

9. Integrated Resource Plan and Risk Analysis

Highlights

- *Ameren Missouri has developed a robust range of alternative resource plans that reflect different combinations of new conventional and renewable generation, energy storage, energy efficiency (EE), demand response (DR), and retirement of each of its existing coal-fired generators.*
- *In addition to the scenario variables and modeling discussed in Chapter 2, one critical independent uncertain factor has been included in the final probability tree for risk analysis: project cost.*
- *Our risk analysis also includes the evaluation of a range of Ameren Missouri load growth.*

Ameren Missouri's modeling and risk analysis consists of a number of major steps:

1. **Pre-analysis** to determine a key element for inclusion in alternative resource plans – Callaway Energy Center license extension or replacement.
2. Identification of **alternative resource plan attributes**. These attributes represent the various resource options used to construct and define alternative resource plans – demand side resources, new renewable and non-renewable supply side resources, and retirement of existing supply side resources.
3. Development of the **baseline capacity position**, which reflects forecasted peak demand, reserve requirements and existing resources.
4. Development and/or affirmation of **planning objectives** to guide the development of alternative resource plans.
5. Development of **alternative resource plans**. The Company developed the alternative resource plans using the results of the pre-analysis conducted in step 1, the plan attributes identified in step 2, the base capacity position developed in step 3, and the planning objectives identified in step 4.
6. Identification and screening of **candidate uncertain factors**, which are key variables that can influence the performance of alternative resource plans.

7. **Sensitivity analysis** and selection of critical uncertain factors, which are key variables that are determined to have a significant impact on the performance of alternative resource plans.
8. **Risk analysis** of alternative resource plans, which is used to evaluate the performance of alternative resource plans under combinations of the scenarios discussed in Chapter 2 and the critical uncertain factors identified in step 7.

This chapter describes these steps and the results and conclusions of our integration and risk analysis.

9.1 Nuclear License Extension

Prior to determining other planning attributes and capacity positions, a pre-analysis was conducted to evaluate the option of extending Callaway Energy Center's operating license versus retiring the generator at the end of 2044 upon expiration of its current license. Capacity positions with and without large loads showed that if Callaway retires at the end of 2044, a replacement generation resource is needed in 2045.¹ Three replacement resources were included in the analysis: 1) new nuclear, 2) a combined cycle (CC), and 3) CC with carbon capture and sequestration (CCS). All three options were assumed to have a net capacity of 1,200 MW.

The net present value of revenue requirements (PVRR) of all four options are shown in Table 9.1. Extending the operating license results in the lowest PVRR, by more than \$1.3 Billion than the closest option; therefore, Callaway Energy Center was assumed to be operating through the analysis period in all the alternative resource plans developed.

Table 9.1 License Extension vs. Replacement Generation

PVRR	\$Million
License Extension	\$ (967)
New Nuclear	\$ 6,613
New CC	\$ 397
New CC w/CCS	\$ 2,089

9.2 Alternative Resource Plan Attributes²

Development of alternative resource plans includes considering various combinations of demand-side and supply-side resources to meet future capacity needs. However,

¹ Once the alternative resource plans were developed, capacity positions were reviewed again, which yielded the same conclusion: if the Callaway license is not extended beyond 2044, a replacement resource is needed in 2045.

² 20 CSR 4240-22.060(1); 20 CSR 4240-22.060(3)

alternative resource plans may also include elements or attributes that serve the other planning objectives described in Section 9.4. Including these elements or attributes can significantly affect the capacity position that needs to be considered when developing alternative resource plans. Figure 9.1 includes the attributes considered during the development of resource plans.

Figure 9.1 Attributes of Alternative Resource Plans

Retirements (End of Year) - Sioux 2031/2035 - Labadie 2 Units 2036, 2 Units 2042 - Labadie All Units 2036 - Labadie All Units 2042	New Supply-Side Types - Combined Cycle* (Nat. Gas) - Simple Cycle (Nat. Gas) - Nuclear - Pumped Storage - Solar - Wind - Batteries - Fuel Cells
Load Additions - No Large Load (LL) Addition - Low LL (4 GW by 2046) - Base LL (6 GW by 2046) - High LL (9 GW by 2046) - Load Loss - Base to Low LL - Load Loss - High to Base LL	Renewable Portfolios - Missouri Renewable Energy Standard (RES) with No Future DSM - Base LL - RES with LTR DSM - Base LL - RES with MAP DSM - Base LL - RES with LTR DSM - Low LL - RES with LTR DSM - High LL - Additional Renewables - No LL - Additional Renewables - Low and Base LL - Additional Renewables - High LL - Additional Renewables - High to Base LL
Demand-Side Management - Maximum Achievable Potential (MAP) - Realistic Achievable Potential (RAP) - Less than RAP (LTR) - LTR 25% - No Future DSM	

* With and without carbon capture

9.3 Capacity Position

To determine the timing and need for resources, Ameren Missouri first developed its baseline capacity position, including:

- Peak demand forecast by season without any large load additions, as described in Chapter 3.
- Seasonal planning reserve margin (PRM) requirements, based on MISO's Planning Year 2025-2026 Loss of Load Expectation (LOLE) Study Report, as shown in Chapter 2.
- Existing plant seasonal unforced capacity values, as described in Chapter 4, and wind, solar and battery storage seasonal accreditation (SAC) values as described in Chapter 2.

Considering the points noted above, Figures 9.2 and 9.3 show Ameren Missouri's net capacity position with no large load additions and with no new major generating resources other than Castle Bluff and Big Hollow (both simple cycle and battery storage) Energy Centers, because the certificate of convenience and necessity (CCN) for these resources are approved, and no additional DSM programs after the Company's approved Missouri Energy Efficiency Investment Act (MEEIA) Cycle 4 portfolio for summer and winter.

Figure 9.2 Summer Baseline Capacity Position – No New Resources

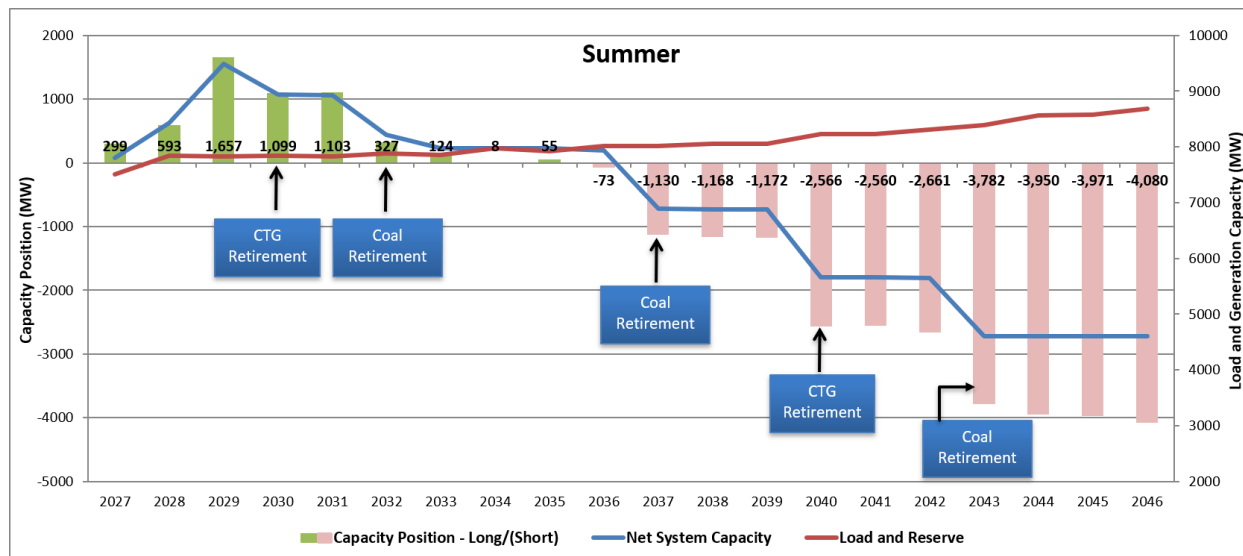
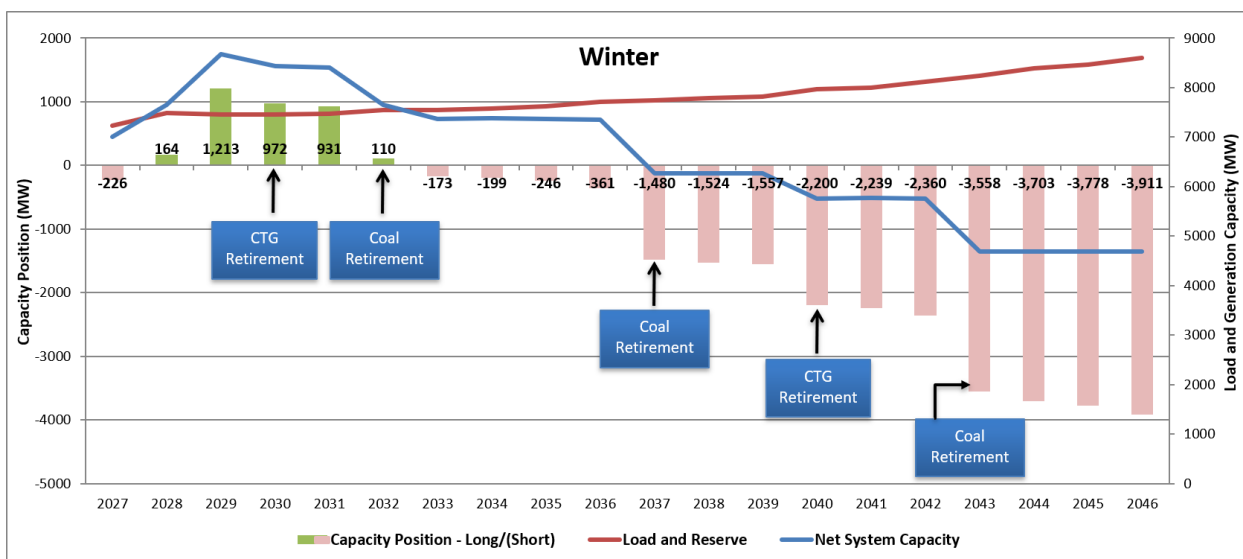


Figure 9.3 Winter Baseline Capacity Position – No New Resources



The charts above show the system capacity, customer needs (including the MISO reserve requirement), and capacity above/below the MISO requirement (i.e., long/short position).

The system capacity includes the capacity benefit of the RES Plus portfolio, which includes 75 MW of solar generation in addition to what was shown in the Company's latest RES Compliance filing with the Missouri Public Service Commission (MPSC).³ Retirement dates reflected in the base capacity position for existing coal-fired units are those established in Ameren Missouri's preferred resource plan (PRP) adopted in February 2025 with the filing of Notice of Change in Preferred Resource Plan (EO-2025-0235) and are considered to be the base retirement dates.

Retirements and Modifications

Ameren Missouri is considering retirement of its four older gas- and oil-fired CTG units – Fairgrounds, Mexico, Moberly, and Moreau – with a total summer net capacity of 217 MW, over the next 20 years. Additionally, Ameren Missouri will be retiring its IL CTGs – with a total summer net capacity of 1,920 MW – due to requirements of the Climate and Equitable Jobs Act (CEJA), passed in Illinois in 2021. Chapter 4 - Table 4.4 provides a summary of the planned CTG retirements. The CTG retirements were included in all alternative resource plans. Also included in the alternative resource plans is increased winter capacity at Audrain Energy Center due to addition of dual-fuel capability by the end of 2026.

Coal energy center retirements were also included in the capacity planning process. Two different Sioux retirement options were considered: 1) retirement by December 31, 2031, as reflected in the preferred resource plan adopted by the Company in 2025, and 2) retirement by December 31, 2035. Three different retirement options for Labadie were considered: 1) current retirement dates, with two units retired by December 31, 2036 and two units retired by December 31, 2042, 2) all four units retired by December 31, 2036, and 3) all four units retired by December 31, 2031. Varying capital and operations & maintenance cost assumptions were used in the analysis for different retirement dates.⁴

DSM Portfolios

EE and DR programs as described in detail in Chapter 8 are included in the DSM portfolios. DSM programs not only reduce the peak demand but also reduce reserve requirements associated with those demand reductions. The following combinations of DSM portfolios were evaluated: 1) RAP EE and DR, 2) MAP EE and DR, 3) LTR EE and RAP DR, 4) LTR 25% EE and RAP DR, 5) LTR EE and MAP DR, 6) no EE and RAP DR, 7) no EE and MAP DR, and 8) No DSM after MEEIA Cycle 4. The No DSM portfolio reflects completion of Ameren Missouri's current program cycle with no further EE or DR

³ Appendix A, Table 9A.1 shows the RES filing additions as filed with the MPSC.

⁴ File No. ER-2022-0337, Report and Order

during the planning horizon. Table 9.2 summarizes the cumulative demand and energy savings included in integration analysis.

Table 9.2 DSM Savings Summary

DSM Program	Summer Peak Reduction MW @Gen			Winter Peak Reduction MW @Gen			Energy Savings MWh @Transmission		
	2028	2035	2046	2028	2035	2046	2028	2035	2046
EE RAP	96	508	938	49	264	554	264,406	1,341,255	2,551,142
EE MAP	130	742	1387	71	416	876	382,287	2,096,429	4,019,746
EE LTR	35	191	349	16	95	243	89,677	487,994	1,012,442
EE LTR 25%	58	292	540	25	138	329	133,912	691,937	1,416,586
DR RAP	290	389	462	176	247	300	-	-	-
DR MAP	312	436	500	190	290	348	-	-	-

Renewable Portfolios

Compliance with Missouri's RES was updated to reflect current assumptions, including baseline revenue requirements and an updated 10-year forward-looking model, which calculates the impact of the statutory 1% rate impact limitation.

Ameren Missouri performed its RES compliance analysis with the *10-Year MO RES Compliance Model 2026 IRP* (Model). The Model is designed to calculate the retail rate impact, as required by the Commission's RES rules.⁵ This Model determines the quantity of renewable energy needed to meet both the overall RES portfolio standard and the 2% solar portfolio standard "carve-out" absent any rate impact constraints. The Model then determines the amount of renewable energy, both solar and non-solar, that can be built without exceeding an average one percent revenue requirement increase over a ten-year period.

Table 9.3 shows the amounts of new solar and wind resources added for various renewable portfolios, including RES compliance under different load cases. The RES compliance portfolio established by the previously described Model is used for alternative resource plans allowing full compliance with the RES while remaining under the one percent rate impact limitation.

When developing the RES compliance investment needs, consideration was given to the potential difference between different levels of DSM portfolios, including the implementation of no further DSM. As MAP DSM results in more energy savings, the RES Compliance requirements are slightly lower than the requirements when LTR DSM is assumed, which also results in lower requirements than load with No Further DSM.

⁵ 20 CSR 4240-20.100(5)

In addition to the RES Compliance portfolios, "RES Plus" renewable portfolios were developed to evaluate the performance of additional solar and wind resources beyond those required for compliance. For both the Low and Base LL scenarios, the RES Plus portfolio includes additional solar for a total of 3,600 MW and 1,500 MW of wind resources, while the RES Plus portfolio for High LL scenario includes 1,500 MW of new wind and a total of 4,500 MW of solar. The renewable portfolio for the No LL case includes 1,800 MW of solar additions, increasing the Company's total solar portfolio to 2,700 MW, which is the total that has been included in the Company's preferred resource plans since the Company's 2020 IRP filing.

Table 9.3 shows the timing of new resources for renewables included in the alternative resource plans.

Table 9.3 Renewable Portfolios (Nameplate Capacity)

Renewable Additions		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	Total
RES Compliance Base LL-No Further DSM	Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	425	675	200	281	168	180	181	85	68	80	82	94	77	85	90	101	84	93	3,049
RES Compliance Base LL-LTR DSM	Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	425	675	200	265	165	177	178	82	65	77	80	92	75	83	88	99	82	91	2,999
RES Compliance Base LL-MAP DSM	Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	425	675	200	216	155	167	168	72	56	68	71	84	68	77	83	94	78	88	2,845
RES Compliance Low LL-LTR DSM	Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	425	554	51	65	62	72	73	77	65	74	77	87	74	80	86	94	82	89	2,187
RES Compliance High LL-LTR DSM	Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	425	675	200	626	188	200	202	150	131	144	147	161	140	150	156	169	147	159	4,170
RES Plus No LL	Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	425	675	200	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,800
RES Plus Low and Base LL	Wind	-	-	-	1,000	-	-	-	250	-	-	-	250	-	-	-	-	-	-	1,500
	Solar	425	675	200	550	250	-	250	-	250	-	250	-	250	-	250	-	250	-	3,600
RES Plus High LL	Wind	-	-	-	1,000	-	-	-	250	-	-	-	250	-	-	-	-	-	-	1,500
	Solar	425	675	200	550	250	-	400	-	400	-	400	-	400	-	400	-	400	-	4,500
RES Plus High to Base LL	Wind	-	-	-	1,000	-	-	-	250	-	-	-	250	-	-	-	-	-	-	1,500
	Solar	425	675	200	550	250	-	400	-	400	-	400	-	400	-	-	-	-	-	3,700

Battery storage additions were also included with each of the renewable portfolios.⁶ The RES Plus portfolio for no LL scenario had a total of 1,050 MW, and all other renewable portfolios reflect a total of 2,400 MW of battery storage additions. Ameren Missouri assumes some of these batteries would be placed at retired energy centers; others can be stand-alone projects or co-located with wind or solar additions, which would not change the analysis results given that all resources are connected directly to the grid.

⁶ Battery storage is included in the portfolios for modeling convenience, not for RES compliance.

Table 9.4 Battery Additions (Nameplate Capacity)⁷

Battery Storage Additions	2029	2030	Total
RES Plus- No LL Portfolio	1,050	-	1,050
All Other Renewable Portfolios	1,050	1,350	2,400

Ameren Missouri assumed the full production tax credit (PTC) for wind resources placed in service by 2032, a 30% investment tax credit (ITC) for solar resources placed in service by 2032, and no PTC/ITC for renewable resources placed in service after 2032. For battery storage, a 30% ITC was included for projects placed in service through 2035.

Other Supply-side Resources

After including DSM resources and the renewable portfolios in the development of alternative plans, if the capacity shortfall in a given year met or exceeded the build threshold, then supply-side resources selected from the following technologies are added to eliminate the shortfall: combined cycle (CC), CC with carbon capture (CCS), simple cycle (SC) with dual fuel capability, nuclear, fuel cells, and pumped hydro storage. In the Company's 2023 IRP and 2025 Preferred Resource Plan filings, the long-term planning criterion allowed for a 200 MW capacity deficit. Consistent with that approach, summer and winter build thresholds used in this analysis were estimated by subtracting 200 MW from the load and reserve requirements under extreme weather conditions as discussed in Chapter 2, which resulted in a 300 MW threshold for summer and 550 MW threshold for winter, regardless of the type of supply-side resource under consideration. The accredited seasonal capacities for each supply side type are shown in Table 9.5. Ameren Missouri has assumed reliance on short-term capacity purchases to cover shortfalls that are less than the build threshold and has assumed that any long capacity position would be sold. The earliest in-service dates for each supply-side resource are also shown in Table 9.5. The in-service date constraints represent the expectations for construction lead time as well as the commercial availability of each technology.

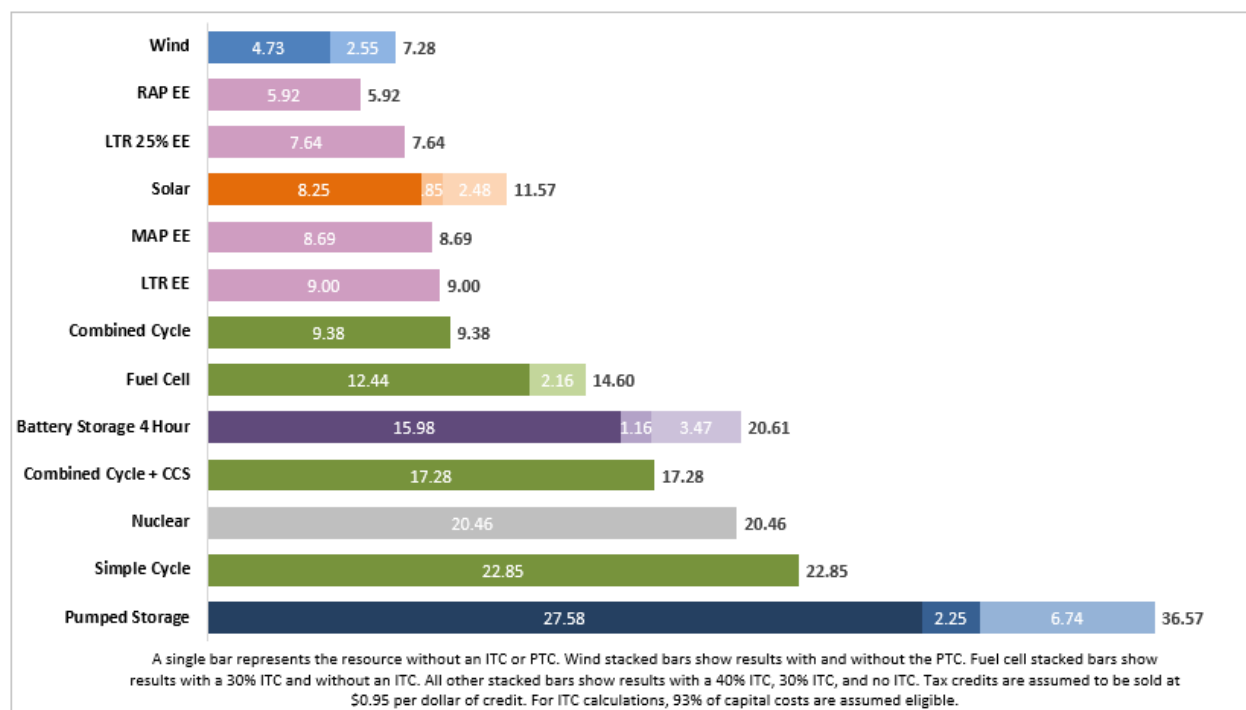
⁷ Order Approving Stipulation and Agreement and Granting Certificate of Convenience and Necessity, File No. EA-2024-0237

Table 9.5 Summer and Winter Capacity for Supply-Side Types

Supply-Side Type	Capacity (MW)	Winter	Spring	Summer	Fall	Earliest Year In-Service
CC	1,400	1,274	1,288	1,274	1,316	2032
CC with CCS	1,400	1,210	1,224	1,210	1,250	2045
SC	800	720	672	720	672	2028
Fuel Cells	50	46	46	46	47	2029
Nuclear	1,200	1,140	1,104	1,140	1,152	2040
Pumped Storage	1,000	940	890	990	910	2035

The resolution of the remaining net capacity position was represented in the financial model as capacity purchases and sales priced at the market-based seasonal capacity costs described in Chapter 2. Capacity purchases and sales were also adjusted for the various peak demand forecasts and DSM impacts.

Figure 9.4 summarizes the levelized cost of energy (LCOE) for all potential future resources evaluated in the alternative resource plans.

Figure 9.4 Levelized Cost of Energy (cents/kWh) – All Resources⁸

⁸ 20 CSR 4240-22.010(2)(A)

9.4 Planning Objectives

The fundamental objective of Missouri's electric resource planning process is to provide energy to customers in a safe, reliable, and efficient way, at just and reasonable rates, while complying with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies.⁹ Ameren Missouri considers several factors, or planning objectives in meeting the fundamental objective. Planning objectives provide a guide to the decision-making process while ensuring the resource planning process is consistent with business planning and strategic initiatives.

Five planning objectives were used in the development of alternative resource plans: Portfolio Transition (formerly Environmental/Resource Diversity); Financial/Regulatory; Customer Satisfaction; Economic Development; and Cost. These planning objectives, which are the same as those discussed in Ameren Missouri's IRP filings since 2011, were selected by Ameren Missouri decision makers and are discussed below.¹⁰

Portfolio Balance

While Ameren Missouri has recently retired coal-fired generating resources, coal currently produces the majority of the energy the Company generates. Ameren Missouri continues to add natural gas and renewable resources to its expanding fleet, resulting in a portfolio that is cleaner and more fuel diverse while ensuring reliability. We evaluate alternative resource plans based on the type, degree, and pace resource additions and retirements, including reductions in energy consumption resulting from customer energy efficiency programs, as we also maintain reliability and affordability.

Financial/Regulatory

The continued financial health of Ameren Missouri is crucial to ensuring safe, reliable and cost-effective service for customers in the future. Ameren Missouri will continue to need the ability to access large amounts of capital for investments needed to meet unprecedented demand growth and provide reliable and affordable service to customers. Measures of expected financial performance and creditworthiness are evaluated along with potential risks.¹¹

Customer Satisfaction

While there are many factors that can influence customer satisfaction, there are several that can be significantly affected by resource decisions. Ameren Missouri has focused on

⁹ 20 CSR 4240-22.010(2)

¹⁰ 20 CSR 4240-22.010(2)(C)

¹¹ 20 CSR 4240-22.060(2)(A)6

levelized average rates, supply and service reliability, and inclusion of renewable and DSM resource options to assess relative customer satisfaction expectations.¹²

Economic Development

Ameren Missouri assesses the relative economic development potential for its service territory and for the state of Missouri associated with its resource choices to serve all customers. We do this by examining the potential for of alternative resource plans to result in job growth opportunities associated with its resource investment decisions. Plans were rated on a relative scale based on direct jobs (FTE-years) required for both construction and operation.¹³

Cost

Ameren Missouri is mindful of the impact that its future resource choices will have on its customers' rates and bills. Maintaining reasonable costs while meeting its other planning objectives is of utmost importance to Ameren Missouri. Cost alone does not and should not dictate resource choices at the expense of other important considerations, but it is a very important factor in making resource decisions. Therefore, minimization of the present value of revenue requirements (PVRR) was used as the primary selection criterion.¹⁴

The application of these planning objectives to the selection of the Company's preferred resource plan is described in Chapter 10.

9.5 Determination of Alternative Resource Plans¹⁵

Twenty-six alternative resource plans were developed to incorporate different combinations of demand-side and supply-side resource options, seek to fulfill Ameren Missouri's planning objectives, and answer key questions, including the following:

- How do varying levels of large load additions impact plans and costs?
- What are the planning and cost implications of a reduction in large load demand relative to forecast?
- How does inclusion of DSM programs affect overall customer costs?
- How would our plans and customer costs be affected if we implemented demand response but no energy efficiency programs?
- How does earlier/later retirement of Labadie Energy Center affect customer costs?

¹² 20 CSR 4240-22.060(2)(A)4

¹³ 20 CSR 4240-22.060(2)(A)7

¹⁴ 20 CSR 4240-22.060(2)(A)1; 20 CSR 4240-22.010(2)(B); 20 CSR 4240-22.060(2)(B)

¹⁵ 20 CSR 4240-22.060(3)

- How does later retirement of Sioux Energy Center affect customer costs?
- What is the impact of including mitigation technology to meet potential future emissions requirements?
- What are the benefits of including renewables beyond those needed for RES compliance?
- What is the impact of pursuing only dispatchable resources?
- How do various supply-side resource options compare?

Table 9.6 provides a summary of the alternative resource plans.¹⁶ All of the alternative resource plans analyzed include Castle Bluff and Big Hollow simple cycle additions. Furthermore, all plans with large loads include 500 MW of fuel cells: 150 MW in-service in 2029, another 150 MW in 2030 and 200 MW in 2031.¹⁷ Plans listed as including "MEEIA 4" for EE and/or DR include no future DSM programs after MEEIA Cycle 4.¹⁸

Table 9.6 Alternative Resource Plans¹⁹

Plan Name (LL, Coal Retirement-Modification, DSM)		Renewables	New Supply-Side
A	No LL, Sx31, Lb36-42, EE LTR-DR RAP	RES Plus for No LL	CC 2032, SC 2040, Nuke 2043, SC 2044
B	Base LL, Sx35, Lb42-42, EE MEEIA 4-DR MEEIA 4, RES Compliance Only	RES Compliance Only	SC300 2030, CC2100 2032, CC 2033, CC 2035, SC 2036, Nuke 2040, CC 2043, SC 2043, SC 2043, CCwCCS 2045
C	Base LL, Sx35, Lb42-42, EE LTR-DR RAP, RES Compliance Only	RES Compliance Only	SC300 2030, CC2100 2032, CC 2033, CC 2036, SC 2039, Nuke 2040, CC 2043, SC 2043, SC 2044
D	Base LL, Sx35, Lb42-42, EE MAP-DR MAP, RES Compliance Only	RES Compliance Only	SC300 2030, CC2100 2032, CC 2034, CC 2036, Nuke 2040, SC 2043, CC 2043, SC 2044
E	Low LL, Sx35, Lb42-42, EE LTR-DR RAP, RES Compliance Only	RES Compliance Only	SC300 2030, CC2100 2032, SC 2038, Nuke 2040, CC 2043, SC 2043, SC 2044

¹⁶ The sensitivity analysis described later in Chapter 9 reflects consideration of the 26 plans described in this section. Three additional plans were included in the risk analysis described later in Chapter 9 to explicitly evaluate alternatives for the Company's planned West Alton combined cycle facility.

¹⁷ All at the beginning of the calendar year.

¹⁸ Unless otherwise stated, the capacity of the resources is as displayed on Table 9.5. SC300 is a 300 MW simple cycle and CC2100 is a 2100 MW combined cycle. The Company has an active certificate and convenience (CCN) application with the MPSC for the latter.

¹⁹ 20 CSR 4240-22.010(2)(A); 20 CSR 4240-22.060(3); 20 CSR 4240-22.060(3)(A)1 through 8; 20 CSR 4240-22.060(3)(B); 20 CSR 4240-22.060(3)(C)1; 20 CSR 4240-22.060(3)(C)2; 20 CSR 4240-22.060(3)(C)3; File No. EO-2026-0037 1.B.iii; Order Approving Stipulation and Agreement and Granting Certificate of Convenience and Necessity File No. EA-2025-0238

Plan Name (LL, Coal Retirement-Modification, DSM)	Renewables	New Supply-Side
F High LL, Sx35, Lb42-42, EE LTR-DR RAP, RES Compliance Only	RES Compliance Only	SC300 2030, SC 2031, CC2100 2032, CC 2033, CC 2035, CC 2036, SC 2039, Nuke 2040, CC 2042, CC 2043, SC 2043, CCwCCS 2045
G Base LL, Sx31, Lb36-42, EE LTR-DR RAP	RES Plus for Low & Base LL	SC300 2030, CC2100 2032, CC 2033, CC 2034, CC 2037, Nuke 2040, SC 2043, SC 2043, SC 2045
H Base LL, Sx35, Lb36-42, EE LTR-DR RAP	RES Plus for Low & Base LL	SC300 2030, CC2100 2032, CC 2033, CC 2036, CC 2037, Nuke 2040, SC 2043, SC 2043, SC 2045
I Base LL, Sx31, Lb42-42, EE LTR-DR RAP	RES Plus for Low & Base LL	SC300 2030, CC2100 2032, CC 2033, CC 2034, Nuke 2040, CC 2043, SC 2043, SC 2043, SC 2045
J Base LL, Sx35, Lb36-36, EE LTR-DR RAP	RES Plus for Low & Base LL	SC300 2030, CC2100 2032, CC 2033, CC 2036, SC 2037, CC 2037, SC 2039, Nuke 2040, SC 2045
K Base LL, Sx35, Lb42-42-Cofire, EE LTR-DR RAP	RES Plus for Low & Base LL	SC300 2030, CC2100 2032, CC 2033, CC 2036, Nuke 2040, SC 2043, CC 2043, SC 2043, SC 2045
L Base LL, Sx35, Lb42-42-FGD-SCR, EE LTR-DR RAP	RES Plus for Low & Base LL	SC300 2030, CC2100 2032, CC 2033, CC 2036, Nuke 2040, SC 2043, CC 2043, SC 2043, SC 2045
M Base LL, Sx35, Lb42-42, EE LTR-DR RAP	RES Plus for Low & Base LL	SC300 2030, CC2100 2032, CC 2033, CC 2036, Nuke 2040, CC 2043, SC 2043, SC 2043, SC 2045
N Low LL, Sx35, Lb42-42, EE LTR-DR RAP	RES Plus for Low & Base LL	SC300 2030, CC2100 2032, SC 2039, Nuke 2040, CC 2043, SC 2043, SC 2044
O High LL, Sx35, Lb42-42, EE LTR-DR RAP	RES Plus for High LL	SC300 2030, SC 2031, CC2100 2032, CC 2033, CC 2035, CC 2036, Nuke 2040, SC 2041, CC 2043, CC 2043, SC 2043, SC 2045, SC 2046
P Base LL, Sx35, Lb42-42, EE LTR-DR RAP, Pumped Storage	RES Plus for Low & Base LL	SC300 2030, CC2100 2032, CC 2033, CC 2036, Nuke 2040, Pumped Storage 2043, CC 2043, SC 2043, SC 2046
Q Base LL, Sx35, Lb42-42, EE LTR-DR RAP, No New Nuke	RES Plus for Low & Base LL	SC300 2030, CC2100 2032, CC 2033, CC 2036, CC 2040, CC 2043, SC 2043, SC 2043, SC 2046
R Base LL, Sx35, Lb42-42, EE RAP-DR RAP	RES Plus for Low & Base LL	SC300 2030, CC2100 2032, CC 2034, CC 2036, Nuke 2040, CC 2043, SC 2043, SC 2043
S Base LL, Sx35, Lb42-42, EE MAP-DR MAP	RES Plus for Low & Base LL	SC300 2030, CC2100 2032, CC 2034, CC 2036, Nuke 2040, CC 2043, SC 2043, SC 2045
T Base LL, Sx35, Lb42-42, EE LTR25%-DR RAP	RES Plus for Low & Base LL	SC300 2030, CC2100 2032, CC 2033, CC 2036, Nuke 2040, CC 2043, SC 2043, SC 2043, SC 2045

Plan Name (LL, Coal Retirement-Modification, DSM)		Renewables	New Supply-Side
U	Base LL, Sx35, Lb42-42, EE LTR-DR MAP	RES Plus for Low & Base LL	SC300 2030, CC2100 2032, CC 2033, CC 2036, Nuke 2040, CC 2043, SC 2043, SC 2043, SC 2045
V	Base LL, Sx35, Lb42-42, EE MEEIA 4-DR MEEIA 4	RES Plus for Low & Base LL	SC300 2030, CC2100 2032, CC 2033, CC 2035, SC 2037, Nuke 2040, CC 2043, SC 2043, SC 2043, SC 2045
W	Base LL, Sx35, Lb42-42, EE MEEIA 4-DR RAP	RES Plus for Low & Base LL	SC300 2030, CC2100 2032, CC 2033, CC 2036, SC 2039, Nuke 2040, CC 2043, SC 2043, SC 2044
X	Base LL, Sx35, Lb42-42, EE MEEIA 4-DR MAP	RES Plus for Low & Base LL	SC300 2030, CC2100 2032, CC 2033, CC 2036, SC 2039, Nuke 2040, CC 2043, SC 2043, SC 2044
Y	Base to Low LL, Sx35, Lb42-42, EE LTR-DR RAP	RES Plus for Low & Base LL	SC300 2030, CC2100 2032, CC 2033, CC 2036, Nuke 2040, SC 2044
Z	High to Base LL, Sx35, Lb42-42, EE LTR-DR RAP	RES Plus for High to Base LL	SC300 2030, SC 2031, CC2100 2032, CC 2033, CC 2035, CC 2036, Nuke 2040, SC 2043, SC 2045

All CCs are assumed to have 95% of their CO₂ emissions eliminated beginning in 2045. This may be achieved through some combination of alternative fuels (e.g., hydrogen, renewable natural gas), carbon capture and sequestration, purchased offsets, or reduced operation. Because of the uncertainty regarding the eventual method used to mitigate carbon emissions, the higher variable and fixed operating and maintenance (O&M) costs for CC with CCS are included with no major capital expenditures for CCS. Ameren Missouri assumed green hydrogen and CCS projects may become commercially available by 2045. Lastly, Ameren Missouri did not analyze a plan with the addition of only new renewables as it did in the 2023 IRP, since that analysis also showed that such a plan did not meet reliability requirements at any practical level of renewable additions.

How do varying levels of large load additions impact plans and costs?

Plans N, O, P, Y and Z have the same attributes other than the varying large load additions. These plans can be compared against each other and also against Plan A, which does not assume large load additions. Additionally, Plans C, E and F also have varying degrees of large loads with RES Compliance only and can be evaluated relative to one another.

What are the planning and cost implications of a reduction in large load forecasts?²⁰

Plans Y includes the Base to Low LL scenario where load reduction occurs, and Plan Z includes the High to Base LL scenario as explained in Chapter 3. Comparing Plan Y and Plan M, and Plan Z and Plan O provides insight into the implications of large loads not persisting and the resulting impacts on resource requirements and costs.

How does inclusion of DSM programs affect overall customer costs?²¹

Plans M, R, S, T and U include combinations of RAP, MAP, LTR and LTR 25% energy efficiency portfolios, and RAP and MAP level demand response programs. Therefore, these plans can be compared against Plan V that has the same level of large load and renewable additions, but do not include DSM programs, to assess the impact on cost and other performance measures due to inclusion of different levels of DSM. Additionally, the same comparison can be made between Plan B with no further DSM and Plan C with LTR EE and RAP DR as they both have same level of large load additions and RES Compliance only portfolios.

How would our plans and customer costs be affected if we implemented demand response but no energy efficiency programs?

Plans W and X include no EE programs, but do include RAP and MAP DR programs, respectively. These plans can be compared against Plan V that includes neither EE nor DR after MEEIA Cycle 4 to evaluate how each DR portfolio performs. These same plans can also be assessed against plans with the same level of demand response programs in addition to energy efficiency portfolios: Plan W against Plans M, R and T, which includes LTR, RAP and LTR 25% EE portfolios, respectively, and Plan X against Plans S and U that include MAP and LTR EE portfolios, respectively.

How does later retirement of Sioux Energy Center affect customer costs?

Plans G and H can be compared to evaluate the cost effectiveness of retiring the Sioux Energy Center by 2031 vs. 2035.

How does earlier/later retirement of Labadie Energy Center affect customer costs?

Plans J and M assess the cost-effectiveness of advancing and deferring the retirement of two units, respectively, relative to the base retirement assumptions for all four units

²⁰ 20 CSR 4240-22.060(3)(A)6

²¹ 20 CSR 4240-22.060(3)(A)3

represented in Plan H. Similarly, Plan I with the later retirement date for two units can be compared against the base retirement dates in Plan G.

What is the impact of including mitigation technology to meet potential future emissions requirements?

Plan K includes addition of cofiring capability at all four Labadie units in 2035 while Plan L includes the installation of SCR and FGD systems on two units in 2035. Both plans can be compared against Plans J and M to assess the cost effectiveness of adding these mitigation technologies.

***What are the benefits of including renewables beyond those needed for RES compliance?*²²**

To assess the relative benefits of including additional renewable resources, several alternative resource plans were developed that exceed the level of renewable investment indicated by the RES compliance model. Plans B and V with Base LL and no further DSM, Plans C and M with Base LL and LTR EE, Plans D and S with Base LL and MAP DSM, Plans E and N with Low LL and LTR EE, and Plans F and O with High LL and LTR EE can be compared to assess the costs/benefits of additional renewables.

What is the impact of pursuing only dispatchable supply-side resources?

Plan B evaluates the cost-effectiveness of adding no additional DSM programs, renewable resources for only RES compliance and dispatchable supply-side resources.

How do various supply-side resource options compare?

Plans P and Q can be compared with Plan M to evaluate the impacts of replacing a simple cycle with pumped storage and replacing nuclear resource with a combined cycle, respectively.

The type, size, and timing of resource additions/retirements for the alternative resource plans are provided in Appendix A and in the electronic workpapers.²³

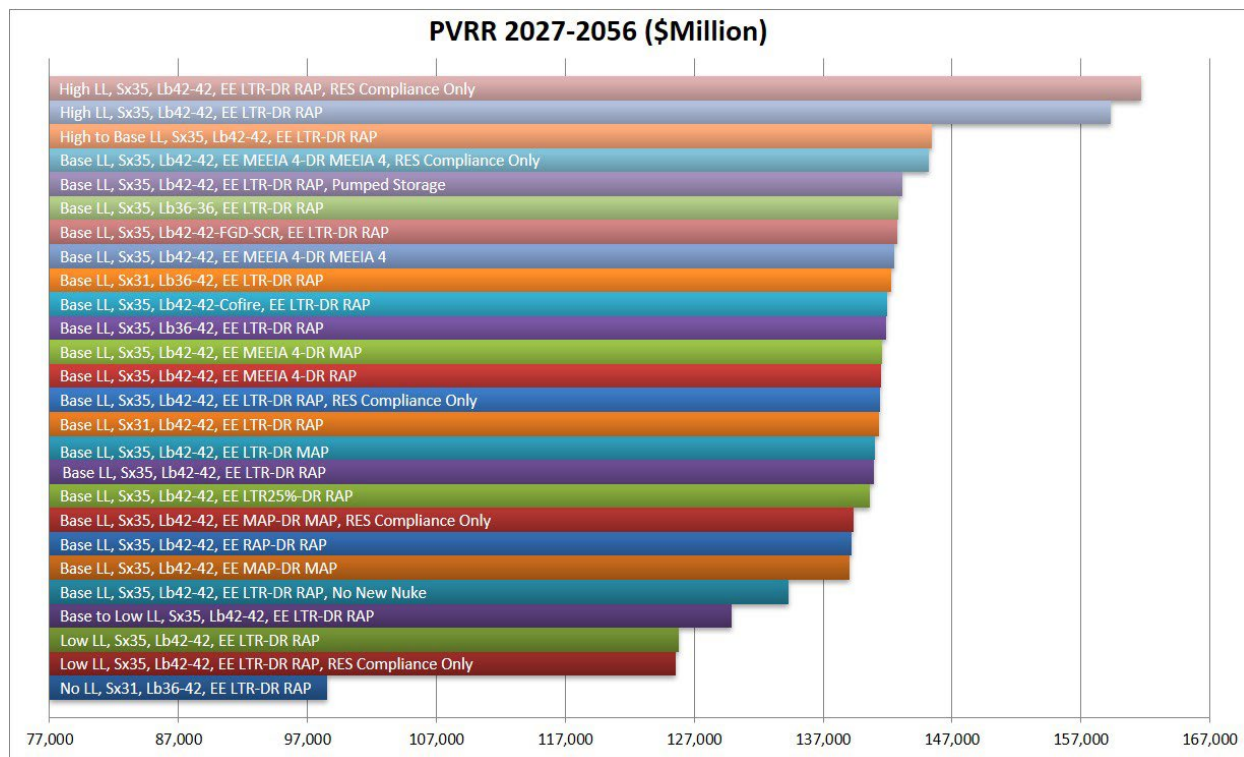
Integration, sensitivity, and risk analyses for the evaluation of alternative resource plans were done assuming that rates would be adjusted annually for the 20-year planning horizon and 10 additional years for end effects, and by treating both supply-side and demand-side resources on an equivalent basis. Integration analysis was performed on the most likely scenario of the probability tree (Scenario 8) as explained in Chapter 2. Integration analysis PVRR results are shown below in Figure 9.5. Results for the

²² 20 CSR 4240-22.060(3)(A)1

²³ None of the alternative resource plans analyzed include any load-building programs
20 CSR 4240-22.060(3)(B); 20 CSR 4240-22.080(2)(D); 20 CSR 4240-22.060(3)(D)

remaining performance measures for integration analysis are provided in the workpapers.²⁴

Figure 9.5 Integration PVRR Results



It should be noted that all costs and benefits in all analyses were expressed in nominal dollars, and Ameren Missouri's current discount rate of 6.96% was used for present worth and levelization calculations. Also, in all integration, sensitivity, and risk analyses, it was assumed that rates are adjusted annually to reflect the Company's full revenue requirement in each year (i.e., no regulatory lag).²⁵

9.6 Sensitivity Analysis

Sensitivity analysis involves determining which of the candidate independent uncertain factors are critical independent uncertain factors. Once identified in this step, critical uncertain factors were added to the scenario probability tree discussed in Chapter 2 to create the risk analysis probability tree.

²⁴ 20 CSR 4240-22.060(4)

²⁵ 20 CSR 4240-22.060(2)(B)

9.6.1 Uncertain Factors²⁶

Ameren Missouri developed a list of uncertain factors to determine which factors are critical to resource plan performance. Table 9.7 contains the list as well as information about the screening process.

Table 9.7 Uncertain Factor Screening

Uncertain Factor	Candidate?	Critical?	Included in Final Probability Tree?
Load Growth	✓	--	✓
Carbon Policy [*]	✓	--	✓
Fuel Prices			
Coal	X	X	X
Natural Gas [*]	✓	--	✓
Nuclear	X	X	X
Project Cost (including transmission interconnection costs)	✓	✓	✓
Project Schedule	✓	X	X
Emissions Prices			
SO ₂	X	X	X
NO _x	X	X	X
CO ₂ [*]	✓	--	✓
Purchased Power	X	X	X
Forced Outage Rate	X	X	X
DSM Load Impacts & Costs ^α	✓	X	X
Fixed and Variable O&M	✓	X	X
Return on Equity ^ε	✓	X	X
Interest Rates ^ε	✓	X	X

* Included in the scenario probability tree.

-- Not tested in sensitivity analysis.

α DSM impacts and costs combined.

ε Return on Equity and Long-term Interest rates were combined.

²⁶ 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5) (B) through (F); 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5) (A) through (M)

Chapter 2 describes how three of the candidate uncertain factors were determined to be critical dependent uncertain factors, which defined the fifteen scenarios described in that chapter. The three critical dependent uncertain factors are load growth, natural gas prices and CO₂ prices. Energy and capacity prices are an output of the scenarios, as described in Chapter 2, and reflect a range of uncertainty consistent with the scenario definitions.

A review of these candidates prior to the sensitivity analysis determined several could be eliminated without conducting a quantitative analysis.

- Coal Price – Both the 2020 and 2023 IRP sensitivity analyses showed that variations in coal prices did not impact the relative performance of alternative resource plans. A similar conclusion is expected if low and high coal price sensitivities were included in this IRP, particularly because the price dispersion between base and low/high cases is smaller in this IRP than in previous IRPs.
- Nuclear Fuel Prices – Our 2011 and 2014 IRP analyses concluded that nuclear fuel prices were not critical to the relative performance of the alternative resource plans, primarily due to the high fixed costs for new nuclear generation; the same conclusion is expected to be obtained should high/low nuclear prices be included in the sensitivity analysis, particularly given the significant increase in our assumption for nuclear capital costs.
- Purchased Power – Purchased power is excluded since Ameren Missouri is a member of MISO and Ameren Missouri has employed planning criteria that minimize our dependence on the market in the long term as well as market price scenarios, described above and in Chapter 2, that account for differences in generation.
- Forced Outage Rate (FOR) – All analyses from 2011 IRP to 2020 IRP concluded that forced outage rates were not critical to the relative performance of the alternative resource plans; the same conclusion is expected to be obtained again should the high and low FOR be included in sensitivity analysis. Also note that Ameren Missouri's assumptions for maintenance capex and availability are linked, so cost assumptions correspond to a specific level of forced outages.
- SO₂ and NO_x Emissions Prices – SO₂ and NO_x Emissions Prices were excluded as candidate independent uncertain factors since they were part of the scenario analysis work discussed in Chapter 2.

There are two pairs of candidate independent uncertain factors that are highly correlated:

- Interest Rates and Return on Equity
- DSM Load Impacts and Costs

Including all the possible permutations of high/base/low would geometrically increase the size and complexity of the analysis, with some combinations being much less meaningful and less probable. Since the expectation is that these factors are highly correlated, we have made the simplifying assumption that the individual probability nodes for each pair be combined into a single probability node reflecting the high value for both, base value for both, and low value for both without explicitly considering the less likely and less meaningful joint probabilities.

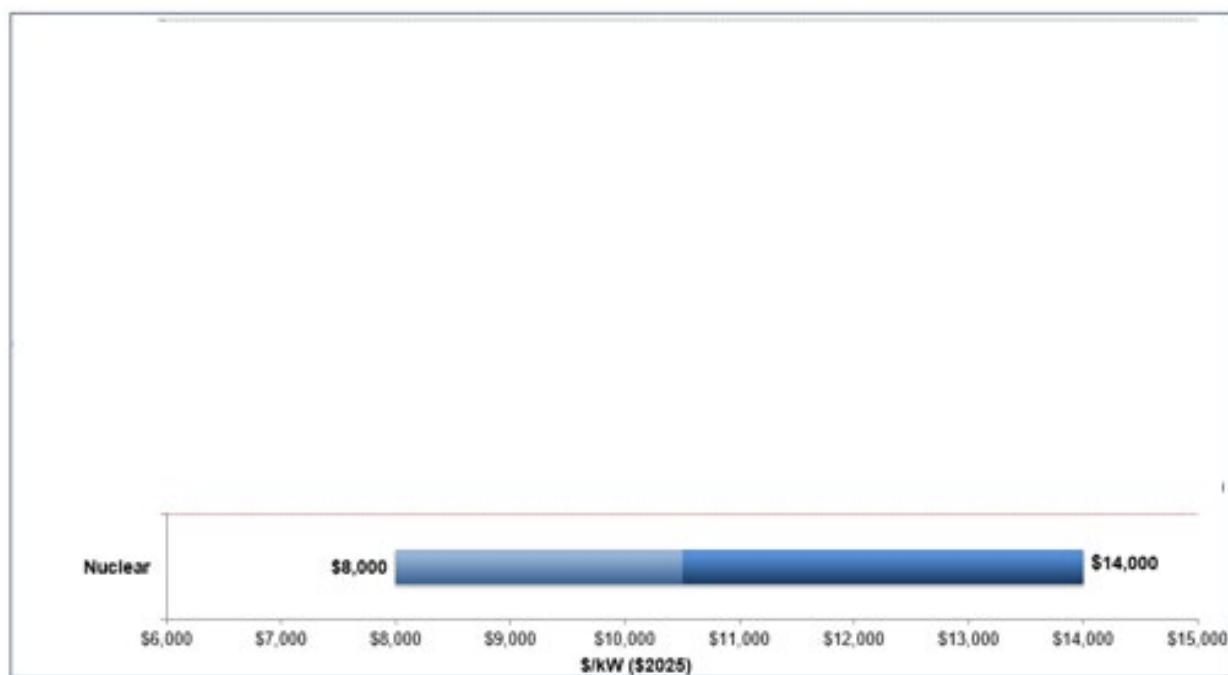
Uncertain Factor Ranges²⁷

We use the sensitivity analysis to examine whether candidate independent uncertain factors have a significant impact on the performance of alternative resource plans, as measured by their impact on PVRR.

The candidate uncertain factors are characterized by a 3-level range of values for this analysis; those 3 levels being low, base, and high values. These ranges were obtained or estimated through a variety of methods and sources including external resources such as NREL, EPRI, EIA, Lazard and Roland Berger, Ameren Missouri subject matter experts, and Ameren Missouri project cost uncertainty grids.

Figure 9.6 displays the project cost ranges for new supply-side resources along with Figure 9.7, which displays the curves used for wind, solar and battery storage resources.

Figure 9.6 Resource-Specific Project Cost Ranges (2025\$/kW)



²⁷ 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

Figure 9.7 Solar, Wind and Battery Project Cost Ranges (2025\$/kW)²⁸

Tables 9.8 and 9.9 show the uncertain factor ranges for the various candidate uncertain factors. It should be noted that, for the project schedule uncertainty, as the number of years in a project schedule change, the distribution of the cash flows was also updated to be consistent with those changes. Costs shown in this table are for generic resources. Where site-specific assumptions were available, such as for the West Alton CC project, those assumptions were used in the analysis.²⁹

Table 9.8 Resource-Specific Uncertain Factor Ranges

Uncertain Factor	Value	Probability	CC	CC with CCS	SC	Fuel Cell	Pumped Storage	Nuclear	Solar	Wind	Battery
Project Cost (\$/kW) 2025 \$	Low	10%						\$8,000	Cost changes by year		
	Base	80%						\$10,500			
	High	10%						\$14,000			
Project Schedule (Years)	Low	10%	4	4	3	2	5	4	2	3	2
	Base	80%	5	5	4	3	6	5	3	4	3
	High	10%	6	6	5	4	8	7	4	5	4
Fixed O&M (\$/kW-yr) 2025 \$	Low	10%	\$9.49	\$39.07	\$6.08		\$9.80	\$111.45	\$15.38	\$33.15	\$10.85
	Base	80%	\$11.17	\$52.09	\$7.16		\$13.07	\$148.60	\$20.50	\$39.00	\$13.65
	High	10%	\$12.84	\$65.11	\$8.23		\$16.34	\$185.75	\$25.63	\$44.85	\$17.50
Variable O&M (\$/MWh) 2025 \$	Low	10%	\$2.69	\$7.19	\$3.54	-	\$3.27	\$2.41	-	-	-
	Base	80%	\$3.16	\$9.59	\$4.16	-	\$3.85	\$3.21	-	-	-
	High	10%	\$3.63	\$11.99	\$4.78	-	\$4.43	\$4.01	-	-	-

²⁸ Cost ranges are shown in real dollars including transmission interconnections, i.e., they do not include inflation.

²⁹ File No. EA-2025-0238

Table 9.9 Project Cost Uncertainty Multipliers

Cost Multipliers	Low	Base	High
Coal Ongoing Capex	83%	100%	123%
Landfill Cell	83%	100%	121%
SCR	85%	100%	125%
FGD	75%	100%	110%
Transmission	80%	100%	150%
Lateral Pipeline	85%	100%	130%

Table 9.10 contains the non-resource specific uncertain factor ranges analyzed.

Table 9.10 Non-Resource Specific Uncertain Factor Ranges

Uncertain Factors	Low	Base	High
Probability →	10%	80%	10%
Long Term Interest Rates			
Return on Equity			
DSM Load Impact and Cost			
MAP - EE Load Impact	82.2%	100%	109.2%
MAP - EE Cost	89.5%	100%	112.2%
MAP - DR Load Impact	99.5%	100%	119.9%
MAP - DR Cost	99.2%	100%	116.5%
RAP - EE Load Impact	82.2%	100%	109.2%
RAP - EE Cost	89.5%	100%	112.2%
RAP - DR Load Impact	99.5%	100%	119.9%
RAP - DR Cost	99.2%	100%	116.5%
LTR - EE Load Impact	82.2%	100%	109.2%
LTR - EE Cost	89.5%	100%	112.2%
LTR 25% - EE Load Impact	82.2%	100%	109.2%
LTR 25% - EE Cost	89.5%	100%	112.2%

As discussed in Chapter 2, long-range interest rate assumptions are based on the December 2025, semi-annual Blue Chip Financial Forecast, a consensus survey of 44 economists from numerous firms including banks, investment firms, universities, and economic advisors. Ameren Missouri internal experts used this same set of data and process to develop a range of interest rate assumptions for use in the 2026 IRP. The high and low interest rate assumptions are based on the average of the 10 highest and 10 lowest forecasts from the survey. Additionally, the high and low forecasts for Treasury rates are used as inputs to the calculation of high and low values for allowed return on equity using the same process discussed in Chapter 2.

Table 9.10 summarizes the winter peak savings for the DSM load impact sensitivity, although load impacts for all seasons were included in the analysis. Chapter 8 includes details on how low and high ranges were obtained for DSM portfolios.

9.6.2 Sensitivity Analysis Results³⁰

To conduct the sensitivity analysis, each of the 26 alternative resource plans was analyzed using the varying value levels (low/base/high) for each of the candidate independent uncertain factors, for Scenario 8, which is the most likely scenario in the probability tree.³¹ An uncertainty-probability weighted result for PVRR was obtained for each plan for each relevant candidate uncertain factor. Finally, the results of using a “non-base” value were compared to the results of using an integration/base value for each plan for each candidate uncertain factor. The sensitivity analysis results for all of the candidate independent uncertain factors (resource-specific and non-resource specific) are presented in Appendix A.

The sensitivity analysis identified one critical independent uncertain factor: Project Cost. Table 9.11 shows the change in PVRR ranking (i.e., number of positions the plan moved in the ranking) for the critical independent uncertain factor compared to the integration/base value.

Table 9.11 Critical Independent Uncertain Factors – Change in PVRR Ranking

Plan	Integration Ranking	Project Cost		
		PWA	Low	High
A-No LL, Sx31, Lb36-42, EE LTR-DR RAP	1	0	0	0
B-Base LL, Sx35, Lb42-42, EE MEEIA 4-DR MEEIA 4, RES Compliance Only	23	0	0	0
C-Base LL, Sx35, Lb42-42, EE LTR-DR RAP, RES Compliance Only	13	0	2	-1
D-Base LL, Sx35, Lb42-42, EE MAP-DR MAP, RES Compliance Only	8	0	0	-2
E-Low LL, Sx35, Lb42-42, EE LTR-DR RAP, RES Compliance Only	2	0	1	0
F-High LL, Sx35, Lb42-42, EE LTR-DR RAP, RES Compliance Only	26	0	0	0
G-Base LL, Sx31, Lb36-42, EE LTR-DR RAP	18	0	0	0
H-Base LL, Sx35, Lb36-42, EE LTR-DR RAP	16	0	0	1

³⁰ 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(6); 20 CSR 4240-22.060(7)(A); 20 CSR 4240-22.060(7)(C)1A

³¹ Scenario 8 reflects base assumptions for each of the three scenario variables – carbon prices, natural gas prices, and load growth.

Plan	Integration Ranking	Project Cost		
		PWA	Low	High
I-Base LL, Sx31, Lb42-42, EE LTR-DR RAP	12	0	0	1
J-Base LL, Sx35, Lb36-36, EE LTR-DR RAP	21	0	1	0
K-Base LL, Sx35, Lb42-42-Cofire, EE LTR-DR RAP	17	0	0	-1
L-Base LL, Sx35, Lb42-42-FGD-SCR, EE LTR-DR RAP	20	0	0	0
M-Base LL, Sx35, Lb42-42, EE LTR-DR RAP	10	0	0	0
N-Low LL, Sx35, Lb42-42, EE LTR-DR RAP	3	0	-1	0
O-High LL, Sx35, Lb42-42, EE LTR-DR RAP	25	0	0	0
P-Base LL, Sx35, Lb42-42, EE LTR-DR RAP, Pumped Storage	22	0	-1	0
Q-Base LL, Sx35, Lb42-42, EE LTR-DR RAP, No New Nuke	5	0	0	0
R-Base LL, Sx35, Lb42-42, EE RAP-DR RAP	7	0	0	1
S-Base LL, Sx35, Lb42-42, EE MAP-DR MAP	6	0	0	1
T-Base LL, Sx35, Lb42-42, EE LTR25%-DR RAP	9	0	0	0
U-Base LL, Sx35, Lb42-42, EE LTR-DR MAP	11	0	0	0
V-Base LL, Sx35, Lb42-42, EE MEEIA 4-DR MEEIA 4	19	0	0	0
W-Base LL, Sx35, Lb42-42, EE MEEIA 4-DR RAP	14	0	-1	0
X-Base LL, Sx35, Lb42-42, EE MEEIA 4-DR MAP	15	0	-1	0
Y-Base to Low LL, Sx35, Lb42-42, EE LTR-DR RAP	4	0	0	0
Z-High to Base LL, Sx35, Lb42-42, EE LTR-DR RAP	24	0	0	0

Table 9.12 shows the change in PVRR (\$) for the critical independent uncertain factor compared to the integration/base values. The 'project cost' uncertain factor was selected as a critical independent uncertain factor because of the changes it caused in PVRR rankings and the considerable dispersion observed in the PVRR results on the low and high ends.

Table 9.12 Critical Independent Uncertain Factors – Change in PVRR (Million \$)³²

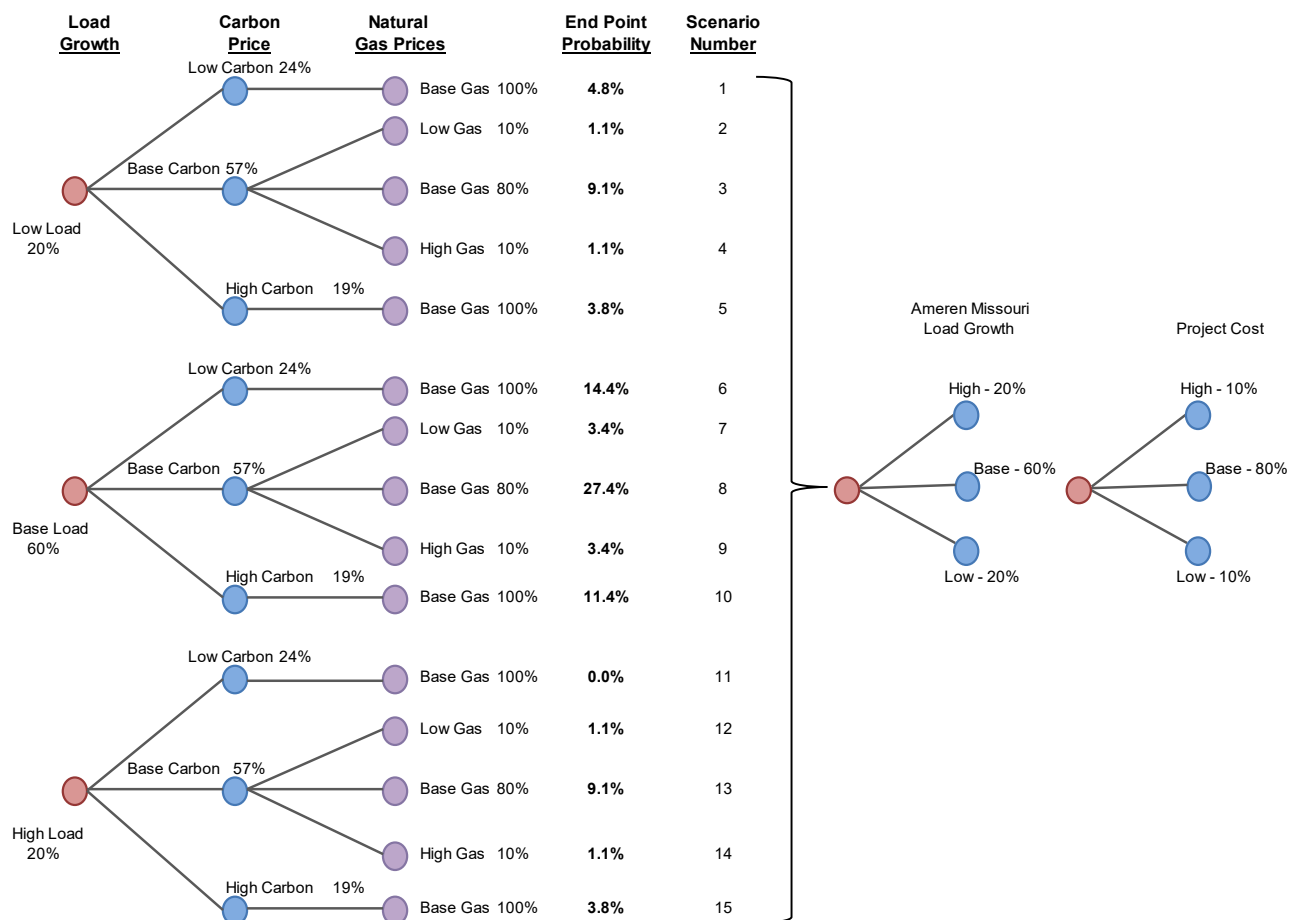
Plan	Integration PVRR (\$Million)	Project Cost		
		PWA	Low	High
A-No LL, Sx31, Lb36-42, EE LTR-DR RAP	98,520	166	(3,470)	5,130
B-Base LL, Sx35, Lb42-42, EE MEEIA 4-DR MEEIA 4, RES Compliance Only	145,220	494	(6,556)	11,494
C-Base LL, Sx35, Lb42-42, EE LTR-DR RAP, RES Compliance Only	141,422	438	(5,952)	10,332
D-Base LL, Sx35, Lb42-42, EE MAP-DR MAP, RES Compliance Only	139,373	430	(5,722)	10,021
E-Low LL, Sx35, Lb42-42, EE LTR-DR RAP, RES Compliance Only	125,605	358	(4,676)	8,253
F-High LL, Sx35, Lb42-42, EE LTR-DR RAP, RES Compliance Only	161,676	571	(7,799)	13,504
G-Base LL, Sx31, Lb36-42, EE LTR-DR RAP	142,318	472	(6,288)	11,006
H-Base LL, Sx35, Lb36-42, EE LTR-DR RAP	141,919	466	(6,222)	10,882
I-Base LL, Sx31, Lb42-42, EE LTR-DR RAP	141,373	461	(6,141)	10,754
J-Base LL, Sx35, Lb36-36, EE LTR-DR RAP	142,852	466	(6,284)	10,947
K-Base LL, Sx35, Lb42-42-Cofire, EE LTR-DR RAP	141,997	460	(6,123)	10,718
L-Base LL, Sx35, Lb42-42-FGD-SCR, EE LTR-DR RAP	142,743	452	(6,395)	10,916
M-Base LL, Sx35, Lb42-42, EE LTR-DR RAP	140,974	456	(6,075)	10,630
N-Low LL, Sx35, Lb42-42, EE LTR-DR RAP	125,811	382	(5,044)	8,869
O-High LL, Sx35, Lb42-42, EE LTR-DR RAP	159,299	543	(7,585)	13,013
P-Base LL, Sx35, Lb42-42, EE LTR-DR RAP, Pumped Storage	143,140	533	(6,756)	12,085
Q-Base LL, Sx35, Lb42-42, EE LTR-DR RAP, No New Nuke	134,341	388	(4,157)	8,033
R-Base LL, Sx35, Lb42-42, EE RAP-DR RAP	139,187	450	(5,941)	10,445
S-Base LL, Sx35, Lb42-42, EE MAP-DR MAP	139,083	449	(5,919)	10,413
T-Base LL, Sx35, Lb42-42, EE LTR25%-DR RAP	140,636	456	(6,075)	10,630
U-Base LL, Sx35, Lb42-42, EE LTR-DR MAP	141,029	456	(6,075)	10,630
V-Base LL, Sx35, Lb42-42, EE MEEIA 4-DR MEEIA 4	142,542	465	(6,311)	10,963
W-Base LL, Sx35, Lb42-42, EE MEEIA 4-DR RAP	141,479	456	(6,119)	10,683

³² All plans include Renewable Plus portfolios unless otherwise noted.

Plan	Integration PVRR (\$Million)	Project Cost		
		PWA	Low	High
X-Base LL, Sx35, Lb42-42, EE MEEIA 4-DR MAP	141,535	456	(6,119)	10,683
Y-Base to Low LL, Sx35, Lb42-42, EE LTR-DR RAP	129,937	431	(5,540)	9,852
Z-High to Base LL, Sx35, Lb42-42, EE LTR-DR RAP	145,416	486	(6,595)	11,455

Ameren Missouri load growth cases (low, base, and high before large load addition), along with the project cost critical independent uncertain factor, were added as nodes to the scenario probability tree that was developed in Chapter 2. The updated and expanded probability tree is shown in Figure 9.8, with the two uncertain factors shown on the right-hand side.

Figure 9.8 Final Probability Tree Including Sensitivity Analysis Results³³



³³ 20 CSR 4240-22.060(6)

9.7 Risk Analysis³⁴

At this point in the analysis, Ameren Missouri added three additional alternative resource plans to be analyzed to evaluate alternatives to building the 2,100 MW West Alton CC facility, which is planned to be located adjacent to the Company's existing coal-fired Sioux Energy Center. Only dispatchable resources that could be reasonably expected to be placed in-service in early 2030s were considered for these additional plans.³⁵

Table 9.12 Additional Alternative Resource Plans

Plan Name (LL, Coal Retirement-Modification, DSM)	Renewables	New Supply-Side
AA Base LL, Sx35, Lb42-42, EE LTR-DR RAP, SC instead of CC	RES Plus for Low & Base LL	SC300 2030, SC2100 2032, CC 2033, CC 2036, Nuke 2040, CC 2043, SC 2043, SC 2043, SC 2045
BB Base LL, Sx35, Lb42-42, EE LTR-DR RAP, Fuel Cells instead of CC	RES Plus for Low & Base LL	SC300 2030, Fuel Cell2100 2032, CC 2033, CC 2036, Nuke 2040, CC 2043, SC 2043, SC 2043, SC 2045
ZZ Base LL, Sx35, Lb42-42, EE LTR-DR RAP, No Replacement Resource for CC	RES Plus for Low & Base LL	SC300 2030, CC 2033, CC 2036, Nuke 2040, CC 2043, SC 2043, SC 2043, SC 2045

The Risk Analysis consisted of analyzing each of the candidate resource plans in Table 9.6 and Table 9.12 under each set of assumptions described by each of the branches on the final probability tree shown in Figure 9.8. The probability tree consisted of 135 different branches. Each branch is the combination of different value levels among the fifteen scenarios, themselves defined by combinations of the three critical dependent uncertain factors (Eastern Interconnect load growth, gas prices, and environmental regulations/carbon policy), and the two critical independent uncertain factors (project cost and Ameren Missouri load growth excluding large loads). Each branch therefore represents a unique combination of the critical uncertain factors. Once all the combinations are calculated, the sum of the individual branch probabilities equals 100%.

Risk Analysis Results

The PVRR results of the risk analysis of the 29 alternative resource plans are shown in Figure 9.10. The levelized rate results for the risk analysis are shown in Figure 9.11. Rates are levelized on a nominal basis and represent the average annual rate over the full planning horizon.³⁶ The PVRR results are significantly lower for plans with lower loads

³⁴ 20 CSR 4240-22.060(6)

³⁵ File No. EA-2025-0238

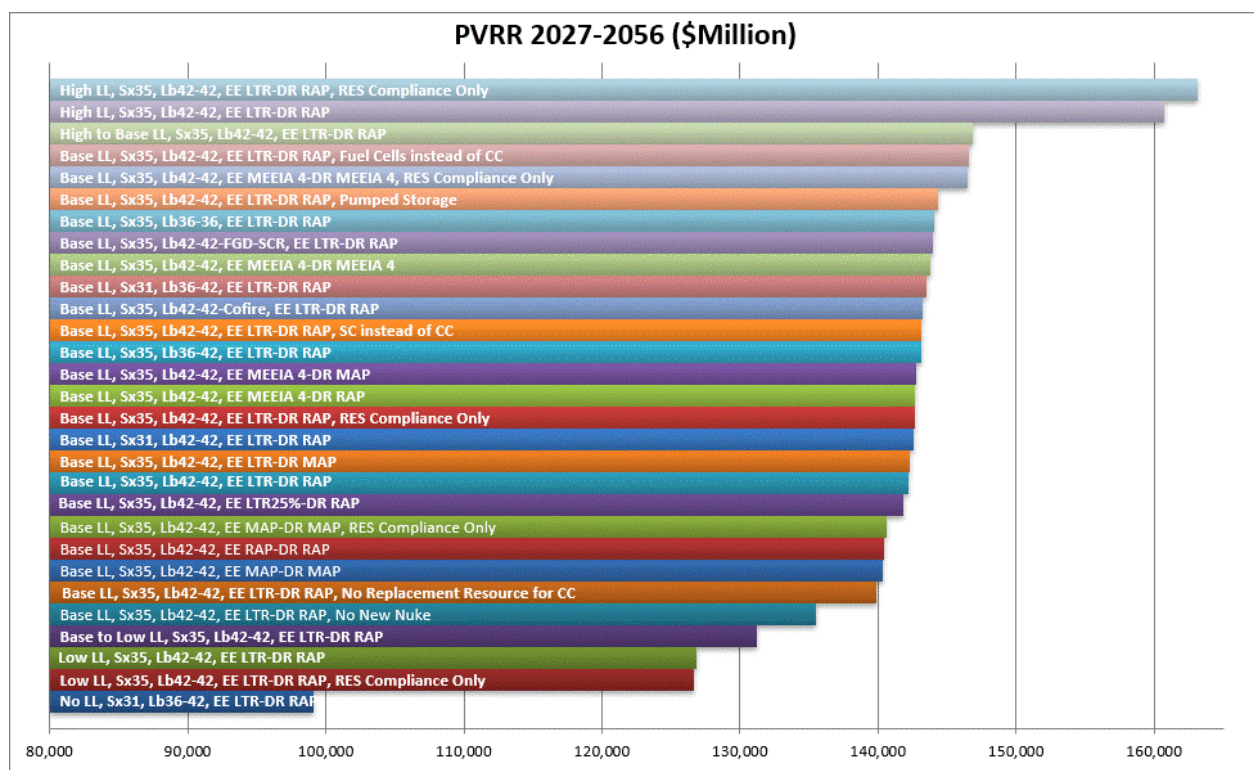
³⁶ Levelized nominal rates is the single constant dollar value that, when applied over the analysis period, produces the same present value as the entire stream of projected future nominal revenue requirements. Because the calculation is performed using nominal dollars, future costs include expected inflation and

than higher loads while levelized rates are higher for plans with lower levels of load. Plan A, which has No LL has the lowest PVRR and the highest levelized rate. In contrast, Plan F with High LL and RES Compliance Only renewables yields the highest PVRR and one of the lowest levelized rates.

Plans with DSM yield lower PVRR compared to plans without DSM or lower levels of DSM, and the same generally holds true for levelized rates. RES Plus portfolios generally result in lower PVRR and levelized rates than RES Compliance Only portfolios. Lastly, delaying the retirement of coal units results in lower PVRR and lower levelized rates.

Results for all performance measures can be found in Chapter 9 - Appendix A.

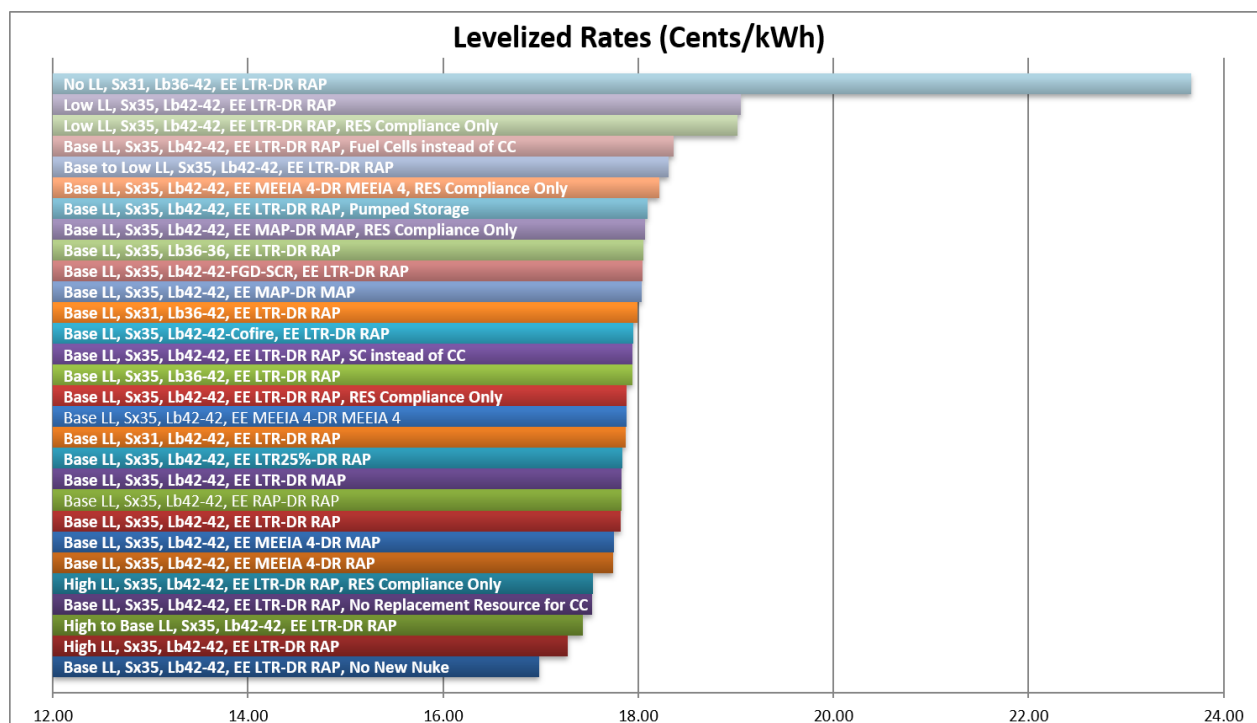
Figure 9.10 Probability-Weighted PVRR Results³⁷



other escalations. As a result, the levelized nominal value will generally be higher than an equivalent levelized real value expressed in constant dollars without inflation.

³⁷ All plans include RAP DSM and Renewable Expansion portfolios unless otherwise noted.

Figure 9.11 Probability-Weighted Levelized Rate Results



Since decision making is multi-dimensional, Ameren Missouri created a scorecard that embodies its planning objectives to evaluate the performance of alternative resource plans. With 29 alternative resource plans, Ameren Missouri can take a closer look at the performance of the plans by evaluating their relative strengths and weaknesses in meeting our planning objectives and whether other factors may be important in the selection of the preferred resource plan. Chapter 10 – Strategy Selection includes the additional analysis and decision-making considerations that inform the selection of the Resource Acquisition Strategy.

9.8 Conclusions from Integration and Risk Analysis

Below are several conclusions from the integration and risk analysis.

- The higher the large load additions, the higher the PVRR and the lower the levelized rates are. Reductions in large load demand, going from either the high to the base case or base case to the low case, reduces revenue requirements relative to plans in which the higher large load persists. This analysis does not take into account allocation of costs between large load customers and other customers nor any safeguards that are included in the Company's large load tariff.
- Inclusion of DSM resources results in lower costs than adding more supply-side alternatives. This finding demonstrates that using an avoided capacity curve at

cost of new entry as demonstrated in Chapter 2 is useful for ensuring inclusion of a broad range of demand-side portfolios for IRP analysis, in which avoided costs are more explicitly modeled. Using a more restrictive capacity curve could have resulted in screening out DSM resources that may ultimately prove to be lower cost options when compared to supply-side alternatives.

- Among different demand-side portfolios, No Further DSM after MEEIA 4 plans result in higher PVRR than plans with continued energy efficiency, while plans including RAP EE result in lower PVRR compared to plans with different levels of EE except for plans with MAP EE. Similarly, implementing DR results in lower costs than no further DR, with the RAP level of DR yielding a lower PVRR than the MAP level.
- Sioux 2035 retirement results in lower cost than 2031 retirement. For Labadie, 2042 retirement for all four units yields the lowest PVRR, while early retirement of Labadie's four units by the end of 2036 results in the highest costs among the Labadie retirement options. Adding environmental mitigation options does result in lower costs than early retirement, albeit very slightly for the plan with FGD-SCR systems.
- Including more renewable resources beyond those required for RES compliance for plans with the base or the high large load additions, such as Plans C and F, reduces costs and customer rates compared to plans that have the same attributes but RES Compliance Only additions. For the low large load case, the results are reversed, but only to a mild disadvantage for additional renewables.³⁸
- The alternative resource plan that adds only dispatchable resources, i.e., no additional DSM and no additional renewables beyond RES Compliance, is among the costliest plans among the plans with base large loads.
- Pumped storage replacing a simple cycle, as well as fuel cells or a simple cycle replacing a combined cycle, results in higher costs. Conversely, replacing a nuclear resource with combined cycle reduces PVRR.³⁹

9.9 Resource Plan Model

Ameren Missouri has used a modular approach to modeling for this IRP as it did in its previous IRPs since 2017. Instead of using MIDAS or other off-the-shelf alternatives for integration and risk analyses, Ameren Missouri continues to use a combination of stand-alone models for 1) production costing, 2) market settlements, 3) revenue requirements,

³⁸ 20 CSR 4240-22.060(4)(E)

³⁹ File No. EA-2025-0238

and 4) financial statements. Items 2-4 on this list are collectively referred to as the “Financial Model”. This approach permitted analysts maximum flexibility, customization and trouble-shooting capabilities. It also lends itself to greater transparency for stakeholders by limiting the use of proprietary third-party software.

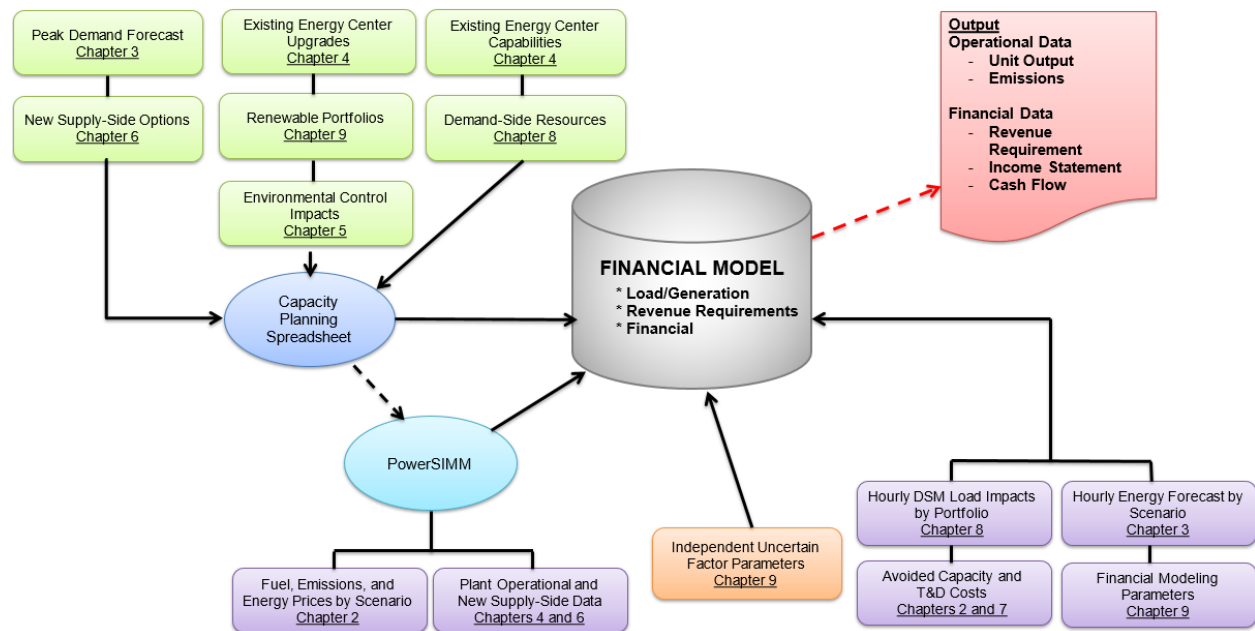
Ameren Missouri used a generation simulation model from Ascend Analytics, typically referred to as PowerSIMM for production cost modeling.⁴⁰ PowerSIMM provides a realistic simulation of an electric generating system for a period of a few days to multiple years.

PowerSIMM simulates hourly dispatch of all system generating units, including unit commitment logic that is consistent with the operational characteristics and constraints of system resources. The PowerSIMM model contains all unit operating variables required to simulate the units. These variables include, but are not limited to, heat rates, fuel costs, variable operation and maintenance costs, emission rates, emission allowance costs, scheduled maintenance outages, and full and partial forced outage rates. Each generation unit is dispatched competitively against market prices, which were discussed in Chapter 2.

Ameren Missouri developed its own revenue requirements and financial model using Microsoft Excel. This model incorporates the capacity position and PowerSIMM outputs, as well as other financial aspects regarding costs external to the direct operation of units and other valuable information that is necessary to properly evaluate the economics of a resource portfolio. The financial portion of the model produces bottom-line financial statements to evaluate profitability and earnings impacts along with revenue requirement and various financial and credit metrics.

Figure 9.12 shows how the various assumptions are integrated into the financial model.

⁴⁰ 20 CSR 4240-22.060(4)(H)

Figure 9.12 Resource Plan Model Framework⁴¹

Future Plans for Modeling Tools

Ameren Missouri plans to continue to evaluate options for modeling tools for use in its resource planning process. Having developed a modular approach to our modeling, we have the flexibility to evaluate models with varying degrees of capabilities (production costing, market settlements, revenue requirements, and financial statements) that can be used in place of, and/or in combination with, the current modules. New IRP rules are expected to include requirements for the use of capacity expansion optimization software in addition to our current modeling approach. Ameren Missouri included an evaluation of capacity expansion optimization models in its 2025 IRP Annual Update and continues to evaluate options for future modeling work. While several tools are available in the market, we expect that acquiring any such tools and developing the capabilities needed for their proficient use will take several years. At the same time, there may be a desire for Missouri utilities to standardize on particular tools or tool sets for IRP analysis. As a result, we expect that our modeling needs over time will be characterized more by evolution rather than the deployment of a single integrated solution.

Our current modular approach was in large part an outcome of our evaluation of solutions that were, and continue to be, commercially available. For example, we were unable to identify any available integrated solutions that produce full financial statements, and that remains true today. Our current approach also allows us to expand our review of

⁴¹ 20 CSR 4240-22.060(4)(H)

production costing solutions beyond those used primarily for long-term resource planning. We are currently using a production cost modeling software PowerSIMM for use in our fuel budgeting and short-term trading support analysis which has the potential to support longer term analysis like the IRP.

We expect to continue our efforts to improve the efficiency, effectiveness, and transparency of our modeling tools going forward. The nature and timing of any changes we make will largely be a function of regulatory requirements and our assessment of the currently available options. As we consider these options, we plan to share thoughts with other Missouri utilities and with our stakeholder group. This may or may not provide opportunities to move to a common modeling platform. In the meantime, it may be appropriate to outsource any capacity expansion optimization modeling to consultants with experience in using such tools. Ameren Missouri has used consultants to perform the price modeling work discussed in Chapter 2 for both this IRP and the Company's 2023 IRP. That work includes the use of capacity expansion optimization modeling at a market level, so the capabilities could be readily used for utility-specific modeling of the kind included in new draft IRP rules. Ameren Missouri will remain open to potential modeling solutions while ensuring that its own tools and processes are able to support the Company's business needs and objectives.

9.10 Compliance References

20 CSR 4240-20.100(5)	6
20 CSR 4240-22.010(2)	10
20 CSR 4240-22.010(2)(A)	9, 12
20 CSR 4240-22.010(2)(B)	11
20 CSR 4240-22.010(2)(C)	10
20 CSR 4240-22.040(5)	18
20 CSR 4240-22.040(5) (B) through (F)	18
20 CSR 4240-22.060(1)	2
20 CSR 4240-22.060(2)(A)1	11
20 CSR 4240-22.060(2)(A)4	11
20 CSR 4240-22.060(2)(A)6	10
20 CSR 4240-22.060(2)(A)7	11
20 CSR 4240-22.060(2)(B)	11, 17
20 CSR 4240-22.060(3)	2, 11, 12
20 CSR 4240-22.060(3)(A)1	16
20 CSR 4240-22.060(3)(A)1 through 8	12
20 CSR 4240-22.060(3)(A)3	15
20 CSR 4240-22.060(3)(A)6	15
20 CSR 4240-22.060(3)(B)	12, 16
20 CSR 4240-22.060(3)(C)1	12
20 CSR 4240-22.060(3)(C)2	12
20 CSR 4240-22.060(3)(C)3	12
20 CSR 4240-22.060(3)(D)	16
20 CSR 4240-22.060(4)	17
20 CSR 4240-22.060(4)(E)	30
20 CSR 4240-22.060(4)(H)	31, 32
20 CSR 4240-22.060(5)	18, 23
20 CSR 4240-22.060(5) (A) through (M)	18
20 CSR 4240-22.060(6)	23, 26, 27
20 CSR 4240-22.060(7)(A)	23
20 CSR 4240-22.060(7)(C)1A	20, 23
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20 CSR 4240-22.080(2)(D)	16
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