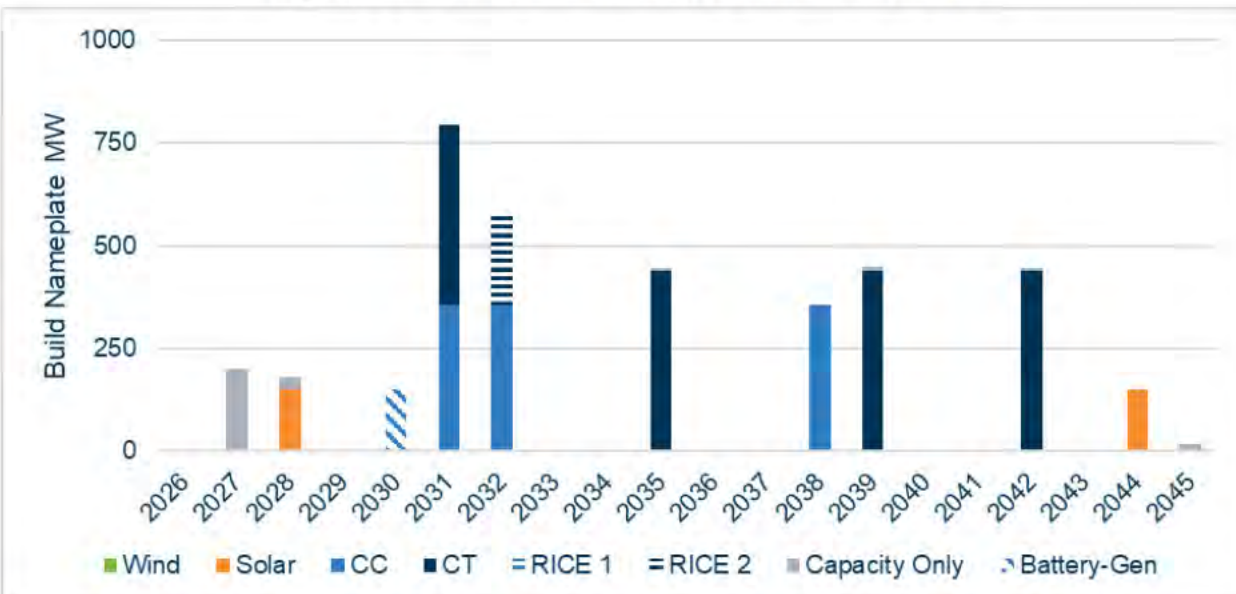
Table 33: New Large Customer Load Ramp Scenarios (MW)

New Load Scenario	2031	2032	2033	2034	2035+
500 MW	250	500	500	500	500
750 MW	250	500	750	750	750
1,000 MW	250	500	750	1000	1000
1,500 MW	250	500	750	1000	1500

Plans BCAA, CCAA, DCAA and ECAA evaluate additional large customer loads.

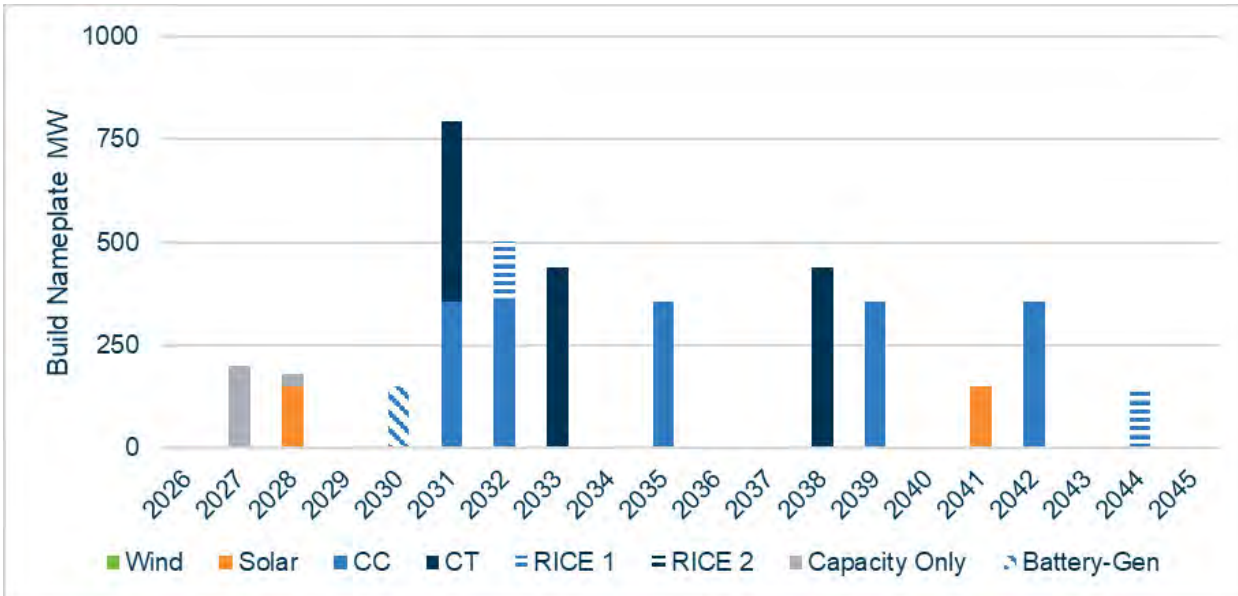
Plan BCAA accommodates an additional 500 MW load in the near term by adding an additional ½ CCGT in 2031 and RICE in 2032. With 250 MW of additional load in 2031 and ramping to a peak of 500 MW in 2032, the plan requires additional thermal resources in those years. Consistent with Plan ACAA, the next resource is an SCGT in 2035. Next the plan selects ½ CCGT in 2038, SCGTs in 2039 and 2042, and 150 MW solar in 2044.

Figure 44: Additional 500 MW Load Plan BCAA



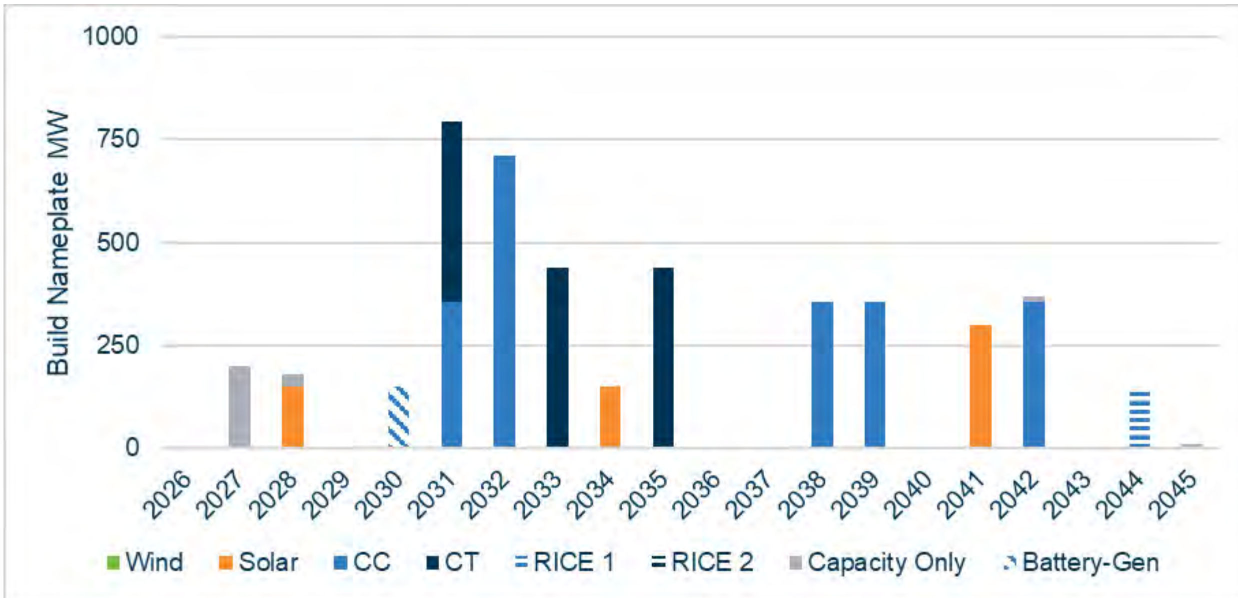
Plan CCAA considers the addition of a customer that has a peak load of 250 MW in 2031, 500 MW in 2032, and 750 MW in 2033 and beyond. Similar to Plan BCAA, which has the same 2031 and 2032 needs, it adds an additional ½ CCGT in 2031 and a RICE in 2032 to the near-term resource plan in Plan ACAA. It selects an additional SCGT in 2033 to meet the higher load that year. The resource plan also selects ½ CCGTs in 2035, 2039, and 2042, an SCGT in 2038, 150 MW solar in 2041, and RICE in 2044.

Figure 45: Additional 750 MW Load Plan CCAA



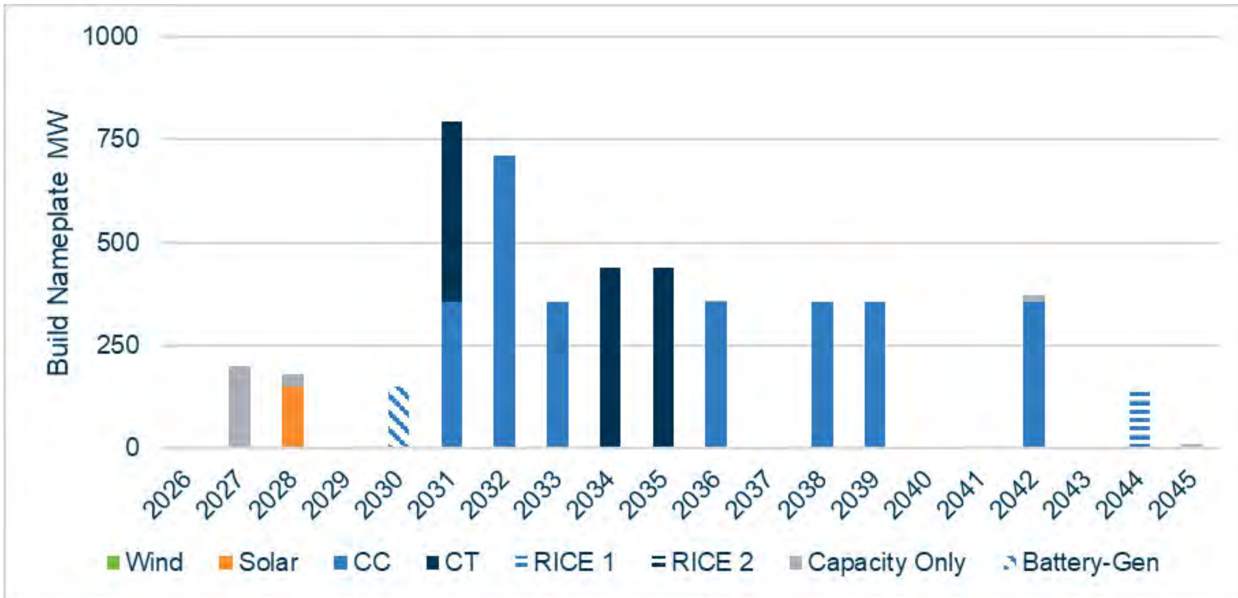
Plan DCAA accommodates a new large load that peaks at 1,000 MW in 4 years. It has the same additional load as Plan CCAA in 2031- 2033, and ramps to its peak of 1 GW in 2034. It adds ½ CCGT in 2031 and ½ CCGT in 2032 to the near-term resource plan in Plan ACAA. It selects an SCGT in 2033, 150 MW solar in 2034, and an SCGT in 2035. It also selects ½ CCGTs in 2038, 2039, and 2042 as well as 300 MW solar in 2041 and RICE in 2044.

Figure 46: Additional 1,000 MW Load Plan DCAA



Plan ECAA accommodates an additional 1.5 GW large load that ramps up over 5 years. The load has the same profile as the load in Plan DCAA 2031-2034 but adds another 500 MW peak in 2035. Plan ECAA also selects ½ CCGTs in addition to the Plan ACAA resources in 2031 and 2032. It then adds ½ CCGT in 2033 and an SCGT in 2034. In 2035 it selects an SCGT, followed by four additional ½ CCGTs in 2036, 2038, 2039, and 2042, and a RICE in 2044.

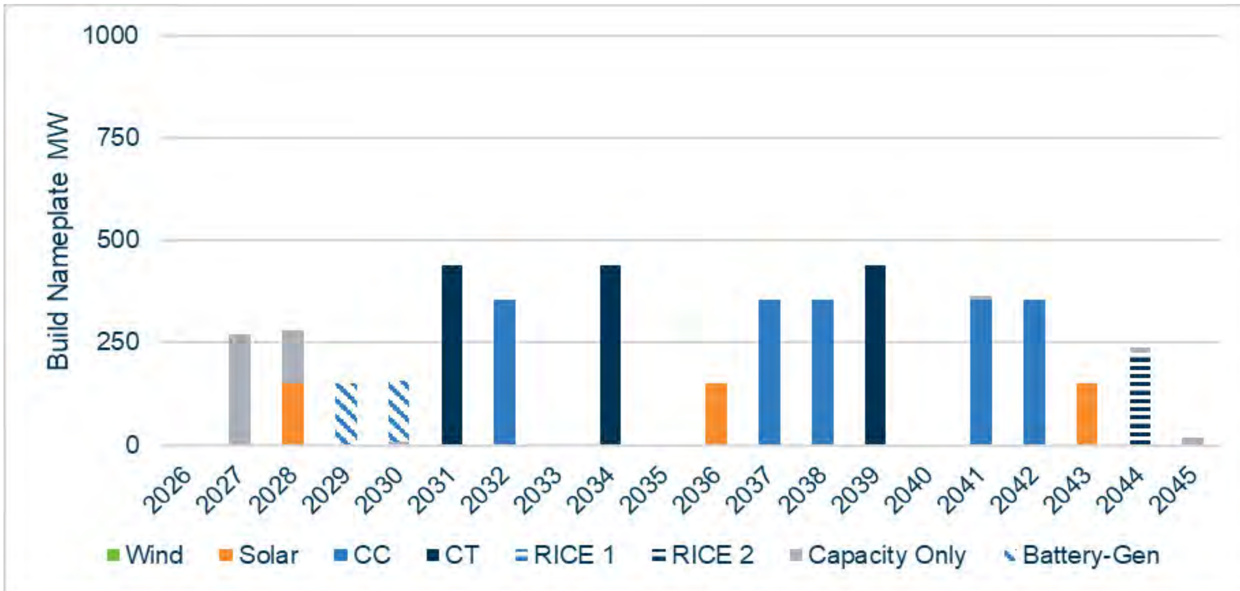
Figure 47: Additional 1,500 MW Load Plan ECAA



11.2 High Electrification and Low Load Growth Scenarios

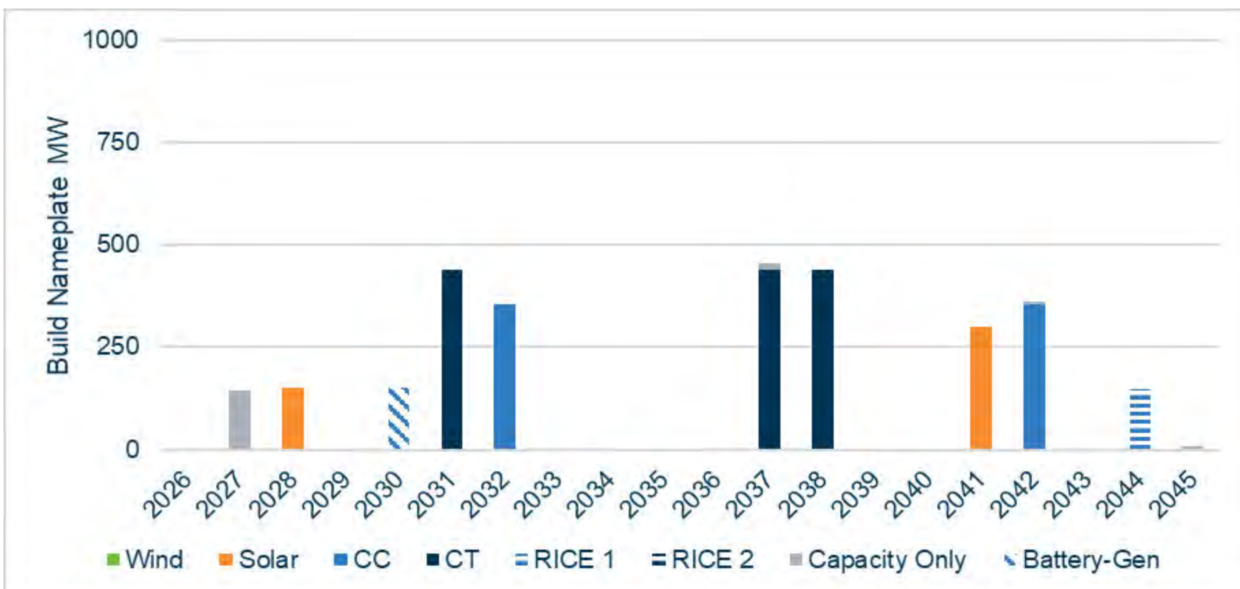
Evergy Missouri Metro's high load growth and economy-wide electrification forecast incorporates a higher load than the base planning forecast but has a slower load ramp than the large load customer scenarios. Plan FCAA shows that to meet this growth, additional storage generation will be needed in 2029 as well as additional solar and thermal generation beginning in 2036.

Figure 48: High Electrification Plan FCAA



The low load growth scenario, Plan GCAA, also resembles the early years of the Preferred Plan but delays generation after 2032. Additional resources are not needed until 2037.

Figure 49: Low Load Growth Plan GCAA



Section 12: Preferred Plan Selection and Resource Acquisition Strategy Update

12.1 2026 Annual Update Preferred Plan

The ARPs developed and analyzed under the requirements of 20 CSR 4240-22.060 were designed to meet the objectives of 20 CSR 4240-22.010(2). A balanced mix of demand- and supply-side resources has been a key component of the Company's resource planning efforts for over a decade and remains a key part of its preferred plan going forward.

Evergy Metro has selected Plan ACAA as the Preferred Plan for the 2026 Annual Update. Plan ACAA was chosen based on a comprehensive evaluation of ARPs across multiple CUF endpoints, near-term build option sensitivities, retirement scenario testing, and contingency load analyses. The Preferred Plan represents the resource portfolio that Evergy Metro believes best satisfies the planning objectives of providing safe, reliable, and efficient energy services at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies. Table 34 details the supply-side and demand-side requirements for the 20-year planning period.

Table 34: Evergy Metro Preferred Plan ACAA

Year	Wind (MW)	Solar (MW)	Battery (MW)	Thermal (MW)	Capacity (Summer MW)	DSM (Summer MW)	Retirements (MW)
2026	0	0	0	0	0	143	0
2027	0	0	0	0	201	169	0
2028	0	150	0	0	32	192	0
2029	0	0	0	0	0	151	0
2030	0	0	150	0	0	150	0
2031	0	0	0	440	0	150	0
2032	0	0	0	355	0	148	0
2033	0	0	0	0	0	146	0
2034	0	0	0	0	0	146	0
2035	0	0	0	440	0	145	0
2036	0	0	0	0	0	144	0
2037	0	0	0	0	0	141	0
2038	0	0	0	440	0	137	375
2039	0	0	0	0	0	134	0
2040	0	0	0	355	16	134	0
2041	0	0	0	0	0	133	0
2042	0	0	0	355	0	132	0
2043	0	0	0	0	0	130	0
2044	0	0	0	148	0	129	0
2045	0	0	0	0	0	130	0

Figure 50: Preferred Plan ACAA Summer Capacity Composition (MW)

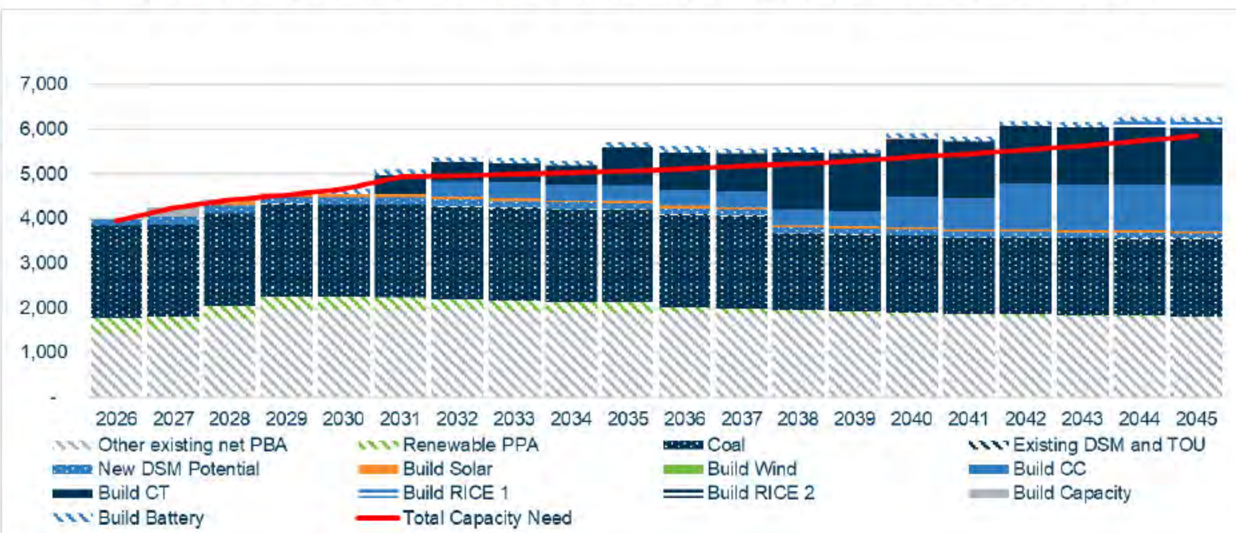
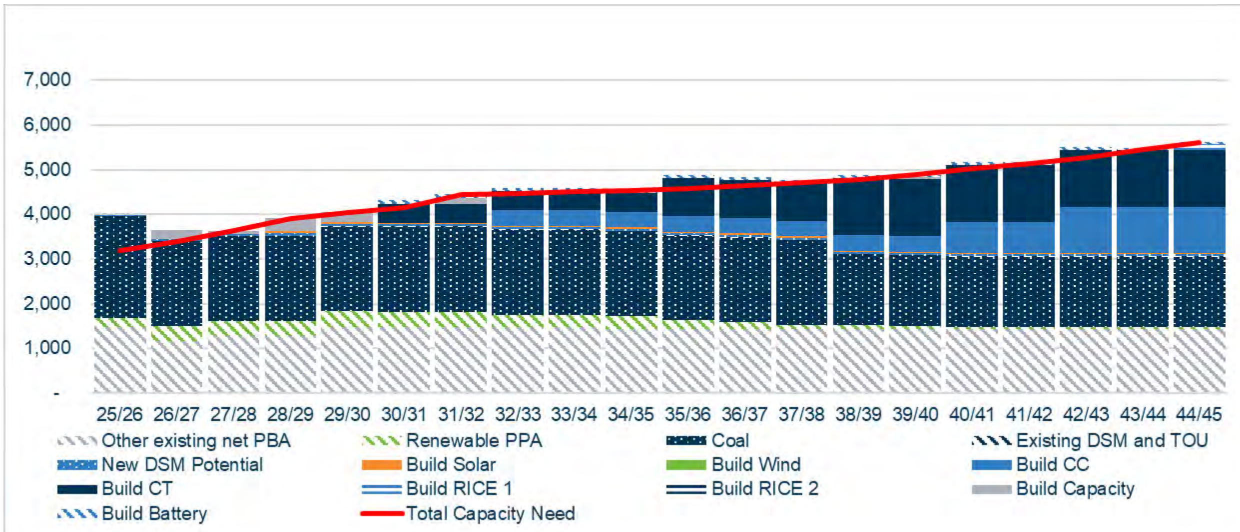


Figure 51: Preferred Plan ACAA Winter Capacity Composition (MW)



12.2 Preferred Plan Selection

Evergy Metro selected Plan ACAA as the 2026 Preferred Plan based on a risk-adjusted evaluation that considers both the quantitative NPVRR analysis and the practical realities of project execution, permitting, and portfolio resilience. While Plans ACEA and ACCA produce a marginally lower probability-weighted NPVRR — a difference of $15 million, or less than 0.05% of the 20-year revenue requirement — those plans carry materially higher execution and deliverability risk that is not captured in the capacity expansion model.

Plans ACEA and ACCA require both the 440 MW Mullin Creek #2 SCGT and a 355 MW half CCGT to reach commercial operation in the same year (2031). These plans would require another partner to take equity ownership of the second half of a CCGT in 2031. They would also concentrate capital deployment and construction within overlapping timelines during a period of constrained Engineering, Procurement, and Construction ("EPC") availability and gas turbine lead times of five to seven years. While possible, plan ACAA sequences these projects across 2031 and 2032, reducing construction concentration risk.

The lower-cost plans also substitute a second 150 MW solar resource for the battery storage resource selected in Plan ACAA. Solar development in Missouri faces growing permitting challenges, including local zoning restrictions, organized community opposition, and proposed state legislation that could further constrain siting. Evergy has identified a viable solar project for the 2028 addition but has fewer executable options for a second project in the 2029–2030 window. A 2030 solar resource would have the risk of not qualifying for the production or investment tax credit under the OBBBA's accelerated phase-out, increasing its net cost above what was modeled. Battery storage, by contrast, qualifies for the ITC, faces fewer siting obstacles, provides superior winter capacity accreditation under SPP's ELCC framework during Evergy Metro's most acute winter capacity deficit years, and offers dispatchable operational flexibility that solar cannot provide. The plan maintains compliance with Missouri RES requirements through the early 2030s with existing and planned renewable resources, with strategies to address the compliance gap that emerges later in the planning horizon as discussed in Section 10.8.

Plan ACAA delivers a more diverse near-term resource portfolio — solar, battery storage, SCGT, and CCGT— that hedges against technology-specific risks and is consistent with Missouri Senate Bill 4's emphasis on firm, dispatchable generation. The $15 million cost premium is a prudent investment in plan executability and resilience that protects customers from the consequences of project delays, permitting failures, or stranded tax credit eligibility in a rapidly changing development environment.

12.3 Preferred Plan Composition

The 2026 Preferred Plan charts Evergy Metro's path to solve for growing capacity requirements over the 20-year planning horizon, sequenced in three phases that balance near-term urgency with long-term flexibility.

12.3.1 Near-term (2026–2032)

The plan addresses the most pressing capacity deficits with four resource additions that were consistently selected across most ARPs tested. A 150 MW solar project in 2028, qualifying for the PTC, adds renewable energy and contributes to Missouri RES compliance. A 150 MW battery storage project in 2030, qualifying for the ITC, provides dispatchable winter and summer capacity during the years of greatest near-term deficit. The Mullin Creek #2 SCGT (440 MW) in 2031 delivers the firm dispatchable capacity that load growth and tightening SPP reserve margin requirements demand. A half CCGT (355 MW) in 2032, likely jointly owned with EMW, adds efficient baseload energy and capacity as the system transitions from net energy seller to a position requiring new generation to match growing customer consumption. Between 2026 and 2030, before these owned resources come online, Evergy Metro bridges its capacity position through market capacity purchases and continuation of demand response programs.

12.3.2 Mid-term (2033–2038)

The plan adds two additional SCGTs in 2035 and 2038 (440 MW each) to offset the La Cygne 1 retirement in March 2038 and sustain reliability as load continues to grow. This is the only coal retirement scheduled in the Preferred Plan; Iatan 1 and La Cygne 2 are extended beyond the planning horizon, avoiding the cost and reliability risk of replacement during a period of elevated construction costs. No new renewable resources are selected in this phase, reflecting the loss of PTC eligibility and the current carbon policy outlook. Evergy Metro continues to value resource diversity and will continue to evaluate renewable economics in future IRP cycles and will pursue additions to the extent they are competitive and buildable.

12.3.3 Long-term (2039–2045)

Two half CCGTs in 2040 and 2042 (355 MW each) and a 148 MW RICE in 2044 round out the portfolio to meet continued load growth and replace expiring wind PPA contracts. Resource selections this far into the planning horizon carry inherent uncertainty and will be refined in future IRP cycles as technology costs, customer commitments, carbon policy, and regional RARs evolve.

Across all three phases it is expected that sourcing resources to cover needs will be achieved through a combination of projects identified through the 2025 all source RFP that was issued in May 2025, potential future all source RFPs, and Evergy self-developed projects.

12.4 Resource Acquisition Strategy — Near-Term Preferred Plan Resources

The following acquisition strategies outline Evergy Missouri Metro's approach to executing the three near-term supply-side resources identified in the 2026 Preferred Plan. Each strategy reflects the Company's assessment of project viability, market conditions, regulatory requirements, and the urgency of meeting capacity and energy needs driven by committed large-customer load growth and increasing SPP resource adequacy obligations. Evergy Metro's overarching procurement philosophy is to evaluate all viable options — including self-development, third-party RFP offers, and PPAs — and to select the pathway that provides the lowest cost and maximum flexibility to customers while managing execution risk and maintaining schedule certainty.

12.4.1 150 MW Solar — 2028 Commercial Operation

Evergy Missouri Metro plans to acquire a 150 MW single-axis tracking photovoltaic solar resource with a targeted commercial operation date in the first half of 2028. This resource serves dual purposes in the Preferred Plan: it adds accredited capacity to address near-term summer reserve margin needs and produces on peak energy with the associated RECs to satisfy Missouri RES requirements, including the 0.3% solar carve-out, throughout the planning horizon.

2028 Solar Tax Credit Strategy

The 2028 solar resource is expected to qualify for the full Section 45Y PTC for the first ten years of operation. Eligibility requires that construction of the facility begin on or before July 4, 2026, and that the project satisfy the Physical Work Test established in IRS Notice 2025-42. The PTC benefit is a material component of the resource's economic value to customers; loss of eligibility would increase the project's levelized cost by approximately 30–35% and could alter its ranking relative to alternative near-term options.

2028 Solar Sourcing Approach

Evergy is evaluating both self-development options and offers received through the 2025 all-source RFP issued in May 2025. The RFP solicited proposals for solar, wind, storage, and thermal resources across the Evergy service territory. Several solar proposals were received for delivery in the 2028 timeframe. Evergy is conducting detailed evaluation of these proposals against its self-development alternatives, considering total delivered cost (inclusive of tax credits), counterparty creditworthiness, interconnection status, permitting maturity, and schedule certainty. The Company expects to make a final sourcing decision in the third quarter of 2026.

2028 Solar Permitting and Siting

Solar permitting in Missouri has become increasingly challenging due to local zoning restrictions and organized community opposition in several counties. Evergy has identified a project site with favorable permitting conditions, including existing or anticipated county approvals and compatible land use designations. The Company is actively managing stakeholder engagement at the local level to maintain project viability. In the event that the primary site encounters permitting delays, Evergy has identified alternative sites that could support a 2028 commercial operation date, though with potentially higher interconnection or development costs. Evergy will not commit material development capital to a solar project until permitting certainty is sufficient to support the construction timeline.

2028 Solar Interconnection

The solar resource requires completion of SPP's generator interconnection process, including the facilities study and execution of an interconnection agreement. Evergy's development team is monitoring the interconnection timeline of potential projects to align with the 2028 commercial operation target. Transmission and distribution equipment lead times, particularly for substation transformers, represent a potential schedule risk and are being actively managed through early procurement activity.

2028 Solar Regulatory Approvals

Evergy anticipates that a solar resource to meet the nominally 150 MW solar resource need may be included in a CCN filing later in 2026. The Company will determine the appropriate regulatory pathway based on the final sourcing decision and project timeline.

12.4.2 150 MW Battery Storage — 2030 Commercial Operation

Evergy Missouri Metro plans to acquire a nominally 150 MW, 4-hour lithium-ion battery energy storage system with a targeted commercial operation date in 2030. Battery storage was selected over a second solar resource in the Preferred Plan based on its superior winter capacity accreditation under SPP's ELCC framework, its dispatchable operating profile, reduced siting risk relative to solar, and its eligibility for the ITC.

2030 Battery Storage Tax Credit Strategy

The 2030 battery storage resource is expected to qualify for a 40% Section 48E ITC, consisting of the 30% base credit plus a 10% bonus for location in an energy community, consistent with IRA provisions. Unlike the PTC for wind and solar, the ITC for storage was not subject to the OBBBA's accelerated phase-out and remains available for projects beginning construction before 2034. The ITC benefit is received in the first year of operation and reduces the project's effective capital cost by approximately 40%, making storage economically competitive with alternative capacity resources on a net-cost basis. Evergy's tax team is monitoring the evolving FEOC guidance to ensure that the storage procurement strategy supports ITC qualification under the Material Assistance Cost Ratio thresholds established in Treasury Notice 2026-15. In addition to the energy community bonus, an additional 10% bonus could be realized by meeting domestic content qualifications as outlined by the IRS. Evergy will evaluate the availability of this credit, along with the others mentioned, when evaluating battery storage projects.

2030 Battery Storage Sourcing Approach

Evergy is evaluating multiple sourcing pathways for the 2030 storage resource:

- ***RFP offers.*** The 2025 all-source RFP generated several battery storage proposals with delivery dates in the 2029–2030 window. These include standalone storage projects and co-located solar-plus storage configurations. Evergy is evaluating these offers based on total delivered cost (net of ITC), FEOC compliance, supplier creditworthiness, and interconnection readiness.
- ***Self-development — existing site expansion.*** Evergy is evaluating the addition of battery storage capacity at existing generation or substation sites where

interconnection infrastructure is already in place. Co-location with existing facilities can reduce development timelines by 2-3 years relative to greenfield development by avoiding the need for new substation and transmission equipment.

- ***Self-development — standalone.*** Evergy is also evaluating standalone storage sites identified through its development pipeline. Standalone configurations provide siting flexibility but require full interconnection and may face longer equipment lead times for substation and transmission components.

Evergy expects to make a final sourcing decision within the next year, allowing sufficient time for equipment procurement, FEOC compliance verification, and construction to meet the 2030 commercial operation target.

2030 Battery Storage FEOC Compliance

The global lithium-ion battery supply chain is heavily concentrated in China, and the OBBBA's Prohibited Foreign Entity restrictions create sourcing constraints that did not exist under prior IRP assumptions. The Company is working with potential suppliers to identify compliant sourcing configurations that maintain the aggregate prohibited foreign entity (“PFE”) content below the 45% Material Assistance Cost Ratio threshold applicable to 2030 projects. Evergy expects that FEOC-compliant storage options will be available, though potentially at a cost premium of 10–15+% relative to unconstrained sourcing. This premium is reflected in the Company's storage cost assumptions for the 2026 IRP.

2030 Battery Storage Permitting and Siting

Battery storage projects face significantly fewer siting challenges than solar development. Storage facilities have a compact physical footprint (typically 5–10 acres for 150 MW); do not raise the agricultural land use concerns that drive solar opposition and are generally compatible with industrial or utility-adjacent zoning. Evergy does not anticipate material permitting risk for the 2030 storage resource.

12.4.3 440 MW Simple Cycle Gas Turbine — 2031 Commercial Operation

Evergy Missouri Metro plans to self-develop the Mullin Creek #2 SCGT, a J-Class unit with approximately 440 MW of summer capacity, as a sister unit to Mullin Creek #1 in Nodaway County, Missouri. The targeted commercial operation date is late 2030 to support capacity needs for summer 2031. Mullin Creek #2 is the single most critical near-term resource in the Preferred Plan. Its removal from the resource portfolio (Plan ACDA) increases the 20-year NPVRR by $245 million — the largest cost impact of any near-term build sensitivity tested. A schedule of the major milestones for the Mullin Creek #2 plant is detailed in Table 35.

Table 35: Mullin Creek #2 Implementation Milestones

Milestone Description	Expected Completion
Site Control Complete	October 2024
SPP Large Generator Interconnection Application	October 2024
Environmental and Land Permitting Complete	Q4 2026
Design Spec & EPC Award	First Half 2026
State Utility Regulatory Approvals	Q4 2026
Detailed Design and Engineering	Second Half 2026
Construction Begins	2027
Major Equipment Delivery	2028
Construction Complete	2030
Testing and Commissioning Complete	2030
Commercial Operation	Dec 31, 2030

2031 SCGT Project Configuration

Mullin Creek #2 is configured as a twin to the Mullin Creek #1 facility approved for Evergy Missouri West in CCN Case No. EA-2025-0075 (July 31, 2025). The twin configuration provides significant cost and schedule advantages by leveraging shared site infrastructure including gas pipeline interconnection, electrical switchyard, access roads, water supply, and common facilities. Evergy has engaged the same EPC contractor for both units, enabling procurement efficiencies for turbine equipment, civil works, and balance-of-plant systems. The shared-site approach reduces the per-unit installed cost by an estimated 8–12% relative to a standalone greenfield project.

2031 SCGT Equipment Procurement

Evergy has issued a limited notice to proceed to the EPC contractor for long-lead equipment. Additionally, Evergy has secured manufacturing slots for the Power Island Equipment including the gas turbine generator package, which currently carries a manufacturing lead time of 5-7 years. This early procurement commitment is necessary to secure a delivery slot and maintain the 2031 commercial operation schedule. The limited notice to proceed is structured to minimize the Company's financial exposure if the project does move forward, while preserving schedule optionality that would be lost if procurement were deferred until after the regulatory process concludes.

2031 SCGT Natural Gas Supply

Evergy plans to secure natural gas transportation capacity to the Mullin Creek site through a long-term contract with a lateral provider. The Company expects to utilize dual-fuel capability (natural gas and fuel oil) to provide additional fuel supply redundancy during extreme cold weather events, consistent with SPP's increasing focus on fuel assurance following Winter Storm Uri.

2031 SCGT SPP Interconnection

Mullin Creek #2 has been submitted to SPP's ERAS process, approved by FERC in July 2025, which provides an accelerated interconnection pathway for resources needed to meet near-term capacity obligations. The ERAS process was specifically designed to address the reliability challenge created by rapidly increasing load forecasts and long interconnection queue lead times. Evergy expects ERAS study results and an interconnection agreement to be completed on a timeline consistent with the 2031 commercial operation target.

2031 SCGT Regulatory Strategy

Evergy Missouri Metro plans to file an application for a CCN with the Missouri Public Service Commission in May 2026, pursuant to § 393.170 RSMo. Evergy Missouri Metro is committed to executing on each of these resources in the timeframes identified in the Preferred Plan. The Company has taken early procurement and development actions to maintain project schedules and will pursue regulatory approvals on timelines that support the capacity needs identified in this IRP. Evergy will report on acquisition progress in its annual RES Compliance Plans, future IRP filings, and quarterly investor communications.

Section 13: Joint Agreements and MO CCN Stipulations

From the 2024 Triennial Joint Agreement (EO-2024-0153) and CCN Stipulation and Agreement (EA-2025-0075), the following agreements are addressed as follows:

13.1 Ranges of Critical Factors

Evergy Metro conducted sensitivity analysis to determine how variations in CUF probabilities would change the expected economics of the resource plans. Evergy Metro used seven probability variations to understand how the ranges are most impactful. Variation 1 uses a 75% weighting for the Low forecast and 25% weighting for the Mid forecast, with 0% weighting for the High forecast. Variations 2 and 3 decrease the Low weighting while increasing the Mid weighting, still giving no weight to the High. Variation 4 gives equal weight (1/3) to all three forecasts. Variations 5-7 give no weight to the Low Forecast and vary the weights of the Mid and High forecasts.

Table 36: Variations in Probability of CUF Forecast

	1	2	3	4	5	6	7
Low	75%	50%	25%	33%	0%	0%	0%
Mid	25%	50%	75%	33%	75%	50%	25%
High	0%	0%	0%	33%	25%	50%	75%

Three representative plans were compared with the Preferred Plan ACAA. Plan ACCA has a very similar weighted-average NPVRR. In the near-term, the plan chooses 150 MW solar in 2030 over the 150 MW of storage in Plan ACAA and it moves up the ½ CCGT from 2032 to 2031. There are also some minor future differences.

Table 37: NPVRR Difference Plan ACCA – Plan ACAA

	1	2	3	4	5	6	7
NG	(5)	(7)	(9)	(29)	(26)	(42)	(57)
CO_2	17	8	(1)	(19)	(26)	(41)	(56)
ConCost	(50)	(37)	(24)	(9)	4	18	32

Plan ACCA has a lower weighted-NPVRR than Plan ACAA. As the probability of higher natural gas prices increases, Plan ACCA becomes increasingly more favorable with lower

NPVRRs than Plan ACAA. However, with higher probability of Low (no) CO_2 tax, Plan ACAA becomes the more economic plan. As the higher CO_2 tax probability increases, Plan ACCA becomes more favorable. With probabilities skewing toward Low Construction Cost, Plan ACCA is the lower cost plan, but as the probability of High Construction Cost increases, Plan ACAA becomes more favorable.

Plan ACDA does not allow the Mullin Creek #2 resource in 2031 and instead builds an additional 150 MW storage in 2029 and a ½ CCGT in 2031 in the near term. There are other future resource plan differences from Plan ACAA.

Table 38: NPVRR Difference Plan ACDA – Plan ACAA

	1	2	3	4	5	6	7
NG	230	233	235	220	227	216	206
CO_2	269	258	248	225	218	199	179
ConCost	205	216	227	239	249	261	272

Plan ACDA has a higher NPVRR than Plan ACAA on a weighted average basis and in all futures. However, Plan ACDA becomes slightly more favorable as NG Price forecasts skew higher. It also becomes more favorable as the High CO_2 tax or Low Construction Cost probabilities increase.

Plan ACAI was optimized for the High NG Forecast scenario. In the near term, it substitutes 150 MW of 2030 solar for the same amount of storage in Plan ACAA. It also moves up the ½ CCGT to 2031 from 2032. It has 900 MW additional solar in the later years of the plan and some additional future plan differences.

Table 39: NPVRR Difference Plan ACAI – Plan ACAA

	1	2	3	4	5	6	7
NG	131	124	117	39	49	(11)	(72)
CO_2	202	171	140	67	47	(15)	(77)
ConCost	(4)	34	72	114	151	192	233

Plan ACAI is much more expensive than Plan ACAA with higher probabilities of Low NG prices and no CO_2 taxes. It becomes the cheaper plan when the high and mid forecasts are each at 50% probability, and gains value as the high forecast probability increases for NG price or CO_2 tax. Plan ACAI has a slight NPVRR discount with a high probability of Low Construction Costs but becomes significantly more expensive as the probability of High Construction Costs increases.

13.2 Battery Storage and Surplus Interconnection

Evergy Metro considered battery storage as a resource candidate in the 2026 IRP. Consistent with the 2025 IRP, 150 MW Storage was selected in 2030 in the Preferred Plan. In its most recent RFP, Evergy received offers for stand-alone and co-located storage. Evergy has also explored options for locating storage at existing resource sites that have surplus interconnection available. Evergy Metro has not finalized project selection to fill the 2030 Preferred Plan need and will consider all options to choose the most viable project.

13.3 AQCS, Environmental Mitigation, and Unit Upgrade Costs

It is assumed for this IRP that no significant air quality control equipment is required to be added. Remediation costs, including those associated with coal combustion residual ("CCR") disposal, are fully dependent on prior operations and do not vary based on electric generating unit retirement decisions. Any remediation required will be dependent on environmental monitoring results taken for that asset and the applicable regulations at time of closure.

13.4 Retirement Cost-Benefit Analysis

As outlined in Section 10.4 Plans Testing Retirements, Evergy Metro tested coal resource retirement decisions using capacity expansion and base planning assumptions, including the updated load, MEEIA and KEEIA demand-side programs, and resource adequacy forecasts.

The baseline Plan AAAA uses retirement dates identified in the 2025 Annual Update Preferred Plan. Plans ABAA and ACAA use the same base assumptions but vary the retirement dates. Plan ABAA moves the La Cygne 1 retirement from March 2033 to March 2038. Plan ACAA also moves the Iatan 1 and La Cygne 2 retirements from March 2040 to beyond 2045 (the last year in the IRP 20-year window). These retirements dates are summarized in the following Table.

Table 40: Coal Resource Retirement Dates

Generation Unit	Plan AAAA	Plan ABAA	Plan ACAA
Iatan 1	March 2040	March 2040	Beyond 2045
Iatan 2	Beyond 2045	Beyond 2045	Beyond 2045
La Cygne 1	March 2033	March 2038	March 2038
La Cygne 2	March 2040	March 2040	Beyond 2045

The 2025 Preferred Plan is the highest cost based on the weighted-average NPVRR of $33.463 billion across all planning endpoints. Extending the La Cygne 1 retirement in Plan ABAA reduces cost by $156 million to $33.307 billion. The incremental extension of Iatan 1 and La Cygne 2 in Plan ACAA reduces cost by an additional $468 million to $32.839 billion for a total benefit of $624 million versus the Plan AAAA.

The cost reductions demonstrate the economic benefit of extending coal resources, which can adjust the nature and timing of new resource additions or eliminate the need altogether. Referring to the build plan figures in Section 10.4, Plans ABAA and ACAA produce the following changes compared to Plan AAAA:

- **Plan ABAA vs. Plan AAAA:** Extending the retirement of La Cygne 1 delays 440 MW CT by five years from 2033 to 2038. Additionally, the plan advances by one year 355 MW CC from 2036 to 2035 and 150 MW solar from 2038 to 2037.
- **Plan ACAA vs. Plan AAAA:** Extending retirements for all coal resources eliminates three new resources totaling 945 MW (150 MW Solar in 2038, 440 MW CT in 2040, and 355 MW CC in 2043) and adds 148 MW RICE in 2044. The plan delays investment in a total of 1,150 MW (440 MW CT from 2033 to 2035, 355 MW

CC from 2036 to 2040, and 355 MW CC from 2041 to 2042) and advances 440 MW CT from 2039 to 2038.

While the total NPVRR presents the relative value of the plans, a more detailed review of the NPVRR components can provide a better understanding of what drives the capacity expansion decisions. The weighted-average NPVRR is composed of 27 distinct endpoints representing various assumptions for electricity prices, natural gas prices, carbon dioxide regulation, and construction costs. Since capacity expansion modeling is conducted using the mid-point for these assumptions, a review of the results for the M2C endpoint can illustrate the relative costs and benefits of the plans. The following results show that the M2C endpoint yields similar values to the overall weighted-average NPVRR.

Table 41: Coal Retirement Plan Midpoint vs. Weighted-Average NPVRR

NPV ($ million)	Plan AAAA	Plan ABAA	Plan ACAA	ABAA vs AAAA	ACAA vs AAAA
Wtd-Avg	33,463	33,307	32,839	(156)	(624)
M2C	33,414	33,279	32,847	(135)	(567)
M2C vs W-A	(49)	(28)	8	-	-
% Diff	-0.1%	-0.1%	0.0%	-	-

Focusing on the M2C results, Plan ABAA is $135 million less than Plan AAAA and Plan ACAA is $567 million less than Plan AAAA. For simplification, the following detailed review presents a comparison of Plan ACAA to Plan AAAA. Since all of the retirement extensions produce a reduction in costs, the findings are similar for the comparison of Plan ABAA to Plan AAAA.

At the plan level, the $567 million cost reduction is driven by lower fixed costs, generation cost, and generator retirement cost partly offset by higher emissions cost.

Table 42: Coal Retirement Plan NPVRR Detailed Summary

NPVRR ($ million)	M2C ACAA	M2C AAAA	ACAA vs AAAA
Cost to Load	$8,959	$8,955	$4
Total Fixed Costs	$5,502	$5,856	($354)
Generation Cost	$5,953	$6,222	($269)
Emissions Cost	$1,804	$1,581	$222
Generator Pool Revenue	$7,972	$7,941	$30
Penalty Cost	$0	$0	$0
Generator Retirement Cost	$134	$274	($140)
Model RR (All Costs - Pool Revenue)	$14,380	$14,947	($567)
Rest of Company RR	$18,467	$18,467	$0
NPVRR	$32,847	$33,414	($567)

The $354 million in lower fixed cost is the net of $880 million in reductions due to the elimination and timing differences for new builds and $526 million in increases due to the extension of the coal generators ($482 million) and the RICE addition ($44 million).

The $269 million in lower generation cost consists of a decrease of $680 million for gas resources and an increase of $411 million for coal ($383 million) and RICE ($28 million).

The $140 million reduction in generator retirement costs is attributed to the extension of operations for the coal resources.

The $222 million increase in emissions cost consists of an increase of $354 million for coal generators ($348 million) and the RICE addition ($6 million) and a decrease of $132 million for gas resources.

In summary, the cost of extending coal resources produces a benefit for customers based on lower fixed costs and fuel costs relative to potential replacement resources. This benefit is offset somewhat by an increase in emissions cost.

13.5 Virtual Power Plants ("VPPs")

Evergy engaged with Cadmus to evaluate the VPP as a grid storage resource. This analysis evaluates the costs and operational performance of a proposed 5 MW/20 MWh residential behind the meter ("BTM") battery fleet, consisting of customer-owned 3.6 kW/14.4 kWh battery systems. The program analysis reflects realistic dispatchable capacity, program administration requirements, and an annual incentive for participants.

13.5.1 Realistic Dispatchable Capacity

A key modeling element is the differentiation between a battery's available capacity and its achievable capacity for demand-response dispatch. While the LG ESS H8 inverter is capable of short duration output near 6 kW, a 14.4 kWh battery can sustain no more than 3.6 kW over a four-hour event. To account for customer-owned systems and realistic operating constraints, the model applies a 70% availability factor based on state of charge limits (85% maximum, 15% minimum). This adjustment results in an estimated 2.52 kW of achievable dispatch capacity (or 3.5 MW for the total program battery fleet), which is used to calculate incentive payments. Annual battery degradation is estimated at 2%, and incentive payments are reduced to reflect this decline in capacity.

13.5.2 Program Costs

Program costs are categorized into one-time marketing and recruitment costs and ongoing fixed O&M costs. Annual fixed costs include program administration—based on Evergy's demand response management system ("DRMS") and overhead assumptions—and performance-based participation incentives.

13.5.3 Performance-Based Participation Incentives

Customer enrollment varies with incentive structure, so this analysis considered 3 potential incentive scenarios:

- **Low Incentive Scenario**: Based on avoided capacity costs (adjusted for losses), representing the most cost-effective approach.
- **High Incentive Scenario**: Reflects the highest performance incentive identified in benchmarking, providing a comparison with leading residential bring your own battery programs.
- **Mid Incentive Scenario**: Calculated as the midpoint between the low and high scenarios.

13.5.4 Cost Modeling

Since the customer participation rate at any given incentive level can't be known without a potential study, Evergy conducted detailed modeling using avoided capacity costs (low incentive) assuming participation at the full 5MW / 20 MWh level. Avoided capacity was valued at the price of market capacity purchases in the IRP model. Program administration costs were included to arrive at total expenses. The net revenues from battery operations were subtracted from the program expenses to produce a net cost estimate.

13.5.5 Total Program Cost

Using the low incentive assumptions, the VPP program was modeled as an addition to the preferred plan. The NPVRR comparison of the plans shows that the VPP adds $10 million in cost. The following Table presents these results.

Table 43: VPP Program Cost Summary

Rank	Plan	NPVRR	Difference	Description
1	ACAA	32,839		Base
2	ACAM	32,849	10	VPP Plan

Section 14: Special Contemporary Issues

From the Commission Order, EO-2026-0035, the following Special Contemporary Resource Planning Issues are addressed as follows:

14.1 Nuclear Permitting, Construction, Credits, and Policies

The process is generally divided into three main phases: Planning and Licensing, Construction, and Commissioning & Operation. The typical timeline for the permitting and construction of a new commercial nuclear power plant in the US at a greenfield site is 10 to 12 years total, with 4-6 years for the licensing/permitting phase and over 6 years for construction and commissioning. This can be longer or shorter depending on project management, regulatory stability, and whether a certified reactor design is used. In addition, recent executive orders and congressional acts seek to improve these timelines.

14.1.1 Phase 1: Planning and Licensing (Approximately 4-6 Years)

This phase is dominated by extensive studies, design finalization, and approvals from the Nuclear Regulatory Commission ("NRC"). Pre-application licensing correspondence and supporting design analysis and calculations should be completed at early stages prior to studies and permit application requests.

Project Initiation and Feasibility Studies

Initial engineering, design, and site analysis (geological, hydrological, meteorological, environmental).

- Duration: 1-2 years

Early Site Permit ("ESP") Application and Review

The applicant may apply for an ESP to address site suitability independent of a specific reactor design. This can include a Limited Work Authorization ("LWA") for non-safety related site preparation.

- Application Development and NRC Review: 2-4 years (NRC review has typically been 24 months).

Design Certification

The NRC certifies a standard reactor design through a separate rulemaking process, which is then valid for 40 years and can be referenced by multiple applicants to streamline their process.

- Duration: ~18 months for the NRC review of the application.

Combined Operating License (“COL”) Application and Review

If an ESP and certified design are used, the process is more streamlined. A COL application need not be preceded by an ESP and a certified design. The NRC review will be longer as site suitability and reactor design will be reviewed as part of the COL review. The NRC conducts safety and environmental reviews, a mandatory public hearing, and a final decision on whether to issue the COL, which authorizes both construction and operation.

- Duration: ~18 months for the NRC review (if a certified design and ESP are used).

14.1.2 Phase 2: Construction (Approximately 6-8 Years)

Once the COL is issued, physical construction of safety-related facilities can begin. Construction of non-nuclear assets such as training facilities, etc. typically are before nuclear construction or in parallel.

Site Preparation and Infrastructure

Clearing, excavation, and grading (some non-safety work may be done earlier with an LWA).

- Duration: ~1 year (overlaps with licensing phase if LWA is used)

Major Construction

Pouring foundation concrete, building primary structures, installing major components (reactor vessel, steam generators, piping, electrical systems).

- Duration: 4-6 years

Inspections and Testing

Throughout construction, the NRC performs inspections, tests, and analyses to verify the plant is built according to the approved design and safety requirements.

14.1.3 Phase 3: Commissioning and Operation (Approximately 1 Year)

This phase involves final testing and transitioning the facility to commercial operation.

Fuel Loading and Pre-operational Testing

Once construction is substantially complete, the NRC conducts final reviews and authorizes the loading of nuclear fuel.

Startup Testing and Commercial Operation

A period of testing to ensure all systems operate correctly, followed by the start of commercial power generation.

- Duration: ~1 year

Past data within the US is provided in the Table below for the existing nuclear fleet build times and recent Vogtle 3 reactor. International data is provided for recent builds of large nuclear reactors as comparison. Some SMRs are partially through Phase 1 but have not completed Phase 2 or 3. For those reactors, estimates are provided based on published schedules.

Table 44: New Nuclear Reactor Timeline Comparison

Technology	Phase 1	Phase 2	Phase 3
Generic Large Nuclear Reactor	4-6 yrs	6-8 yrs	1 yr
Vogtle 3 Reactor (~1000 MWe)	3-4 yrs	9-10 yrs	<1 yr
International Large Nuclear Reactor (>800 MWe)	1-2 yrs	8-9 yrs	<1 yr
Small Modular Reactor (Terrapower 345 MWe)	1-2 yrs	3 yrs	<1 yr

As for existing sites, using Wolf Creek Nuclear Generating Station as an example, here are several considerations:

- Licensing and permitting timelines would be generally shortened as existing analysis and studies can be used versus creating new ones.
- Architectural planning and alternate siting reviews would be roughly the same timeline as a new construction.
- Impacts to the existing station's switchyard and transmission capacity would have to be analyzed to determine needs to additional switchyard buildout and whether another 345kV transmission line would be needed to remove power from new builds and prevent congestion.
- Other impacts requiring analysis and attention would be water rights/needs of a new station including expected impacts to Coffey County cooling lake temperatures.
- Based on existing infrastructure, training staff, and experienced nuclear personnel, it is expected that commissioning timelines would be shortened.

14.1.4 Tax Credit Availability and Achievability

While tax credits for both existing and new nuclear facilities are available under the IRA, new tax credit restrictions and accelerated phaseouts were enacted by the OBBBA in July 2025, which may make achieving milestones for new projects more difficult. The following are influenced by the aforementioned congressional acts:

- **Zero-Emission Nuclear Power Production Credit (Section 45U):** Available for existing nuclear facilities through 2032.
- **Advanced Nuclear Reactor Production Tax Credit (Section 45J):** Applied to facilities in service after August 9, 2005. It provides a tax credit for the first eight years of operation.
- **Clean Electricity Investment/Production Tax Credits ("CEITC/CEPTC"):** Nuclear plants placed in service after 2024 were initially eligible for these technology-neutral credits under the IRA. However, the OBBBA repealed CEITC and CEPTC for nonnuclear facilities built after late 2028, and it introduced a slower phaseout schedule for nuclear facilities starting in 2033. A caveat is that facilities

beginning construction after December 31, 2025, are ineligible for the credit if they receive "Material Assistance" from or are under "effective control" by a PFE, including those from China or Russia.

- **Bonus credits:** New and existing reactors may qualify for bonus tax credits for generating clean hydrogen, and the OBBBA added a new bonus for advanced nuclear facilities in specific metropolitan areas.

14.1.5 Nuclear-Based Energy Attributes

Nuclear-based energy attributes are tracked through regional, electronic Energy Attribute Certificate ("EAC") tracking systems. While many of these systems were initially designed for RECs, many now also register and track attributes from non-renewable sources, including nuclear generation. The U.S. does not have a single national tracking system, but rather a number of regional systems, such as PJM-GATS, NEPOOL-GIS, WREGIS, and ERCOT. These systems create a unique, serial-numbered electronic certificate for every megawatt-hour of electricity generated. The certificates contain information about the generation source (fuel type, location, emissions rate, etc.), ensuring transparency and preventing double-counting of claims.

A specific type of EAC often associated with nuclear generation is the Zero-Emissions Credit ("ZEC"), also called an emission-free energy certificate. These credits verify the carbon-free nature of nuclear power. ZECs provide qualifying reactors with a supplemental payment—in addition to what they receive in the wholesale market—for every megawatt-hour of carbon-free electricity sold. While Illinois was one of the first states to enact a ZECs policy, the legislature decided to expand its support for the state's nuclear fleet with the passage of the Climate and Equitable Jobs Act in 2021. The state now supports five nuclear power plants through ZECs-style policies—up from two that were supported under the 2016 legislation. Through the Infrastructure Investment and Jobs Act ("IIJA"), Congress established a federal program that is substantially similar to these state ZECs programs: the Civil Nuclear Credit Program ("CNCP"). The CNCP is available to nuclear power plants across the nation.

14.1.6 State Policies (Renewable or Clean Energy Standards)

State-level policies on energy standards are the primary drivers for the use of these certificates. The key distinction in policies is between a Renewable Portfolio Standard (“RPS”) and a Clean Energy Standard (“CES”).

RPS

These standards typically require electricity suppliers to source a minimum percentage of their electricity Missouri Public Service Commission Order Response Input 8 from renewable resources (e.g., wind, solar, hydro, geothermal). Nuclear energy is generally not considered a renewable source and is therefore often ineligible under traditional RPS policies.

CES

CES policies employ a broader definition of qualifying resources to include any zero-carbon or carbon-neutral energy source. Many states have adopted a CES specifically to include nuclear power, recognizing its carbon-free attributes. The goal of a CES is often to achieve more ambitious overall emissions reductions by allowing a wider range of technologies to count toward the goal.

States with Policies that Include Nuclear Attributes (often via ZECs or a CES)

Several states have adopted policies to support their existing nuclear fleets or promote new nuclear capacity by recognizing its clean energy attributes. Examples include:

- New York (adopted ZEC program in 2016)
- Illinois (adopted ZEC program in 2016)
- New Jersey (adopted ZEC program in 2018)
- Connecticut (established ZEC program in 2022)

These state policies use the regional tracking systems (like PJM-GATS and NYGATS) to verify compliance, ensuring that utilities and power marketers can demonstrate their use and retirement of the appropriate energy attribute certificates.

14.2 Large Load Customers

Evergy is evaluating a pipeline of large load customer requests to connect within the Evergy service territories. In addition to the customers that were discussed in detail in Section 3 and included in the 2026 IRP base load forecast, there are numerous customer projects that are being considered for electric service at the Metro jurisdictions. Table 45 describes the attributes of four customers in Metro's large load pipeline by detailing the Evergy Metro rate jurisdiction, customer type, status of Evergy's internal transmission interconnection study, status of whether the project has completed SPP's transmission study for load additions, and the customer's requested ramp in the years 2028 to 2033. The ability to meet the customer's desired ramp will be heavily dependent upon transmission infrastructure requirements and timing for delivery of interconnection facilities and transmission network upgrades. Additionally, generation capacity to meet the customer's ramp may not be available on the timeline requested. The combination of potential transmission and generation capacity constraints may require the customer to ramp their projects online later than originally requested. Evergy expects to continue to work with customers in its pipeline to further understand the requirements, feasibility, and fit for Evergy's service territory.

Table 45: Metro Large Load Customer Pipeline

Customer	Jurisdiction	Customer Type	Interconnection Studies Evergy Complete?	 SPP Complete?	2028	2029	2030	2031	2032	2033
Company A	EMM	Data Center	No	No	250	500	750	1,000	1,000	1,000
Company B	EKM	Manufacturing	No	No	40	40	40	40	40	40
Company C	EKM	Data Center	No	No	96	192	288	396	540	576
Company D	EKM	Data Center	No	No	275	575	800	800	800	800
					661	**1,307**	**1,878**	**2,236**	**2,380**	**2,416**

**Load request information based on most recent customer engagement and subject to change.*

14.3 Renewable Energy Standard Requirement

Graphs/metrics are included in the plan workbook workpapers to gauge how much future resource plans meet the RES requirement. However, capacity expansion models were not calibrated to solve for this. With recent policy headwinds favoring dispatchable, base load generation to meet emerging capacity needs, the Evergy Metro 2026 Preferred Plan falls short in 2036 (however builds can be delayed until 2037 since 2036 will be satisfied by the prior 3 years' worth of renewable credits), so minimum RES plans were made in

Section 10.8. Analysis shows that complying with the Missouri RES with either only solar or wind resources significantly makes the plan more expensive than the Preferred Plan. Evergy will also explore utilizing renewable energy credits/PPAs in the future to help meet the requirement.

In terms of varying large load scenarios, the already short RES position becomes even shorter as depicted in the following Table. The general rule of thumb was that on an average hourly generation basis, it would take about half as many wind units when compared to the number of solar units needed to generate a similar amount of renewable energy for RES compliance (the solar/wind units below have some rounding to them).

Table 46: Metro Large Load Plans RES Compliance Comparison

	ACAA	BCAA	CCAA	DCAA	ECAA
RES (Short) by 2045 (Average Hourly MWh)	(246)	(220)	(322)	(307)	(448)
150 MW Solar Units Needed	10	9	13	12*	18
150 MW Wind Units Needed	5	4	6	6	9

**Prior to the solar build in 2041, however, the number of solar units needed by 2040 was 13*

Plan ACAA, as was seen in Section 10.8, needed either 1.5 GW of solar or 750 MW of wind to satisfy the RES requirement all the way through the time horizon. Plan BCAA builds a solar unit in 2044 which helps decrease the number of renewable resources needed by 2045 when compared to Plan ACAA (both plans have a 2028 solar resource). Although Plan CCAA builds a solar unit in 2041, and both CCAA and ACAA plans have a 2028 solar resource, Plan CCAA needs either 13 solar units or 6 wind units by the end of the time horizon to fulfill the RES requirement. This shows a greater need than Plan ACAA due to the higher level of large load in the system. Although Plan DCAA has an even greater amount of large load when compared to Plan CCAA, Plan DCAA shows slightly less need than Plan CCAA since Plan DCAA built 300 MW of solar in 2041 (both plans have a 2028 solar resource and another solar resource in or before 2041). Lastly, Plan ECAA has the greatest renewable resource need since it had the largest large load addition when compared to the other plans, with Plan ACAA being the best comparison since both the ECAA and ACAA plans only have a 2028 solar resource and no other renewable resource built in their resource plans.

NPVRR analysis was not done for plans other than Plan ACAA, as they are contingency plans listed in Section 11 of this IRP. However, the NPVRR comparison shown in Section 10.8 makes it evident that fulfilling the RES requirement for the varying large load scenarios would result in much more expensive plans when compared to the Preferred Plan ACAA.

14.4 Geologic Hydrogen Onsite or Near Natural Gas Storage

As recently as September 2022, Evergy has supported the analysis of the presence of geologic hydrogen within our region and the viability of storing it underground (specifically in salt caverns). Appendix D: H-2-SALT Storing Fossil Energy as Hydrogen in Salt Caverns, coordinated by Dr. Franciszek Hasiuk at the University of Kansas and submitted to the U.S. Department of Energy, highlighted that storing hydrogen both below and above ground were viable opportunities within the Company's service territory. The study's authors go as far as indicating, under certain circumstances, the commercial viability of co-locating hydrogen storage with both an electrolyzer and a natural gas combustion cycle plant that is capable of burning fuel with blended hydrogen. While the result seems promising, it is the Company's position to continue monitoring the exploration of geologic hydrogen formations and how it could be utilized to serve customer needs.