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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. EA-2025-0239

DIRECT TESTIMONY

OF

MATT MICHELS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
August, 2025

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DIRECT TESTIMONY

OF

MATT MICHELS

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I. INTRODUCTION

Q. Please state your name and business address.

A. Matt Michels, Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. What is your position with Ameren Missouri?

A. I am the Director of Corporate Analysis.

Q. Please describe your educational background and employment experience.

A. I joined Ameren Services Company in 2005 as a Consulting Engineer in Corporate Planning. My responsibilities included coordination of the integration of processes and systems following the acquisition by Ameren Corporation of Illinois Power Company ("Illinois Power") in October 2004. I was subsequently involved in the integration of combustion turbine facilities acquired by Ameren Missouri in 2006. In September 2008, I was promoted to Managing Supervisor of Resource Planning with responsibility for long-range resource planning, including Ameren Missouri's Integrated Resource Plan ("IRP") filings and associated analysis. In February 2013, I was promoted to Corporate Analysis Manager, and in June 2017, I was promoted to my current position. In that capacity, I continue to have direct responsibility for Ameren Missouri's resource planning process, including plans that include significant new load additions, such as data centers.

I earned a Bachelor of Science degree in Electrical Engineering from the University of Illinois at Urbana-Champaign in May 1990. I have been employed by Ameren or Illinois Power since June 1990 in various positions related to resource and business planning. During most of that time, my responsibilities have included the development, use and oversight of various planning models used for purposes such as production costing, acquisition evaluation, corporate restructuring, financial forecasting, and resource planning. I have previously testified before this Commission in proceedings involving resource planning, natural gas-fired resources, renewable energy resources, and energy efficiency.

II. PURPOSE OF TESTIMONY AND KEY CONCLUSIONS

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to support the Company's application for a certificate of convenience and necessity ("CCN") for the construction of a solar generation facility, to be known as the Reform Solar Project ("the Project"), in Callaway County, Missouri.

Q. What are the key conclusions reflected in your Direct Testimony?

A. The key conclusions of my Direct Testimony are:

- The Project will meet the energy needs of existing and new customers, including new large load customers ("LLC"), consistent with the Company's preferred resource plan ("PRP");

- The Project will provide renewable energy credits ("RECS") that are needed to meet the Company's Missouri Renewable Energy Standard ("RES") obligations; and
- The Project provides several other important benefits because it can be implemented in the near-term, including avoiding the risk of delays if the Company were to wait to add additional energy resources, allowing the Company to take advantage of valuable federal tax credits that are available for the Project now, and providing an important hedge against fuel costs and critical risk mitigation against existing or future environmental regulations that could negatively impact the production of energy from the Company's fossil-fueled resources.

III. AMEREN MISSOURI'S PREFERRED RESOURCE PLAN AND NEED FOR ENERGY AND RECS

Q. Did Ameren Missouri change its PRP from the one included in the Company's 2023 triennial Integrated Resource Plan ("IRP") filing?

A. Yes. Ameren Missouri filed a Notice of Change in PRP with the Missouri Public Service Commission ("Commission") on February 28, 2025.[1] The Company's formal Notice of Change in PRP is attached to my testimony as **Schedule MM-D1**.

Q. What were the main reasons for changing the Company's PRP?

A. There were two primary reasons. First, the Company has seen a surge in interest from LLCs locating in Ameren Missouri's service territory and has signed construction agreements relating to over two gigawatts of new load. Peak demand for

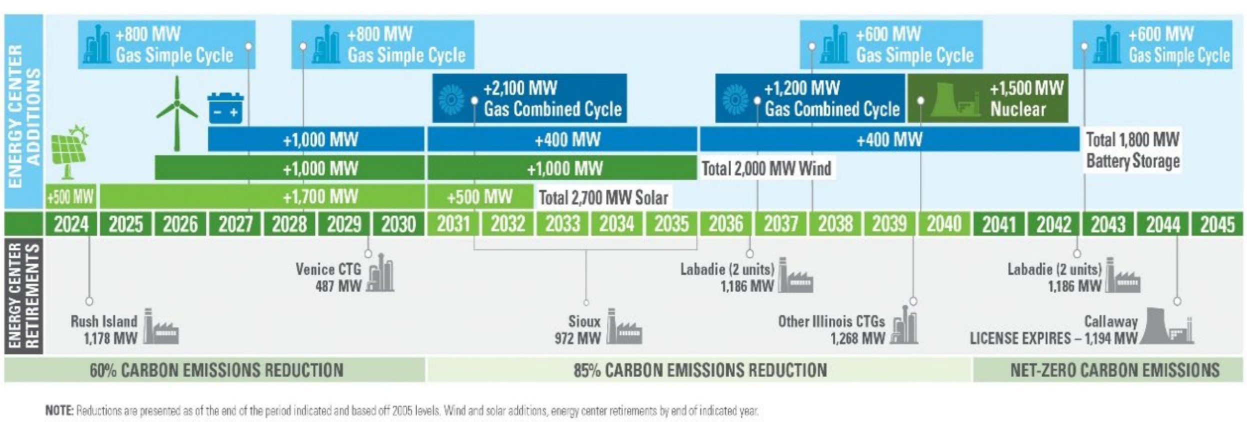
[1] On February 13, 2025, Ameren Missouri filed a brief notice of its intent to file a formal Notice of Change in PRP. The formal notice was filed in accordance with 20 CSR 4240-22.080(12).

individual LLCs can range from 100 megawatts ("MW") to over a gigawatt ("GW"). As discussed in Company witness Ajay Arora's Direct Testimony, the Company expects as much as approximately 2 GW of such loads to begin ramping up on the system as early as 2026 and to be fully ramped-up within three to five years. Given the Company's obligation to serve, a change in the PRP was necessary to accelerate the resources needed to reliably provide service. Second, while significantly less impactful from an overall portfolio perspective, the reductions in anticipated demand and energy savings based on the conclusion of the case involving its most recent application for demand-side program approval under the Missouri Energy Efficiency Investment Act ("MEEIA") required that the Company reassess its long-term capacity and energy position.

Q. Please describe the Company's current PRP as modified pursuant to its February 28, 2025, Notice of Change in PRP.

A. The Company's current PRP is shown in Figure 1 below, which shows the Company's planned timeline for resource retirements and additions through 2043.

Figure 1. Ameren Missouri 2025 PRP



As Figure 1 shows, the Company's PRP reflects the following:

- Retirement of Sioux Energy Center ("SEC") as early as the end of 2031 and as late as the end of 2035.[2] The retirement date range reflects the need for flexibility to retire the existing coal units at the site only when planned new generation at the site becomes fully operational. That flexibility is important in part because of the long lead time necessary to construct and commission such generation, which can be impacted by supply chains for equipment, materials, and labor.
- Retirement of two units at Labadie Energy Center at the end of 2036 and the remaining two units at the end of 2042. This remains unchanged from the Company's 2023 IRP preferred plan.
- Retirement of Venice Energy Center, a natural gas simple cycle ("NGSC") facility located in Illinois, at the end of 2029. The retirement of Venice is required to comply with the requirements of Illinois' Climate and Equitable Jobs Act ("CEJA"), enacted in 2021, and remains unchanged from the Company's 2023 IRP preferred plan.
- Retirement of the Company's remaining Illinois NGSC facilities at the end of 2039, also to comply with CEJA and unchanged from the Company's 2023 IRP preferred plan.

[2] For modeling purposes, the retirement date for Sioux was assumed to be December 31, 2031, and the in-service date for the replacement generation was assumed to be January 1, 2032.

- Addition of 800 MW of NGSC capacity in late 2027 – the Castle Bluff facility for which the Commission approved a CCN in October 2024 – unchanged from the Company's 2023 IRP preferred plan.[3]
- Addition of another 800 MW of NGSC capacity in late 2028 at the former site of the Company's coal-fired Rush Island Energy Center, which was retired in October 2024 – the Big Hollow Energy Center ("BHEC"), which includes a planned NGSC for which the Company is currently seeking a CCN.[4] This is a new addition not previously explicitly reflected in the Company's 2023 IRP preferred plan but also represents an acceleration of a portion of the "clean dispatchable" resources the Company had planned to add by 2040, as indicated in its 2023 IRP. Adding this generation by 2028 is also driven by the need to make use of the former Rush Island coal plant's valuable transmission interconnection rights without the extended time that would be needed for a new generator interconnection request, and the risks associated with such a new request were one to become necessary for failure to implement new generation at Rush Island by September 1, 2028.
- Addition of 1,000 MW of wind generation by 2030 and another 1,000 MW by 2035, unchanged from the Company's 2023 IRP preferred plan.
- Addition of 2,200 MW of solar generation by 2030 (including 500 MW placed in service in late 2024,[5] another 400 MW for which the Commission

[3] File No. EA-2024-0237.
[4] File No. EA-2025-0238.
[5] Ameren Missouri's Huck Finn, Cass County, and Boomtown solar energy centers.

approved CCNs,[6] and another 1,300 MW, including the Reform project for which the Company is seeking a CCN in this case) and another 500 MW by 2035. This represents an acceleration of solar generation additions from that planned in the Company's 2023 IRP preferred plan. Renewable resource additions are a particularly important consideration in attracting and serving new LLCs, such as data centers.

- Addition of 1,000 MW of battery energy storage systems ("BESS") by 2030, 400 MW of which is planned for the BHEC and for which the Company is currently seeking a CCN,[7] another 400 MW by 2036, and another 400 MW by 2042, for a total of 1,800 MW.[8] This also represents an acceleration as compared to the 2023 PRP, as well as an increase, relative to the 800 MW of BESS additions included in the Company's 2023 PRP. Adding 400 MW of BESS at the former site of the Company's Rush Island Energy Center by September 1, 2028, like the gas generation addition at Rush Island, allows us to take advantage of the valuable transmission interconnection rights that already exist at the Rush Island site.
- Addition of 2,100 MW of natural gas combined cycle ("NGCC") capacity by the end of 2031 and another 1,200 MW of NGCC capacity by the end of 2036. This represents an acceleration of a portion of the "clean

[6] Ameren Missouri's planned and under construction Split Rail, Bowling Green, and Vandalia solar energy centers.
[7] File No. EA-2025-0238.
[8] All BESS included in the PRP is assumed to be 4-hour lithium-ion battery storage for modeling purposes. Additions beyond 2030 may deploy technologies currently under development.

dispatchable" resources included in the Company's 2023 IRP preferred plan, shown in 2040 and 2043.

- Addition of a further 600 MW of NGSC capacity at the beginning of 2038 and another 600 MW of NGSC capacity at the beginning of 2043, both representing new additions relative to the Company's 2023 IRP preferred plan.
- Addition of 1,500 MW of nuclear generation at the beginning of 2040. This represents the addition of further clean dispatchable generation, with the selection of specific technology to be made at a later date.[9]

Q. How did Ameren Missouri arrive at its PRP?

A. In short, Ameren Missouri evaluated a range of potential outcomes, or cases, for new large loads, determined for each case the need for acceleration and addition of resources relative to its 2023 PRP to meet load and MISO planning reserve margin ("PRM") requirements, and selected the plan that 1) best represents expectations at the time the 2025 PRP was adopted of future large load additions, 2) provides some flexibility in the near term regarding further large load additions, and 3) ensures that the Company maintains both short-term and long-term resource flexibility to address various risks to its portfolio and to facilitate compliance with both the letter and spirit of recently passed statutory provisions included in SB 4 to ensure reliable service to all customers.

Q. Please describe the LLC cases that were evaluated.

A. Ameren Missouri evaluated seven different load cases, as shown in Table 1 below. The seven cases reflect three different levels of large load additions in the near term

[9] For modeling purposes, the Company's assumptions for modular nuclear generation were used.

– 500 MW, 1,500 MW, and 2,000 MW by 2032. Cases 1-3 reflect no further growth in large loads after 2032. Cases 4 and 5 reflect continued growth from 1,500 MW and 2,000 MW loads achieved by 2032, respectively, to 2,500 MW and 3,500 MW, respectively, by 2040. Cases 6 and 7 reflect no further growth in large loads after 2032 (1,500 MW and 2,000 MW in place by 2032, respectively), then a reduction in large loads to 500 MW in 2039. Cases 6 and 7 are used as the basis for evaluating the cost of resource acceleration to meet near-term LLC demand, as I explain later in my Direct Testimony.

Table 1. Large Load Cases – Annual Peak Demand (MW) at Meter[10]

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1 500 MW by 2032	300	500	500	500	500	500	500	500	500	500	500	500	500	500	500
2 1,500 MW by 2032	300	500	700	1,000	1,200	1,400	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
3 2,000 MW by 2032	300	700	1,000	1,300	1,600	1,900	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
4 1,500 MW by 2032 and 2,500 MW by 2040	300	500	700	1,000	1,200	1,400	1,500	1,625	1,750	1,875	2,000	2,125	2,250	2,375	2,500
5 2,000 MW by 2032 and 3,500 MW by 2040	300	700	1,000	1,300	1,600	1,900	2,000	2,200	2,400	2,600	2,800	3,000	3,200	3,400	3,500
6 1,500 MW by 2032 dropping to 500 MW	300	500	700	1,000	1,200	1,400	1,500	1,500	1,500	1,500	1,500	1,500	1,500	500	500
7 2,000 MW by 2032 dropping to 500 MW	300	700	1,000	1,300	1,600	1,900	2,000	2,000	2,000	2,000	2,000	2,000	2,000	500	500

Q. What kind of load factor was assumed for the additional large load demand?

A. A load factor of 85% was used. This results in additional sales of approximately 4 million MWh for each 500 MW of large load demand.

Q. What resources are needed to meet customer demand and energy needs in each of the seven load cases you just described?

A. The resource additions for each case are summarized in the attached **Schedule MM-D2**. Note that a further 900 MW of solar resources, including the Reform Project for which the Company is seeking a CCN in this case, is needed even if the Company realizes only a small part of the new LLC demand we are planning for – just 500

[10] Large load demand is assumed to begin at the levels shown on January 1st of each calendar year.

MW. Mr. Arora discusses the Company's expectations with respect to LLC demand in his Direct Testimony.

Q. Which case did the Company choose for inclusion in its recently adopted PRP?

A. Ameren Missouri chose Case 4 for inclusion in its PRP and therefore as the basis for determining resource needs. Based on on-going discussions with potential customers, it is also actively planning for Case 5 as an alternative scenario, as I discuss later in my Direct Testimony and as Mr. Arora discusses in his Direct Testimony.

Q. Is it possible that large load demand could exceed the amounts included in the PRP?

A. Yes. Ameren Missouri has included Case 5 as an alternative plan in the Notice of Change in PRP filed with the Commission on February 28, 2025.[11] It should be noted that resource additions through 2032 for Case 5 are identical to those included for Case 4. This provides flexibility in the near term as the Company continues to evaluate requests for connection and service from prospective customers.

Q. Please explain why the Company chose to accelerate its addition of solar generation when it adopted its new PRP.

A. As the Company has previously described in its 2023 IRP and in several CCN application cases in recent years, it is important to replace the Company's fleet as aging coal-fired energy centers retire, ensuring reliability, maintaining affordability, and addressing risks regarding the over-reliance on fossil fuels, including exposure to future environmental regulations. The Company's replacement plans target a balanced portfolio

[11] Schedule MM-D1, page 6, Table 1.1.

mix of both dispatchable generation and renewable energy resources that have no on-going fuel costs associated with the production of energy. Solar resources, along with efficient natural gas, wind, storage resources, and nuclear generation, play a key role in that transition. The addition of increased demand from LLCs, who also place a high value on the role of lower emitting resources, means more energy generation is needed to serve rising customer energy needs in addition to meeting their needs during times of peak demand, which can be met with peaking resources like NGSC and BESS. While potential wind projects can also be attractive for providing additional energy generation, solar projects have proven to pose fewer implementation challenges relative to wind projects and provide energy generation during summer peak times. As the Company has explained in its application for a tariff to provide service to LLCs,[12] making sure renewable resources are timely available to address prospective customers' energy needs and their desire to meet their carbon free energy goals is important to attracting the customers in the first place.

Q. What portion of the Company's annual energy production capability is expected to be provided by renewable energy under the plan reflecting Load Case 5?

A. While actual energy production from the Company's fleet depends on a number of factors, including fuel and energy prices and weather conditions, renewables are expected to provide around 30% of the Company's energy production capability. The charts in Figures 2 and 3 below show the Company's expected mix of energy production capability for the years 2030 and 2035, respectively.

[12] File No. ET-2025-0184.

Figure 2. Energy Production Capability Mix – Load Case 5 - 2030

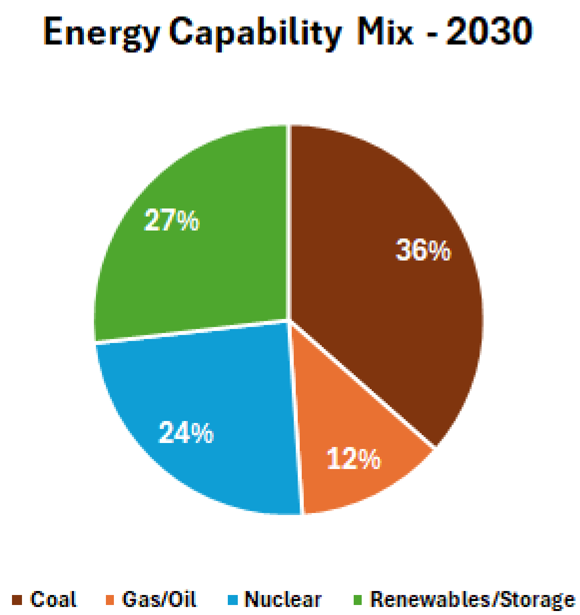
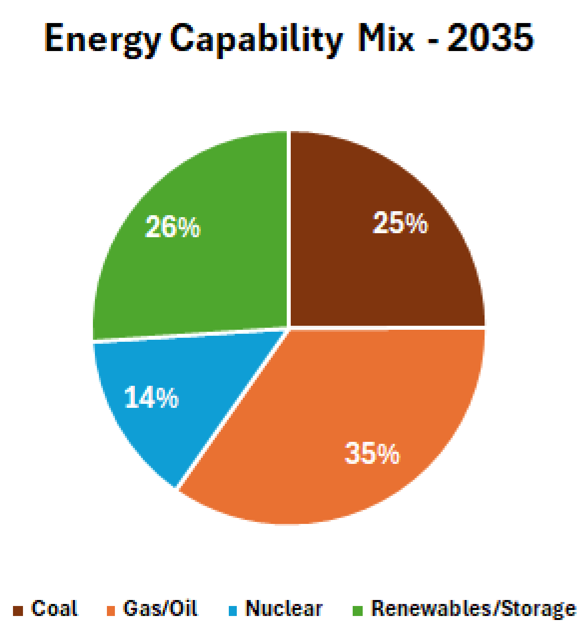


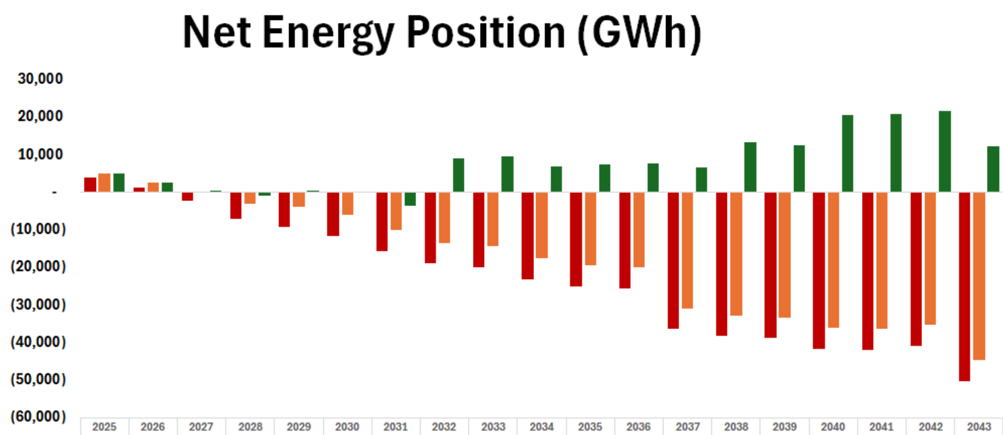
Figure 3. Energy Production Capability Mix – Load Case 5 - 2035



Q. One of your key conclusions is that the Project is necessary to meet the energy needs of new and existing customers. How did you determine this?

A. In short, by looking at the Company's expected energy position without new resources. Figure 4 below shows the Company's energy position based on load Case 5 in Table 1 and reflects the full expected energy production capability of generation resources. This is in contrast to forecasted energy positions based on expected economic dispatch of generating units, which may or may not require the full utilization of generators during the year based on market conditions. Instead, we consider the levels of production of each unit if it were operated at its full capability in every hour in which it is available. For example, the Company's existing combustion turbine generators ("CTG") are subject to permit constraints on the number of hours they can be operated during the year, so their energy production capability is based on operating for that limited number of hours. All thermal units are subject to potential forced outages, and intermittent renewable resources like wind and solar are subject to weather conditions, so we make reasonable assumptions for capacity factors based on the characteristics of each resource. Because we use the full energy production capability of resources, I refer to the resultant energy position as an "energy capability position." A summary of the assumptions used for determining generating capability used to develop energy capability positions is shown in Schedule MM-D3.

Figure 4. Energy Capability Position With and Without New Resources – Case 5 Load, Normal Weather



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Only Existing Resources	3,755	1,150	(2,207)	(7,233)	(9,360)	(11,699)	(15,621)	(19,032)	(19,878)	(23,166)	(25,027)	(25,576)	(36,504)	(38,329)	(38,926)	(41,693)	(41,936)	(40,855)	(50,364)
Existing and Approved Resources	4,893	2,517	(157)	(3,080)	(3,806)	(6,145)	(10,067)	(13,478)	(14,324)	(17,613)	(19,473)	(20,022)	(30,950)	(32,775)	(33,372)	(36,139)	(36,382)	(35,301)	(44,810)
Existing and All Planned Resources	4,893	2,517	445	(1,039)	129	(199)	(3,581)	8,998	9,418	6,874	7,331	7,510	6,577	13,160	12,550	20,645	20,762	21,695	12,304

Only Existing Resources   Existing and Approved Resources   Existing and All Planned Resources

Q. What does the energy capability position in Figure 4 show?

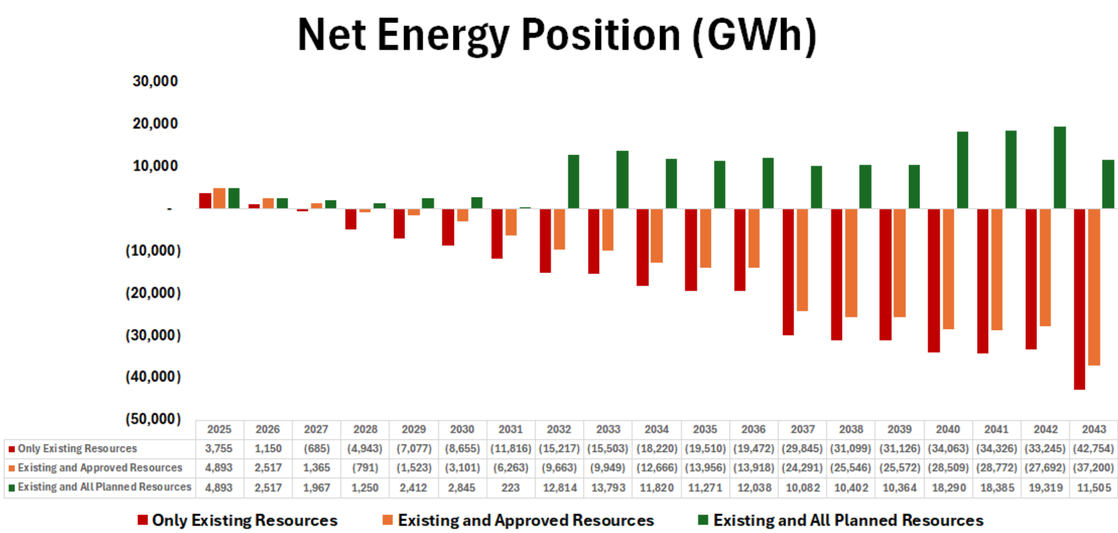
A. It shows that without new resources, the Company expects to be short energy capability starting in 2027 and continuing through the planning horizon at steadily increasing levels. If approved resources are included, the shortfall is reduced but still persists from 2027 through the end of the planning horizon.[13] If all planned resources, including the Project, are included, the energy capability of the Company's portfolio is sufficient to cover expected load in all but three years – 2028 (approximately one million MWh short), 2030 (approximately 200 thousand MWh short), and 2031 (approximately 3.6 million MWh short). For those years and based on the modeled assumptions, the Company would be a net purchaser of energy in the MISO market.

[13] "Approved resources" include the Castle Bluff NGSC and 400 MW of solar resources for which the Commission has approved CCNs but have not been placed in service – Split Rail, Vandalia, and Bowling Green. For purposes of the energy capability positions presented here, I have also included the Big Hollow NGSC and BESS facilities for which the Company is currently seeking CCNs.

Q. Have you also examined the Company's energy capability positions for Case 4 loads?

A. Yes. Figure 5 below shows the Company's expected energy capability position for its PRP, which reflects Case 4 loads. As with Case 5 loads, there is an energy capability shortfall starting in 2027 and persisting through the planning horizon. Adding approved resources delays the start of energy shortfalls to 2028, and including all planned resources results in sufficient energy capability to cover load in all years.

Figure 5. Energy Capability Position With and Without New Resources – Case 4 Load, Normal Weather



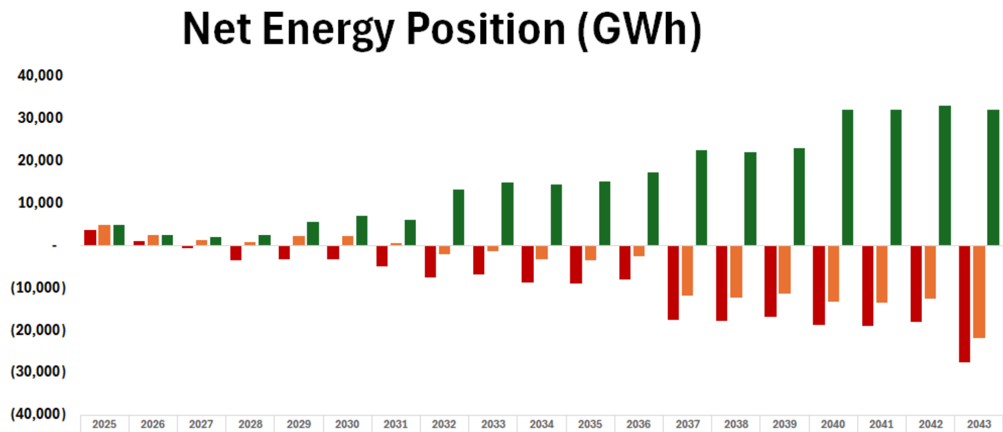
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Only Existing Resources	3,755	1,150	(685)	(4,943)	(7,077)	(8,655)	(11,816)	(15,217)	(15,503)	(18,220)	(19,510)	(19,472)	(29,845)	(31,099)	(31,126)	(34,063)	(34,326)	(33,245)	(42,754)
Existing and Approved Resources	4,893	2,517	1,365	(791)	(1,523)	(3,101)	(6,263)	(9,663)	(9,949)	(12,666)	(13,956)	(13,918)	(24,291)	(25,546)	(25,572)	(28,509)	(28,772)	(27,692)	(37,200)
Existing and All Planned Resources	4,893	2,517	1,967	1,250	2,412	2,845	223	12,814	13,793	11,820	11,271	12,038	10,082	10,402	10,364	18,290	18,385	19,319	11,505

Q. You mentioned that the Project is necessary even if only 500 MW of new additional load is realized. Have you prepared an energy capability position for Case 1 loads?

A. Yes. Figure 6 shows the Company's expected energy capability position for Case 1 loads. As with the other two load cases, this shows an energy capability shortfall starting in 2027 and continuing throughout the planning horizon absent new resources.

With all planned resources, the energy capability would be sufficient to meet load in all years.

Figure 6. Energy Capability Position With and Without New Resources – Case 1 Load, Normal Weather



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Only Existing Resources	3,755	1,150	(685)	(3,417)	(3,272)	(3,328)	(4,968)	(7,586)	(6,941)	(8,708)	(9,046)	(8,026)	(17,479)	(17,782)	(16,858)	(18,801)	(19,107)	(18,026)	(27,534)
Existing and Approved Resources	4,893	2,517	1,365	735	2,282	2,226	586	(2,032)	(1,388)	(3,154)	(3,492)	(2,472)	(11,925)	(12,228)	(11,304)	(13,247)	(13,553)	(12,472)	(21,981)
Existing and All Planned Resources	4,893	2,403	2,024	2,549	5,534	6,919	6,161	13,112	14,908	14,342	15,199	17,177	22,448	22,143	23,056	31,974	32,028	32,962	31,980

Only Existing Resources   Existing and Approved Resources   Existing and All Planned Resources

Q. The energy capability position with all planned resources shows a very large surplus in the later years of the planning horizon. Does the Company expect to generate that much energy beyond its load?

A. No. As I mentioned previously, the charts above reflect energy production capability rather than expected generation based on future market conditions. To see energy positions reflecting the expected economic dispatch of the Company's fleet, we need to look at a different set of charts that reflect those expectations. Figures 7-9 below show the expected economic energy position representing forecast energy production based on modeled economic dispatch. Figure 7 shows that the Company would expect to be a net purchaser of energy based on economic dispatch in MISO in a number of years until 2032 – four million MWh or less in all but 2032 (about seven million MWh) – and in some years between 2035 and 2039 (five million MWh or less) based on Case 5 loads. In years where the Company would be a net seller, the sales are, in general, significantly less than the Company's historical (over the past decade or two) net energy sales and which for many years created a substantial offset to net energy costs in the Company's fuel adjustment clause. Figure 8 shows that the Company would expect to be a net purchaser of economic energy in a handful of years, never much more than three million MWh, with most years showing a net surplus, although still less than the Company's historical surplus in most years. Figure 9 shows that only 2027 would be short economic energy, with surpluses up to twelve million MWh in some years through 2040 (less than ten million MWh in most years), which would be within the range of the Company's historical surplus.

**Figure 7. Economic Energy Position (MWh) –
Case 5 Load, Normal Weather**

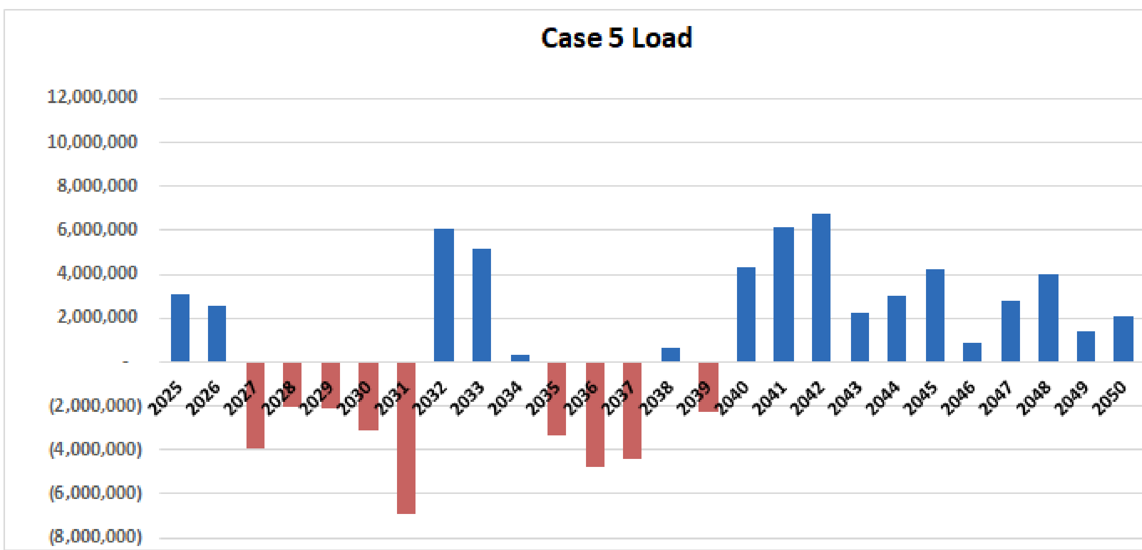


Figure 8. Economic Energy Position (MWh)– Case 4 Load, Normal Weather

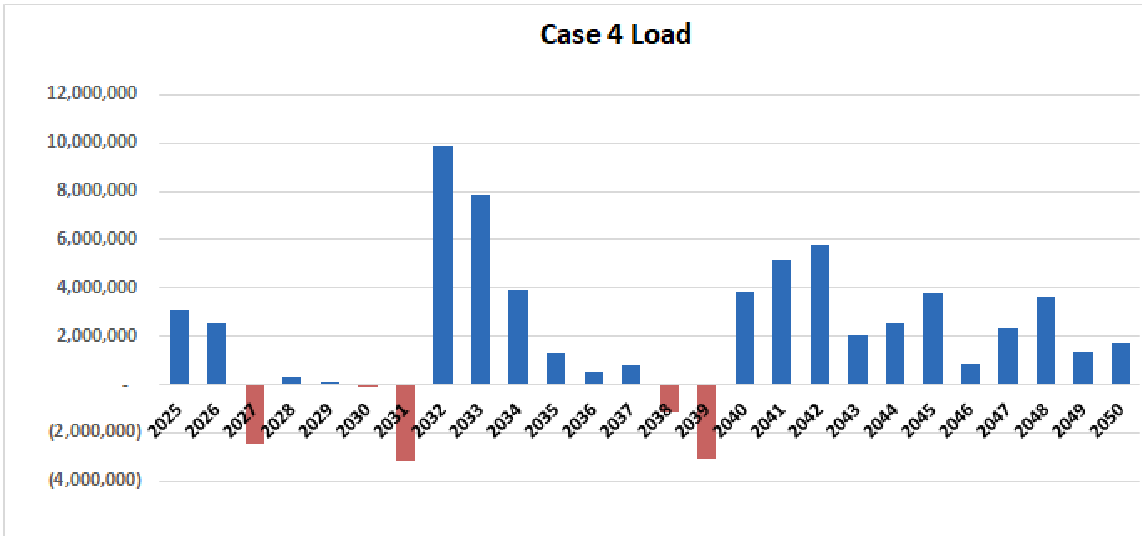
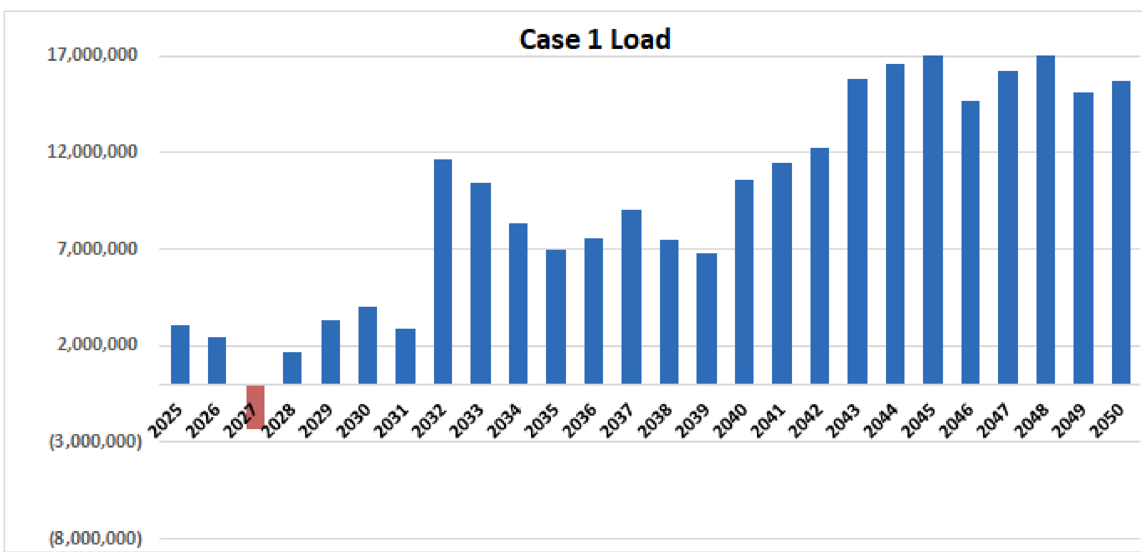


Figure 9. Economic Energy Position (MWh)– Case 1 Load, Normal Weather



Q. What is the basis for the forecasted dispatch of the Company's fleet represented in Figures 7-9?

A. The dispatch represented in Figures 7-9 reflects a power price scenario assuming a middle level of large load growth across the Eastern Interconnect and the resultant impact on power prices. This scenario is based on modeling performed by Charles River Associates and described in the Company's February 2025 Notice of Change in PRP report.[14]

Q. Why did you choose the scenario that includes the middle level of large load growth?

A. The middle scenario best represents the midpoint of expectations regarding large load additions across the Eastern Interconnect. That scenario also reflects the base scenario assumptions for natural gas and carbon prices included in the Company's 2023 IRP and used for analysis supporting its February 2025 PRP change.

Q. Besides the overall need for energy resources in the Company's portfolio that you've described above, is there a specific need for renewable resources?

A. Yes. While the Reform Project and other planned renewable resource additions to the Company's overall portfolio transition provide needed energy without incurring any fuel costs, they are also important in attracting and serving the needs of new LLCs, including through programs focused on renewable energy service, as Mr. Arora describes in his Direct Testimony. The increase in customer demand also results in a need for renewable resources to satisfy the Company's obligations under Missouri's Renewable Energy Standard ("RES").

[14] Schedule MM-D1, pp. 19-20.

Q. Has Ameren Missouri estimated the need for additional renewable resources necessary to meet the Company's RES obligations?

A. Yes. In the Company's 2025-2027 RES Compliance Plan, filed with the Commission in April of this year,[15] the Company showed a need for 332 thousand RECs in 2029, which would steadily increase in the absence of additional REC production capability, and determined that it would need to add 450 MW of additional solar generation in 2029 beyond that in operation or in development subject to a Commission-approved CCN to ensure compliance over the next ten years. The Company's 2025-2027 RES Compliance Plan is attached to my Direct Testimony as Schedule MM-D4 and reflects the customer demand included in Case 4 loads shown in Table 1. The discussion on page 7 of the RES Compliance Plan indicates the need for 450 MW of additional solar generation to meet the Company's post-2027 compliance requirement. The Company's RES Compliance Plan model is included with the RES Compliance Plan filed with the Commission, as described on Page 10 of the RES Compliance Plan. Table 2 below shows an excerpt from the model indicating the need for 450 MW in 2029, as well as a need for a further 200 MW in 2034.

Table 2. RES Compliance Plan Additions (MW)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MW of Management Wind Build	0	0	0	0	0	0	0	0	0	0
MW of Management Solar Build	0.0	0.0	0.0	0.0	450.0	0.0	0.0	0.0	0.0	200.0

Q. Does the Company expect to have a need for resources to meet its RES obligations if customer demand reflects Case 1 loads?

A. Yes. To determine the need, I started with the Company's RES Compliance Plan model, removed the resource additions shown in Table 2, and replaced the Case 4

[15] File No. EO-2025-0281.

LLC load with the Case 1 LLC load shown in Table 1. Table 3 below shows the resultant renewable energy credit ("REC") shortfall through 2035.

Table 3. Annual REC Need – Case 1 Loads

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
REC Surplus/(Shortfall) (MWh)	(85,774)	(665,176)	(54,742)	(143,784)	(231,510)	(312,176)	(369,218)	(430,689)	(496,220)	(565,444)	(622,277)

Q. Would the Project be expected to provide sufficient RECs to cover the needs shown in Table 3?

A. Yes. The Project is expected to produce 498,918 MWh per year based on P90 production expectations. Because the project is within the state of Missouri, it will qualify for the 1.25 REC multiplier under the Missouri RES, meaning it is expected to produce 623,648 RECs per year for purposes of the Missouri RES, just enough to cover the need in 2035 as shown in Table 3 above.

Q. You have discussed two main drivers of the need for the Project, to meet energy needs for existing and prospective customers and to provide RECs for RES compliance. Aside from meeting those specific needs, are there other important reasons to implement the Project at this time?

A. Yes. There are several, as the Commission itself has previously recognized, including in its Report and Order approving the Boomtown facility.[16] First, they fulfill energy needs for customers in both the near term and the long term, as I have described earlier in my Direct Testimony. Waiting to deploy renewable resources could result in falling short of meeting energy needs, particularly if viable projects are limited or transmission constraints cause delays or higher costs.

[16] File No. EA-2022-0245.

Second, the Project is expected to benefit from lucrative tax credits made available by federal law in the near term, as discussed by Mr. Arora in his Direct Testimony. Failure to take advantage of those tax credits now would likely mean adding needed solar generation at a later time that is very likely to cost customers substantially more. This is because under the One Big Beautiful Bill Act ("OBBBA"), which was recently signed into law, in order to qualify for the tax credits, solar projects beginning construction after July 4, 2026, must be in service by the end of 2027.[17] Company witness Scott Wibbenmeyer discusses these tax benefits in his Direct Testimony.

Third, adding renewable resources provides an important hedge against various market risks. This includes risks associated with power prices, carbon prices, and fuel prices.

Q. Can you elaborate on why it is important to add renewable energy resources in general, and the Project in particular, to provide a hedge against fuel price risks?

A. Yes. Renewable resources are characterized by moderate capital costs, modest non-fuel operating and maintenance costs, and zero fuel costs. Once built or acquired, the costs of the resource are known and relatively stable. In fact, the fixed asset costs of renewables decline over time as the assets depreciate. Adding the benefits of federal tax credits significantly mitigates or offsets those costs. With no fuel costs, any production from renewable resources results in revenues from the market. In periods of high fuel costs (e.g., gas or coal), market prices will tend to increase as well while the "fuel" for renewable resources remains free.

[17] The Reform Project is subject to existing safe harbor provisions and must be completed by December 31, 2029, to qualify for tax credits under OBBBA.

Q. Can you provide an example of how solar generation can help to mitigate price volatility risk?

A. Yes. Table 4 below shows the peak days for each summer and winter month from 2019 through 2021. For each peak day, it shows what the net energy position (generation minus load) would have been had the now-retired Meramec and Rush Island coal units not been available to generate. Note that in every instance, net energy would have been negative. That is, Ameren Missouri would have had to purchase more energy than it generated to serve native load.

Also shown for each peak day is the actual measured solar irradiance, or global horizontal irradiance ("GHI"), in watts per meter squared (w/m^2), along with its ratio compared to the highest daily GHI for that month and that year. Note that for 13 of the 18 months shown, solar irradiance is at or above 80% of its daily maximum for the month, and in four of the nine winter months shown, solar irradiance is at or above 30% of its daily maximum for the year.

Table 4 also shows the on-peak and average power prices ("LMP") for each peak day and the approximate cost to purchase to cover the energy shortfall at the average LMP. This shows that four of the 18 peak days would have been expected to result in added costs of over a million dollars, with the peak day in February 2021 (during winter storm Uri) seeing a cost of over $9 million on that day alone. Such events may, and often do, last for multiple days.

Finally, the table shows the estimated amount of electric energy the Reform Project would have produced had it been available on these days and the savings it would have produced at the on-peak LMP. It shows that the Reform Project would have been expected to produce tens of thousands of dollars in benefits on each of the peak days and over one hundred thousand dollars *per day* on five of the 18 monthly peak days.[18]

Table 4. Winter Peak Period Solar Benefits Example

Peak Day Net Energy, Solar Irradiance and LMP

Date	Net Energy (excl. Mer/RI) (MWh)	Global Horizontal Irradiance (W/m^2)	NDX	Month High	% Of Month High GHI	% Of Year High GHI	On-Peak LMP ($/MWh)	Average LMP ($/MWh)	Estimated Cost ($000)	Approx. Reform Gen. (MWh)	Estimated Reform Savings ($000)
01/30/19	(19,597)	2648	2019-1	3113	85%	30%	62.32	54.29	1,064	918	57
02/08/19	(14,616)	4310	2019-2	5082	85%	48%	28.17	26.19	383	1,494	42
06/05/19	(1,688)	8098	2019-6	8918	91%	91%	26.90	24.16	41	2,808	76
07/19/19	(19,655)	8109	2019-7	8365	97%	91%	40.76	33.87	666	2,811	115
08/12/19	(17,938)	6567	2019-8	7883	83%	74%	31.00	26.62	478	2,277	71
12/16/19	(13,826)	1111	2019-12	2980	37%	12%	25.00	23.24	321	385	10
01/20/20	(19,331)	1391	2020-1	3336	42%	16%	28.00	26.15	505	482	14
02/14/20	(12,193)	4762	2020-2	4992	95%	55%	24.25	23.02	281	1,651	40
06/26/20	(33,860)	7974	2020-6	8684	92%	92%	25.61	21.55	730	2,765	71
07/09/20	(16,160)	7083	2020-7	8415	84%	82%	40.41	32.79	530	2,456	99
08/10/20	(13,392)	5689	2020-8	7560	75%	66%	38.28	31.38	420	1,972	75
12/25/20	(28,948)	2865	2020-12	3186	90%	33%	32.55	29.18	845	993	32
01/28/21	(36,177)	3640	2021-1	3684	99%	42%	26.73	25.41	919	1,262	34
02/15/21	(67,905)	2612	2021-2	4916	53%	30%	167.83	142.44	9,672	906	152
06/18/21	(52,823)	8113	2021-6	8705	93%	93%	44.72	37.49	1,980	2,813	126
07/29/21	(50,880)	6859	2021-7	8169	84%	79%	50.92	43.75	2,226	2,378	121
08/25/21	(27,348)	6285	2021-8	7745	81%	72%	69.21	57.04	1,560	2,179	151
12/07/21	(10,843)	605	2021-12	2929	21%	7%	61.21	52.95	574	210	13

Q. Are you suggesting that such benefits should be a primary basis for deploying renewable resources?

A. No. As I described previously, the main drivers of the need for the solar projects and other renewable resources is to meet customer energy needs and at times, as is the case for the Project, the Company's RES compliance needs. The analysis shown above simply provides an indication of the kind of benefits solar projects can deliver during peak demand or extreme conditions. And even though a solar facility obviously will deliver more energy in the summer, solar energy generation in the winter can provide substantial benefits as well.

[18] The Project proposed in this case is also expected to provide benefits during periods of high prices and/or loads.

Q. You mentioned risks that may affect the timing and magnitude of the need for new energy resources. Can you describe some of these risks?

A. The most significant risk may be the inability to serve the kinds of LLC customers that are seeking to locate in the Company's service territory. As Mr. Arora discusses in his Direct Testimony, the Company is seeing significant interest from data centers and hyper-scalers far beyond those for which construction contracts have been executed and that the Company is confident that it will realize at least 500 MW of new demand from the various interested parties in the near term. Even at only 500 MW, the Company will need energy resources to serve the new LLC energy requirements. The Project, along with other planned energy resource additions, will continue to position the Company and the state of Missouri favorably with respect to attracting and serving LLCs and realizing significant economic development benefits that result, as also described by Mr. Arora.

Other significant risks are those that may affect the ongoing operation and economic viability of Ameren Missouri's coal-fired fleet, including significant changes in energy policy, either through legislation or regulation. Examples include the greenhouse gas ("GHG") emission rule for power plants promulgated by the U.S. Environmental Protection Agency ("EPA") in 2024 and rules for ozone season NOx emissions (the "Good Neighbor Rule"). While these rules are being reviewed by the current administration and may be repealed or replaced, they are indicative of the kinds of significant changes in energy policy that could drive the need for an imminent and significant expansion of renewable energy resources within an uncomfortably short timeframe. Regarding existing unit operations and economics, our remaining coal-fired fleet has faced and continues to face actual changes and further potential changes in regulation as well as market dynamics that may affect coal energy center economics, which could in turn result in a need for new energy resources. The aforementioned Good Neighbor Rule, if it remained in effect, would likely result in significant reductions in output during May through September each year from units without additional NOx controls. The GHG emission rule would require further mitigation and/or reductions in the operation of existing coal and gas units as well as new gas units. Even if those particular requirements are not imposed near-term, similar requirements in the future could restrict the energy production of new gas-fired generation, putting such units even more firmly in the role of providing electric generation to fill in the gaps otherwise left by intermittent wind and solar production.

IV. ECONOMICS OF THE REFORM PROJECT

Q. Did Ameren Missouri revise any of its IRP assumptions in developing its 2025 PRP for its evaluation of different large load plans?

A. Yes. As described in the Company's February 28, 2025, Notice of Change in PRP, Ameren Missouri reviewed its assumptions and made updates to its costs for wind and natural gas-fired resources to reflect current and expected market conditions as well as any necessary transmission infrastructure and environmental mitigation requirements.[19]

Q. You mentioned earlier that the Company revised its long-term outlook for the implementation of MEEIA programs. How did that change affect the Company's need for resources?

A. As also described in the Company's February 28, 2025, Notice of Change in PRP, the change in the Company's long-term outlook for MEEIA programs results in

[19] Schedule MM-D1 – 2025 Change in Preferred Plan Report, pp. 13-14.

reduced demand savings of approximately 300 MW by 2032 and 700 MW by 2043.[20] Adding the winter PRM of 25 percent results in an increase in resource needs driven by the recent MEEIA decision of approximately 375 MW by 2032 and 875 MW by 2043. The specific annual demand and energy savings and forecasted program budgets for the Company's long-term MEEIA programs is shown in **Schedule MM-D1**, page 16, Table 2.3.

Q. Did the Company update its assumptions for its power price scenarios used in its IRP risk analysis?

A. No. The Company reviewed its price scenario assumptions as part of its 2024 IRP Annual Update process and elected to make no changes at that time. However, Ameren Missouri did use the analytical services of Charles River Associates ("CRA") to evaluate price sensitivity to large additions of large loads across MISO and the broader market, as described in **Schedule MM-D1**, pages 19-22. In general, power prices increased with the inclusion of additional large loads in MISO, with the high-case large load yielding the greatest increase in power prices. These additional power price scenarios were used to test the performance of the various alternative plans, including those with varying large loads (i.e., Cases 1-7).

Q. What were the results of the analysis of the alternative plans for large load cases 1-7?

A. Unsurprisingly, the results show that the higher the load, the higher the revenue requirement. That conclusion is not, in and of itself, useful. However, it does provide a basis for evaluating the balance between costs and the new revenue contributions

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[20] Schedule MM-D1 – 2025 Change in Preferred Plan Report, p. 15.

from the additional demand and energy charges from new LLCs whose demand increases result in the need to accelerate resource additions, as described in the Company's application for a tariff to serve LLCs.[21]

Q. Did the analysis of price sensitivity using the new price scenarios from CRA indicate any concerns with relying on the Company's 2023 IRP price scenario assumptions for purposes of analyzing the cost of the various plans?

A. No. The results of the price sensitivity analysis are shown in **Schedule MM-D1**, pages 26-27 and indicate that using such prices does not alter the conclusions of the Company's plan analysis.

Q. Have you performed additional analysis specific to the Project for which the Company is seeking a CCN? If so, please describe the analysis.

A. Yes. Specifically, I have evaluated the Company's PRP with updated costs for the Project that are the subject of this case, and I have evaluated alternative plans that exclude the Project. I have evaluated plans with both the base project costs and the risk adjusted project costs described in the Direct Testimony of Company witness Scott Wibbenmeyer. While the Company fully expects the Project to qualify for investment tax credits, as discussed by Mr. Wibbenmeyer in his Direct Testimony, I have also evaluated the impact of the inclusion of investment tax credits for the Project to examine their impact on the Project in light of the statutory phase out of the credits and the benefits of capturing those tax credits now.

[21] File No. ET-2025-0184.

Q. What were the results of the analysis?

A. Table 5 below shows the results of the analysis of the PRP with and without the Project. As the table shows, NPVRR under probability-weighted average ("PWA") CO_2 prices decreases by $164-369 million when the Project is removed, depending on assumptions for ITC and project capital costs. This cost differential represents a change of approximately 0.15 percent to 0.34 percent of total costs to customers as measured by total NPVRR. NPVRR results for the different levels of CO_2 price assumption are similar for each combination of assumptions for ITC and project capital costs.

Table 5. NPVRR Results – PRP With and Without the Project[22]

	NPVRR Results ($MM)	Low CO2 Price	Base CO2 Price	High CO2 Price	PWA CO2 Price
a	Modified PRP - with Project-Specific Base Costs and No ITC on Reform	111,287	110,031	110,362	110,554
b	Modified PRP - with Project-Specific Risk Adjusted Costs and No ITC on Reform	111,307	110,051	110,382	110,574
c	Modified PRP - with Project-Specific Base Costs and 40% ITC on Reform	111,149	109,893	110,223	110,415
d	Modified PRP - with Project-Specific Risk Adjusted Costs and 40% ITC on Reform	111,163	109,907	110,237	110,429
e	Modified PRP - with Project-Specific Base Costs and 50% ITC on Reform	111,114	109,858	110,189	110,381
f	Modified PRP - with Project-Specific Risk Adjusted Costs and 50% ITC on Reform	111,127	109,871	110,201	110,393
g	Modified PRP - without Reform	110,951	109,682	110,018	110,210
	NPVRR Differences				
	Modified PRP without Reform (g) - Modified PRP with Base Costs and No ITC (a)	(337)	(349)	(344)	(343)
	Modified PRP without Reform (g) - Modified PRP with Risk Adjusted Costs and No ITC (b)	(357)	(369)	(364)	(363)
	Modified PRP without Reform (g) - Modified PRP with Base Costs and 40% ITC (c)	(198)	(211)	(205)	(205)
	Modified PRP without Reform (g) - Modified PRP with Risk Adjusted Costs and 40% ITC (d)	(212)	(225)	(219)	(219)
	Modified PRP without Reform (g) - Modified PRP with Base Costs and 50% ITC (e)	(164)	(176)	(171)	(170)
	Modified PRP without Reform (g) - Modified PRP with Risk Adjusted Costs and 50% ITC (f)	(176)	(189)	(183)	(182)

Q. What are the implications of the analysis results you just described?

A. Simply that these resources, which are necessary to serve expected customer energy needs and to comply with the requirements of the Missouri RES, result in costs that must be recovered through customer rates. It is worth noting that the Company's 2023 PRP already included the implementation of 1,800 MW of solar generation additions

[22] Plan a in Table 5 reflects a plan with project specific costs and no ITC for the Project. Plans b-f also reflect project specific costs for the Project, but with different assumptions for project capital costs (base or risk adjusted) for the Project and/or ITC (none, 40%, or 50%). Plan g reflects removal of the Project with no replacement (i.e., it assumes the CCN for the Project is not approved and the resource is not added).

by 2030, including 500 MW of solar projects placed in service in 2024 and another 400 MW for which the Company has been granted CCNs.

Q. You previously mentioned the benefits of tax credits available to the Project. What is the estimated value of those tax credits?

A. As Table 5 shows, the inclusion of a 40% ITC results in a reduction in NPVRR of approximately $139 million compared to including no ITC (Plan a vs. Plan c). Similarly, the inclusion of a 50% ITC results in a further reduction of about $34 million compared to including a 40% ITC (Plan c vs. Plan e). Based on the results presented in Table 5, we can expect a $34 million NPVRR benefit for every 10% increment of ITC applied to the qualifying costs of the Project.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

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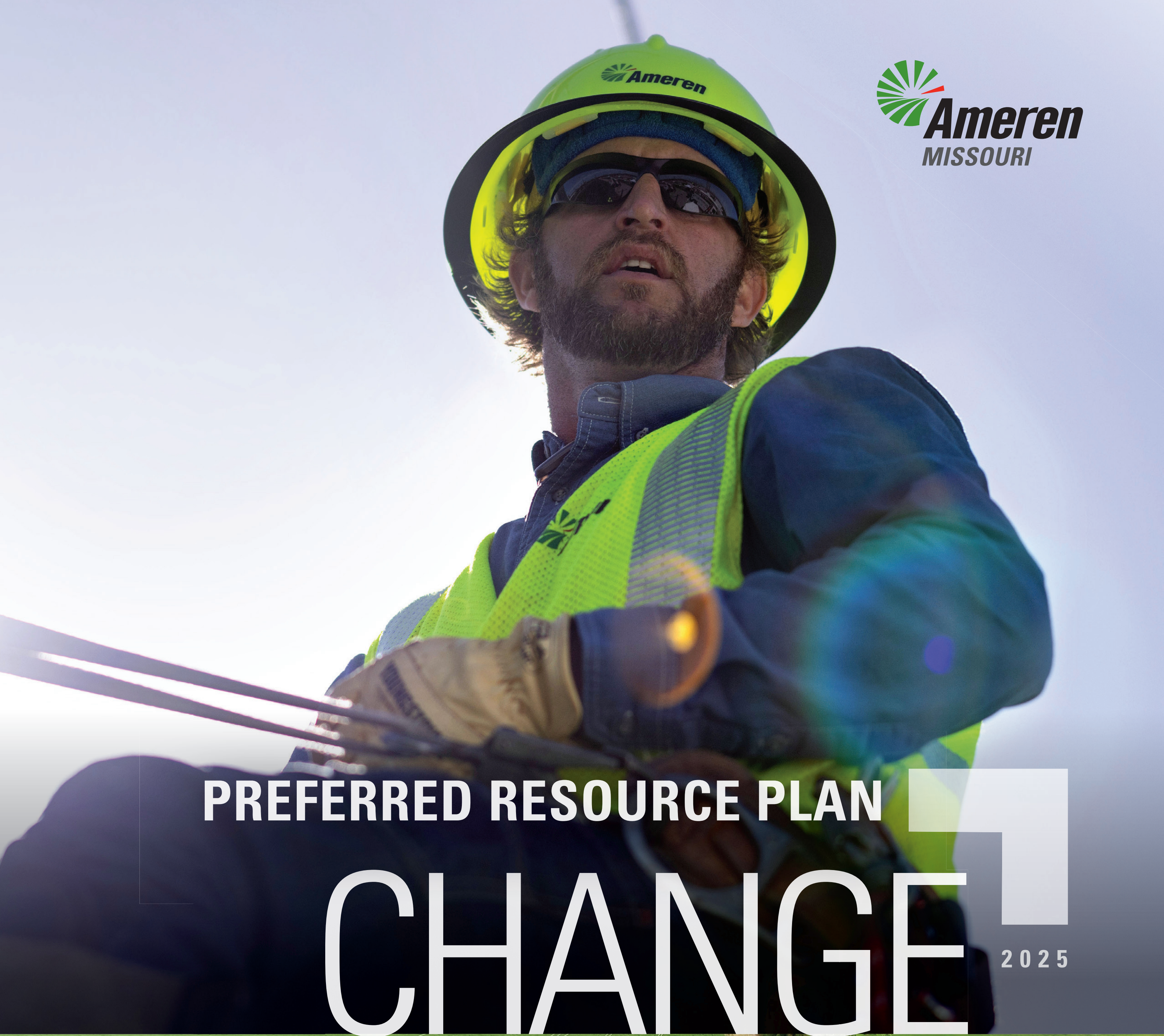


PREFERRED RESOURCE PLAN

CHANGE

2025

Schedule MM-D1

P

1. Executive Summary

Ameren Missouri's senior management has concluded that the Preferred Resource Plan (PRP) presented in its 2023 Triennial Integrated Resource Plan (IRP) (File No. EO-2024-0020) is no longer appropriate and should be revised. This conclusion was reached as a result of two key changes in the planning environment:

- Data Center and Large Load Potential – Since the Company's 2023 IRP was filed, the Company has seen significant growth in interest of potential data center customers to locate in Ameren Missouri's service territory. Specifically, the Company has fielded interest from customers representing aggregate potential peak demand of approximately 3 GW, with signed construction contracts related to interconnecting to Ameren Missouri's system totaling 1.8 GW. While other steps remain to add these prospective customers to Ameren Missouri's system, including the approval of a new rate tariff under which such customers would be served, these developments evidence both the likelihood and magnitude of these potential load additions.
- Changes in Company-Sponsored Energy Efficiency Programs – The Missouri Public Service Commission (MPSC) approved a non-unanimous stipulation and agreement in File No. EO-2023-0136 in November 2024 regarding the Company's Missouri Energy Efficiency Investment Act (MEEIA) energy efficiency and demand response program budgets and expected energy and demand savings over the next several years. In recognition of concerns raised by the MPSC and some stakeholders, the Company has revised its long-term outlook for these programs. This change results in a reduction in expected winter peak demand savings of approximately 300 MW by 2032 and 700 MW by 2043 relative to the Company's 2023 PRP levels.

In addition to these key changes, Ameren Missouri has also revised its assumptions for the costs of certain resources to reflect current and expected market conditions. Resources with updated costs include wind, simple cycle gas combustion turbine generators (CTG), and natural gas combined cycle (NGCC) generation. The Company also reviewed its assumptions for natural gas prices, carbon prices, power prices and capacity prices and determined they were still appropriate for evaluating the performance of alternative resource plans. Ameren Missouri continues to consider its resource planning decisions in the context of a comprehensive generation strategy, which includes the following objectives:

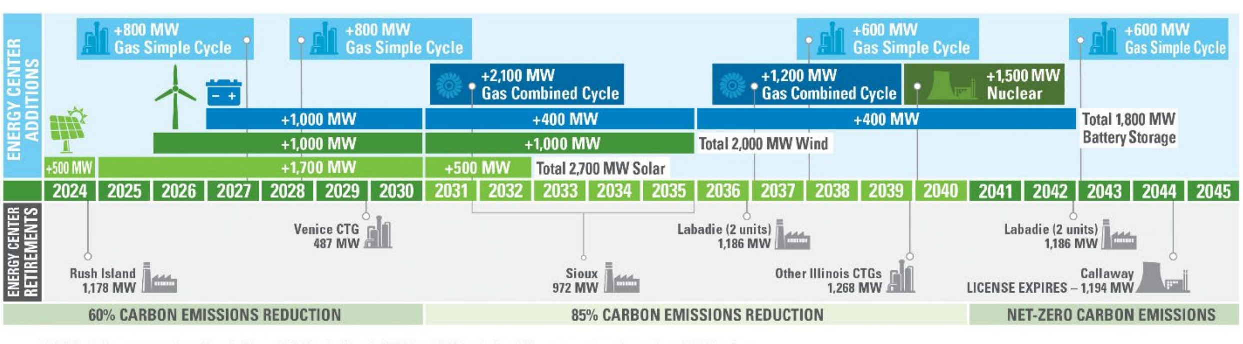
- Operate Energy Centers safely, economically, and in an environmentally responsible fashion while transitioning the generation fleet.
- Ensure overall energy (supply and grid) reliability and affordability.
- Create and capitalize on investment opportunities that are beneficial to customers, shareholders, the environment, and our communities.
- Maintain financial, technical, regulatory, and environmental flexibility.

As part of meeting these objectives, the Company seeks greater utilization of renewable energy resources together with appropriate reliance on existing and new dispatchable generation. Ameren Missouri also strives to ensure specific planning objectives are met by its Preferred Resource Plan. These objectives include:

- Minimize customer costs (Present Value Revenue Requirements or "PVRR").
- Customer Satisfaction (including rate impacts and reliability).
- Portfolio Transition (clean energy expansion and carbon reduction while maintaining reliability).
- Mitigate Financial/Regulatory Risk.
- Economic Development.

After considering the prospects for new large load additions and the other changes noted above and with the above stated objectives in mind, Ameren Missouri has selected a PRP that will support 1.5 GW of new additional demand by 2032 and 2.5 GW by 2040. The 2025 PRP resource timeline is shown below in Figure 1.1.

Figure 1.1: Ameren Missouri's 2025 PRP Resource Timeline



The key elements of the Company's new PRP are as follows:

- 2,700 MW of solar generation by 2032 – This includes 500 MW of solar generation placed in service at the end of 2024, another 1,700 MW by the end of 2030 (including 400 MW for which the MPSC has granted the Company's requests for certificates of convenience and necessity (CCN)), and another 500 MW by the end of 2032. Ameren Missouri expects to apply for CCNs for additional solar generation facilities during 2025, with the first CCN application expected in the second quarter of 2025.

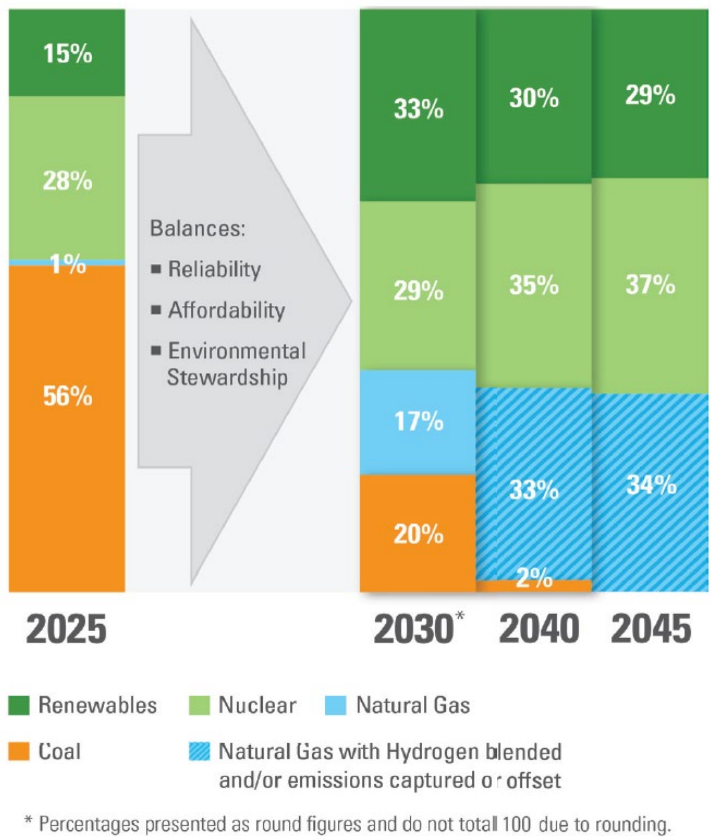
- 2,000 MW of wind generation by 2035 – This remains unchanged from the Company's 2023 PRP and includes 1,000 MW of wind by 2030 and another 1,000 MW by 2035.
- 1,800 MW of battery energy storage systems (BESS) by the end of 2042 – This includes 1,000 MW of BESS additions by 2030, another 400 MW by 2035, and another 400 MW by 2042. The Company expects to submit an application to the MPSC for a CCN for the first tranche of BESS in the second quarter of 2025.
- 1,600 MW of new CTG generation by 2030 – This includes the 800 MW Castle Bluff CTG facility at the site of the Company's former Meramec coal-fired energy center by the end of 2027, for which the MPSC granted the Company a CCN in October 2024.[1] It also includes an additional 800 MW CTG facility to be located at the site of the Company's former Rush Island coal-fired energy center by the end of 2028. The Company expects to seek MPSC approval for a CCN for this facility in the second quarter of 2025.
- An additional 1,200 MW of CTG generation by 2042 – This includes 600 MW of CTG generation by the end of 2037 and another 600 MW by the end of 2042. The Company expects to eliminate or offset emissions from CTG facilities by 2045.
- 3,300 MW of NGCC generation by 2037 – This includes a 2,100 MW NGCC facility at the site of the Company's existing Sioux coal-fired energy center by the end of 2031 and an additional 1,200 MW NGCC facility by the end of 2036. The Company expects to eliminate or offset carbon dioxide emissions from these facilities by 2040 through some combination of hydrogen blending and carbon capture and sequestration (CCS), assuming such technologies are commercially viable.
- Retirement of all of the Company's coal-fired generation by the end of 2042 – This includes retirement of two units at the Labadie Energy Center (LEC) by the end of 2036 and the other two units at LEC by the end of 2042, all unchanged from the Company's 2023 PRP. It also includes retirement of the coal-fired units at Company's Sioux Energy Center (SEC) between the end of 2031 and the end of 2035. The Company is maintaining flexibility with regard to the retirement date for SEC at this time to ensure system reliability during the transition to the new NGCC generation.

[1] File No. EA-2024-0237

- 1,500 MW of new nuclear generation in 2040 – While selection of a specific nuclear technology has not be made, the Company continues to monitor development of new technologies closely, including small modular reactors (SMR). Ameren Missouri expects to see successful implementation of new SMR technology before making a commitment to the technology for deployment in its own fleet. Ameren Missouri also expects to seek an extension to its operating license for its existing Callaway Energy Center nuclear facility, which is currently set to expire in 2044.

Figure 1.2 shows the Company's expected generation energy mix under the 2025 PRP.

Figure 1.2: Ameren Missouri's 2025 PRP Generation Energy Mix



The PRP described above allows the Company to achieve its previously established carbon reduction targets – 60% reduction by 2030 and 85% reduction by 2040, compared to 2005 levels, and net zero emissions by 2045. The carbon reduction targets include both Scope 1 and Scope 2 emissions of greenhouse gases, including carbon dioxide, nitrogen oxides and sulfur hexafluoride.[2] Figure 1.3 below shows the Company's

[2] Note that roughly 99% of the Scope 1 and Scope 2 greenhouse gas emissions are carbon dioxide emissions from Ameren Missouri's fleet of coal and natural gas fired generators.

expected carbon emissions for its new PRP compared to its 2023 PRP. Figure 1.4 shows the Company's expected carbon intensity for its new PRP compared to its 2023 PRP.

Figure 1.3: 2025 PRP Carbon Emissions Compared to 2023 PRP

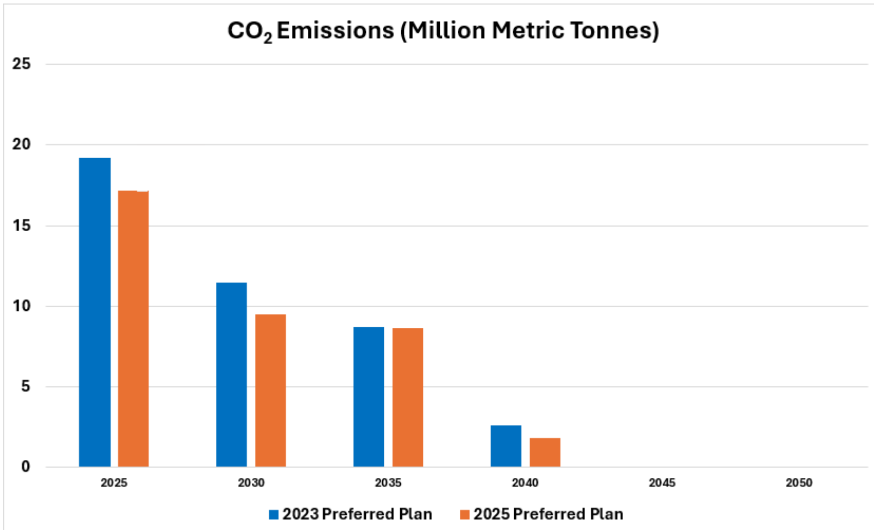
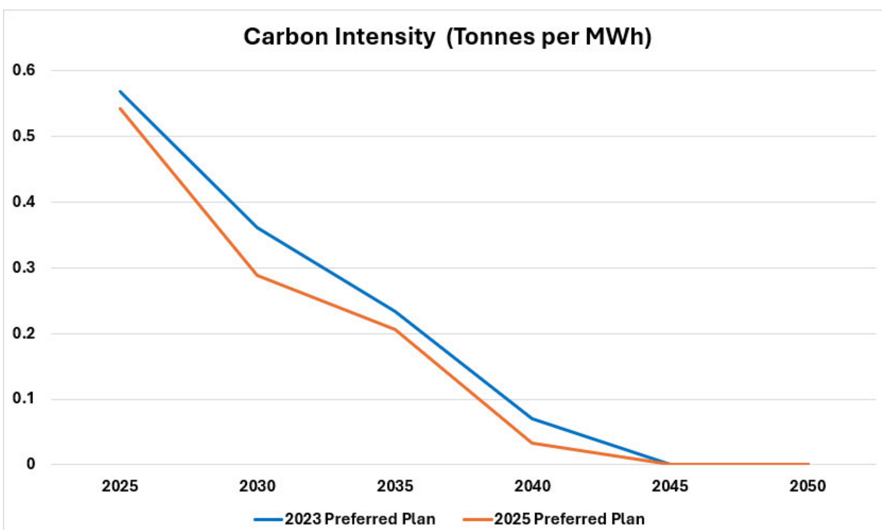


Figure 1.4: 2025 PRP Carbon Intensity Compared to 2023 PRP



In addition to the PRP, Ameren Missouri has also developed and analyzed contingency plans to recognize the uncertainty regarding potential data center load additions. These include an upside contingency plan to support 2 GW of new data center demand by 2032 and 3.5 GW by 2040 and a low contingency plan to support 500 MW of new data center demand by 2032 with no additional data center demand growth thereafter. It is important to note that the resource additions through 2032 for the contingency plan for 2 GW of data center demand by 2032 are the same as the resource additions through 2032 for the

PRP. Also, the addition of 800 MW of CTG generation in 2028 is included in both the upside and low contingency plans as well as the PRP. While the extent and timing of data center load additions remain somewhat uncertain, the combination of the PRP and these contingency plans position Ameren Missouri to serve a range of demand that may materialize while ensuring reliable service at a reasonable cost to all of its customers. Table 1.1 below shows the resource additions for the 2025 PRP as well as the two contingency plans described above. Resource additions for the 2023 IRP are also shown for comparison.

Table 1.1: Resource Additions for the 2025 PRP and Contingencies Compared to the 2023 PRP

	2023 IRP Preferred Plan	500 MW Large Loads	1.5 GW Large Loads	2.0 GW Large Loads
Data Center Load Additions (beginning of year)	N/A	500 MW by 2027 (4 GWh)	1.5 GW by 2032 (12 GWh) 2.5 GW by 2040 (20 GWh)	2 GW by 2032 (16 GWh) 3.5 GW by 2040 (28 GWh)
Energy Efficiency / Demand Response	Aggressive Energy Efficiency and Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs
Total Retail Sales in 2040	36 Million MWh	40 Million MWh	56 Million MWh	64 Million MWh
Coal Retirements (end of year)	Sioux (2032) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)
Gas Retirements (end of year)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)
Wind Additions (end of year)	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035
Solar Additions (end of year)	1,800 MW by 2030 2,700 MW by 2035	1,800 MW by 2030 2,700 MW by 2035	2,200 MW by 2030 2,700 MW by 2032	2,200 MW by 2030 2,700 MW by 2032
Battery Additions (end of year)	400 MW by 2030 800 MW by 2033	400 MW by 2030 800 MW by 2033	1,000 MW by 2030 1,400 MW by 2037 1,800 MW by 2042	1,000 MW by 2030 1,400 MW by 2037 1,800 MW by 2042
Combined Cycle Gas Additions (beginning of year)	1,200 MW (2033)	1,200 MW (2032)	2,100 MW (2032) 1,200 MW (2037)	2,100 MW (2032) 1,200 MW (2037) 1,200 MW (2038)
Simple Cycle Gas Additions (beginning of year, except 2027 and 2028 additions in Q4)	800 MW (2027)	800 MW (2027) 800 MW (2028)	800 MW (2027) 800 MW (2028) 600 MW (2038) 600 MW (2043)	800 MW (2027) 800 MW (2028) 600 MW (2035) 600 MW (2037)
New Nuclear Additions (beginning of year)	N/A	900 MW (2040)	1,500 MW (2040)	1,500 MW (2040)
Other Clean Dispatchable Additions (beginning of year)	1,200 MW (2040) 1,200 MW (2043)	1,200 MW (2037) 1,200 MW (2043)	N/A	N/A

Over the next two years, Ameren Missouri will be carrying out specific actions to execute on the new Preferred Resource Plan. These include:

- Submitting an application to establish a new tariff for large load customers, such as data centers, in the second quarter of 2025
- Submitting applications for CCNs to the MPSC for:
    - New solar generation projects (the first in the second quarter of 2025)
    - New BESS facilities to be located at former coal energy center sites (the first in the second quarter of 2025)

    - 800 MW of CTG generation at the former Rush Island coal energy center site (second quarter of 2025)
- Continuing to evaluate proposals for new wind and solar generation projects
- Continuing preparations for the addition of NGCC generation, including an application to the MPSC for a CCN in 2026
- Continuing to manage approved MEEIA programs for customer energy efficiency and demand response
- Continuing to monitor developments regarding environmental regulations, identifying and evaluating options for compliance, and taking steps to maintain available options
- Initiating a new market potential study to identify opportunities for further energy and demand savings from future MEEIA programs

2. Planning Environment

2.1 Environmental Regulations

Ameren Missouri has made significant investments to comply with existing environmental regulations and maintain a sufficient compliance margin. Rules proposed or promulgated since the IRP filing in 2023 include the 2023 update to the Mercury and Air Toxics Standards (MATS), the 2023 Steam Electric Power Generating Effluent Limitations Guidelines (ELG) Update, regulation of greenhouse gas emissions under section 111 of the Clean Air Act (GHG Rule), and the Legacy CCR Rule. Ameren Missouri has reviewed its assumptions on the eventual requirements for pending environmental regulations, as discussed in this section.

Clean Air Act Regulation of Greenhouse Gases (GHG)

On April 25, 2024, EPA issued final actions under Clean Air Act (CAA) section 111 applicable to GHG emissions from power plants: a section 111(b) rule governing new stationary combustion turbines; and a section 111(d) rule, governing existing steam-generating units (Final Rules). Many parties, including State Attorneys General, industry groups and rural electric cooperatives, among others, have sought judicial review of the Final Rules. The GHG rule for existing coal plants base the operational compliance requirements on the planned retirement date of the plant:

- Operation beyond January 1, 2039 - requires emissions reductions equivalent to 90% CCS by 2032.
- Coal fired steam units retiring between 2032 and 2039 - require CO_2 emissions reductions equivalent to 40% natural gas co-firing by 2030.

- Coal plants retiring by 2032 - no additional regulations.

For new natural gas fired combustion turbine units, the rule has different categories for compliance. Specifically, the new gas unit rules establish three categories of units based on unit capacity factor or how much the gas units will operate:

- Low load < 20% of maximum annual capacity; intermediate load-between 20-40% capacity; and base load units > 40% capacity.
- Low and intermediate loads are subject to low emitting fuels and efficient design of the units.
- New base load gas units, however, will require 90% carbon capture and storage (CCS) by 2032.

Litigation pending before the D.C. Circuit Court of Appeals has been stayed following a request by USEPA to hold the GHG rule in abeyance pending administration review. Based upon various Executive Orders, it is likely that USEPA will reconsider both underlying policies and the compliance requirements set forth in the GHG Rule. Nevertheless, for purposes of its current plan analysis, the Company has evaluated plans both with and without compliance with the GHG rule. Compliance with the GHG rule includes scenarios reflecting retirement of SEC by the end of 2031, 40% natural gas cofiring of LEC beginning in 2030, retirement of LEC by the end of 2038, NGCC operation without CCS limited to a 40% capacity factor, and CTG operation limited to a 20% capacity factor.

Cross States Air Pollution Rule (CSAPR) – Ozone Season

In January 2023, EPA disapproved Missouri's Good Neighbor State Implementation Plan (SIP). The disapproval of the state plan is a pre-requisite for EPA to promulgate a federal implementation plan (FIP) implementing the "Good Neighbor" requirements of the Clean Air Act (CAA) for the 2015 Ozone Standard. However, the State of Missouri, Ameren Missouri, and others challenged the EPA's final rule disapproving of the MO Good Neighbor SIP in the 8th Circuit Court of Appeals. The 8th Circuit stayed the EPA's disapproval of the MO Good Neighbor SIP pending the outcome of the ongoing litigation. Recently, The Court of Appeals granted the U.S. Department of Justice request to hold the case in abeyance indefinitely with status reports due every 90 days to allow EPA leadership to review the underlying SIP disapproval. In all, twelve states, including Missouri, have challenged, and obtained stays of, EPA's disapproval of their Good Neighbor SIPs for the 2015 Ozone Standard. Ameren Missouri will continue to follow the judicial process in this case.

On June 5, 2023, EPA promulgated the "Good Neighbor Plan" (FIP) to require upwind states to reduce emissions of the ozone precursor nitrogen oxide (NO_x) from electric generating units (EGUs) and certain stationary industrial sources, in accordance with

EPA's 2015 ozone National Ambient Air Quality Standards (NAAQS). Disapproval of a state SIP is a necessary predicate to the issuance of a FIP. The FIP applied to 23 states including Ameren Missouri EGUs in both Illinois and Missouri and impacted Ameren Missouri's CSAPR allowances and compliance strategy going forward. The FIP was immediately challenged in the DC Circuit Court of Appeals. While the DC Circuit denied a stay request, it intends to conduct an expedited review of the rule and has set a date for oral argument of April 2025 following supplemental briefing. The Supreme Court, however, has stayed the effective date of the FIP following the issuance of stay requests from numerous circuit courts including the 8th Circuit Court of Appeals. If the FIP is eventually implemented in Missouri, additional control technologies and/or reduced dispatch could be necessary as it was modeled and discussed in the 2023 IRP.

It is uncertain as to how USEPA intends to proceed, but USEPA could grant petitions for reconsideration of the FIP or issue an advance notice of proposed rulemaking to rescind the SIP disapprovals. Given such uncertainty, for purposes of the Company's current planning analysis, the Company has analyzed plans that include 40% natural gas cofiring at LEC starting in 2030 and plans that include selective catalytic reduction (SCR) equipment retrofits for compliance with the FIP, if applicable.

Attainment Designations for NAAQS for Ozone

The St. Louis area was designated as marginal with a marginal area attainment date of August 2021. Based on the 2018-2020 design value the St. Louis area failed to attain the 2015 standard and a bump up to moderate non-attainment was expected. However, because the St. Louis area 2019-2021 design value met the 2015 standard, Missouri DNR submitted a redesignation request in January 2022. Illinois EPA was working on a similar request for the Illinois portion of the St Louis non-attainment area. Unfortunately, prior to Illinois EPA's submission, 2022 ozone data indicated that the St. Louis Area ozone design value for 2020-2022 would show non-attainment. As a result, EPA bumped up the St. Louis Ozone non-attainment area to moderate nonattainment in 2022. Because the 2021-2023 design value (and the 2022-2024 design value) also shows non-attainment, the St. Louis Area has failed to attain the 2015 Ozone standard by the August 2024 moderate area attainment date. As a result, it is expected that EPA will "bump up" the St. Louis Area to Serious Non-attainment shortly. Ameren Missouri's coal units are already subject to, and meeting, Reasonably Achievable Control Technology (RACT) for the 2015 Ozone Standard as required by Consent Agreements in the Missouri State Implementation Plan. No additional NO_x control requirements are expected for the coal units if the area is designated serious non-attainment. The bump up to Serious will result in a new attainment date of August 2027 and a reduction in the major source thresholds for PSD and Title V purposes. After the bump up to serious non-attainment, the major source level for NO_x emissions will be 50 tons per year (down from 100 tons per year) for new resources.

On August 6, 2024, EPA published in the Federal Register, at 89 Fed. Reg. 63,860, a proposed rule disapproving Missouri's Supplemental Good Neighbor State Implementation Plan submission with respect to the 2015 8-hour ozone NAAQS. On January 24, 2025, the State of Missouri filed a petition with the U.S. Court of Appeals for the Eighth Circuit petitioning the Court for review of this final ruling.

For purposes of the Company's planning analysis, compliance was evaluated with either SCR retrofit or 40% natural gas cofiring at LEC starting in 2030.

Attainment Designations for NAAQS for SO_2

The EPA lowered the SO_2 ambient standard to 75 ppb on June 2, 2010. Initial attainment designations were finalized on August 5, 2013, and included the designation of two areas in Missouri as nonattainment. The two nonattainment areas included an area in the vicinity of Kansas City (portions of Jackson County) and an area around Herculaneum (portions of Jefferson County). In December 2017, the MDNR submitted a formal request to the EPA to re-designate the Jefferson County SO_2 nonattainment area to attainment. On January 28, 2022, EPA published in the Federal Register a formal redesignation of the Jefferson County, MO SO_2 nonattainment area to attainment. As a part of MDNR's state implementation plan for the Herculaneum area, Ameren Missouri agreed to lower SO_2 emissions limits for the Rush Island, Labadie and Meramec Energy Centers that took effect on January 1, 2017.

On June 30, 2016, the EPA issued a final determination of "unclassifiable" for the area around the Labadie Energy Center. Data collected from the ambient SO_2 monitors indicates that air quality in the vicinity of the Labadie Energy Center complies with the EPA standards. In September 2020, the EPA proposed to re-designate the area around Labadie from unclassifiable to attainment. The EPA is expected to finalize the re-designation by the end of the year. Ameren Missouri continues to operate the monitoring systems and submit the data to both the MDNR and the EPA. Based on monitoring data gathered to date and the EPA proposal to designate the area as attainment, we have assumed the area around Labadie will ultimately be designated as "attainment". Ameren Missouri's assumptions for compliance regarding SO_2 emissions reflect this expectation as well as expected steps necessary to comply with CSAPR.

For purposes of the Company's current planning analysis, compliance at LEC was evaluated with either flue gas desulfurization (FGD) retrofit or 40% natural gas co-firing starting in 2030.

NAAQS for Fine Particulate Matter

Based on current data, St. Louis and Metro East in Illinois are both in attainment with the 2012 PM2.5 standard. The Clean Air Act requires the EPA to review all of the ambient standards on a periodic basis. In December 2020, the EPA finalized a rule to retain the current standard for fine particulate matter. On February 7, 2024, the EPA promulgated a final rule reducing the primary annual PM2.5 NAAQS from 12 µg/m3 to 9 µg/m3. The revised standard is being challenged in court.

Based on recent PM2.5 monitoring in the metro St. Louis Area, the St. Louis area will be designated a non-attainment area for the 2024 PM2.5 standard. As a result of a non-attainment designation, RACT for Particulate Matter (PM 2.5) and precursors (NO_x/SO_2) would be required by the State of Missouri as part of an attainment plan that is required to be submitted to EPA for approval by February 2027.

For purposes of the Company's current planning analysis, compliance at LEC was evaluated with either FGD retrofit or 40% natural gas co-firing starting in 2030.

Clean Air Act Regional Haze Requirements

The goal of the Regional Haze Rule is to set visibility equivalent to natural background levels by 2064 in Class I areas. Class I areas are defined as national parks exceeding 6,000 acres, wilderness and national memorial parks exceeding 5,000 acres and all international parks in existence on August 7, 1977. There are currently 156 Class I areas, two of which are in the State of Missouri (Hercules Glade and Mingo). As part of the first planning period (2008-2018), states have developed implementation plans necessary to meet the glide path for the first 10-year planning period. In addition, the Regional Haze Rule requires compliance with Best Available Retrofit Technology (BART) for SO_2 & NO_x for the first planning period. The EPA has determined that compliance with CSAPR meets the BART requirements. Ameren Missouri is fully compliant with CSAPR, and thus, is compliant with the BART requirements. On August 26, 2022, the Missouri Department of Natural Resources (MDNR) submitted its State Implementation Plan to EPA for approval. As part of this SIP, Ameren Missouri entered into agreements with MDNR to assure continued use of existing control technology. On July 3, 2024, EPA published in the Federal Register, at 89 Fed. Reg. 55,140, a proposal to partially disapprove Missouri's State Implementation Plan for the regional haze second implementation period.

For purposes of the Company's current planning analysis, compliance at LEC was evaluated with either FGD retrofit or 40% natural gas co-firing starting in 2030.

CWA, Steam Electric Effluent Limitation Guidelines Revisions

In May 2024, the EPA finalized regulations generally known as the Steam Electric Effluent Limitations Guidelines (ELG) Rule that govern certain discharge limitations in the Steam Electric Power Generating category. The ELG Rule establishes technical requirements and discharge standards for wastewaters generated at coal fired power plants such as flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate. The ELG rule also establishes a new set of definitions and new effluent limitations for various legacy wastewaters, which may be present in surface impoundments. This new rule is not expected to materially affect Ameren Missouri's generating fleet.

Coal Combustion Residuals

Ameren Missouri is executing its compliance strategy in advance of the regulatory deadlines. On May 8, 2024, EPA finalized changes to the CCR regulations for inactive surface impoundments at inactive electric utilities, referred to as "legacy CCR surface impoundments". Within tailored compliance deadlines, owners and operators of legacy CCR surface impoundments must comply with all existing requirements applicable to inactive CCR surface impoundments at active facilities, except for the location restrictions and liner design criteria. In addition, through implementation of the 2015 CCR rule, EPA found areas at regulated CCR facilities where CCR was disposed of or managed on land outside of regulated units at CCR facilities, referred to as “CCR Management Units", or CCRMUs. Ameren Missouri is performing the facility reviews required by the Rule. The rule is currently being challenged judicially, and on February 13, 2025, the US Court of Appeals for the DC Circuit issued an order to hold the case in abeyance for 120 days. Ameren Missouri plans to closely watch the current judicial processes and adjust its planning accordingly.

Ash Basin Closure Initiatives

Ash basin impoundments at the Rush Island, Labadie, and Sioux Energy Centers are now complete. Remaining Meramec Energy Center ash basins are expected to be closed by the end of 2026. Closure of the original gypsum pond at Sioux Energy Center is now complete. The closure of the ash ponds will reduce our consumption of approximately 11 billion gallon of water per year.

Capital cost assumptions for mitigation technologies evaluated are shown in Table 2.1.

Table 2.1: Capital Cost Assumptions for Mitigation Technologies ($2024)

$Million (2024$)	Base Capex (Overnight)
ESP	$279
SCR	$637
FGD	$935
Wastewater Treatment for FGD	$65
Cofiring Boiler Modifications	$159

2.2 Supply-Side Resource Review

Ameren Missouri analyzed the cost and performance characteristics of a wide range of supply side resources in its 2023 IRP and has documented its analysis in Chapter 6 of its 2023 IRP filing. New supply side resources that were evaluated in the alternative resource plans in the 2023 IRP include the following:

- Gas Combined Cycle
- Gas Simple Cycle Combustion Turbine
- Wind
- Solar
- Pumped Hydroelectric Energy Storage
- Battery Storage
- Nuclear

Ameren Missouri has reviewed its assumptions for generating resources and determined that changes in cost assumptions are appropriate for wind, natural gas simple cycle, and natural gas combined cycle resources; comparisons to capital costs assumed in the 2023 IRP are shown in Figures 2.1-2.3 below.

Figure 2.1: Wind Capital Cost (Overnight - $/kW)

*** [redacted] ***

Figure 2.2: Simple Cycle Capital Cost (Overnight - $/kW)

*** [redacted] ***

Figure 2.3: Combined Cycle Capital Cost (Overnight - $/kW)

*** [redacted] ***

Transmission Costs

Ameren Missouri has reviewed its assumptions for transmission costs and determined the costs included in the 2023 IRP are appropriate while also including an additional **__________** (2024$) interconnection cost for the combined cycle increased capacity (2,100 MW vs 1,200 MW) in some alternative plans.

2.3 Load Forecast Review

Since the time of its 2023 IRP filing, Ameren Missouri has seen significant growth in the prospects for data centers in its service territory. Ameren Missouri had included incremental economic development load in its 2023 IRP forecast starting at 40 MW in 2025 and reaching 220 MW in 2031. However, the requests Ameren Missouri has received to date far exceed those assumed additions. Ameren Missouri has determined that large load additions, including data centers, are expected to add 500 MW to 2 GW of demand by 2032, and continued growth beyond 2032 could increase total demand to 2.5-3.5 GW by 2040. Table 2.2 below shows the annual peak demand additions assumed for modeling alternative resource plans for three scenarios. Note that the timing of load additions, including in the near term, is still uncertain.

Table 2.2: Data Center Load Addition Scenarios

@Transmission	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
500 MW	300	500	500	500	500	500	500	500	500	500	500	500	500	500	500
2500 MW	300	500	700	1,000	1,200	1,400	1,500	1,625	1,750	1,875	2,000	2,125	2,250	2,375	2,500
3500 MW	300	700	1,000	1,300	1,600	1,900	2,000	2,200	2,400	2,600	2,800	3,000	3,200	3,400	3,500

2.4 Demand-Side Resource Review

Ameren Missouri has reassessed its long-term expectations regarding energy efficiency programs under the Missouri Energy Efficiency Investment Act (MEEIA) following the conclusion of its MEEIA Cycle 4 application proceedings in File No. EO-2023-0136. In that docket, the MPSC approved a stipulation and agreement that substantially reduced program budgets to approximately $50 million annually, with lower energy and demand savings than what the Company had sought in its application. While the potential for greater energy and demand savings is expected to be available in the future, given the concerns that the MPSC and stakeholders expressed in that docket regarding the degree to which such savings can be relied upon for purposes of resource planning, Ameren Missouri has assumed that energy efficiency program budgets would remain relatively constant at MEEIA Cycle 4 levels over the planning horizon.

The Company worked with GDS Associates, Inc., the consulting firm that supported the Company's most recent demand-side resource market potential study, to update its expected energy and demand savings consistent with the aforementioned approved stipulation and agreement. As a result, total annual demand savings for the winter season, which drives overall resource needs, are expected to be reduced by about 300 MW by 2032 and about 700 MW over the 20-year planning horizon through 2043, compared to a portfolio at the realistic achievable potential (RAP) level as was included in the Company's 2023 PRP. Table 2.3 below summarizes the Company's current assumptions for MEEIA program budgets, demand savings, and energy savings through 2043.

Table 2.3: Revised MEEIA Program Budgets and Demand and Energy Savings

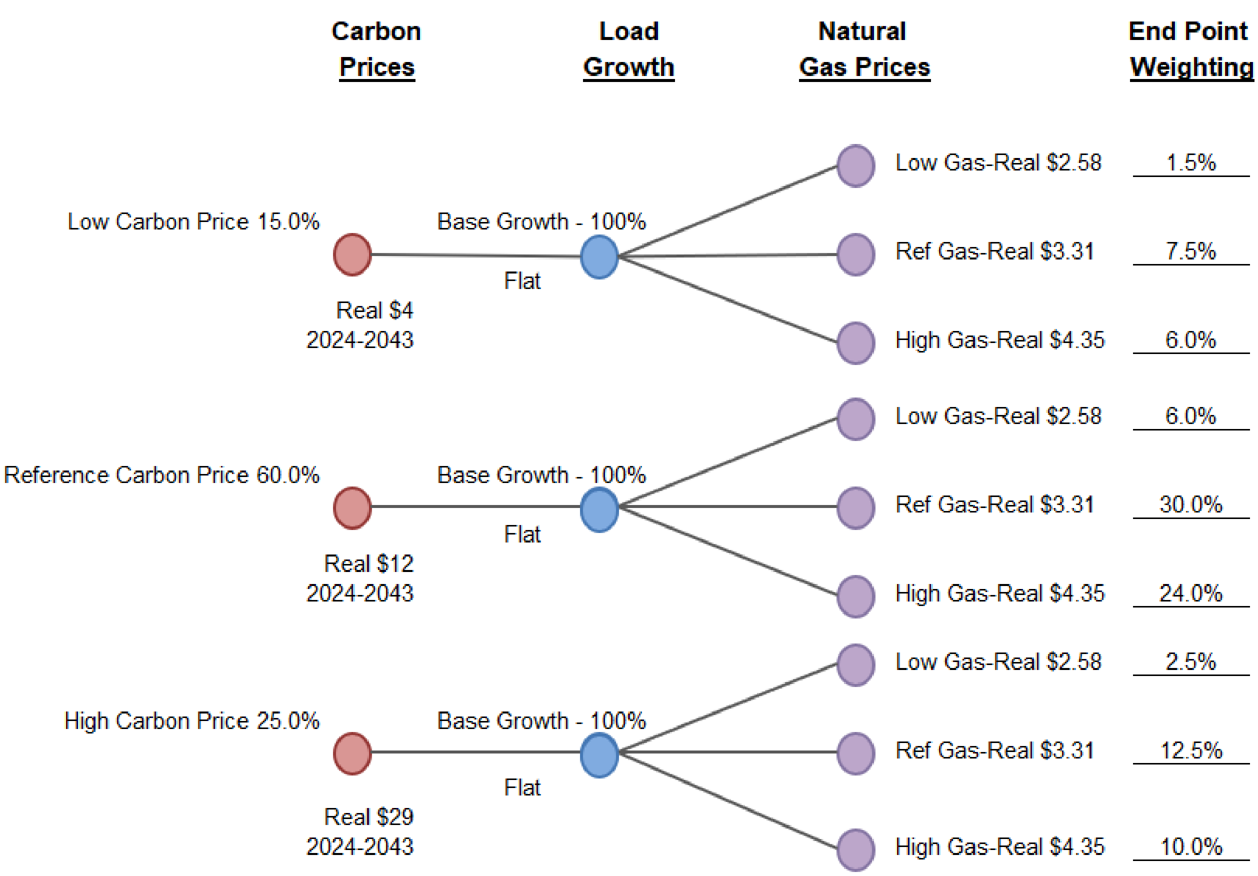
@ Transmission	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
GWh @Meter	180	230	281	332	383	419	465	510	549	573	579	605	632	658	653	659	657	648	651
Summer MW @Gen-EE	75	99	122	146	169	179	198	216	233	245	253	265	276	288	285	289	290	287	289
Summer MW @Gen-DR	264	271	277	277	277	277	277	277	277	277	277	277	277	277	277	277	277	277	277
Winter MW @Gen-EE	33	43	53	63	72	82	91	101	109	113	115	121	126	132	133	135	136	133	134
Winter MW @Gen-DR	86	112	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113
Cost $Million-EE	61	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Cost $Million-DR	15	21	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22

2.5 Uncertain Factors

2.5.1 Price Scenarios

Ameren Missouri has reviewed its assumptions for carbon prices and natural gas prices, which are the major drivers of power prices. As discussed in more detail in this section, Ameren Missouri has determined that its current expectations for the driver variables are within the ranges established in the 2023 triennial IRP. Figure 2.4 shows the scenario tree and the probabilities of each branch from the 2023 IRP.

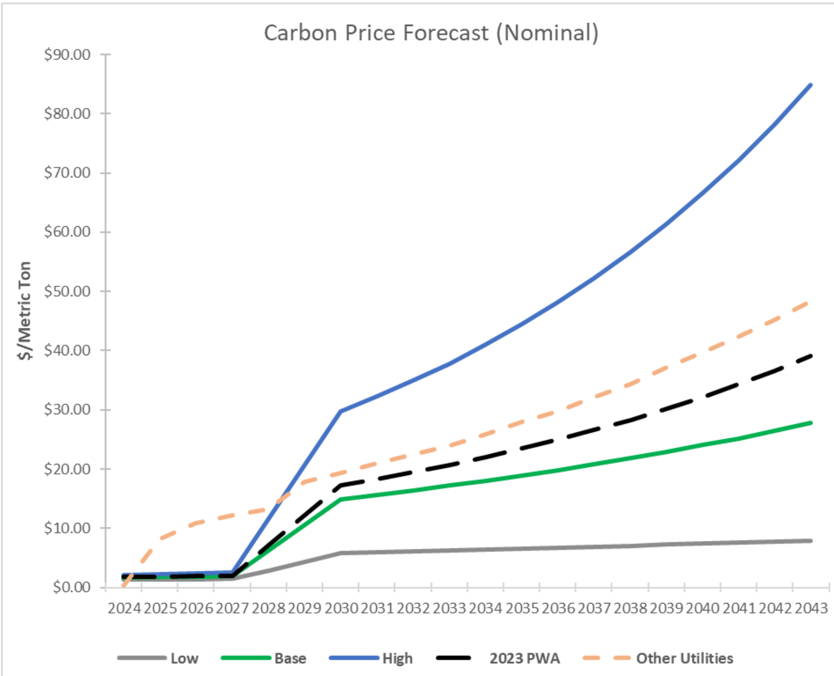
Figure 2.4: Scenario Tree



Carbon Dioxide Emission Prices

The carbon price assumptions from the 2023 IRP were reviewed and remain reflective of expectations for the future price of carbon dioxide emissions. The carbon price scenarios and the probability-weighted average (PWA) are shown in Figure 2.5.

Figure 2.5: CO_2 Price Assumptions



It should be noted that the price assumptions shown do not presume a particular mechanism (e.g., carbon tax, cap-and-trade program, etc.) by which the carbon price is implemented. It can be explicit or implicit and may reflect expectations regarding potential regulations, including those that target other emissions associated with carbon-emitting resources. Ameren Missouri continues to monitor policy proposals and developments that may affect assumptions for carbon pricing.

Natural Gas Prices

Ameren Missouri has also revisited its assumptions for natural gas prices. Figure 2.6 shows the three price scenarios and the PWA price. Ameren Missouri continues to monitor factors that may affect assumptions for natural gas prices.

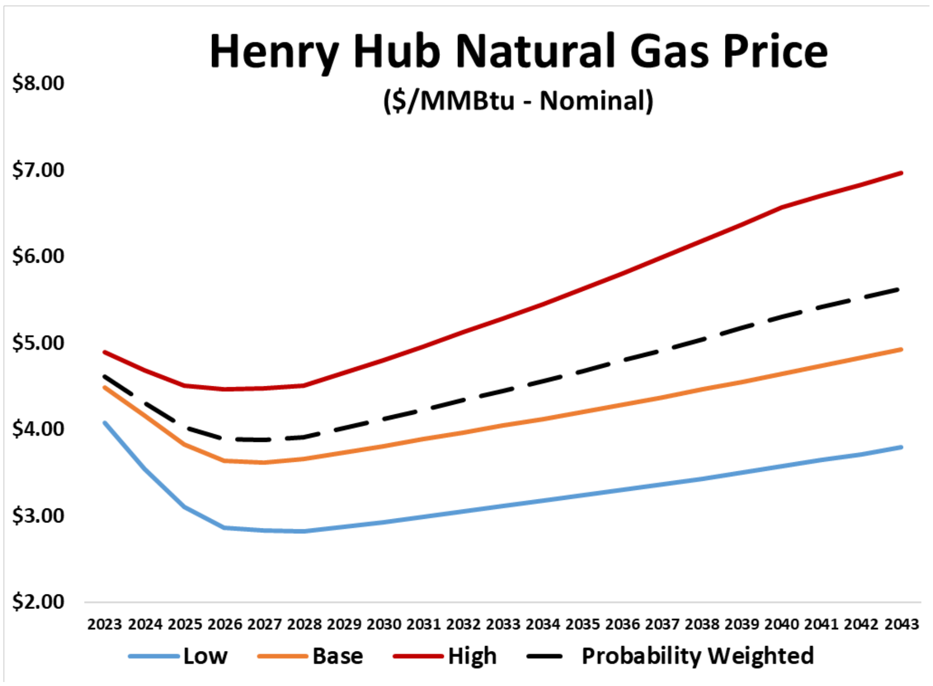
Ameren Missouri considers a number of key natural gas price drivers and risks. For the development of natural gas prices for the Company's 2023 IRP, the following key drivers and risks were examined:[3]

[3] File No. EO-2024-0020 Joint Filing, Resolution for NEE Deficiency 1

- LNG Exports
- Geopolitical Market Drivers
- Domestic Production and Extraction Costs
- Natural Gas Infrastructure Permitting
- Environmental Regulations for Gas Production and Transportation

The Company examined LNG exports based on information from the U.S Department of Energy's 2022 Annual Energy Outlook, which indicated a wide range of potential LNG exports (see Figure 2.6 below). The Company also considered relevant geopolitical events, including the Russian invasion of Ukraine in early 2022.

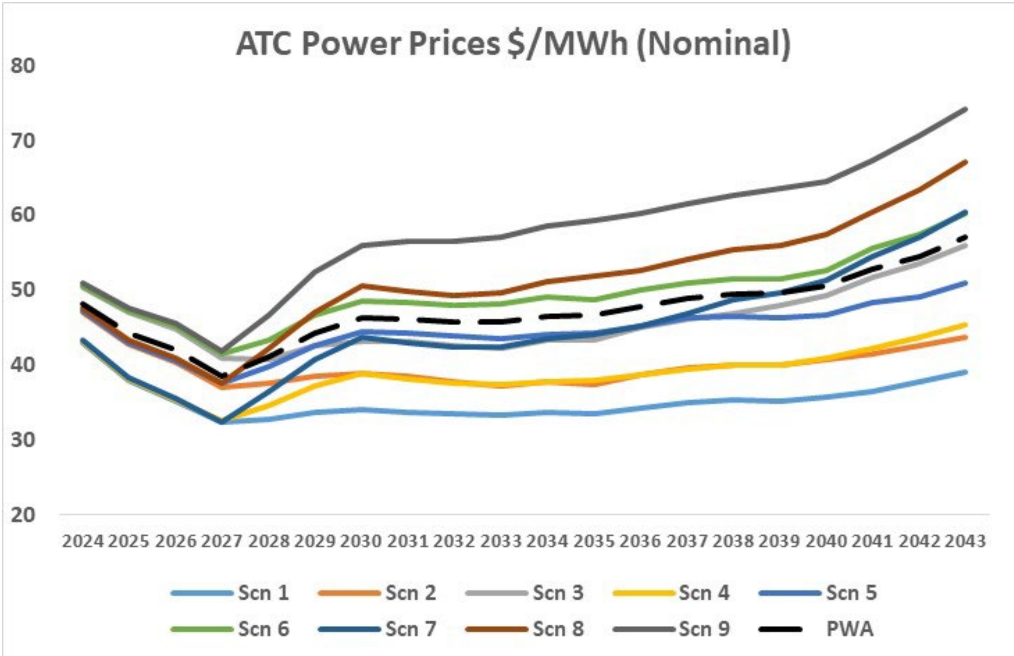
Figure 2.6: Natural Gas Price Forecasts



2.5.2 Scenario Modeling

Since current assumptions for the key driver variables described in section 2.5.1 are within the ranges defined in the 2023 IRP, there is no change to the power price forecasts modeled for the 2023 IRP and the probability-weighted average prices, which are presented in Figure 2.7 below.

Figure 2.7: Market Price Scenarios



Sensitivities for Data Center Load Levels

With the recent surge in data center load potential, not only within Ameren Missouri's service territory but across other regions in the United States, it is important to consider the sensitivity of market prices to the rapid addition of large loads. To evaluate the sensitivity of plan performance to different levels of data center load in the broader Eastern Interconnect and the MISO market, Ameren Missouri contracted with Charles River Associates (CRA) to analyze three scenarios of data center load and provide resultant market prices for energy and capacity. Table 2.4 below shows the data center load for high, middle and low scenarios for both MISO and PJM.

For price scenario modeling, CRA analyzed the following combinations of assumptions using the Company's 2023 IRP scenarios for natural gas prices and carbon prices and load scenarios reflecting the data center load assumptions shown in Table 2.4 as follows:

- High Scenario – 2023 IRP high carbon and gas prices, loads with high assumptions for data center additions
- Middle Scenario – 2023 IRP base carbon and gas prices, loads with middle assumptions for data center additions
- Low Scenario – 2023 IRP low carbon and gas prices, loads with low assumptions for data center load additions

The resultant market prices for energy are shown in Figure 2.8, and the resultant capacity prices are shown in Figures 2.9 to 2.11. The sensitivity to power prices is discussed in Section 3.

Table 2.4: Data Center Load for Sensitivity Scenarios (MW)

PJM	Low Case	Mid Case	High Case
2024	6,665	6,665	6,665
2025	6,825	7,098	7,965
2026	7,250	8,665	11,914
2027	8,163	11,252	18,177
2028	10,226	15,000	24,000
2029	12,110	20,000	30,000
2030	13,843	25,000	37,500
2031	15,444	30,317	45,475
2032	16,929	35,146	52,719
2033	18,311	39,101	58,652
2034	19,600	42,156	63,234
2035	20,804	44,750	66,582
2036	21,931	46,500	68,898
2037	22,986	47,500	70,419
2038	23,750	48,500	72,000
2039	24,500	49,250	73,500
2040	25,000	50,000	75,000

MISO	Low Case	Mid Case	High Case
2024	1,829	1,829	1,829
2025	2,100	2,400	2,608
2026	3,000	3,900	4,950
2027	4,350	6,300	9,000
2028	5,700	9,000	13,500
2029	7,050	12,000	18,000
2030	8,306	15,000	22,500
2031	9,266	18,190	27,285
2032	10,158	21,088	31,631
2033	10,987	23,461	35,191
2034	11,760	25,294	37,941
2035	12,482	26,850	39,949
2036	13,158	27,900	41,339
2037	13,792	28,500	42,251
2038	14,250	29,100	43,200
2039	14,700	29,550	44,100
2040	15,000	30,000	45,000

PJM+MISO	Low Case	Mid Case	High Case
2024	8,494	8,494	8,494
2025	8,925	9,498	10,573
2026	10,250	12,565	16,864
2027	12,513	17,552	27,177
2028	15,926	24,000	37,500
2029	19,160	32,000	48,000
2030	22,148	40,000	60,000
2031	24,710	48,507	72,760
2032	27,087	56,234	84,350
2033	29,298	62,562	93,843
2034	31,360	67,450	101,175
2035	33,286	71,600	106,531
2036	35,089	74,400	110,237
2037	36,778	76,000	112,670
2038	38,000	77,600	115,200
2039	39,200	78,800	117,600
2040	40,000	80,000	120,000

Figure 2.8: Market Energy Prices for Data Center Load Scenarios

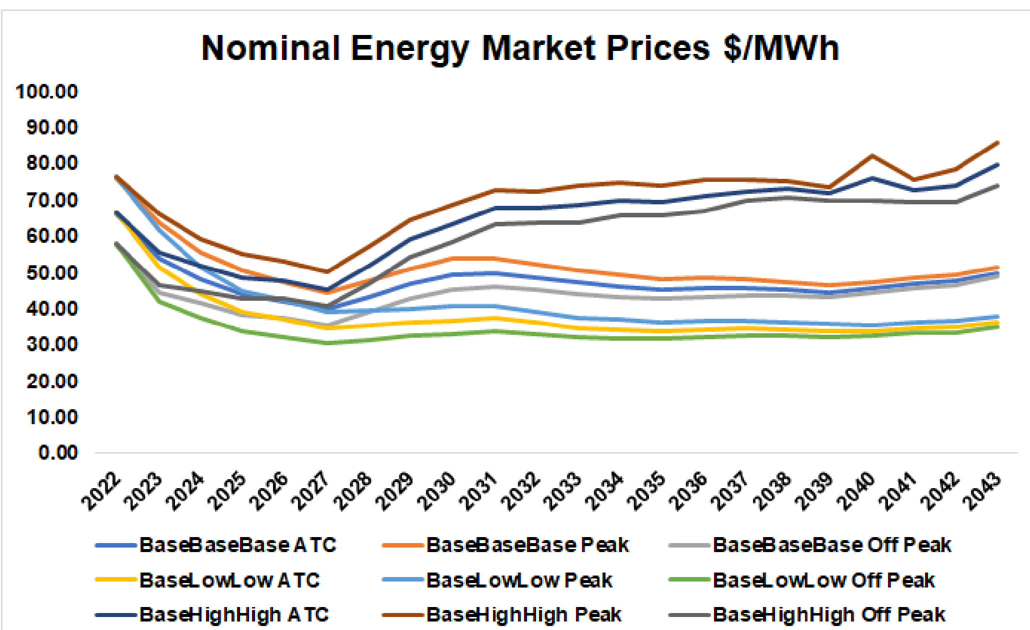


Figure 2.9: Market Capacity Prices for High Data Center Load Scenario

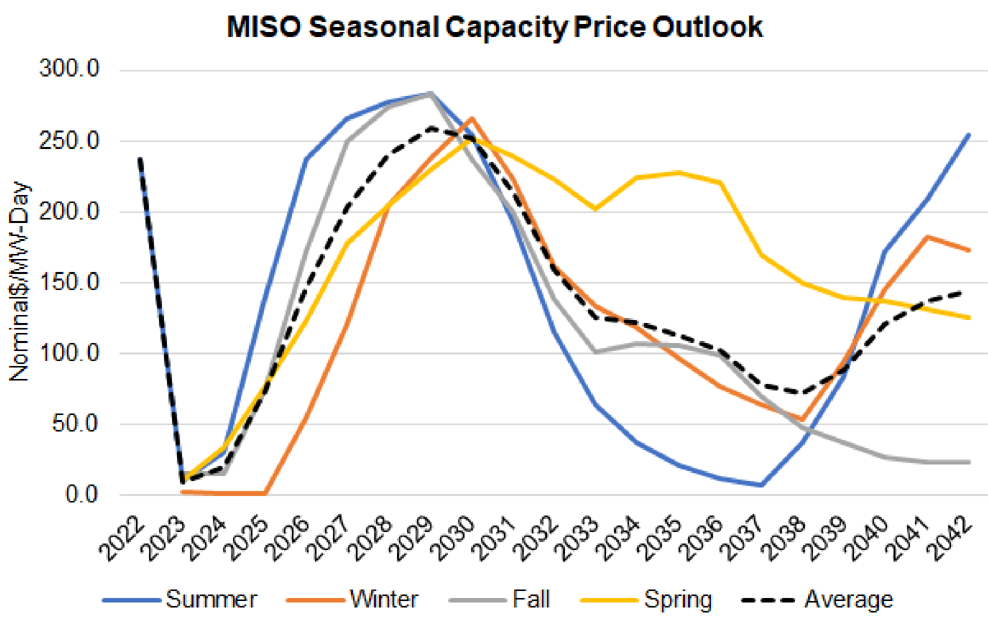


Figure 2.10: Market Capacity Prices for Middle Data Center Load Scenario

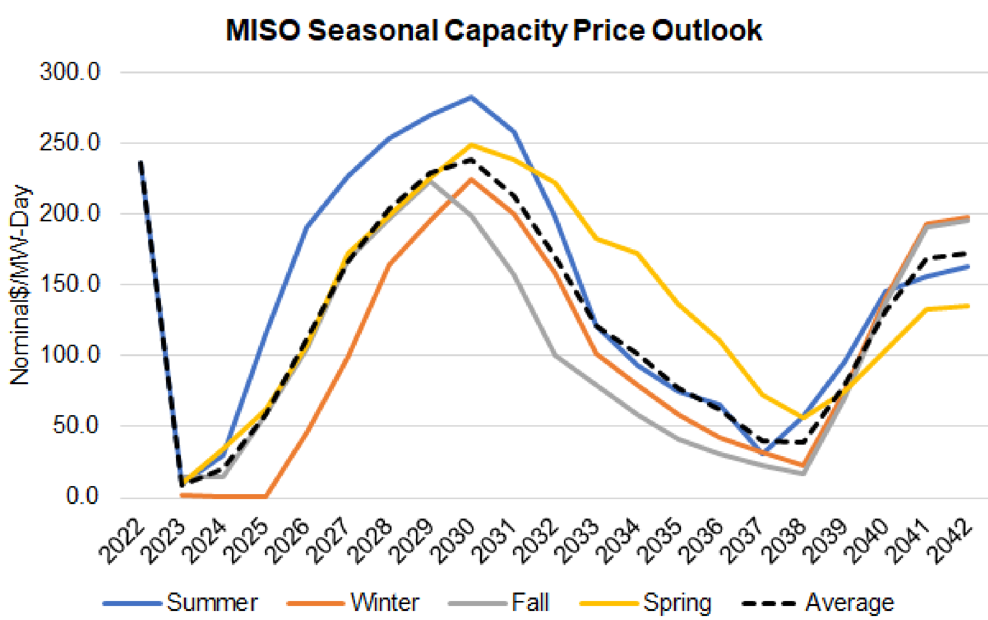
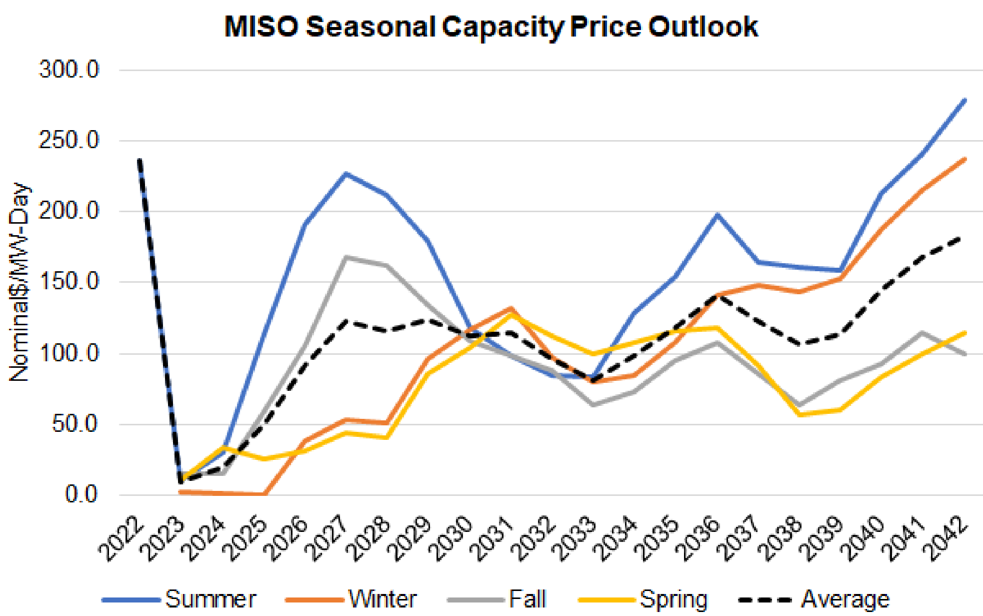


Figure 2.11: Market Capacity Prices for Low Data Center Load Scenario



3. Alternative Plans and Risk Analysis

Ameren Missouri's analysis of alternative plans focused on several objectives:

- Analyze differences in costs for different data center load scenarios, including scenarios in which data center loads are reduced after some period of time
- Analyze the impact of the change in the Company's planned MEEIA programs
- Analyze the relative incremental cost of different compliance alternatives for LEC

To that end, the alternative plans shown in Table 3.1 below were analyzed.

Table 3.1: Alternative Resource Plans Analyzed

	Plan Name	DSM	Renewables	New Supply-Side	Coal Retirements/ Modifications
A	2023 Preferred Plan (RAP)	RAP	Renewable Expansion	SC 2028, CC 2033 CC 2040 and 2043	Base*
B	2023 PRP (RAP)- Sioux'31	RAP	Renewable Expansion	SC 2028, CC 2032 CC 2040 and 2043	Sioux Dec-2031*
C	2023 PRP (RAP) - ESP - Sioux'31	RAP	Renewable Expansion	SC 2028, CC 2032 CC 2040 and 2043	Sioux Dec-2031
D	Lower DSM - CC - ESP	MEEIA 4	Renewable Expansion	SC 2028, CC 2032, SC 2037 CC 2040 and CC 2043	Sioux Dec-2031

	Plan Name	DSM	Renewables	New Supply-Side	Coal Retirements/ Modifications
E	Nuke - ESP	MEEIA 4	Renewable Expansion	SC 2028, CC 2032, SC 2037 Nuke900 2040, CC 2043	Sioux Dec-2031
F	SCR - FGD	MEEIA 4	Renewable Expansion	SC 2028, CC 2032, SC 2037 Nuke900 2040, CC 2043	Sioux Dec-2031 Labadie 2U SCR & FGD
G	Labadie Ret 2031	MEEIA 4	Renewable Expansion	SC 2028, CC 2032, SC 2032 CC 2032, Nuke900 2040	Sioux Dec-2031
H	Labadie Ret 2031 GHG	MEEIA 4	Renewable Expansion	SC 2028, CC 2032, SC 2032 CC 2032, Nuke900 2040	Sioux Dec-2031 Labadie 4U Dec-2031
I	GHG Cofire	MEEIA 4	Renewable Expansion	SC 2028, CC 2032, SC 2039 CC 2039, Nuke900 2040	Sioux Dec-2031 Labadie 4U Cofire Labadie 4U Dec-2038
J	GHG Cofire - FGD	MEEIA 4	Renewable Expansion	SC 2028, CC 2032, SC 2039 CC 2039, Nuke900 2040	Sioux Dec-2031 Labadie 4U Cofire Labadie 2U FGD Labadie 4U Dec-2038
K	Cofire - FGD	MEEIA 4	Renewable Expansion	SC 2028, CC 2032, SC 2037 Nuke900 2040, CC 2043	Sioux Dec-2031 Labadie 4U Cofire Labadie 2U FGD
L	Cofire	MEEIA 4	Renewable Expansion	SC 2028, CC 2032, SC 2037 Nuke900 2040, CC 2043	Sioux Dec-2031 Labadie 4U Cofire
M	Cofire GHG +2500 MW Load	MEEIA 4	Renewable Expansion - Solar Accelerated +1000MW Battery Storage	SC 2028, CC2100 2032, SC 2029, CC 2039, SC600 2038, SC600 2039 Nuke1500 2040	Sioux Dec-2031 Labadie 4U Cofire Labadie 4U Dec-2038
N	Cofire +500 MW Load	MEEIA 4	Renewable Expansion - Solar Accelerated +1000MW Battery Storage	SC 2028, SC 2029, CC 2032 CC 2037, Nuke900 2040 CC 2043	Sioux Dec-2031 Labadie 4U Cofire
O	Cofire +1500 MW Load	MEEIA 4	Renewable Expansion - Solar Accelerated +1000MW Battery Storage	SC 2028, SC 2029 CC2100 2032, SC600 2039 Nuke1500 2040 SC600 2043	Sioux Dec-2031 Labadie 4U Cofire
P	Cofire +2000 MW Load	MEEIA 4	Renewable Expansion - Solar Accelerated +1000MW Battery Storage	SC 2028, SC 2029 CC2100 2032, SC600 2037 CC600 2038 Nuke1500 2040 SC600 2043	Sioux Dec-2031 Labadie 4U Cofire

	Plan Name	DSM	Renewables	New Supply-Side	Coal Retirements/ Modifications
Q	Cofire +2500 MW Load	MEEIA 4	Renewable Expansion - Solar Accelerated +1000MW Battery Storage	SC 2028, SC 2029 CC2100 2032, CC 2037 SC600 2038 Nuke1500 2040 SC600 2043	Sioux Dec-2031 Labadie 4U Cofire
R	Cofire +3500 MW Load	MEEIA 4	Renewable Expansion - Solar Accelerated +1000MW Battery Storage	SC 2028, SC 2029 CC2100 2032, SC 2029 SC600 2035, CC 2037 SC600 2037 CC 2038, Nuke1500 2040	Sioux Dec-2031 Labadie 4U Cofire
S	Cofire +1500 to 500 MW Load	MEEIA 4	Renewable Expansion - Solar Accelerated +600MW Battery Storage	SC 2028, SC 2029 CC2100 2032, CC600 2043 Nuke900 2043	Sioux Dec-2031 Labadie 4U Cofire
T	Cofire +2000 to 500 MW Load	MEEIA 4	Renewable Expansion - Solar Accelerated +600MW Battery Storage	SC 2028, SC 2029 CC2100 2032, CC600 2037 SC600 2037 Nuke900 2043	Sioux Dec-2031 Labadie 4U Cofire

*All plans except for Plans A and B include new ESPs at two Labadie units.

3.1 Alternative Plans Analysis Results

Table 3.2 shows the present value of revenue requirements (PVRR) results for the alternative plans shown in Table 3.1. These results reflect the 2023 IRP price scenarios described in section 2.5. Several conclusions can be drawn from these results.

First, with respect to data center load additions, the greater the load addition and the longer such load additions are sustained, the higher the total cost in terms of PVRR. It is important to recognize that differences in cost for significantly different levels of customer demand does not imply that higher cost plans are detrimental. In fact, analysis results show that alternative plans with higher data center demand result in lower levelized rates than those with lower data center demand (or none), as shown in Table 3.2. Because the cost effects on Ameren Missouri's existing customers are necessarily dependent on rates for new data center customers, such considerations must be made in the context of establishing a new tariff, for which the Company plans to apply with the MPSC in the second quarter of 2025.

Second, results for environmental compliance options for LEC indicate that 40% natural gas co-firing starting in 2030 is lower cost than either early retirement or retrofitting LEC with FGD and SCR equipment.[4] This is true whether or not EPA's GHG rule for power plants goes into effect. As discussed in section 2.1, significant uncertainty regarding various pending environmental regulations remains. Ameren Missouri will continue to monitor developments with respect to environmental regulations and identify and evaluate compliance options while maintaining flexibility to implement viable options.

Third, the change from the RAP DSM portfolio included in the Company's 2023 PRP to the portfolio based on a continuation of budget levels approved for the Company's MEEIA Cycle 4 programs results in an increase in PVRR of about $2 billion. Ameren Missouri is initiating a new DSM market potential study to inform the preparation of its 2026 triennial IRP and will reassess its long-term plans for MEEIA programs as part of that effort.

Table 3.2: PVRR and Levelized Rates Results for Alternative Plans

Alternative Resource Plan	PVRR ($ Million)	Levelized Rates Cents/kWh
A - 2023 Preferred Plan (RAP)	$85,471	$22.16
B - 2023 PRP (RAP)- Sioux'31	$85,501	$22.17
C - 2023 PRP (RAP) - ESP - Sioux'31	$85,805	$22.25
D - Lower DSM - CC - ESP	$87,927	$22.43
E - Nuke - ESP	$90,725	$23.14
F - SCR - FGD	$92,532	$23.60
G - Labadie Ret 2031	$92,207	$23.52
H - Labadie Ret 2031 GHG	$92,316	$23.55
I - GHG Cofire	$92,000	$23.47
J - GHG Cofire - FGD	$93,126	$23.75
K - Cofire - FGD	$92,696	$23.64
L - Cofire	$91,530	$23.35
M - Cofire GHG +2500 MW Load	$108,898	$20.52
N - Cofire +500 MW Load	$97,386	$22.49
O - Cofire +1500 MW Load	$104,284	$21.02

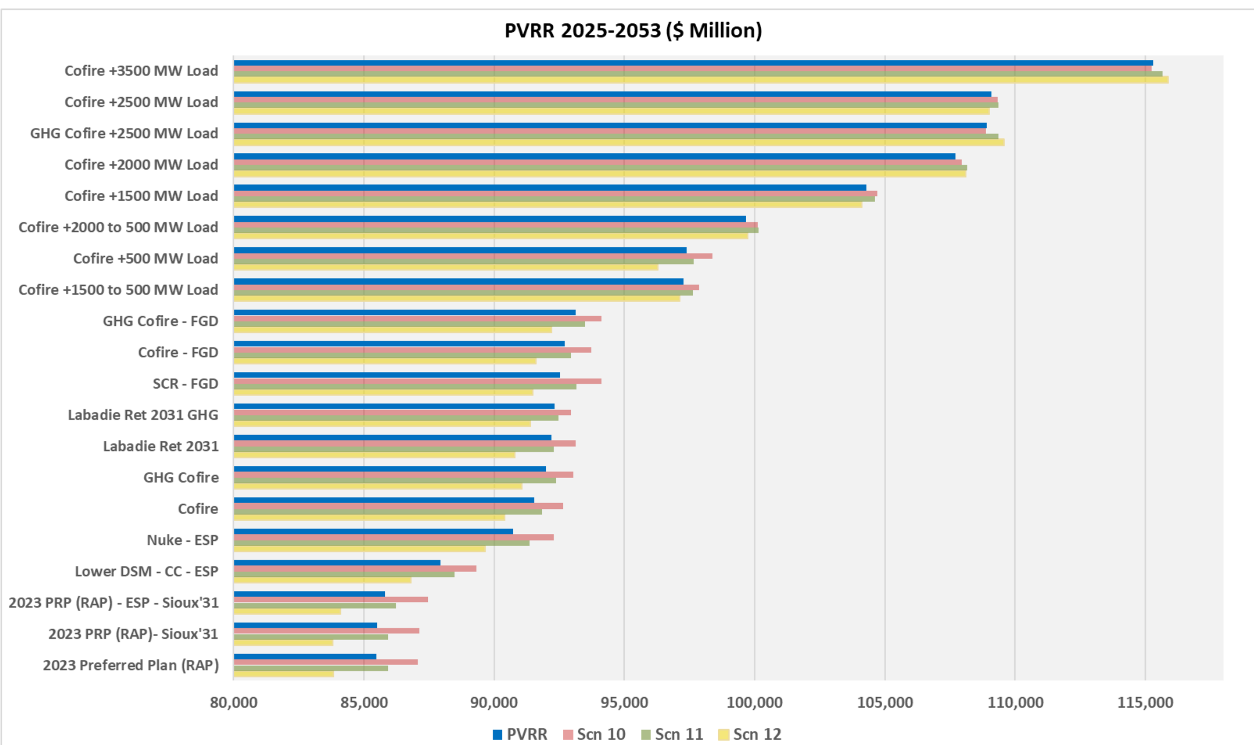
[4] Analysis of environmental compliance is included in this report in part to satisfy the commitment made by Ameren Missouri in its June 2024 Joint Filing in File No. EO-2024-0020.

Alternative Resource Plan	PVRR ($ Million)	Levelized Rates Cents/kWh
P - Cofire +2000 MW Load	$107,708	$20.30
Q - Cofire +2500 MW Load	$109,078	$20.55
R - Cofire +3500 MW Load	$115,307	$19.76
S - Cofire +1500 to 500 MW Load	$97,265	$20.71
T - Cofire +2000 to 500 MW Load	$99,652	$20.30

3.2 Data Center Price Scenario Sensitivity

As mentioned previously, Ameren Missouri has worked with CRA to create additional price scenarios to reflect different levels of data center additions in the Eastern Interconnect to analyze the price sensitivity of alternative plans. Figure 3.1 below shows the PVRR For each alternative plan for the 2023 IRP probability weighted average power prices and separately for each of the additional data center load price scenarios.

Figure 3.1: PVRR Sensitivity to Alternative Data Center Price Scenarios



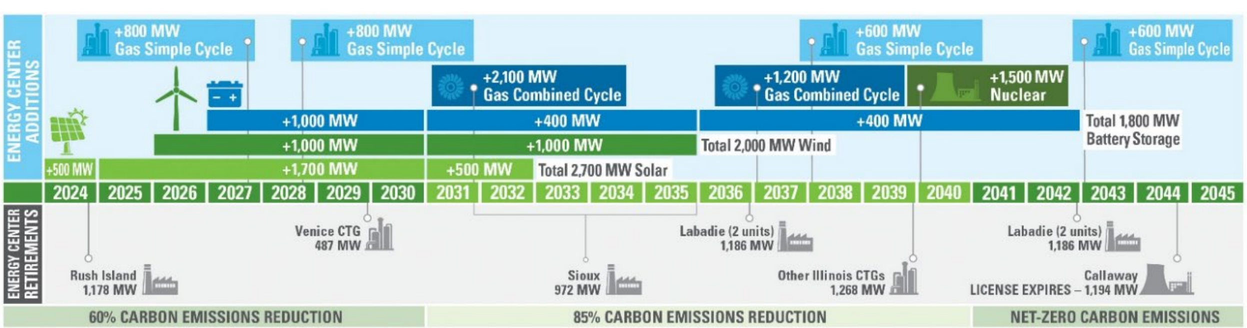
As the chart in Figure 3.1 shows, PVRR changes under some scenarios may slightly alter the order of some plans in the aggregate, but in only one case does the rank of an alternative plan change by more than one position, and this change does not affect the relative cost of relevant decisions regarding environmental compliance or resources needed to serve demand. As a result, final plan analysis results are shown using only the full range of 2023 IRP price scenarios.

3.3 Preferred Resource Plan and Contingencies

Ameren Missouri's management has selected its new PRP in consideration of the prospects for new large load additions and the various costs and risks associated with the resource additions needed to serve them. A diverse portfolio of resources will be needed to ensure reliable service at reasonable rates to both existing and new customers, including resources that primarily provide capacity benefits (CTG, BESS), resources that provide carbon-free energy benefits (solar, wind), and resources that provide both significant capacity and energy (NGCC, nuclear). The potential for a range of large load additions and the potential for future changes in load associated with large load customers, both increases and reductions, has led Ameren Missouri to select a PRP that represents an acceleration of resource additions that were included in its prior PRP but that would be needed in the long-term even if such load additions were not permanent. This includes acceleration of solar resource additions, which provide significant carbon-free energy for large customers like data centers with corporate sustainability and clean energy goals. It includes the acceleration of gas-fired generation and BESS resources to meet peak demand requirements in all seasons.

At the same time, the new PRP reflects more specificity regarding resource additions in the long-term if large load additions are more permanent. The 2023 PRP included 2,400 MW of "clean dispatchable" generation additions. The new PRP includes 1,500 MW of new nuclear generation in 2040. While the specific technology to be used has not yet been determined, the Company will continue to monitor developments in the market and fully evaluate new nuclear potential as part of its future IRP analyses. Ameren Missouri's new PRP is shown in Figure 3.2.

Figure 3.2: Ameren Missouri's Revised PRP



NOTE: Reductions are presented as of the end of the period indicated and based off 2005 levels. Wind and solar additions, energy center retirements by end of indicated year.

Description of Changes and Rationale

Following are the changes represented in the Company's new PRP relative to its prior PRP and the rationale:

- **Addition of data center loads** – The new PRP includes the addition of data center loads with cumulative demand reaching 1.5 GW by 2032 and 2.5 GW by 2040.
- **Reduction in MEEIA programs** – The new PRP includes MEEIA programs through 2043 at levels similar to those recently approved by the MPSC instead of at the RAP level.
- **Acceleration of solar resource additions** – The new PRP includes the same total solar additions as the prior PRP – 2,700 MW – but with accelerated timing for the additions to provide energy for new demand growth and clean energy to support the corporate clean energy goals of new large customers.
- **Acceleration and expansion of battery storage resource additions** – The new PRP includes acceleration and expansion of BESS to provide flexible capacity for new demand and integrate renewable resources, with 1,000 MW in service by the end of 2030, another 400 MW by the end of 2035, and another 400 MW by the end of 2042. This represents an overall increase in BESS of 1,000 MW relative to the prior PRP, driven by significant new load additions and the reduction in expected demand savings from MEEIA programs.
- **Acceleration and expansion of dispatchable generation resources** – The new PRP includes total natural gas and nuclear generation additions of 7,600 MW (3,300 MW NGCC, 2,800 MW CTG, 1,500 MW nuclear) compared to 4,400 MW of natural gas (1,200 MW NGCC, 800 MW CTG) and "clean dispatchable" resources (2,400 MW) in the prior PRP.

Because the changes are driven collectively by the changes in demand, it is helpful to understand how all of the changes affect the Company's capacity position in the final year of the planning horizon. Table 3.3 below shows a reconciliation of the Company's 2043 capacity position under the new PRP relative to the prior PRP.

Because the extent and timing of data center load additions is uncertain, Ameren Missouri has developed contingency plans for different levels of load additions. Table 3.4 below shows the resource additions for the 2025 PRP as well as the two contingency plans described above. Resource additions for the 2023 IRP are also shown for comparison. It is important to note that the resource additions through 2032 for the contingency plan for 2 GW of data center demand by 2032 are the same as the resource additions through 2032 for the PRP. Also, the addition of 800 MW of CTG generation in 2028 is included in both the upside and low contingency plans as well as the PRP.

Table 3.3: Change in Capacity Position – New PRP vs. Prior PRP

Load and Reserve Changes	2023 PRP	2025 PRP	Change
Data Center Load	-	2,555	2,555
Data Center Reserve (25%)	-	634	634
Energy Efficiency & Demand Response	(925)	(247)	678
EE/DR Reserve (25%)	(229)	(61)	168
Load and Reserve Changes	(1,154)	2,880	4,035
Incremental Generation Additions		**Nameplate**	**Accredited**
Battery Storage		1,000	950
Gas Simple Cycle		2,000	1,817
Gas Combined Cycle		2,100	1,852
Nuclear		1,500	1,425
Audrain Oil Backup		-	312
Clean Dispatchable		(2,400)	(2,066)
Total Generation Additions		4,200	4,290
Net Capacity Position Change			**255**

Table 3.4 Resource Additions for the 2025 PRP and Contingencies Compared to the 2023 PRP

	2023 IRP Preferred Plan	500 MW Large Loads	1.5 GW Large Loads	2.0 GW Large Loads
Data Center Load Additions (beginning of year)	N/A	500 MW by 2027 (4 GWh)	1.5 GW by 2032 (12 GWh) 2.5 GW by 2040 (20 GWh)	2 GW by 2032 (16 GWh) 3.5 GW by 2040 (28 GWh)
Energy Efficiency / Demand Response	Aggressive Energy Efficiency and Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs
Total Retail Sales in 2040	36 Million MWh	40 Million MWh	56 Million MWh	64 Million MWh
Coal Retirements (end of year)	Sioux (2032) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)
Gas Retirements (end of year)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)
Wind Additions (end of year)	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035
Solar Additions (end of year)	1,800 MW by 2030 2,700 MW by 2035	1,800 MW by 2030 2,700 MW by 2035	2,200 MW by 2030 2,700 MW by 2032	2,200 MW by 2030 2,700 MW by 2032
Battery Additions (end of year)	400 MW by 2030 800 MW by 2033	400 MW by 2030 800 MW by 2033	1,000 MW by 2030 1,400 MW by 2037 1,800 MW by 2042	1,000 MW by 2030 1,400 MW by 2037 1,800 MW by 2042
Combined Cycle Gas Additions (beginning of year)	1,200 MW (2033)	1,200 MW (2032)	2,100 MW (2032) 1,200 MW (2037)	2,100 MW (2032) 1,200 MW (2037) 1,200 MW (2038)
Simple Cycle Gas Additions (beginning of year, except 2027 and 2028 additions in Q4)	800 MW (2027)	800 MW (2027) 800 MW (2028)	800 MW (2027) 800 MW (2028) 600 MW (2038) 600 MW (2043)	800 MW (2027) 800 MW (2028) 600 MW (2035) 600 MW (2037)
New Nuclear Additions (beginning of year)	N/A	900 MW (2040)	1,500 MW (2040)	1,500 MW (2040)
Other Clean Dispatchable Additions (beginning of year)	1,200 MW (2040) 1,200 MW (2043)	1,200 MW (2037) 1,200 MW (2043)	N/A	N/A

3.4 Comparison to Prior Preferred Plan

Table 3.5 below shows a comparison of the performance measures used by Ameren Missouri to assess the performance of alternative resource plans and select its preferred plan.

Table 3.5: Comparison of Performance Measures for New and Prior PRP

Performance Measures (2025-2053)	Prior Preferred Plan 2023 IRP	New Preferred Plan 2025 Update	Change	% Change
PVRR, $MM	$82,799	$109,078	$26,279	31.7%
Levelized Annual Rates, Cents/kWh	$21.47	$20.55	-$1	-4.2%
PV of Free Cash Flow, $MM	$3,995	-$295	-$4,290	-107.4%
Cumulative CO_2 Emissions, Million Metric Tons	176	176	0	0.2%
PV of Probable Environmental Costs, $MM	$1,342	$1,899	$557	41.5%
Energy Savings, GWh	92,160	16,178	-75,983	-82.4%
Direct Jobs, FTE-Years	20,920	24,195	3,275	15.7%

As discussed previously in this report, the increase in PVRR is primarily a reflection of the much higher load levels reflected in the new PRP, driven by expected data center customer load additions, relative to the 2023 PRP. Note that the new PRP results in a 4.2% reduction in average rates relative to the 2023 PRP. Free cash flow reflects the need for both accelerated generation investment in the near term and overall greater generation investment in the long term. While the changes to the Company's outlook for MEEIA programs results in changes in both energy savings and jobs, the reduction in jobs is more than offset by construction and operating jobs resulting from new generation additions. Note that jobs are direct jobs and do not reflect job creation resulting from data center construction or economic benefits produced.

3.5 Implementation

Over the next two years, Ameren Missouri will be carrying out specific actions to execute on the new Preferred Resource Plan. These include:

- Submitting an application to establish a new tariff for large load customers, such as data centers, in the second quarter of 2025
- Submitting applications for CCNs to the MPSC for:
    - New solar generation projects (the first in the second quarter of 2025)
    - New BESS facilities to be located at former coal energy center sites (the first in the second quarter of 2025)

  - 800 MW of CTG generation at the former Rush Island coal energy center site (second quarter of 2025)
- Continuing to evaluate proposals for new wind and solar generation projects
- Continuing preparations for the addition of NGCC generation, including an application to the MPSC for a CCN in 2026
- Continuing to manage approved MEEIA programs for customer energy efficiency and demand response
- Continuing to monitor developments regarding environmental regulations, identifying and evaluating options for compliance, and taking steps to maintain available options
- Initiating a new market potential study to identify opportunities for further energy and demand savings from future MEEIA programs

Appendix A

Supplemental Information

Table A.1 Overnight Capital Cost for Combined Cycle (2024$)

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[redacted]		
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

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Table A.2 Overnight Capital Cost for Combined Cycle with CCS (2024$)

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[redacted]		
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

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Table A.3 Overnight Capital Cost for Simple Cycle (2024$)

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[redacted]		
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

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Table A.4 PVRR Sensitivity to Alternative Data Center Price Scenarios

Plan - $ Million		PVRR	Scn 10	Scn 11	Scn 12
A	2023 Preferred Plan (RAP)	85,471	87,077	85,917	83,828
B	2023 PRP (RAP)- Sioux'31	85,501	87,138	85,926	83,792
C	2023 PRP (RAP) - ESP - Sioux'31	85,805	87,441	86,230	84,096
D	Lower DSM - CC - ESP	87,927	89,316	88,463	86,808
E	Nuke - ESP	90,725	92,279	91,369	89,644
L	Cofire	91,530	92,639	91,823	90,410
I	GHG Cofire	92,000	93,028	92,381	91,061
G	Labadie Ret 2031	92,207	93,136	92,297	90,777
H	Labadie Ret 2031 GHG	92,316	92,934	92,472	91,380
F	SCR - FGD	92,532	94,103	93,167	91,461
K	Cofire - FGD	92,696	93,721	92,946	91,581
J	GHG Cofire - FGD	93,126	94,108	93,484	92,195
S	Cofire +1500 to 500 MW Load	97,265	97,857	97,629	97,118
N	Cofire +500 MW Load	97,386	98,382	97,667	96,273
T	Cofire +2000 to 500 MW Load	99,652	100,112	100,131	99,739
O	Cofire +1500 MW Load	104,284	104,716	104,626	104,103
P	Cofire +2000 MW Load	107,708	107,933	108,169	108,088
M	GHG Cofire +2500 MW Load	108,898	108,874	109,358	109,580
Q	Cofire +2500 MW Load	109,078	109,337	109,345	109,008
R	Cofire +3500 MW Load	115,307	115,245	115,652	115,860

	2023 IRP Preferred Plan	500 MW Large Loads	1.5 GW and Stop	2 GW and Stop	1.5 GW Large Loads	2.0 GW Large Loads	1.5 GW to 500 MW	2 GW to 500 MW
Case Number		1	2	3	4	5	6	7
Data Center Load Additions (beginning of year)	N/A	500 MW by 2027 (4 GWh)	1.5 GW by 2032 (12 GWh)	2 GW by 2032 (16 GWh)	1.5 GW by 2032 (12 GWh) 2.5 GW by 2040 (20 GWh)	2 GW by 2032 (16 GWh) 3.5 GW by 2040 (28 GWh)	1.5 GW by 2032 (12 GWh) 0.5 GW by 2039 (4 GWh)	1.5 GW by 2032 (12 GWh) 0.5 GW by 2039 (4 GWh)
Energy Efficiency / Demand Response	Aggressive energy efficiency and demand response programs	Limited Energy Efficiency and Continued Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs	Limited Energy Efficiency and Continued Demand Response Programs
Total Retail Sales in 2040	36 Million MWh	40 Million MWh	56 Million MWh	64 Million MWh	56 Million MWh	64 Million MWh	40 Million MWh	40 Million MWh
Coal Retirements (end of year)	Sioux (2032) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)	Sioux (2031-2035) Labadie - 2 Units (2036) Labadie - 2 Units (2042)
Gas Retirements (end of year)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)	Venice (IL) (2029) Other IL CTGs (2039)
Wind Additions (end of year)	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2036	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035	1,000 MW by 2030 2,000 MW by 2035
Solar Additions (end of year)	1,800 MW by 2030 2,700 MW by 2035	1,800 MW by 2030 2,700 MW by 2035	2,200 MW by 2030 2,700 MW by 2032	2,200 MW by 2030 2,700 MW by 2032	2,200 MW by 2030 2,700 MW by 2032	2,200 MW by 2030 2,700 MW by 2032	2,200 MW by 2030 2,700 MW by 2032	2,200 MW by 2030 2,700 MW by 2032
Battery Additions (end of year)	400 MW by 2030 800 MW by 2033	400 MW by 2030 800 MW by 2033	950 MW by 2030 1,550 by 2037 2,150 by 2042	950 MW by 2030 1,550 by 2037 2,150 by 2043	1,000 MW by 2030 1,400 MW by 2037 1,800 MW by 2042	1,000 MW by 2030 1,400 MW by 2037 1,800 MW by 2042	950 MW by 2030 1,550 by 2037	950 MW by 2030 1,550 by 2037
Combined Cycle Gas Additions (beginning of year)	1,200 MW (2033)	1,200 MW (2032)	1,800 MW (2032)	1,800 MW (2032) 600 MW (2037)	2,100 MW (2032) 1,200 MW (2037)	2,100 MW (2032) 1,200 MW (2037) 1,200 MW (2038)	1,800 MW (2032) 600 MW (2037)	1,800 MW (2032) 600 MW (2037)
Simple Cycle Gas Additions (beginning of year, except 2027 and 2028 additions in Q4)	800 MW (2027)	800 MW (2027) 800 MW (2028)	800 MW (2027) 800 MW (2029) 600 MW (2037)	800 MW (2027) 800 MW (2029) 600 MW (2037) 600 MW (2043)	800 MW (2027) 800 MW (2028) 600 MW (2038) 600 MW (2043)	800 MW (2027) 800 MW (2028) 600 MW (2035) 600 MW (2037)	800 MW (2027) 800 MW (2029)	800 MW (2027) 800 MW (2029) 600 MW (2037)
New Nuclear Additions (beginning of year)	N/A	900 MW (2040)	1,500 MW (2040)	1,500 MW (2040)	1,500 MW (2040)	1,500 MW (2040)	900 MW (2043)	900 MW (2043)
Other Clean Dispatchable Additions (beginning of year)	1,200 MW (2040) 1,200 MW (2043)	1,200 MW (2037) 1,200 MW (2043)	N/A	N/A	N/A	N/A	N/A	N/A

Schedule MM-D2

Assumptions for Energy Capability Positions

New Resources

Simple Cycle Gas Capacity Factors

- Base Permitting (e.g., Castle Bluff) – 30%
- Constrained Permitting (e.g., Big Hollow) – 20%

Combined Cycle Gas Capacity Factor – 80%
Wind Capacity Factor – 42%
Solar Capacity Factor – 26%
Battery Storage Net Energy – As modeled with IRP assumptions
Nuclear – As modeled with IRP assumptions

Existing Resources

Labadie Capacity Factor – 75%
Sioux Generation – As modeled with IRP assumptions and under low carbon price
Nuclear – As modeled with IRP assumptions
Hydro – As modeled with IRP assumptions
Pumped Hydro – As modeled with IRP assumptions

CTG Fleet – Operating hours based on permit limits as follows (per unit):

Audrain – 2,500 hours
Peno Creek – 1,000 hours
Goose Creek – 58 hours (average)*
Kinmundy – 71 hours (average)*
Pinckneyville 1-4 – 590 hours (average)*
Pinckneyville 5-8 – 32 hours (average)*
Raccoon Creek – 26 hours (average)*
Venice – 142 hours (average)*

* Note: Illinois CTG limits based on 2018-2020 actual production as required by the 2021 Climate and Equitable Jobs Act.

Ameren Missouri

Renewable Energy Standard Compliance Plan 2025-2027

Prepared in Compliance with 4 CSR 240-20.100

April 15, 2025

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Introduction

The Missouri Renewable Energy Standard (RES) began as a public initiative and was placed on the Missouri ballot during the November 4, 2008 election. Labeled as Proposition C, it required Ameren Missouri to acquire renewable energy resources as a percentage of total retail sales.

As part of the statute and rulemaking, Section (8) (A) required investor-owned utilities to file a report demonstrating how compliance was met in the previous calendar year, and Section (8) (B) requires investor-owned utilities to file a plan that covers their intended compliance measures for the current year plus the following 2 years.

Compliance with RES can be achieved using RECs from qualified renewable generation resources (wind, hydro, biomass, solar etc.) certified by the Missouri Department of Natural Resources (MoDNR). The MoDNR Division of Energy is responsible for providing renewable certification. The RES requires a percentage of RECs come from designated solar resources or (S-RECs).

The RES allows for two methods to achieve compliance. The first is based on providing enough RECs to meet the requirement, and the other is related to the 1% rate cap calculation. A utility will be in compliance with the RES if the cost of compliance is equal to or greater than the 1% rate cap calculation. Thus, a utility could fall short of meeting the RECs requirement, but if the 1% calculation is met, then the utility is in full compliance.

The following table details the renewables percentage requirements of retail electric sales for the non-solar and solar RES:

Time Period	Total Renewable Requirement	Solar*
2011-2013	2%	2%
2014-2017	5%	2%
2018-2020	10%	2%
2021-forward	15%	2%

*Solar percentages are applied to the Total Renewable Requirement RES amounts

As referenced above, the MoDNR is responsible for certifying all eligible renewable resources that can be utilized to meet the RES requirement. MoDNR rule 10 CSR 140-8.010 (2), contains the list of renewable resources eligible to achieve RES compliance.

Ameren Missouri's compliance with the RES, as demonstrated in this report, adheres to the use of only those renewable resources as currently defined by the above referenced rule.

In addition, the RES rules allow for the banking of RECs for up to a three-year time period. This will allow for the use of eligible RECs generated from January 1, 2022 to the end of 2024 in meeting the RES requirements for calendar year 2024. Any generation and/or RECs from a Missouri renewable resource are entitled to a factor of 1.25 applied to each MWh or REC.

The following information in this report demonstrates the specific means by which Ameren Missouri intends to meet its obligations under both the non-solar and solar RES for the calendar years 2025-2027.

Section (8) (B) 1 A: Planned Actions to Comply

Non-Solar RES

Ameren Missouri currently operates the following eligible non-solar renewable resources:

- Keokuk Hydro-Electric Generation Station
- Maryland Heights Renewable Energy Center (Landfill Gas)
- High Prairie Renewable Energy Center (Wind)
- Atchison County Renewable Energy Center (Wind)[1]

The Ameren Missouri Keokuk Hydro-Electric Generation Station is located on the Mississippi River in Keokuk, Iowa. The station consists of 15 separate generators. The individual nameplate ratings range from 7.2 to 8.8 megawatts (MWs). This generation facility is wholly owned by Ameren Missouri and has been operational since 1913. Due to fluctuations in river flows, generation can range from approximately 738,833 to 1,017,277 MWh annually.

On June 16, 2012, the Maryland Heights Renewable Energy Center (MHREC) became commercially operational. This facility burns methane gas produced by the IESI Landfill in Maryland Heights, Missouri in three Solar 4.9 MW Mercury 50 gas turbines to produce electricity. In recent years, the generation has ranged from 53,358 to 67,284 MWh annually. In accordance with RSMo 393.1030, a factor of 1.25 is applied to the in-state generation from this facility such that the expected generation counts as 66,697 to 84,105 MWh towards the compliance requirements.

On December 23, 2020, the 400 MW High Prairie Renewable Energy Center (HPREC) became commercially operational. This wind farm is in Adair and Schuyler counties, Missouri and consists of 175 wind turbines covering about 50,000 acres. The estimated generational output is approximately 945,033 MWh to 1,351,200 MWh annually, weather dependent. In accordance with RSMo 393.1030, a factor of 1.25 is applied to the in-state generation from this facility such that the expected generation counts as 1,181,291 to 1,689,000 MWh towards the compliance requirements.

[1] High Prairie, Atchison and Maryland Heights Renewable Energy Center were constructed for RES compliance.

On March 2, 2021, the Atchison County Renewable Energy Center (AREC) became operational at a reduced capacity of 120.0 MW and by December 22, 2021 reached its full operational capacity of 298.6 MW. This wind farm is located in Atchison County Missouri and consists of 91 turbines covering about 30,000 acres. The estimated generational output is approximately 866,400 MWh to 1,099,600 MWh annually, weather dependent. In accordance with RSMo 393.1030, a factor of 1.25 is applied to the in-state generation from this facility such that the expected generation counts as 1,083,000 to 1,374,500 MWh towards the compliance requirements.

Solar RES

In late 2010, Ameren Missouri completed the installation of approximately 100 kilowatts (kW) of solar generation capacity at its headquarters facility located in St. Louis. Generation from this facility will be utilized to help meet the solar requirements of the RES.[2]

In addition, on August 28, 2013, due to the passage of HB 142, the RES law was amended. That amendment provided that if a customer accepts a solar rebate from the utility, the S-RECs transfer to the utility.

In 2018, Senate Bill 564 (SB 564) became law. One of the provisions of this law is that up to $28 million in solar rebates be made available to customers that install solar generation on their property between 2019-2023. Ameren Missouri expects to receive the S-RECs from these customer-owned resources pursuant to the provisions of SB 564.

Ameren Missouri estimates that in 2025-2027 approximately 100,000 S-RECs per year will be acquired from customer generators under the terms of the two solar rebate programs for systems that become operational in 2023 and earlier. In accordance with RSMo 393.1030, a factor of 1.25 is applied to the in-state generation from these facilities such that the expected generation counts as 125,000 S-RECs annually towards the compliance requirements.

In addition to solar rebate payments, SB 564 requires Ameren Missouri to invest at least $14 million in additional utility-owned solar generation. The $14 million has been utilized to support community-based projects through Ameren Missouri's Neighborhood Solar Program. On July 21, 2021 the South St. Louis Renewable Energy Center (REC) became commercially operational – the first solar facility supported by the Neighborhood Solar Program. On July 20, 2022, the Cape Girardeau Renewable Energy Center (REC) became commercially operational. On July April 18, 2023 the Fee Fee Renewable Energy Center (REC) became commercially operational. On April 28, 2023, the North Metro Renewable Energy Center (REC) became commercially operational. On July 28, 2023, the Delmar Renewable Energy Center (REC) became commercially operational. On September 7, 2023, the House Springs Renewable Energy Center (REC) became commercially operational – the final solar facility supported by the Neighborhood Solar Program. The estimated combined generational output is approximately 3,984 kWh

[2] Constructed for RES compliance.

annually, weather dependent. In accordance with RSMo 393.1030, a factor of 1.25 is applied to the in-state generation from these facilities such that the expected generation counts as 4,980 MWh towards the compliance requirements.

Ameren Missouri completed construction on its first utility-scale solar generation project, the O'Fallon Renewable Energy Center (OREC) in November 2014.[3] This 5.7 MW (DC) facility is located at the site of the Ameren Missouri O'Fallon substation in O'Fallon, Missouri. The expected annual output for 2025-2027 is approximately 4,824 MWh based on the last five years of historical performance data. In accordance with RSMo 393.1030, a factor of 1.25 is applied to the in-state generation from this facility such that the generation counts as 6,030 MWh towards the compliance requirements.

On September 16, 2019, the BJC Solar Facility became commercially operational. This facility is 1.8 MW (DC) PV project located on the top of an existing parking garage at Barnes Jewish Hospital in St. Louis, MO. The total generational output of this facility during CY 2024 was 846 MWh and is assumed to remain at a similar level for years 2025-2027. In accordance with RSMo 393.1030, a factor of 1.25 is applied to the in-state generation from this facility such that the expected generation counts as 1,057 MWh towards the compliance requirements.

On December 13, 2024, the Huck Finn Solar Facility became commercially operational. This facility is 200 MW (DC) PV project located in Audrain & Ralls County MO. The estimated generational output is approximately 411,979 MWh to 466,207 MWh annually, weather dependent. In accordance with RSMo 393.1030, a factor of 1.25 is applied to the in-state generation from this facility such that the expected generation counts as 514,974 to 582,759 MWh towards the compliance requirements.

Planned Actions

For the 2025-2027 compliance years, Ameren Missouri will continue to utilize the generational output from the Keokuk, MHREC, HPREC, and AREC facilities to meet non-solar RES compliance. Ameren Missouri will continue to place RECs associated with the actual generation from these facilities into the North American Renewable Registry (NAR) account.

For the 2025-2027 compliance years, Ameren Missouri will continue to use the generational output from OREC, BJC Solar, Huck Finn, Neighborhood Solar facilities, and the S-RECs received from Ameren Missouri customer generators to meet solar RES compliance. Ameren Missouri will continue to place RECs associated with the actual generation from these facilities into the NAR account.

In addition, Ameren Missouri was issued certificate of convenience and necessity March 21, 2024 to construct and own the Vandalia Solar, Bowling Green Solar, and Split Rail Solar Projects and under the plan, RECs from each will be utilized to support RES compliance requirements.

[3] Constructed for RES compliance.

The Vandalia Solar Project is a 50 MW solar resource located in Vandalia, MO. The Vandalia Solar Project could be utilized to meet RES compliance upon completion of construction and is certified as a qualified renewable energy resource by the MoDNR, which is expected in 2025. The estimated generational output for the Vandalia Solar is approximately 114,209 MWh to 120,627 MWh annually, weather dependent. In accordance with RSMo 393.1030, a factor of 1.25 is applied to the in-state generation from this facility such that the expected generation counts as 142,761 to 150,784 MWh towards the compliance requirements.

The Bowling Green Solar Project is a 50 MW solar resource located in Bowling Green, MO. The Bowling Green Solar Project could be utilized to meet RES compliance upon completion of construction and the facility is certified as a qualified renewable energy resource by the MoDNR, which is expected in 2026. The estimated generational output for the Bowling Green Solar is approximately 113,943 MWh to 120,410 MWh annually, weather dependent. In accordance with RSMo 393.1030, a factor of 1.25 is applied to the in-state generation from this facility such that the expected generation counts as 142,429 to 150,513 MWh towards the compliance requirements.

The Split Rail Solar Project is a 300 MW solar resource located in Warren County, MO. The Split Rail Solar Project could be utilized to meet RES compliance upon completion of construction and is certified as a qualified renewable energy resource by the MoDNR, which is expected in 2027. The estimated generational output for the Split Rail Solar is approximately 620,400 MWh to 658,400 MWh annually, weather dependent. In accordance with RSMo 393.1030, a factor of 1.25 is applied to the in-state generation from this facility such that the expected generation counts as 775,500 to 823,000 MWh towards the compliance requirements.

While beyond the three-year period directly covered by this Plan, Ameren Missouri will seek approval for, and expects to begin construction in 2026 and 2027 on, an additional 450 MW of solar resources, which are being constructed in order to meet its post-2027 RES compliance requirements.

Existing and future solar resources are expected to be sufficient to fulfill the solar RES requirement in each year from 2025-2027. Excess S-RECs can then be utilized to meet non-solar compliance in each period. However, even after the addition of Huck Finn Solar, Vandalia Solar, and Bowling Green Solar a shortfall in non-solar compliance is expected in 2025 and 2026 and will continue to utilize spot market REC purchases in the short term (2025-2027) to meet compliance. As noted above, the annual renewable generation for solar, wind, and hydroelectric resources is subject to significant year over year variation based on weather. To account for this variation, Ameren Missouri assesses multiple production levels for RES compliance facilities by modeling expected renewable generation output at higher probability of exceedance levels, to ensure compliance will be met on an annual basis[4]. To that end, Tables 2, 3, and 4 reflect estimated generational output at approximately a P-90 production level for Ameren Missouri's largest compliance assets: High Prairie REC, Atchison REC, Keokuk, and Huck Finn Solar.

Actual retail load can also fluctuate annually, potentially causing a higher or lower required compliance level than forecasted. Ameren Missouri will continue to utilize spot market REC purchases in the short term (2025-2027) to meet compliance.

Table 1. Compliance Requirements

	2025	2026	2027
Projected Retail Electric Load (MWh)	30,589,394	33,103,354	34,933,625
Renewable Requirement (%)	15%	15%	15%
Non-Solar	14.7%	14.7%	14.7%
Solar	0.3%	0.3%	0.3%
RES Requirement (MWh)	4,588,409	4,965,503	5,240,044
Non-Solar	4,496,641	4,866,193	5,135,243
Solar	91,768	99,310	104,801

Table 2. Non-Solar Compliance Resources

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Table 3. Solar Compliance Resources

Resource Output (MWh)	2025	2026	2027
O'Fallon REC*	6,030	6,000	5,970
AMO Headquarters Solar*	103	103	102
BJC Solar*	1,053	1,047	1,042
Neighborhood Solar*	4,680	4,657	4,633
Huck Finn Solar*	592,165	589,204	586,258
Customer-Owned Solar*	127,239	125,867	125,600
Vandalia Solar*		148,041	147,301
Bowling Green Solar*		148,041	147,301
Split Rail Solar*			888,248

[4] Probability of exceedance levels ("p-levels") refer to the likelihood that the output of the resource will be above a specified level of MWh in any given year. A P-75 value indicates that in 75% of performance years, the output is expected to be above a specified level. Likewise, a P-90 value indicates that in 90% of performance years, resource output will be above the specified value. Therefore, an increase in the exceedance probability decreases the expected output.

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Solar REC Bank Rollover*			
TOTAL Solar	731,360	1,022,960	1,906,455

**Includes 1.25 MO adjustment*

Table 4. Compliance Position Over/(Under)

	2025	2026	2027
Non-Solar	(725,365)	(1,292,744)	(1,561,794)
Solar	639,592	923,650	1,801,654
Total Compliance Position *(P-90 production level)*	**(85,773)**	**(369,094)**	**239,860**

Section (8) (B) 1 B: List of Executed Contracts

Table 5. List of Executed Contracts, 2025-2027

Contracting Party	Resource Type	Contract Type	Contract Duration	Time Period	Expected RECs	Contract Term
Various Residential & Commercial Customers[5]	Solar	S-REC only	10 years	2025	127,239	
				2026	125,867	
				2027	125,600	

Section (8) (B) 1 C: Projected Retail Sales by Year

Please see Table 1 for Ameren Missouri's projected retail sales by year.

Section (8) (B) 1 D: Comparison to Preferred Resource Plan

The RES Compliance Plan detailed in this report is consistent with the Change in Preferred Resource Plan filed with Integrated Resource Plan by Ameren Missouri February 14, 2025.

Section (8) (B) 1 E: RES Compliance Plan Cost

The ability to utilize renewable resources that were not initially constructed for RES compliance and that are currently in rate base places Ameren Missouri and its customers in a unique position regarding compliance cost. As provided in the RES statute and rule, though the megawatt hours from these renewable resources can be utilized to meet the compliance requirements, since the primary purpose of them was not RES compliance when built, they do not contribute to RES compliance costs and do not factor into the rate cap limitation of 1%. The plan contemplates the need to purchase a limited number of RECs to balance the compliance obligations each year, due to variable annual retail sales or variable production of renewable asset.

[5] All S-RECs procured from customers are entitled to the additional in-state factor of 1.25 and the figures in this table reflect the total including the 1.25 factor.

The cost of the RES Compliance Plan for the 2025-2027 Compliance Plan periods is comprised of the following items:

- Cost to register RECs with the North American Renewable Registry
- Fixed, Fuel and O&M associated with the MHREC
- Fixed and O&M costs associated with the facilities constructed for RES compliance: Ameren Headquarters Solar, Huck Finn Solar, OREC, HPREC, and AREC
- Purchase of RECs

<u>REC Registration Fees</u>
In accordance with 4 CSR 240-20.100 Section (3) (F), utilities are to use a commission designated common central third-party registry for REC accounting of the RES requirements. The North Ameren Renewable Registry (NAR) was selected by the Commission for this purpose. Tracking and registration fees are charged by NAR for all RECs deposited and then retired from the utilities' accounts.

Section (8) (B) 1 F: RES Retail Rate Impact

The *10 Year MO RES Compliance Model 2025_34* (provided to Staff and others as a work paper to this filing) calculates the retail rate impact, as required by 4 CSR 240-20.100(5). The "Report" tab of the model sets forth the size and timing of the new renewable resources that would be needed in the next ten years to fully meet the unconstrained Renewable Energy Standard (RES) requirements along with the size and timing of those renewable resources that can be built while meeting the 1% retail rate impact limitation. The model includes the assumptions needed to develop RES compliance projections, including Ameren Missouri's projected revenue requirements (adjusted for exclusion of costs for existing renewable energy resources), market values for capacity and energy and costs for new wind and solar resources, are also included.

Section (8) (B) 1 G: Compliance with Air, Water or Land Use Requirements

All generating facilities utilized by Ameren Missouri to meet the requirements of the Missouri Renewable Energy Standard have been certified by the Missouri Department of Economic Development in accordance with 393.1030.4, RSMo.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Permission and Approval and Certificates of Public Convenience and Necessity Authorizing it to Construct Renewable Generation Facilities.	)))))	File No.: EA-2025-0239

AFFIDAVIT OF MATTHEW R. MICHELS

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Matthew R. Michels, being first duly sworn on his oath, states:

My name is Matthew R. Michels and hereby declare on oath that I am of sound mind and lawful age; that I have prepared the foregoing *Direct Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

/s/ Matthew R. Michels
Matthew R. Michels

Sworn to me this 29th day of August, 2025.