Evergy Missouri West

Stakeholder Engagement

Integrated Resource Plan

20 CSR 4240-22.080

April 2024

Table of Contents

Table of Tables

Table of Figures

Table of Appendices

Volume 8: Stakeholder Engagement

Section 1: Triennial Stakeholder Group Meetings[1]

Evergy held (3) Triennial Integrated Resource Plan Stakeholder Meetings, the goals of these meetings were:

- **Encourage Transparency:** Share the IRP methodology, analysis, and planning process with stakeholders to build understanding and gain insight
- **Expand and Enrich Analysis:** Engage a variety of viewpoints to expand and enrich the scenarios evaluated through the IRP process
- **Discuss and Balance Trade-Offs:** Understand and balance trade-offs between the different IRP tenets (Reliability, value/affordability, safety, flexibility, environmental stewardship)

The first meeting, open to the public, was held on December 8th, 2023, the following topics were covered:

- Evergy Overview
- Goals & Timeline for Stakeholder Meetings
- Changes from the 2023 Update
- Load Analysis & Load Forecasting
- Demand-Side Resources
- Supply-Side Resources
- Integrated Planning & Risk Analysis

The corresponding slides can be found in appendix 8A.

The second meeting, open to interveners in the case, was held on January 29th, 2024, the following topics were covered:

- Review Goals & Timeline for Stakeholder Meetings
- Build Costs

[1] 20 CSR 4240-22.080 (5); 20 CSR 4240-22.080 (5)(A)

- Interconnection Cost Assumptions
- Market Prices
- Model Education
- Initial Capacity Expansion Modeling Scenarios
- Update on Existing Projects
- Discrete Scenario Discussion

The corresponding slides can be found in appendix 8B.

The third meeting, open to interveners in the case, was held on February 29th, 2024, the following topics were covered:

- Analytical Approach Refresh
- Review of Critical Uncertain Factors
- DSM Portfolios Modeled by Utility
- Modeled Alternative Resource Plans by Utility
- Preliminary Modeling Results

The corresponding slides can be found in appendix 8C.

Triennial Draft

A draft of the following volumes was provided to interveners in the case on February 23rd, 2024:

- Volume 3 / CSR 240-22.030: Load Analysis and Load Forecasting
- Volume 4 / CSR 240-22.040: Supply-Side Resource Analysis
- Volume 4.5 / CSR 240-22.045: Transmission and Distribution Analysis
- Volume 5 / CSR 240-22.050: Demand-Side Resource Analysis

Section 2: Special Contemporary Issues[2]

An Order in docket EO-2024-0044 was issued for Evergy Missouri West with an effective date of November 4, 2023, providing a list of special contemporary issues to be analyzed and documented: The following submittal is the list of issues provided in the Order and Evergy West's responses:

A. **Rate Design: Pricing as a Resource Candidate** Model and explicitly present future resource adequacy scenarios based on the following assumptions:
    1. With demand-side rates and traditional demand-side management investments (e.g. MEEIA);
    2. Only demand-side rates without MEEIA investment;
    3. Neither demand-side rates nor MEEIA (but maintain naturally occurring energy efficiency adoption); and
    4. Indicate whether or not naturally occurring savings and/or federally-sponsored DSM savings are included in the modeling. If yes, these savings should be identified and separated as well.
    5. Include an explicit section within the demand-side management volume and the executive summary where low, medium, and high 4 time-of-use (TOU) differentials are modeled and presented with expected demand savings articulated separate and aside from other demand side management practices

Response:

1. Evergy Missouri West modeled six different ARPs with varying levels of traditional demand-side management investments and demand-side rates. Volume 6 has a discussion comparing the ARPs for different Missouri DSM portfolio options (AAAA, BAAA, CAAA, DAAA, EAAA). The RAP plan was the lowest cost, followed closely by RAP Plus and RAP Minus. For this analysis, Evergy Missouri West also modeled an ARP with no demand-side rates (FAAA).

[2] 20 CSR 4240-22.080 (4); 20 CSR 4240-22.080 (4)(A); 20 CSR 4240-22.080 (4)(B); 20 CSR 4240-22.080 (4)(C)

Table 1 Rankings of Demand-Side Program Options

Rank	Plan	NPVRR	Difference	Description
1	AAAA	11,081		RAP
2	CAAA	11,086	5	RAP Plus
3	DAAA	11,090	9	RAP Minus
4	BAAA	11,272	190	MAP
5	EAAA	11,388	307	No Future DSM
6	FAAA	11,411	330	No Future DSM, No TOU

2. Plan EAAA has only demand-side rates, represented as the time-of-use rate forecast for Missouri, with current Missouri demand-side management programs ending in 2024.

Figure 1 No Future DSM Plan EAAA

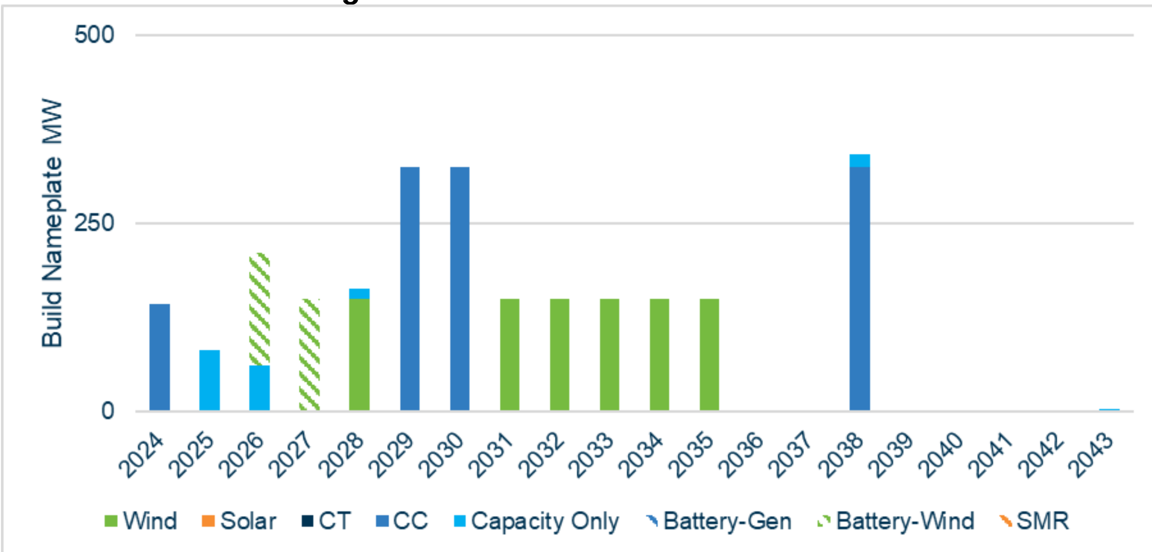
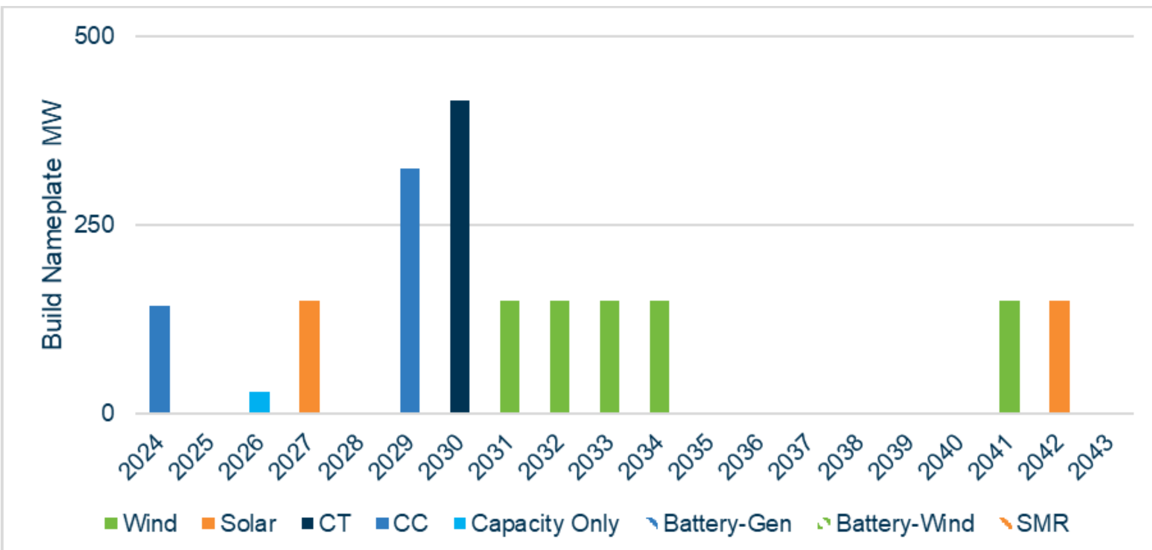


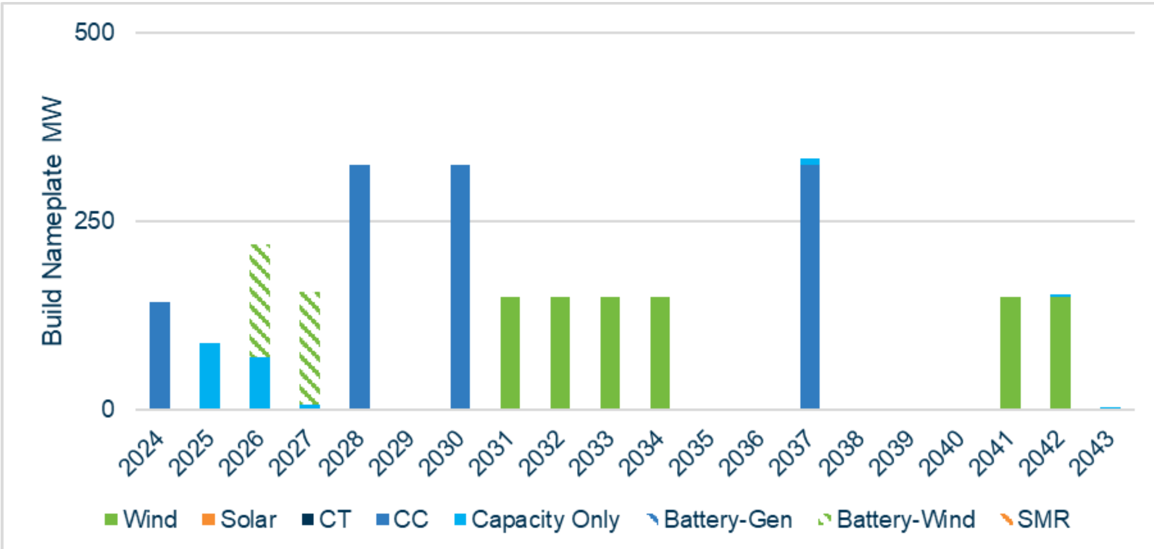
Figure 2 RAP Plus DSM Plan CAAA



The lower level of demand-side management in the EAAA plan results in the need for capacity additions earlier in the resource plan compared with the preferred plan CAAA. In EAAA, 150 MW of battery storage is added in 2026, an additional 150 MW battery storage substitutes for solar in 2027 and 150 MW of wind is added in 2028. The expected values of this resource plan are higher than CAAA by $302 million.

3. All plans include naturally occurring energy efficiency adoption as part of the load forecast. Plan FAAA excludes the time-of-use rate demand reduction forecast and assumes no demand-side management programs after MEEIA.

Figure 3 No TOU, No Future DSM Plan FAAA



The TOU reduction forecast is relatively small compared to the expected demand-side management program reductions. However, the loss of capacity prompts changes in the resource plan. As compared to EAAA, which has the same planning assumptions, but includes the time-of-use reduction, the plan FAAA adds two 1/2 combined cycles earlier, from 2029 to 2028, and also from 2038 to 2037, and moves back some wind additions. The expected value of FAAA is $123 million higher cost than EAAA.

4. Naturally occurring savings and/or federally sponsored DSM savings are included in the load forecasting modeling implicitly. The naturally occurring savings are not separated quantifiably. Savings for the federal standard sponsored saving can be deemed by looking at the indices worksheet provided in the load forecasting workpapers based on the data utilized from EIA.

5. TOU sensitivity analysis details can be found in Volume 5 Demand-Side Management Section 4 Demand-Side Rate development.

B. Solar Adoption

Account for rooftop solar adoption in the load forecast and track its solar subscription program.

Response:

Evergy Load Forecasting uses EIA projections for rooftop solar adoption in the West North Central census division combined with Evergy historical installs to produce a long-term rooftop solar forecast. All solar rooftop and solar subscription information in relation to the forecast and solar projections are included as part of the load forecast workpapers.

C. Battery Storage Operation & Lifecycle Assumptions

Provide detailed assumptions surrounding battery cycle life on any planned future investment in storage. This should include, at a minimum, expected frequency and duration of operational usage of the battery resource. In short, the analysis should be able to reasonably demonstrate that the utility-scale storage investment will be operational for X period based on articulated assumed usage pattern.

Response:

For battery life cycle costs, three main phases of the battery system are typically considered: capital cost (including the Battery Energy Storage System (BESS) and installation), operation & maintenance cost (including energy storage round trip efficiency), and battery degradation and replacement cost.

Evergy used responses from the 2023 All-Source RFP to inform the battery system capital costs used at a site. The capital cost for a 150 MW, 600 MWh facility are estimated at **$1,754/kW** and are assumed to be eligible for an Investment Tax Credit in the model for eligible costs. These costs reflect the significant increase in the cost of batteries as a result of COVID supply chain disruptions. As of early 2024, Evergy has received some vendor indications that capital costs for BESS are coming down but are still elevated from pre-COVID contracted levels; this potential is reflected in the raw Lithium Carbonate costs show in Figure 4 below. In order to achieve accredited capacity in the SPP, a four-hour system must be used. Evergy has assumed a four-hour system for its modeling in the 2024 triennial IRP and assumes a single charge-discharge cycle per day.

Figure 4: Trading Economics Lithium Carbonate Cost[3]

The largest O&M cost of the battery system, outside of routine maintenance, is the roundtrip efficiency of the charge-discharge cycle. Modern lithium-ion BESS has a round trip efficiency of ~90%. This roundtrip efficiency represents the total losses from the BESS which include battery losses from the charge-discharge cycle, inverter losses due to AC/DC conversion and transformer losses in the equipment. Other than the roundtrip efficiency losses, O&M costs are relatively minimal outside of preventative maintenance, break-fix maintenance, and cost of water purification for water-cooled systems.

The third phase of costs are the battery degradation and replacement costs. Lithium-Ion batteries degrade over time due mainly to depth-of-discharge impacts to the battery chemistry itself. A good rule-of-thumb is that batteries will lose 5-10% of their storage capacity per year if they are charged and discharged one full cycle a day at a discharge

[3] https://tradingeconomics.com/commodity/lithium

depth of 90% or more. Thus, lithium batteries are either replaced or augmented throughout their lifetime. Lithium-ion storage sites are designed with augmentation in mind and include container capacity for augmentation as well as rack inface and Battery Management System software control that is intelligent as battery augmentation is utilized. The life-cycle cost of augmentation can be significant in BESS and typically can range in the $50-60/kWh for utility scale, 30-year projects.

For the purposes of IRP modeling of storage projects, Evergy utilized a representative service contract from RFP responses which includes necessary augmentation to maintain battery performance as part of a service contract (included in fixed O&M). This service contract structure is fairly typical for battery storage projects (as opposed to having augmentation costs as separate expenses).[4]

D. Resource Adequacy

Analyze and report on the ability of the planned resource additions in Evergy's current preferred plans to continue to meet energy needs in all hours of each year.

Response:

All tested Alternative Resource Plans were developed in order to meet the objectives of 20 CSR 4240-22.010(2) and to meet SPP Resource Adequacy Requirements as well as hourly customer energy needs. There is no unserved energy in production cost modeling analysis performed for this IRP. SPP Resource Adequacy Requirements are designed to maintain loss-of-load expectation (i.e., the expectation of unserved energy) of less than one day in ten years. The analysis performed to develop these requirements – particularly the planning reserve margin and effective load carrying capability, which are developed using probabilistic modeling – incorporates considerations of extreme weather, generator unavailability, and renewable output (among many other factors) and assesses the risk of loss-of-load (i.e., unserved energy) in all modeled hours. Because every modeled resource plan meets these requirements, every resource plan is designed to be able to

[4] See Volume 4, Table 13.

meet customer energy needs, subject to the allowable level of risk incorporated into SPP requirements.

To supplement the use of SPP requirements, as part of this year's analysis, Evergy also conducted its own probabilistic reliability analysis to assess the reliability of its resource plan. Specifically, Evergy utilized the Strategic Energy and Risk Valuation Model (SERVM) software to assess the performance of future resource portfolios under varying load, weather (including extreme weather), and outage conditions. The purpose of this analysis is to offer relative comparisons of reliability metrics across different resource portfolios. It is important to note that this analysis does not aim to duplicate or directly compare with SPP studies related to future planning reserve margins. However, the general methodology and modeling software used is consistent with SPP and, in subsequent IRPs, efforts will be made to align Evergy's reliability studies even more closely with those conducted by SPP.

The SERVM software evaluates how specific plans align with the industry-standard Loss of Load Expectation (LOLE) metric. According to this metric, a system would experience one day with one or more hours of firm load shedding every 10 years due to a shortage of generating capacity. In simpler terms, the standard LOLE for a system averages 0.1 days per year, as reflected in the SERVM results. Significantly higher LOLE values indicate a system is less reliable in meeting load requirements hourly.

In addition to the Loss of Load Expectation (LOLE) metric, Evergy also monitored the Expected Unserved Energy (EUE) metric while evaluating select plans. This metric quantifies the amount of energy (measured in MWh) that a generating system is unable to supply during loss-of-load events. Specifically, it represents the energy deficit when demand exceeds supply due to system limitations.

In alignment with Evergy's 2024 Preferred Plan, 2033 was chosen as the future study period. By that time, several coal units are expected to be retired and replaced with cleaner thermal and renewable energy resources.

The foundational assumption was developed using a 0.1 LOLE standard. Prior to analyzing select plans, the SERVM database was calibrated to ensure that both Evergy and its neighboring regions maintained an average LOLE of approximately 0.1. This calibration ensures that neither Evergy nor its surrounding areas are overly relying on market support to meet their capacity requirements.

Evergy selected a couple resource portfolios to assess their reliability in meeting load on an hourly basis throughout 2033. These portfolios include the preferred plan (KSC AAAA, MET CAAB, and MOW CAAA) and the high renewable plan (KSC AAAG, MET CAAI, and MOW CAAL). Notably, both sets of plans maintained the resource portfolios of Evergy's neighbors at a constant level. The results of this analysis are summarized in the following table.

Table 2: 2033 SERVM Study Results

	Preferred Plan		High Renewable Plan	
Region	LOLE	EUE	LOLE	EUE
Evergy	0.021	10.149	0.339	434.247

With neighboring utilities calibrated to a LOLE of approximately 0.1, SERVM results reveal that Evergy's preferred plan has a LOLE metric of 0.021. This indicates that the Evergy region is expected to experience a loss of load averaging 0.021 days per year or 0.21 days every 10 years (as compared to the 1 day standard). Conversely, when holding neighbors' resource portfolio constant, Evergy's high renewables plan exhibits a LOLE metric of 0.339, corresponding to an expected loss of load averaging 0.339 days per year or 3.39 days every ten years. The analysis of these two plans demonstrates that the high renewables plan is less reliable than the Preferred Plan in meeting the standard reliability metric for the year 2033.

Additionally, Evergy's Preferred Plan exhibits an EUE metric of 10.149 MWh while the high renewables plan exhibits an EUE metric of 434.247 MWh. This implies that the Preferred Plan results in the Evergy region being unable to supply an average of 10.149 MWh during the 0.021 days of loss-of-load event, whereas the high renewables plan results in the Evergy region falling short by 434.247 MWh on average during the 0.339 days of loss-of-load event in the same year. The following figures illustrate the percent occurrence of EUE events for the specific month and hour of day in the study year 2033 for both resource portfolios. While LOLE modeling is often used in the development of peak capacity requirements (i.e., planning reserve margin is a percentage of peak load), this modeling is performed for 8,760 hours per year and the risk of loss-of-load is assessed across all hours. This hourly analysis is summarized in the tables below.

Table 3: Evergy 2033 Preferred Plan 12x24 EUE Percent Occurrence

	Month of Year											
Hour of Day	1	2	3	4	5	6	7	8	9	10	11	12
1	0.0000%	0.0357%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
3	0.0000%	0.4165%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
4	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
5	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
6	0.0000%	6.2240%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
7	0.0000%	3.7487%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
8	1.0472%	13.1858%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	6.5215%
9	0.0000%	6.7357%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
10	0.0000%	3.4273%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
11	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.6423%
12	0.0000%	2.5229%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
13	0.0000%	0.6664%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
14	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
15	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
16	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.8806%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
17	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	7.1284%	0.0000%	0.0000%	0.0000%	0.0000%
18	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	13.8284%	0.0000%	0.0000%	0.0000%	0.0000%
19	0.1785%	1.3329%	0.0000%	0.0000%	0.0000%	0.0000%	2.4158%	6.2597%	0.0000%	0.0000%	0.0000%	0.0000%
20	0.0000%	0.2856%	0.0000%	0.0000%	0.0000%	0.0000%	4.2128%	2.3206%	0.0000%	0.0000%	0.0000%	0.0000%
21	0.0000%	4.2604%	0.0000%	0.0000%	0.0000%	0.0000%	2.6419%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
22	0.0000%	4.2723%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
23	0.0000%	0.5712%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
24	0.0000%	3.2369%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

Table 4: Evergy 2033 High Renewable Plan 12x24 EUE Percent Occurrence

	Month of Year											
Hour of Day	1	2	3	4	5	6	7	8	9	10	11	12
1	0.0000%	0.0065%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
2	0.0000%	0.0026%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
3	0.0000%	0.0065%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0163%
4	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0098%
5	0.0000%	0.0290%	0.0000%	0.0000%	0.0000%	0.0094%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
6	0.0000%	0.0104%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0681%
7	0.0381%	0.1410%	0.0000%	0.0000%	0.0000%	0.0000%	0.0002%	0.0169%	0.0000%	0.0000%	0.0000%	0.0345%
8	0.1156%	0.3311%	0.0000%	0.0000%	0.0000%	0.0000%	0.0031%	0.0074%	0.0000%	0.0000%	0.0000%	0.2107%
9	0.0738%	0.2967%	0.0000%	0.0000%	0.0000%	0.0000%	0.0026%	0.0000%	0.0000%	0.0000%	0.0000%	0.1985%
10	0.0909%	0.0922%	0.0000%	0.0000%	0.0000%	0.0151%	0.0112%	0.0000%	0.0000%	0.0000%	0.0000%	0.0358%
11	0.1068%	0.1539%	0.0000%	0.0000%	0.0000%	0.0173%	0.0282%	0.0079%	0.0000%	0.0000%	0.0000%	0.1197%
12	0.0609%	0.0531%	0.0000%	0.0000%	0.0000%	0.0154%	0.1803%	0.1233%	0.0000%	0.0000%	0.0000%	0.0855%
13	0.0000%	0.1109%	0.0000%	0.0000%	0.0000%	0.0152%	0.1681%	1.4871%	0.0000%	0.0000%	0.0000%	0.0000%
14	0.0000%	0.0707%	0.0000%	0.0000%	0.0000%	0.0082%	0.3171%	6.1019%	0.0000%	0.0000%	0.0000%	0.0000%
15	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0531%	1.3957%	10.4503%	0.0000%	0.0000%	0.0000%	0.0000%
16	0.0000%	0.0293%	0.0000%	0.0000%	0.0000%	0.0391%	2.5824%	15.0612%	0.0000%	0.0000%	0.0000%	0.0000%
17	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	2.4264%	20.7364%	0.0118%	0.0000%	0.0000%	0.0000%
18	0.0000%	0.1184%	0.0000%	0.0000%	0.0000%	0.0145%	1.6796%	16.9049%	0.0000%	0.0000%	0.0000%	0.0034%
19	0.0000%	0.1879%	0.0000%	0.0000%	0.0000%	0.0000%	1.7887%	9.2203%	0.0000%	0.0000%	0.0000%	0.0000%
20	0.0000%	0.2073%	0.0000%	0.0000%	0.0000%	0.0110%	1.9206%	3.3130%	0.0000%	0.0000%	0.0000%	0.0000%
21	0.0000%	0.2099%	0.0000%	0.0000%	0.0000%	0.0138%	0.1270%	0.2858%	0.0000%	0.0000%	0.0000%	0.0000%
22	0.0000%	0.0580%	0.0000%	0.0000%	0.0000%	0.0000%	0.0058%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
23	0.0000%	0.0301%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
24	0.0000%	0.0088%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

In summary, the selected Preferred Plan has a loss-of-load expectation of well below the industry standard utilized by SPP in developing Resource Adequacy Requirements (LOLE of less than 0.1). Additionally, the unserved energy across these loss-of-load events represents less than 0.1% of Evergy's peak load. By comparison, the loss-of-load expectation in a high renewables plan is three times the industry standard and includes unserved energy of around 4% of Evergy's peak load during each loss-of-load event.

E. Modeling for Low, Medium, High Participation of Aggregator of Retail Customer ("ARCs")

Model for a low, medium, and high participation scenario of commercial and industrial customers electing to participate in demand response activities based on the introduction of a third-party(s) ARC within its footprint and provide an analysis of what the impact said ARC would have on Evergy's IRP.

Response:

Demand response is a valuable tool for the electric industry to use to help maintain the supply and demand balance on the electric grid and to reduce system peak demand. To assess the range of benefits demand response management can provide in the context of this SCI, however, it is important to create distinctions between the two types of demand response: "wholesale market demand response" where demand response products are utilized within the Southwest Power Pool (SPP) regional wholesale market, and "retail demand response programs", such as those administered by Evergy with its customers through commission-approved programs supported by Missouri Energy Efficiency Investment Act (MEEIA) and Kansas Energy Efficiency Investment Act (KEEIA). Also, of importance, is to note that Evergy only operates within SPP, and SPP does not administer a capacity market auction process (such as is conducted by other RTOs/ISOs, for example, MISO or PJM).

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

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

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

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

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

Resource Adequacy. An important distinction between SPP and other organized wholesale market regions is the entity responsible for procurement of adequate resources to serve the needs of the grid reliably ("resource adequacy"). In SPP, it is the responsibility of Load Responsible Entities (LREs, such as Evergy Missouri West), to ensure adequate resources are under Evergy's ownership or control to meet Evergy's forecasted peak energy needs for its service territory, plus a reserve margin established by SPP to account for unplanned events. SPP's resource adequacy requirements allow Evergy to utilize qualified resources enrolled in Evergy-sponsored retail demand response programs to offset Evergy's peak load forecast, and thereby defer construction or procurement of additional resources. As described above, ARC demand response offers are utilized by SPP to serve as a supply resource for the wholesale market. Therefore, these wholesale resources do not count towards Evergy's resource adequacy requirements. Third-party ARC activities will not reduce the planning thresholds for Evergy's IRP.

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

Operations. The lack of visibility by Evergy into wholesale market demand response activity may increase operational volatility on the distribution system and create more uncertainty in long-term forecasting activities once SPP implements the requirements of FERC Order 2222 and as ARC penetration increases over time.

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

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

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

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

Table 5: IRP Impact Assessment from ARCs (Missouri West)

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

F. EPA/GHG

Evaluate the cost impact of the EPA's proposed rules for Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants.

Response:

In May 2023, the U.S. Environmental Protection Agency (EPA) proposed rules that would directly regulate greenhouse gas (GHG) emissions (specifically, carbon dioxide (CO_2)) from new natural gas-based units while also setting guidelines for the states to address emissions from existing coal- and natural gas-based units. The proposal sets standards for CO_2 emissions limitations reflecting the application of the best system of emission reduction (BSER) for covered electric generating units (EGUs). Units subject to the standard of performance can use any system of reduction to meet the limit; they are not required to use the system that EPA determined is the BSER.

EPA established these proposed emission limitations based on utilizing technologies such as hydrogen co-firing with natural gas and carbon capture and sequestration/storage (CCS). It is highly likely this proposed regulation will face administrative and legal challenges prior to finalization. However, this regulation could require hydrogen co-firing with natural gas, natural gas co-firing with coal, reduced generation, CCS, alternate generation, or demand reduction technologies.

While the cost and availability of many of these technologies is highly uncertain, Evergy conducted a screening analysis to evaluate the potential cost impact of the proposed rule using currently available information. The analysis focused on two potential pathways for compliance: 1) a prescriptive application of BSER, and 2) the accelerated retirement of coal resources.

The analysis was conducted at the Evergy level to develop capacity expansion plans and prepare estimated costs. The plans were developed assuming high natural gas prices under SPP Future 3, which aligns with accelerated decarbonization. The optimized plan identified by the capacity expansion modeling was then applied at the individual utility level to assess the relative ranking of the GHG scenario within the IRP.

For the prescriptive compliance pathway, Evergy assumed that coal units would apply BSER according to the preferred plan retirement dates. Additionally, nuclear SMR beginning in 2039 and combined cycle with CCS beginning in 2035 were provided as new resources options to meet the stringent carbon dioxide limits. The BSER technologies and timeline are summarized below.

Table 6: Evergy GHG BSER Prescriptive Technologies

Unit	Retirement Date	GHG BSER	BSER Compliance Period
Hawthorn 5	2039	Co-Firing with 40% Natural Gas	Jan 1, 2030 through Dec 31, 2039
Iatan 1	2039	Co-Firing with 40% Natural Gas	Jan 1, 2030 through Dec 31, 2039
Iatan 2	2039	Co-Firing with 40% Natural Gas	Jan 1, 2030 through Dec 31, 2039
Jeffrey 1	2039	Co-Firing with 40% Natural Gas	Jan 1, 2030 through Dec 31, 2039
Jeffrey 2	2030	Routine Operations	Not Applicable
Jeffrey 3	2030	Routine Operations	Not Applicable
La Cygne 1	2032	20% Capacity Factor Restriction	Jan 1, 2030 through Dec 31, 2032
La Cygne 2	2039	Co-Firing with 40% Natural Gas	Jan 1, 2030 through Dec 31, 2039
Lawrence 4	2028	Routine Operations	Not Applicable
Lawrence 5	2028	Conversion to Natural Gas in 2029	Jan 1, 2030 through Dec 31, 2039

The retirement dates for Hawthorn 5 and Iatan 2 were adjusted to 2039 to model BSER compliance using natural gas co-firing. The Preferred Plan does not include retirement of either of these units in the planning horizon, which would require application of CCS beginning in 2030. However, the electric industry has challenged CCS as BSER for a host of reasons delineated in the Edison Electric Institute's August 2023 comments[5] on the proposed rule. In summary, the concerns with CCS center on the current limited deployment and adequate demonstration of the technologies, the unlikely availability at the required scale according to the proposed compliance date, and the lack of documented integration of the individual components (capture, transportation, and storage). Choosing natural gas co-firing at Hawthorn 5 and Iatan 2 allows the evaluation of BSER without introducing the myriad uncertainties associated with CCS.

As an alternative to BSER, coal unit retirements were pulled forward from the preferred plan dates to earlier dates. According to the following table, early unit retirements were added successively to the model.

[5] https://www.eei.org//-/media/Project/EEI/Documents/Resources-and-Media/TFB/EEIComments_111Rules_FINAL_080823.pdf

Table 7: Evergy GHG Retirement Scenarios

Plan	Early Retirements
BAAB	Preferred Plan 2023
BBAB	Iatan 1 2030
BCAB	Iatan 1 2030, Jeffrey 1 2030
BDAB	Iatan 1 2030, Jeffrey 1 2030, La Cygne 2 2032
BEAB	Iatan 1 2030, Jeffrey 1 2030, La Cygne 2 2032, Hawthorn 5 2027
BFBB	Iatan 1 2030, Jeffrey 1 2030, La Cygne 2 2032, Hawthorn 5 2027, Iatan 2 2030
BGAB	Hawthorn 5 & Iatan 2 2039 (GHG BSER Scenario)

A total of seven plans were evaluated with the preferred plan retirement schedule (BAAB) producing the lowest overall cost. Retiring all units early produced the highest cost plan (BFBB), while the prescriptive BSER plan (BGAB) was higher cost than all the early retirement scenarios that did not include Hawthorn 5 and Iatan 2 (BAAB-BDAB). The plans that introduced the early retirement of Hawthorn 5 (BEAB) followed by Iatan 2 (BFBB) were higher in overall cost than the BSER plan (BGAB). The results are summarized below.

Table 8: Evergy GHG Compliance Resource Plans

New Builds (MW)	**BAAB**	BBAB	BCAB	BDAB	BEAB	BFBB	BGAB
Wind	**7,200**	7,050	7,050	7,050	6,900	7,200	7,200
Solar	**3,150**	3,450	3,450	3,900	3,600	3,000	3,150
CT	**2,490**	2,905	2,905	3,320	3,320	4,565	4,150
CC	**2,093**	1,443	1,443	793	1,443	1,443	1,443
Battery-Gen	**600**	600	750	900	750	900	600
Battery-Wind	**-**	300	150	300	450	-	300
New Build Total	**15,533**	15,748	15,748	16,263	16,463	17,108	16,843
NPVRR Increase vs Low-Cost Plan ($ million)	**$ -**	$ 122	$ 431	$ 512	$ 1,115	$ 1,726	$ 1,106

Based on these results, the IRP rankings for plans based on high natural gas prices and a high carbon restriction can be used to evaluate the relative cost impact of the proposed GHG rules at the utility level. The IRP rankings are presented in Volume 6 of this document.

G. Virtual Power Plants (VPP)

Describe the inclusion of VPP within the Company's IRP update or triennial analysis. In doing so, identify which distributed energy resources (DER) or compliment of DERs were included in the analysis, consider both the retail VPP and market-participant VPP perspectives, and explain the benefits and challenges related to scalability attributed of VPPs. Address VPP contributions to the utility's resource adequacy requirements, grid stability, resiliency, transmission and distribution capacity deferrals, load management strategies, and system optimization. Discuss limitations, if any, to incorporating VPPs in the Company's distribution or resource planning analysis due to challenges of aggregating and dispatching retail and market-participants' DERs.

Response:

A retail VPP that leverages load flexible demand resources could perform and contribute to resource adequacy similar to a conventional generation resource. VPP deployment could support future resource adequacy needs while presenting costs savings and decarbonization benefits. To a degree, VPPs have existed for decades as traditional demand response programs. However, VPPs are rapidly evolving to leverage the expanding mix of DER technologies and use cases to support grid reliability.

We have been successfully deploying demand response programs to support resource adequacy needs as previously described. With the expected new ways that the grid will interact with DERs, reliability on the system is paramount. Grid Operator confidence in Demand Response and DER is critical towards leveraging programs into actively utilized resources, so it is a priority to develop additional tools to analyze current state, track past projections vs. actual performance of DERs, and therefore provide increasingly accurate forecasts of where additional investment is needed or can be avoided with continued load and/or DER growth. Evergy is taking the necessary steps to have this critical insight so we can not only adequately protect and manage the system, but fully leverage these DER resources to support the utility grid and benefit customers.

Key considerations to address with VPPs value towards resource adequacy are; (1) what are the system resource adequacy needs, (2) what accreditation modeling methodology is utilized, (3) what are the load ramp, flexibility and duration (consecutive hours) parameters of the DER programs that comprise each DR resource, (4) how does the DR resource perform in relation to the top load hours of the system forecast, (5) what customer constraints or resource fatigue must be considered and (6) how does the resource perform by season?

Modeling VPP capabilities requires modeling of realistic operational constraints of participating demand response resources. These include limits on customer event and duration capabilities, load impacts limited to actual available load during system peak hours, accounting for event opt-outs and avoidance of power system costs in addition to providing resource adequacy.

Innovation in technology, markets, policy, and regulation will enable and support VPP deployment.

- Technology: DERs are widely available and affordable. DER's can communicate with each other. Continued development of DER software solution and algorithms to schedule, dispatch and settle DR resources to meet market needs will help accelerate and unlock the value of VPPs.
- Market Design: Wholesale market products that recognize VPP characteristics and value. Retail rates and program designs when coupled together that can provide additional value.
- Regulation: Utility regulatory model that recognizes the full value and benefits of VPP deployments.

As technologies emerge and mature, there are opportunities for Evergy to adopt and incorporate additional technologies and value into its existing retail VPP programs. Today (DERs)—including demand response, solar PV, EVs, and battery storage—are typically valued, scheduled, implemented, and managed separately. With that being said, technology platforms are emerging that can automate and integrate the use of these various DER resources as a portfolio of options, which can then more seamlessly adjust the customer demand profile to meet utility system needs in real time and unlock additional value streams for these resources. Evergy is taking these necessary steps to invest in the technology which will unlock additional use cases and value propositions and is learning from pilot projects underway to inform future program design.

In summation, VPPs have the potential to provide similar reliability as conventional alternatives with affordability and decarbonization benefits. VPPs are beginning to be deployed across the U.S. Achieving the full potential of VPPs will require collective industry effort to place VPPs on a level playing field with other resources.

H. Distribution Planning

In light of the emerging developments around Distributed Energy Resources (DER) and VPPs, address what efforts the Company made in its IRP modeling to address distribution planning opportunities and challenges.

Response:

Evergy is currently evaluating the potential impacts of both increased independent DER penetration and those associated with FERC Order 2222. Due to the variability of renewable generation, the lack of historic data regarding the reliability of DERs and VPPs at peak loads, and Evergy's inability to control the devices, Evergy is not currently comfortable justifying the deferral of distribution investment due to these developments. Evergy is focused on increasing the accuracy of distribution planning models and the availability of information to allow us to recognize trends and reevaluate distribution investment in the future.

I. Storage

Consider discussing storage deployment strategies, including the repurposing of retired automotive batteries, exemplified by the Tesla Pilot program in Australia. Additionally, explore investments in energy storage pilot projects with the specific objective of enhancing the reliability and capacity accreditation of renewable energy resources

Response:

As part of its 2022 Missouri Rate case and 2023 Kansas Rate case, the Company proposed and received approval to launch a residential battery energy storage pilot program from each respective Commission. The program will provide participants with the use of a utility owned battery storage system and free installation of the unit in exchange for the Company to utilize the battery at times of high demand to research grid impacts. The Company will evaluate findings over the duration of the pilot through its impact and process evaluation studies that will be finalized in Missouri in 2025 and Kansas in 2026 at the conclusion of each pilot. Based on the findings from the pilot the Company will evaluate and explore potential options for new rebate offerings for residential battery storage units in future filings. Additionally, Evergy has implemented a pilot grid connected battery in the Evergy Kansas Central service territory at the Wichita Zoo. This distribution scale battery has the ability to provide backup support to the Wichita Zoo in case of a service interruption.

Furthermore, the increasing number of electric vehicles (EVs) on the road has spurred the development of solutions to repurpose used battery modules. While these batteries may no longer be meeting the power requirements of EVs, they still have significant life remaining with research suggesting an average of 80% of capacity remaining.[6]This remaining capacity makes them ideal for repurposing in stationary storage applications. Repurposing EV batteries offers several benefits. First, it lowers the cost of entry for customers seeking energy storage solutions, promoting wider adoption. Second, it reduces environmental waste associated with traditional battery disposal and the need for virgin materials in new battery production. Finally, it lessens the demand for new raw materials, contributing to price stability and environmental well-being.

[6] https://www.mckinsey.com/industries/automotive-and-assembly/our-insights/second-life-ev-batteries-the-newest-value-pool-in-energy-storage

However, challenges exist. Ensuring the remaining capacity and safety of these second-life batteries is critical, and rigorous testing and monitoring are essential. Additionally, the current supply of used EV batteries is still in its early stages, requiring strategic sourcing to meet growing demand. Finally, while second-life batteries offer a cost advantage now, the continual decrease in new battery storage solutions necessitates ongoing competitiveness.

Companies like Moment Energy, Smartville, and B2U are leading the way in second-life battery solutions. They specialize in sourcing used batteries from automakers, meticulously evaluating their health, and repackaging them with integrated controls for safe and efficient operation in stationary storage systems. Their solutions offer a substantial cost advantage compared to entirely new battery storage options. The future of second-life batteries is promising. As pressure mounts on automakers[7] to manage their batteries' entire lifecycle and the supply of used batteries matures, second-life solutions are well-positioned to play a role in expanding grid storage capacity and fostering the broader adoption of renewable energy sources.

[7] https://www.nrdc.org/sites/default/files/2023-07/ev-battery-supply-chains-report.pdf