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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. EA-2026-0183

SURREBUTTAL TESTIMONY

OF

MATT MICHELS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
September, 2026

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MATT MICHELS

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Matt Michels. My business address is One Ameren Plaza, 1901 Chouteau Ave., St. Louis, Missouri.

Q. By whom and in what capacity are you employed?

A. I am employed by Ameren Services Company as the Director, Corporate Analysis.

Q. Are you the same Matt Michels that submitted Direct Testimony in this case?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

Q. To what Rebuttal Testimony or issues are you responding?

A. I am responding to the Rebuttal Testimony of Staff witnesses Malachi Bowman and Hari Poudel regarding the need for the Projects[1] and the economic analysis of the Projects. I am also responding to the Rebuttal Testimony of the Office of the Public Counsel ("OPC") witness Jordan Seaver regarding the rationale for inclusion of solar

[1] The Tom Sawyer Solar, Ringer Solar, Castle Bluff Battery Energy Storage System ("BESS"), Millcreek BESS (with the associated Quinn Switching Station), and Huck Finn BESS projects for which the Company is seeking certificates of convenience and necessity ("CCNs") in this case.

generation in the Company's Preferred Resource Plan ("PRP") and the comparison of BESS resources to natural gas simple cycle ("NGSC") generation.

Q. Please summarize the key points you make in your Surrebuttal Testimony.

A. As I described in my Direct Testimony, the Projects are needed to meet customer needs for capacity, energy, and renewable energy credits ("RECs") for compliance with the Missouri Renewable Energy Standard ("RES"),[2] and they represent cost-effective and available means for meeting those needs. In response to the Rebuttal Testimony of Staff and OPC witnesses, I will demonstrate that:

1. The Company's analysis of the economics of the Projects is based on the current cost estimates for the Projects and therefore provides a reasonable assessment of the Projects compared to other options.
2. The Company's cost estimates for the Projects are more aligned with the Company's prior IRP assumptions than Dr. Poudel suggests due to errors in his comparison of costs.
3. Staff concerns with respect to capacity accreditation for the Projects are overstated and are immaterial to the consideration of the need for the Projects and their economics.
4. The capital cost of BESS resources is lower than what Mr. Seaver includes in his comparison to the capital cost of NGSC resources when the effect of

[2] Or, if large load customers participate in the Company's RSP-LLC Program and qualify for the variance approved in File No. ET-2025-0184, to provide RECs under that Program – see Company witness Wills' Surrebuttal Testimony for a more detailed discussion of this issue.

investment tax credits ("ITC") is included as an offset to the BESS capital costs.

5. Substituting additional gas-fired resources at the Company's Castle Bluff Energy Center for the planned BESS resources at that site, as Mr. Seaver suggests, is not supported by the Company's analysis of the relative economics of those resources.

Company witness Rob Dixon specifically addresses issues raised by Staff and OPC regarding the likelihood of Large Load Customer ("LLC") additions, and Company witness Steven Wills addresses an apparent misinterpretation by Staff of the Company's waiver regarding RES compliance. Company witness Scott Wibbenmeyer addresses assertions by Mr. Seaver that additional gas-fired resources should be added at the Company's new Castle Bluff Energy Center instead of BESS resources and that BESS resources should instead be added to the Company's planned Ringer Solar Project site to satisfy capacity needs.

III. RESPONSE TO STAFF CONCERNS

Q. What does Dr. Poudel assert regarding the Company's economic analysis of the Projects?

A. Dr. Poudel asserts that the Company relies solely on its prior IRP analysis in support of the Projects as being economically feasible and that the Company's IRP analysis is inappropriate for evaluating the economic feasibility of the Projects because it relies on generic cost information for resources.[3]

[3] EA-2026-0183, *Staff Rebuttal Report*, p. 40, ll. 19-21, p. 41, ll. 3-7, p. 43, ll. 8-17, and p. 49, ll. 5-10, filed August 11, 2026..

Q. Did the Company rely solely on analysis provided in either its 2023 IRP or its February 2025 Notice of Change in Preferred Plan for purposes of evaluating the economics of the Projects?

A. No.

Q. What did the Company rely on for purposes of evaluating the economics of the Projects?

A. The Company relied on project-specific analysis included in my Direct Testimony in this case. Specifically, on pages 38-42 of my Direct Testimony, I describe the analysis I performed using project-specific cost information provided in the Direct Testimony Company witness Scott Wibbenmeyer. That analysis includes evaluation of plans with project-specific costs for each of the Projects, using both base costs assumptions and risk-adjusted cost assumptions and both including and excluding the benefits of ITCs. It further includes evaluation of plans in which each of the Projects is removed individually to examine the cost impact of each or the individual Projects under both base and risk-adjusted projects costs, with and without ITC benefits. Finally, it includes evaluation of plans in which alternative resources suitable for meeting the same needs as each Project are substituted for each Project independently. Every plan is analyzed under a range of market conditions defined by different levels of natural gas prices and carbon prices, along with the associated market energy prices and market capacity prices for each combination of natural gas prices and carbon prices. Results for net present value of revenue requirements ("NPVRR") for each plan and for relevant comparisons of the various plans are shown in Table 8 in my Direct Testimony. In summary, Dr. Poudel is mistaken and completely overlooked or ignored my Direct Testimony on this very point.

Q. Does Staff recommend an approach to economic analysis for projects for the Company to include with future CCN requests?

A. Yes. On page 105 of the Staff Report, Staff recommends Condition A.c., which states,

> If the Company relies primarily on the IRP analysis to justify the economic feasibility components of the CCN request for the future CCN applications, prior to its first IRP under 393.1900 RSMo., the Company shall conduct an updated analysis upon the occurrence of a material change in capital costs, resource availability, tax credit assumptions, or fuel and market prices. The Company shall perform an updated analysis to refresh those inputs in the economic modeling. Such updates may include, as applicable, potential cost mitigation strategies, updated capital costs estimates, ITC/PTC or other tax credit assumptions, and other material resource-specific assumptions. For purposes of the updated analysis the Company shall evaluate the resource portfolio using the previously modeled market scenario or sensitivity that reasonably best reflects then-current conditions and expectations.

Q. Does the analysis you included in your Direct Testimony address the points in Staff's recommended Condition A.c.?

A. Yes. The analysis in my Direct Testimony includes evaluation of both base and risk-adjusted project costs, including the effects of any cost mitigation strategies and other factors that may influence project costs and representing the best information available at the time the Company's request in this case was filed. The analysis also includes evaluation of uncertainty with respect to qualification for ITC and includes analysis across a wide range of market conditions, as I explained previously above and in my Direct Testimony.

Q. What does Dr. Poudel assert regarding the Company's capital cost estimates for the Tom Sawyer and Ringer Solar Projects?

A. Dr. Poudel asserts that the Company's solar project capital cost estimates, "exceed industry benchmarks and NREL estimates, suggesting a divergence from the observed trends of decline in Solar costs."[4]

Q. On what information does Dr. Poudel rely to make this assertion?

A. Dr. Poudel relies on a comparison of the Company's cost estimates as presented in the Direct Testimony of Company witness Scott Wibbenmeyer to estimates from the National Renewable Energy Laboratory's ("NREL") 2024 Annual Technology Baseline ("ATB").

Q. Is the comparison Dr. Poudel makes a valid comparison?

A. No, for several reasons. First, NREL's 2024 ATB costs are expressed in 2022 dollars; that is, they do not include the effects of inflation from 2022 forward. As a result, the cost trend shown in Figure 7 on page 48 of the Staff Report is misleading, showing a sharp downward trend that does not accurately reflect the true expected costs, which will include effects of inflation. Second, NREL's ATB cost data tend to exhibit a lag in capturing current market trends because they are based on recent historical projects costs. As a result, they do not capture current market realities with respect to tariffs, supply chain impacts, labor availability, and other factors that can affect project costs (i.e., the very type of factors that Staff notes should be considered in its recommended Condition A.c., which I discussed just above). It is noteworthy that the most recent NREL ATB was published in 2024 and relied on actual project data through 2022. On the website for the

[4] EA-2026-0183, *Staff Rebuttal Report*, p. 48, ll. 4-5, filed August 11, 2026.

2024 ATB, under the "Year" heading in the "Assumptions" section, NREL states, "The ATB includes estimates (for the Base Year) and projections (for the projected years) for each technology. Projections are based on trend lines between historical data and long-term (2030 and 2050) estimated costs. For most technologies, the Base Year (2022) is the final year of historical data. Near-term values in the ATB do not reflect every local or near-term market condition, nor are the longer-term ATB projections informed by recent changes."[5] The Company uses current market data based on responses to Requests for Proposals ("RFP") to inform its assumptions for future project costs. While the Company also reviews data sources such as NREL's ATB, it is important to reflect as best as possible the most up-to-date market conditions when making such assumptions. For these reasons, the Company develops its IRP project cost assumptions relying primarily on primary market data from RFP responses in the near term, with a range of future cost trends informed by NREL's ATB and other information.

Q. Did Dr. Poudel also compare the Company's current cost estimates for the Tom Sawyer and Ringer Solar Projects to the Company's prior IRP assumptions?

A. Yes. Dr. Poudel shows the Company's cost estimates for the Tom Sawyer and Ringer Solar Projects in Table 7 on page 45 of the Staff Report and compares those costs to assumptions from the Company's 2023 IRP and 2025 PRP filings. Specifically, he shows costs of $***_____*** per kW for Tom Sawyer and $***_____*** per kW for Ringer compared to 2023 IRP costs of $***_____*** per kW and 2025 PRP costs of $***_____*** per kW. This suggests base project costs for Tom Sawyer are 27% higher

[5] https://atb.nlr.gov/electricity/2024b/index

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than the most recent IRP assumption and the base project costs for Ringer are 25% higher than the most recent IRP assumption.[6]

Q. Are there problems with Dr. Poudel's comparison of project costs to IRP cost assumptions?

A. Yes, there are two key problems with his comparison. First, the costs for the Projects are expressed in nominal dollars, that is, they are the costs that are actually expected to be incurred, including the effects of inflation. In contrast, the IRP assumptions used by Dr. Poudel are expressed in real dollars (i.e., excluding the effects of inflation) – the 2023 IRP assumption is shown in 2023 dollars, and the 2025 PRP assumption is shown in 2024 dollars. Second, the costs for the Projects shown in Table 7 in the Staff Rebuttal Report include financing costs in the form of Allowance for Funds Used During Construction ("AFUDC"), whereas the IRP assumptions are overnight costs[7] that do not include AFUDC. For a proper comparison, we must exclude AFUDC from the costs for the Projects and include the effects of inflation in the IRP assumptions. Otherwise, we would be comparing apples and oranges.

Q. Have you created a comparison with the correction you just mentioned?

A. Yes. The appropriate cost for Tom Sawyer for comparison is $*****____***** per kW. Because it will be in service by the end of 2028, the appropriate value from the Company's prior IRP assumptions for comparison is $*****_____***** per kW. Likewise, the appropriate cost for Ringer, with a 2029 in-service date, for comparison is $*****_____*****

[6] The percentage difference for Ringer reflects a correction to the per-kW cost for Ringer shown in Table 7 in the Staff Report, which should be shown as $*****_____***** per kW. The value in Table 7 is in error.
[7] Per-kW overnight capital costs for solar and BESS discussed below and elsewhere in my Surrebuttal Testimony do not account for the reduction in costs that will be provided by ITCs on the Projects.

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per kW, and the appropriate value from the Company's prior IRP assumptions for comparison is $***_____*** per kW. Figure 1 below shows the solar overnight capital cost assumptions used in the Company's 2023 IRP and 2025 PRP analyses.

Figure 1. Ameren Missouri 2023 IRP and 2025 PRP Solar Overnight Capital Costs

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Using the appropriate figures for comparison means the cost for Tom Sawyer is only 15% higher than the comparable prior IRP assumption, not 27%, and the cost for Ringer is only 10% higher than the comparable IRP assumption, not 25%. Importantly, the costs for the Projects are the result of a competitive bidding process which necessarily better reflects recent market conditions than prior benchmarks and assumptions, and the economic analysis of the Projects included in my Direct Testimony and discussed earlier in my Surrebuttal Testimony was performed using the specific costs for the Projects.

Schedule MM-S1 shows a comparison of the costs of the Projects to the prior IRP assumptions for both base project costs and high, or risk-adjusted, project costs.

Q. Does Dr. Poudel also compare the costs for the Tom Sawyer and Ringer Solar Projects to the costs of solar projects for which the Company previously secured approval of CCNs?

A. Yes. As is the case with Dr. Poudel's comparison to the NREL ATB values, comparisons to previous solar projects ignore differences between current market conditions and market conditions that existed at the time CCNs for those previous projects were approved. As I mentioned previously, the Company used a competitive bidding process to identify appropriate projects to implement, as discussed by Mr. Wibbenmeyer in his Direct Testimony.

Q. Did Dr. Poudel make a similar comparison of costs for the BESS projects?

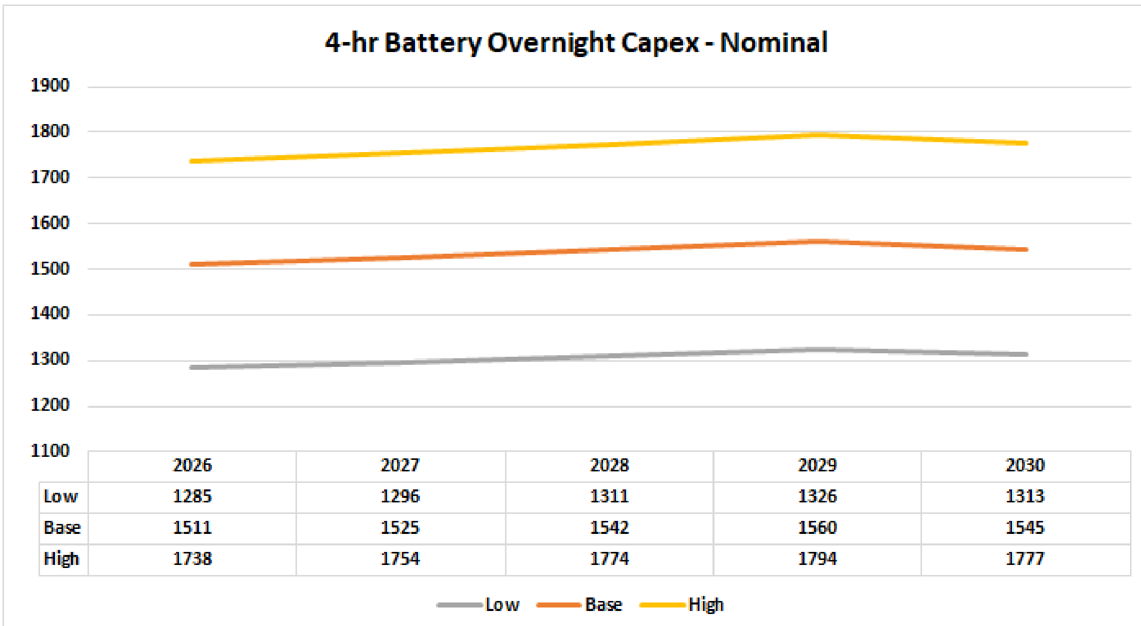
A. Yes. Dr. Poudel compares a value of $***_____**** per kW from the Company's 2023 IRP to projects costs of $***_____**** per kW for Castle Bluff BESS, $***_____**** per kW for Millcreek BESS, and $***_____**** per kW for Huck Finn BESS, implying cost differentials for each of these three projects compared to the IRP assumption of 9%, 11%, and 9%, respectively.[8]

Q. Does Dr. Poudel's comparison of BESS projects costs to IRP cost assumptions reflect the same problems you mentioned with respect to his comparison of solar project costs to IRP cost assumptions?

[8] EA-2026-0183, *Staff Rebuttal Report*, p. 47, ll. 2-9, filed August 11, 2026.

A. Yes. As is the case with the solar cost comparison I described earlier in my Surrebuttal Testimony, the costs for the Projects should exclude AFUDC, and the comparable IRP assumption should include the effects of inflation. Figure 2 below shows the overnight capital cost assumptions for BESS projects from the Company's 2023 IRP and 2025 PRP, including the effects of inflation (i.e., nominal dollars).

Figure 2. Ameren Missouri 2023 IRP and 2025 PRP BESS Overnight Capital Costs



	2026	2027	2028	2029	2030
Low	1285	1296	1311	1326	1313
Base	1511	1525	1542	1560	1545
High	1738	1754	1774	1794	1777

Schedule MM-S1 shows the appropriate comparison for the BESS projects, which demonstrates that the base project costs are within 1%, 2%, and 3% of the comparable IRP assumption for the Castle Bluff, Millcreek, and Huck Finn BESS projects, respectively. Schedule MM-S1 also shows that the risk-adjusted costs for these Projects are below the high end of the cost assumptions used in the prior IRP analysis in 2023 and 2025.

Q. Does Dr. Poudel also compare the costs of the Company's BESS Projects to other cost data?

A. Yes. As he did with the solar project costs, Dr. Poudel compares the costs of the Company's BESS Projects to data from NREL's 2024 ATB. As is the case with the solar cost comparison to NREL ATB data I described earlier, the NREL ATB data for BESS costs shown in Figure 8 on page 50 of the Staff Report do not include the effects of inflation; they are stated in 2024 dollars.

Q. Does Dr. Poudel make any assertions with respect to the accredited capacity of solar and BESS resources?

A. Yes. Specifically, Dr. Poudel asserts the following:

1. MISO seasonal accreditation results "have significant implications for evaluating Solar and BESS Projects."[9] He elaborates that MISO's 2024 RRA presentation[10] concludes that 1) wind and solar account for most future installed capacity and energy, but not most accredited capacity, and 2) reliability risk shifts from summer afternoons to winter mornings, reducing the contribution of solar and short-duration batteries.[11]
2. "Battery accreditation declines as winter reliability events become longer." He elaborates that, "As event duration exceeds the battery's discharge capability, the battery's reliability contribution declines unless adequate opportunities for recharging exist. Therefore, evaluations of BESS should

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[9] EA-2026-0183, *Staff* Rebuttal *Report*, p. 51, l. 14, filed August 11, 2026.
[10] https://cdn.misoenergy.org/20241218%20RRA%20Workshop%20Presentation667199.pdf
[11] EA-2026-0183, Staff Rebuttal *Report*, p. 51, ll. 16-19, filed August 11, 2026.

include prolonged winter stress scenarios to ensure that the modeled reliability benefits are not overstated."[12]

3. "If a utility models only a 4 -hour BESS using generic assumptions without evaluating longer durations, the analysis may not identify the most cost-effective portfolio. Given the capacity needed in the winter season, the 8-hour BESS could be economically effective." Dr. Poudel goes on to note that in response to Staff Data Request 0094, the Company indicated that MISO analysis shows accreditations for 8-hour BESS that are 2-4 percentage points higher than accreditations for 4-hour BESS. He suggests the Company should evaluate the relative economics of 8-hour BESS in addition to 4-hour BESS.

Q. Please address Dr. Poudel's first assertion regarding accreditations for wind and solar generation and the shift in reliability risks to winter mornings.

A. I agree that wind and solar capacity accreditations are expected to be relatively low, especially winter accreditations for solar. However, as I discussed at length in my Direct Testimony,[13] Ameren Missouri's need for solar generation is to supply *energy* and *RECs* for Missouri RES compliance. Any capacity benefits for solar, which are included in the economic analysis shown in my Direct Testimony,[14] are somewhat incidental to the true need. I also agree that the key reliability risks are winter hours, particularly winter mornings. This is why the Company's capacity needs are focused primarily on winter capacity needs, as I discussed in my Direct Testimony,[15] and why I

[12] EA-2026-0183, *Staff Rebuttal Report*, p. 52, ll. 1-7, filed August 11, 2026..
[13] EA-2026-0183, Matt Michels Direct Testimony, pp. 24-37.
[14] EA-2026-0183, Matt Michels Direct Testimony, pp. 38-42.
[15] EA-2026-0183, Matt Michels Direct Testimony, pp. 15-18.

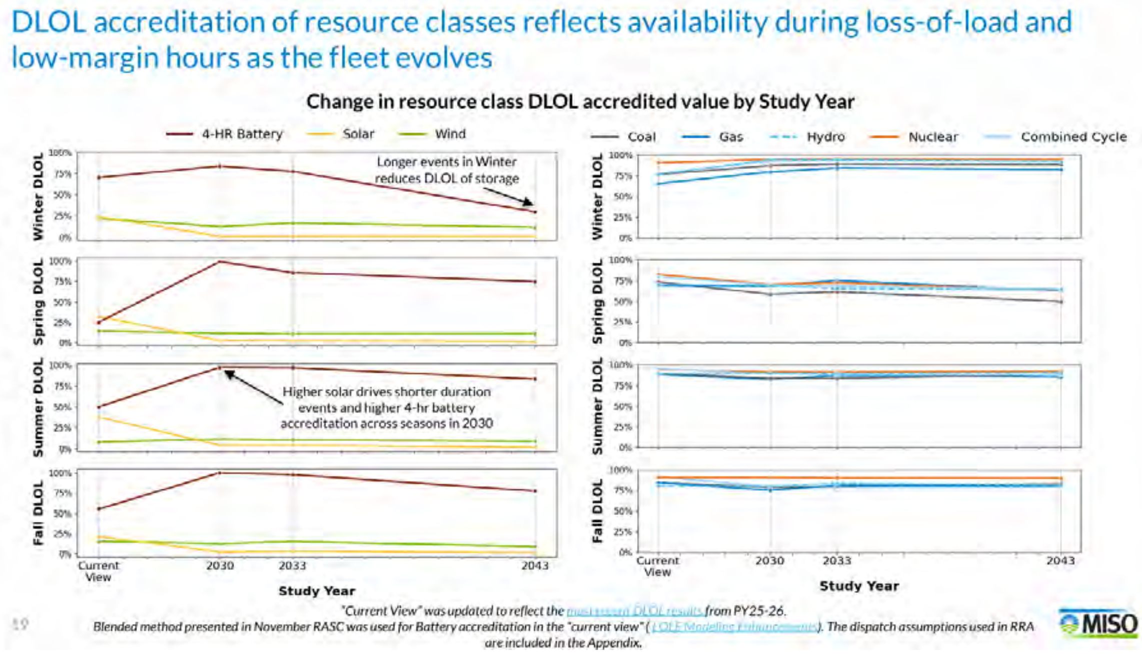
have compared the economics of BESS to that of additional NGSC generation reflecting declining capacity contributions for BESS.[16] That analysis showed that BESS additions have an economic advantage over additional NGSC generation up to at least 2 giga-watt ("GW") of BESS additions, which is more than double the total of 945 mega-watts ("MW") of BESS capacity the Company will have online following completion of the Projects.[17]

Q. Please address Dr. Poudel's second assertion regarding increases in winter reliability events.

A. Dr. Poudel cites a figure on slide 19 of MISO's Regional Resource Adequacy workshop presentation, asserting that "BESS evaluations should include prolonged winter stress scenarios." While it is important to examine stress scenarios when assessing BESS reliability contributions, and while MISO's modeling does in fact include consideration of the probability of extreme weather, it is important to understand what MISO's presentation is conveying. To make this clear, I have included the same figure used by Dr. Poudel on page 52 of the Staff Report below as Figure 3.

[16] EA-2026-0183, Matt Michels Direct Testimony, pp. 18-23.
[17] The comparison of the economics of BESS and NGSC in my Direct Testimony suggests that the economic advantage in favor of BESS could extend well beyond 2 GW.

Figure 3. Excerpt from MISO's December 2024 Regional Resource Assessment Workshop Slides



Dr. Poudel focuses on the note within the top left chart in Figure 3, which states that "Longer events in Winter reduces DLOL of storage." The "events" described in the MISO statement in Figure 3 are reliability events, not weather events, and are characterized by expected unserved energy ("EUE") events when generation is insufficient to meet load. Rather than an exogenous input to the reliability modeling that is used for analysis of BESS accreditation, the reliability events are simply an output of that reliability modeling that describes the reason for the lower accreditation. Said another way, the modeling results indicate that the incremental, or marginal, capacity benefit of additional 4-hour BESS is lower *because* the modeling results show that there are longer EUE events for a given increment of BESS. This is a relatively minor technicality that does not impact the economics of the Project as I described in my Direct Testimony but warrants some clarification given the focus in the Staff Rebuttal Report.

Q. Please address Dr. Poudel's third assertion regarding the need to evaluate 8-hour BESS in addition to 4-hour BESS.

A. In short, the Company has done that, including in its 2023 IRP. Dr. Poudel notes the Company's response to Staff Data Request 0094, which shows MISO's April 2025 comparison of 4-hour BESS accreditation and 8-hour BESS accreditation, as shown in Table 1 below.

Table 1. MISO Comparison of Accreditation for 4-hour BESS and 8-hour BESS[18]

	PY2030-31			PY2030-31 LDS scenario					
	Storage (4h)			Storage (4h)			Storage (8h)		
	Early	Blended	Even loss	Early	Blended	Even loss	Early	Blended	Even loss
Summer	87%	87%	91%	89%	90%	92%	100%	99%	100%
Fall	99%	99%	99%	100%	100%	100%	100%	100%	100%
Winter	92%	92%	93%	95%	95%	96%	97%	97%	100%
Spring	100%	100%	99%	100%	100%	100%	100%	100%	100%

Table 1 shows that the accreditation for 8-hour BESS is just 2-4 percentage points higher than the accreditation for 4-hour BESS, depending on which of three accreditation methodologies is used. However, this does not provide a complete picture of the comparison between 4-hour BESS and 8-hour BESS. Also included in the Company's response to Staff Data Request 0094 is a chart of capital cost assumptions for 4-hour BESS and 8-hour BESS, shown below in Figure 4, from the Company's 2023 IRP.[19]

[18] 20250409 RASC Item 08 LOLE Modeling Enhancements Storage Modeling689245.pdf
[19] Ameren Missouri 2023 IRP Chapter 6, page 20, Figure 6.13. Chapter 6 is attached as Schedule MM-S2.

Figure 4. Overnight Capital Cost for 4-hour BESS and 8-hour BESS (2023 Dollars without inflation effects)

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As Figure 4 shows, the capital cost of 8-hour BESS is approximately *double* that of 4-hour BESS. As a result, the small incremental capacity accreditation benefit (2-4%) for 8-hour BESS relative to 4-hour BESS does not justify the significantly higher (almost double) capital cost. This may change in the future, depending on the composition and behavior of the broader power system and potential advancements in technology and in system costs, but at this time 4-hour BESS is a significantly more cost-effective solution for additional capacity than 8-hour BESS.

IV. RESPONSE TO OPC CONCERNS

Q. Please summarize the main issues raised by OPC witness Jordan Seaver.

A. Mr. Seaver raises issues or concerns with the following:

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1. The Company's characterization of resource acceleration in its recent IRP filings and other resource-related cases.[20]
2. The Company's rationale for the need for solar resources.[21]
3. The appropriateness of adding BESS capacity at the Company's Castle Bluff Energy Center instead of additional gas-fired resources.[22]

Q. What does Mr. Seaver assert with respect to the Company's characterization of resource acceleration in its IRP filings and other resource-related cases?

A. In short, Mr. Seaver asserts that the Company has indicated that it is, "speeding up [its] planned buildout, so it is just what they were already going to do."[23] He further asserts that, based on his assessment of the Company's load for existing customers, the two Solar Projects in this case are not needed for existing customers at this time. Mr. Seaver further suggests that the Company's two remaining coal-fired facilities (the Sioux and Labadie Energy Centers) are, "unlikely to be closed in the next 10-20 years"[24] and that the Company's past IRPs show that new resources were not shown to be needed in the near term.[25]

Q. How do you respond to these assertions?

A. The Company is indeed accelerating resources it had planned to add prior to its inclusion of significant large load additions, as I discussed in my Direct Testimony and in the Company's February 2025 Notice of Change in PRP (Schedule MM-D1 to my

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[20] EA-2026-0183, Jordan Seaver Rebuttal Testimony, pp. 9-10.
[21] EA-2026-0183, Jordan Seaver Rebuttal Testimony, pp. 12-13.
[22] EA-2026-0183, Jordan Seaver Rebuttal Testimony, pp. 14-16.
[23] EA-2026-0183, Jordan Seaver Rebuttal Testimony, p. 9, ll. 12-13.
[24] EA-2026-0183, Jordan Seaver Rebuttal Testimony, p. 9, l. 21 to p. 10, l. 2.
[25] EA-2026-0183, Jordan Seaver, Rebuttal Testimony, p. 10, ll. 3-16.

Direct Testimony). Specifically, I discuss in my Direct Testimony the acceleration of the Company's planned total addition of 2,700 MW of solar generation and that the Company's 2025 PRP reflects accelerating the addition of solar resources, with 2,200 MW installed by the end of 2030 compared to 1,800 MW installed by that same time in the Company's 2023 IRP and with the total of 2,700 MW installed by the end of 2032 instead of by the end of 2035. This is clearly an acceleration of resource additions that the Company had planned to implement prior to its consideration of significant new large loads. But it is not an addition of incremental resources, and but for the large load additions, these resources would have been added anyway.

Mr. Seaver protests that the two Solar Projects for which the Company is seeking CCNs in this case would not have been needed, but the Company's 2023 IRP clearly included the same total solar generation additions as the Company's 2025 PRP, which is also shown in Schedule MM-D2 by comparing the total additions in the Company's 2023 IRP to the total additions in Cases 4 or 5 in the table. The solar additions in the Company's 2023 IRP were supported in its 2023 IRP filing, as described in Chapter 10 of the 2023 IRP and in the Company's June 2022 Notice of Change in PRP, which includes supporting analysis from Roland Berger.[26] Even setting aside the acceleration of solar resources represented in the Company's 2025 PRP, the addition of the Tom Sawyer and Ringer Solar Projects would result in total solar additions of 1,550 MW, still short of the 1,800 MW of total solar additions by 2030 included in the Company's 2023 IRP, at a time when material large load additions were not even on the Company's radar.[27]

[26] Chapter 10 of the Company's 2023 IRP is attached as Schedule MM-S3, and the Company's June 2022 Notice of Change in PRP is attached as Schedule MM-S4.
[27] EA-2026-0183, Matt Michels Direct Testimony, Footnote 8 on p. 7.

Mr. Seaver's claim that the resource additions in the Company's prior IRP filings were, "largely a result of its energy transition goals,"[28] is a gross misrepresentation. The Company's energy transition was developed through thoughtful analysis and consideration of the costs, benefits, and risks attendant to long-term resource planning, not a simplistic result of arbitrary goals. While the added consideration of significant large loads has affected the specifics of the Company's planned transition and its need for, and timing of, resource additions, the principles and considerations that led to the Company's planned transition remain valid.

As for the assertion that the Sioux and Labadie Energy Centers are unlikely to be closed in the next 10-20 years, this is little more than baseless conjecture. The Department of Energy orders pursuant to Section 202(c) of the Federal Power Act are short-term in nature, capped at 90 days. While they can be and have been renewed for additional 90-day periods, Mr. Seaver tellingly fails to cite any support for the suggestion that such orders are expected to be renewed into perpetuity. It is certain that new administrations will come to power in the next 10-20 years, and it is likely that some of those administrations will not be as inclined to provide such relief. It is important to also remember that both the Sioux Energy Center and the Labadie Energy Center will be over 60 years old at the time the Company currently plans to retire the units.

Q. What does Mr. Seaver assert regarding the Company's rationale for its need for solar generation resources?

A. Mr. Seaver asserts that he does "not believe that the Company is attempting to add solar generation at this time because solar is needed over other generation sources

[28] EA-2026-0183, Jordan Seaver Rebuttal Testimony, p. 10, ll. 13-14.

but is adding solar generation because (1) it is the easiest type of generation to procure at this time, and (2) because in prior IRPs, the model used to make building decisions chose solar because there was an assumption that it was the lowest cost generating resource type."[29] He goes on to state that the cost of solar resources does not justify its benefits in terms of accredited capacity[30] and that these resources would only be added for meeting the needs of new large load customers[31] and to attract them to the Company's service territory.[32]

Q. How do you respond to these assertions?

A. As I've mentioned earlier in my Surrebuttal Testimony, I discussed the Company's need for solar resources in my Direct Testimony, that the need is for energy and RECs for compliance with the Missouri RES, and that the relatively small capacity benefits from solar resources are incidental to the Company's consideration of need. The relative ease of acquiring solar resources *compared to wind resources* is indeed relevant to the question of meeting energy and REC needs, but that is where the relevance of its availability ends. Other resources, including the BESS Projects for which the Company is also seeking CCNs in this case, are necessary for meeting capacity needs. It is also a mischaracterization to say that the Company uses a model to pick resources because they are assumed to be lowest cost. Cost is certainly a key consideration in the Company's resource decisions, but so are other considerations, as described in Schedule MM-S3. This includes risk mitigation benefits of zero-emission and zero-fuel-cost renewable resources, a benefit this Commission itself recognized, including in its *Report and Order* in File No.

[29] EA-2026-0183, Jordan Seaver Rebuttal Testimony, p. 12, ll. 12-17.
[30] EA-2026-0183, Jordan Seaver Rebuttal Testimony, p. 12, l. 25 to p. 13, l. 4.
[31] EA-2026-0183, Jordan Seaver Rebuttal Testimony, p. 13, ll. 3-7.
[32] EA-2026-01863, Jordan Seaver Rebuttal Testimony, p. 13, ll. 9-18.

EA-2022-0245. As I also discussed earlier in my Surrebuttal Testimony, the Company has indicated a need for solar resources prior to the consideration of significant large load customer additions. Large load customers do indeed express preferences for low-carbon resources like solar generation, but that has not been the primary driver for the Company's inclusion of solar (and wind) resources in its prior and most recent IRP filings.

Q. What does Mr. Seaver recommend with respect to the Company's planned Castle Bluff BESS Project?

A. Mr. Seaver recommends that the Company co-locate the 95 MW of BESS planned for the Castle Bluff site at its planned Ringer solar facility instead and that additional gas-fired generation be added at Castle Bluff.[33] He asserts that this would better support new solar generation at the Ringer site and allow additional energy benefits from the added NGSC generation at the Castle Bluff site.

Q. Is Mr. Seaver's recommendation reasonable?

A. No. Mr. Wibbenmeyer's Surrebuttal Testimony counters Mr. Seaver's recommendation and corrects his incorrect accreditation assumption. There is also an economic rationale for adding more BESS capacity instead of additional NGSC capacity beyond what the Company is already adding in the next few years (at both Castle Bluff and the Company's planned Big Hollow site), and that rationale is described in detail in my Direct Testimony. In short, additional BESS capacity has an economic advantage over additional NGSC capacity based on the analysis shown in my Direct Testimony, at pages 18-22. Mr. Seaver completely ignores this.

[33] EA-2026-0183, Jordan Seaver Rebuttal Testimony, p. 14, ll. 7-8.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

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 Facility and Battery Energy Storage Systems.	))))))	File No.: EA-2026-0183

AFFIDAVIT OF MATT MICHELS

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

Matt Michels, being first duly sworn on his oath, states:

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

/s/ Matt Michels
Matt Michels

Sworn to me this 4th day of September 2026.

EA-2026-0183

Schedule MM-S1

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Entirety

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6. New Supply-Side Resources

Highlights

- *Large scale wind resources exhibit the lowest cost on a levelized cost of energy (LCOE) basis among all candidate resource options without tax incentives.*
- *With federal investment tax credits (ITC) or production tax credits (PTC), large scale solar resources closely follow wind resources as low-cost energy resources in addition to providing significant summer peak capacity benefits.*
- *Battery storage has been identified as a candidate resource option in addition to pumped storage.*
- *Ameren Missouri selected three natural gas technologies as final candidate resource options – Gas Combined Cycle with and without carbon capture and sequestration (CCS), and Gas Simple Cycle Combustion Turbine. Gas Combined Cycle exhibits the lowest LCOE among non-renewable generation resources.*

The supply-side screening analysis of various coal, gas, and renewable power generation technologies used in the 2020 IRP was reviewed by Ameren Missouri subject matter experts and updated for use in the 2023 IRP. Supply chain constraints and challenges have created upward pressure on wind and solar technology unit-costs, but to a large extent these challenges have been offset by extended and expanded tax credits included in the 2022 Inflation Reduction Act (IRA). Other incentives in the IRA also make the use of hydrogen and carbon capture and sequestration projects more attractive than they have been in the past. This IRP focuses on solar, wind, storage, and natural gas (both simple cycle and combined cycle) as potential new supply-side resources. Nuclear generation is also included due to its ability to provide around-the-clock carbon-free energy.

Ameren Missouri continues to monitor the universe of storage resource options, including pumped hydro storage, compressed air energy storage (CAES), stacked blocks (gravity storage), liquid air, and several battery energy storage system (BESS) technologies. Pumped hydroelectric storage is still an energy storage resource included in our evaluation of alternative resource plans as a major supply-side resource. However, with the advancements in BESS, including various lithium-ion and flow battery technologies, and the challenges associated with permitting new pumped hydroelectric storage facilities, BESS is the primary energy storage resource included as a major supply-side resource in the near to medium term.

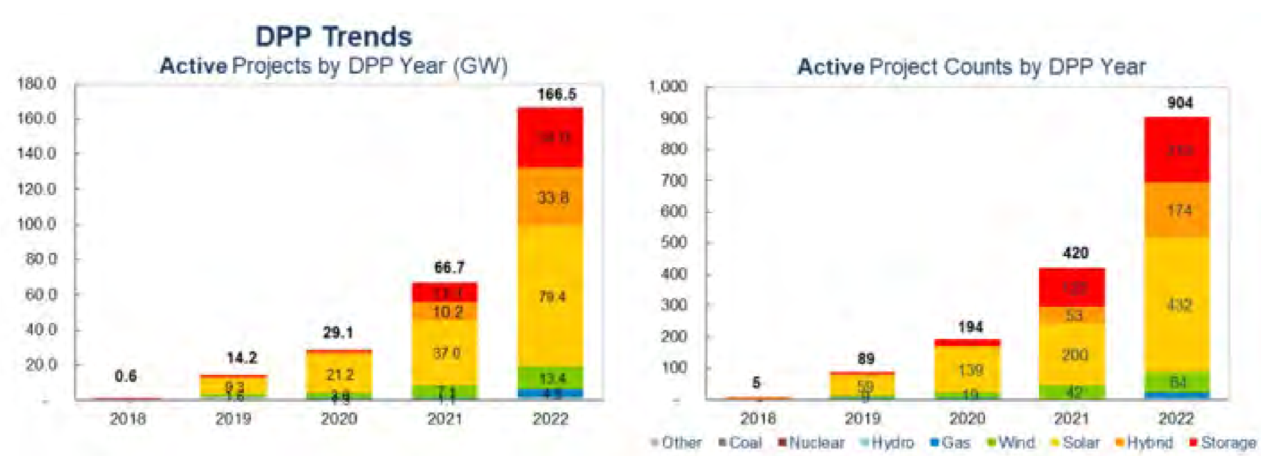
While some energy storage technologies have not been selected for integration analysis, it is important to note that the use cases for such technologies continue to develop, as does the consideration of appropriate market treatment for the services that these technologies can provide. Such ongoing developments will continue to be considered as part of our ongoing resource planning, including consideration of technologies and services provided by and to the transmission and distribution systems.

Capital costs for all preliminary candidate supply-side options include any necessary transmission interconnection costs. No preliminary candidate supply-side resource option was eliminated from further consideration due to interconnection or other transmission analysis.[1]

6.1 Potential Renewable Resources[2]

As of March 2023, the Midcontinent Independent System Operator (MISO) shows a year-over-year increase across all renewable technology generation interconnection (GI) requests. Although wind project GI requests ticked meaningfully upwards in 2022, they are still far outnumbered by solar projects by both project count and total capacity. 2022 also saw an increase in the number of storage project GI requests, from 122 projects in 2021 up to 210 in 2022. All GI requests proceed through the Definitive Planning Phase (DPP) process as MISO and the appropriate transmission owners evaluate how the generation projects will affect the bulk electric system. Figure 6.1 shows DPP trends by year, in terms of both capacity (left) and project count (right).

Figure 6.1 MISO Generator Interconnection: Overview[3]



There are a total of three DPP iterations, and GI requests may proceed to the next phase or be withdrawn depending on business case decisions for each project. The recent extension of federal tax credits for wind, solar, and storage through the IRA is expected to further accelerate the development of these resources across MISO, as seen already in the large increase in projects in the queue in 2022. A detailed characterization of the

[1] 20 CSR 4240-22.040(4)(B); 20 CSR 4240-22.040(4)(C)
[2] 20 CSR 4240-22.040(1); 20 CSR 4240-22.040(2); 20 CSR 4240-22.040(4)(A)
[3] https://cdn.misoenergy.org/GIQ%20Web%20Overview272899.pdf

information gathered through Ameren Missouri's subject matter experts for use in the 2023 IRP can be found in Chapter 6 – Appendix A.

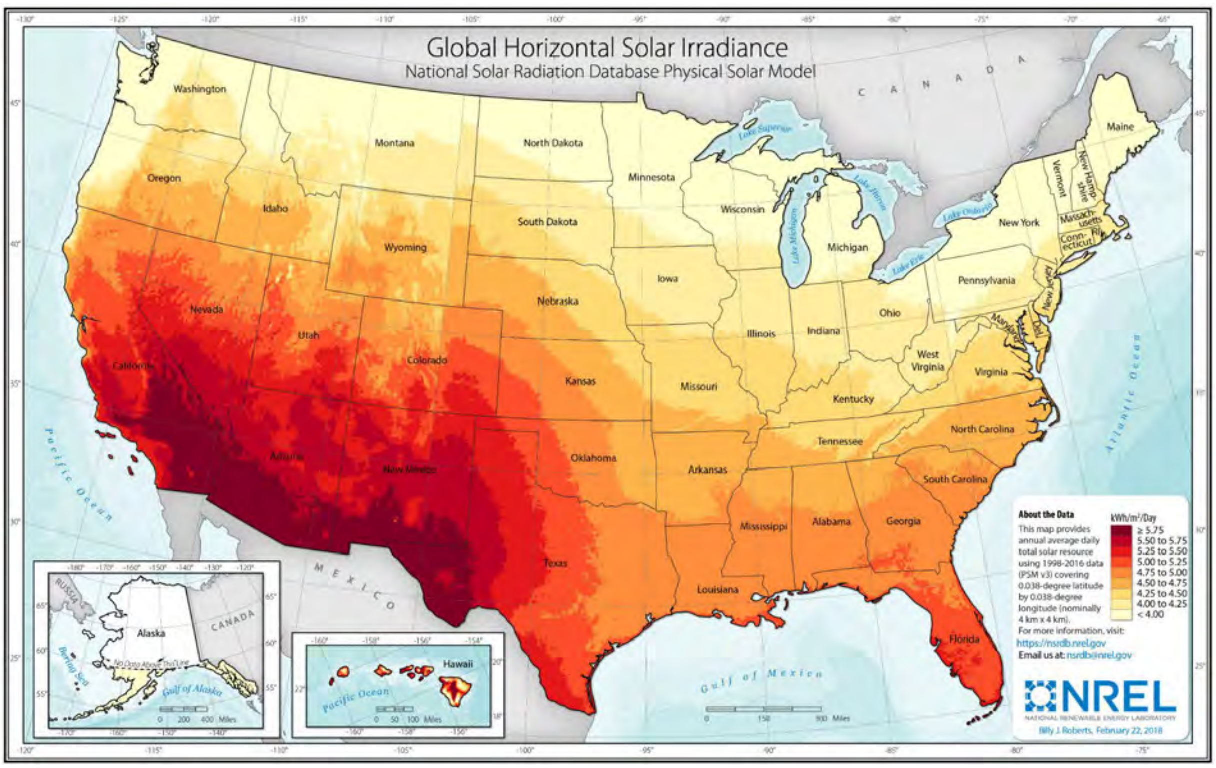
6.1.1 Potential Solar Resources

Based on a review of available solar technologies and Ameren Missouri's service territory, flat-plate solar photovoltaic (PV) is among the most practical, common, and cost-effective technologies for implementation.

Solar Resource & Technologies

The solar resource has three primary components: direct, diffuse, and ground reflected solar irradiances. Global Horizontal Irradiance (GHI) is the sum of all irradiances observed by a flat-plate over time. A map of the GHI for the U.S. is shown in Figure 6.2.

Figure 6.2 U.S. Global Horizontal Irradiance Map



As illustrated in the figure above, Missouri has a reasonably strong solar resource. St. Louis specifically averages an annual GHI value of 4.36 kWh/m^2-day.[4]

Concentrating solar power (CSP) technologies convert direct normal irradiance (DNI) into thermal energy to generate electricity via steam-turbine or engine. While the desert southwest has the highest DNI, there is ample GHI across much of the U.S. Solar PV technologies convert GHI into electricity via the photovoltaic effect. Both flat-plate PV and concentrating photovoltaic (CPV) collectors can be used to generate solar energy. Flat-

[4] NSRDB Physical Solar Model (PSM); St. Louis; TMY hourly data; GHI

plate collectors may be monofacial or bifacial, meaning light is collected on the top and bottom of the module. Due to the low cost of silicon-based materials and ample GHI resource across the U.S, bifacial flat-plate PV is the most practical and cost-effective solar technology.

Flat Plate Photovoltaics

PV capacity has grown to be the most common form of solar technology in the U.S., and Ameren Missouri expects it will remain the dominant solar technology option for deployment for the foreseeable future. As of March 2023, Wood Mackenzie reported there were nearly 90 GW of PV operating in the U.S. and 125 GW in the contracted pipeline. Of the utility-scale solar contracts signed in 2020, only 4% were under a mandated renewable portfolio standard, while more than 80% of projects were signed under voluntary procurement by a utility or corporate off-taker.[5] This is evidence of the continued improvement in technology and implementation techniques including:

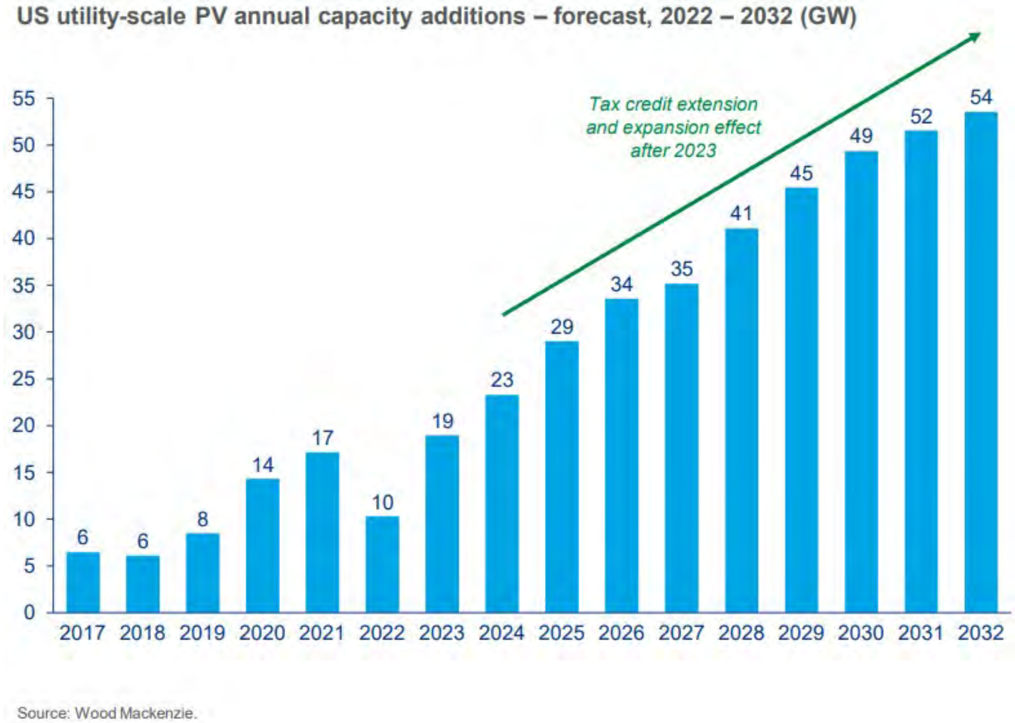
- Adoption of glass-on-glass bifacial modules that decreases degradation and extends its useful life
- Widespread use of single-axis trackers that yields higher capacity factors along with extended energy production windows
- Increase of solar module to inverter (DC:AC) ratios to further increase capacity factor

In the coming years, PV will continue to realize tax credit benefits thanks to the IRA. The IRA returned the Investment Tax Credit (ITC) to 30% of qualified costs and enabled PV to take advantage of the Production Tax Credit (PTC), which has historically been limited to wind projects. These full credits are contingent upon the project meeting prevailing wage and apprenticeship requirements. The law also enables projects to qualify for bonus tax credit adders including a domestic content adder (10% bonus) that applies to projects utilizing a defined amount of US manufactured materials, and an energy community adder (10% bonus) that applies to projects located in qualified areas such as brownfield, former fossil fuel sites, and those with lower employment rates.[6]

As discussed above, the IRA is expected to lead to increased PV capacity additions as depicted in Figure 6.3.

[5] Wood Mackenzie US Utility Scale Solar Market Update: Q4 2022, Page 14
[6] File No. EO-2023-0099 1.C

Figure 6.3 U.S. Utility-Scale PV Annual Capacity Additions – Forecast 2022-2032[7]



These capacity additions may further exacerbate supply chain challenges that have arisen due to the following:

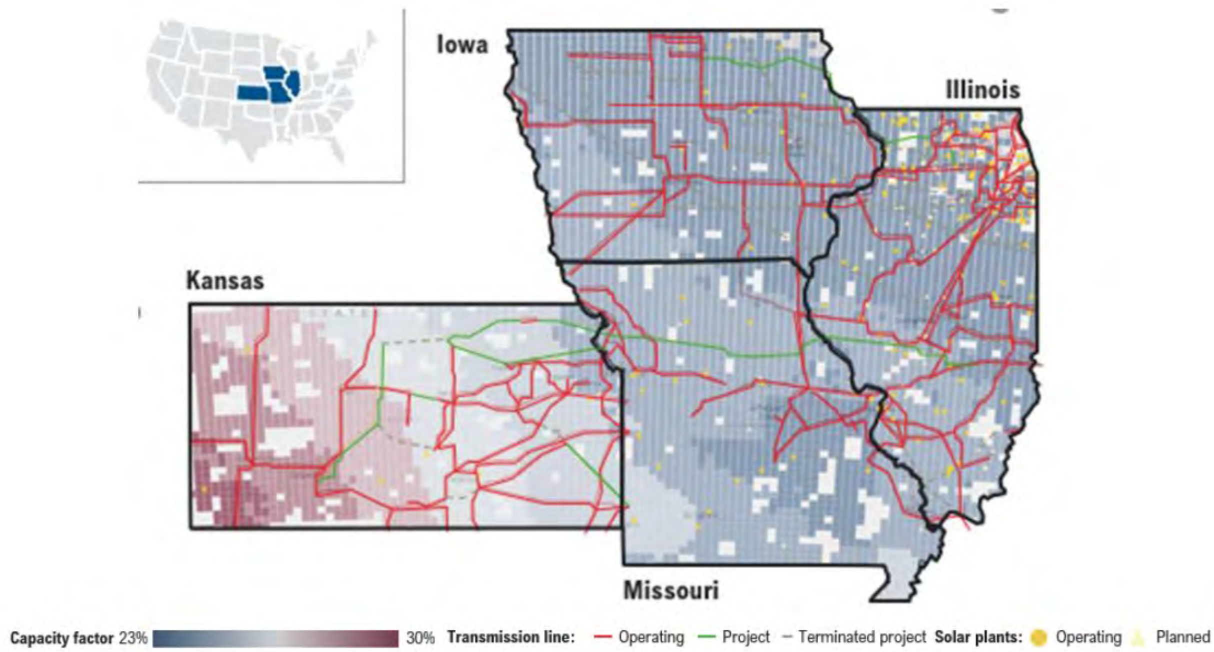
- Pandemic induced bottlenecks for key solar equipment in addition to increased containerized freight prices,
- U.S. Department of Commerce (DOC) anti-dumping and countervailing duties investigation in 2022, leading to potential significant punitive and retroactive tariffs on solar panels procured from Southeast Asia. An executive order signed by President Biden imposing a two-year moratorium on solar panel tariffs for solar projects completed by December 2024 has exponentially increased near term demand for solar panels,
- Passage of the Uyghur Forced Labor Prevention Act (UFLPA) banning imports of solar panels from China's Xinjiang region, leading to significant importation delays at U.S. customs,
- High U.S. inflation and a constrained construction labor market and increasing labor costs economy-wide.

Continued deployment of both PV and wind, discussed below, may be further constrained by the transmission system. More specifically, the high volume of MISO interconnection applications is leading to the need for additional transmission upgrades and to delays in receiving Generator Interconnection Agreements (GIAs). Interconnection queue reform remains critical for MISO as utilities across the ISO work to bring new resources online.

[7] Wood Mackenzie US Utility Scale Solar Market Update: Q4 2022, Page 6

Figure 6.4 overlays solar resource capacity factors, existing and planned projects, and existing and planned transmission lines in Ameren Missouri's region.

Figure 6.4 Map of Solar Capacity Factors, Development, and Transmission Lines[8]



Source: Roland Berger; NREL; S&P Global. Note: AC capacity factor.

The transmission system constraints coupled with balance of system savings may lead to repowering or extending the life of PV facilities. When repowering, the solar PV modules and inverters are replaced at or near end-of-life to maintain the power output of the facility. While the expected economic life of a utility-scale PV facility is 30 years in Missouri, developer land leases often extend out 35 years and beyond – an indication that the market is considering these strategies for the future. Ameren Missouri continues to evaluate how repowering strategies may provide value for customers.

Ameren Missouri Photovoltaics

In addition to the solar assets currently in operation in Ameren Missouri's generation fleet, the Company plans to build additional solar resources in the coming years. Two of those solar resources have received regulatory approval and are moving forward with construction: Huck Finn and Boomtown Renewable Energy Centers. Each planned solar resource addition is detailed below:

Huck Finn Renewable Energy Center

Huck Finn Renewable Energy Center is a 200 MW-AC solar energy center located in Audrain and Ralls County, Missouri. The resource received regulatory approval on

[8] Roland Berger Market Study: The Risk of Ameren Missouri Delaying Renewable Development; May 2022, pg. 24

February 8, 2023 and is currently under construction. It is expected to be commercially operational in late 2024 and will be utilized to support Ameren Missouri's compliance with the Missouri Renewable Energy Standard.

Boomtown Renewable Energy Center

Boomtown Renewable Energy Center is a 150 MW-AC solar energy center located in White County, Illinois. The resource received regulatory approval on April 12, 2023 and is currently under construction. It is expected to be commercially operational in late 2024 and will be utilized to support the Renewable Solutions Program.

Table 6.1 lists the primary characteristics of solar resources. Chapter 6 – Appendix A contains more detailed information.

Table 6.1 Forecasted Potential Solar Resources (2023$)

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Despite supply chain challenges, Ameren Missouri expects that on average the installed cost of solar will continue to decline in real terms, and therefore is using a declining curve informed by market data and the NREL 2022 Annual Technology Baseline (ATB) data, which is shown in Figure 6.5 below.

Figure 6.5 Base Solar Overnight Capital Cost Assumption (2023$)

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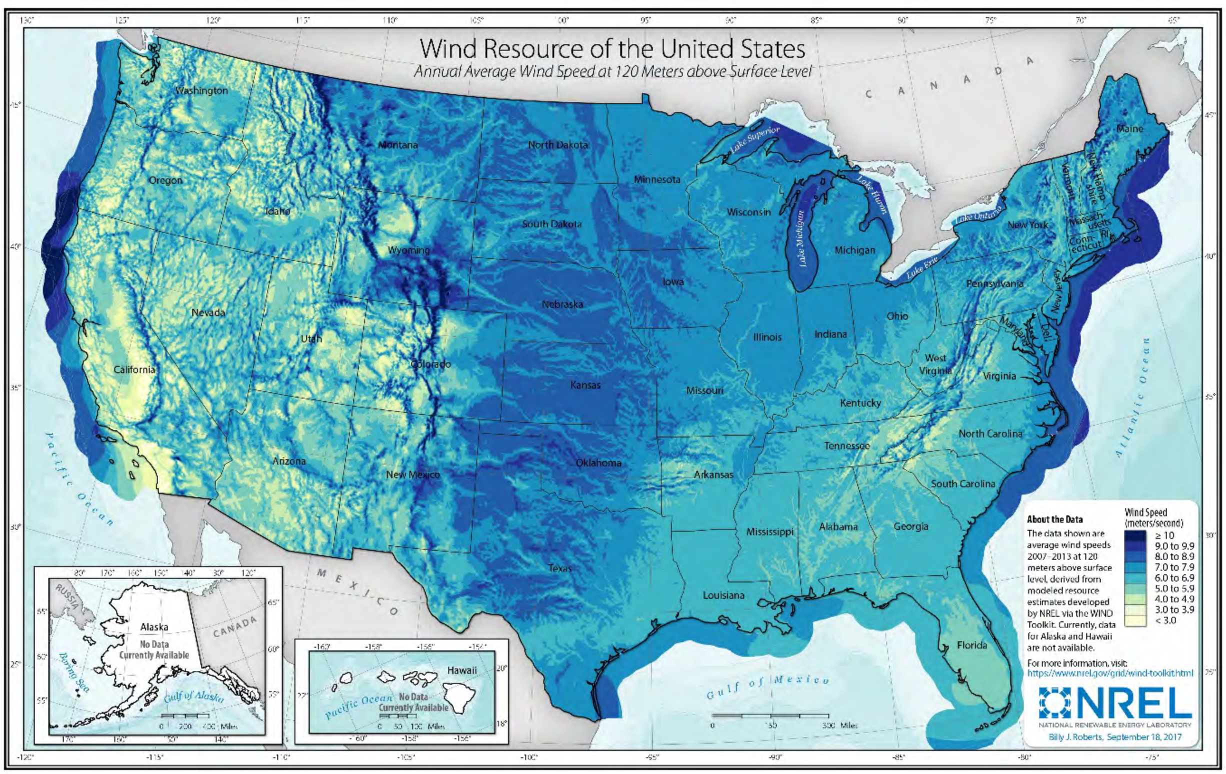
6.1.2 Potential Wind Resources

Wind Resource & Technologies

Historically, Missouri has seen limited deployment of wind generation compared to its western neighbor states. This is because the wind speed drops moving from west to east as one crosses the Kansas-Missouri border. Figure 6.6 below, which maps the average wind speed at 120 meters above surface level illustrates this fact.

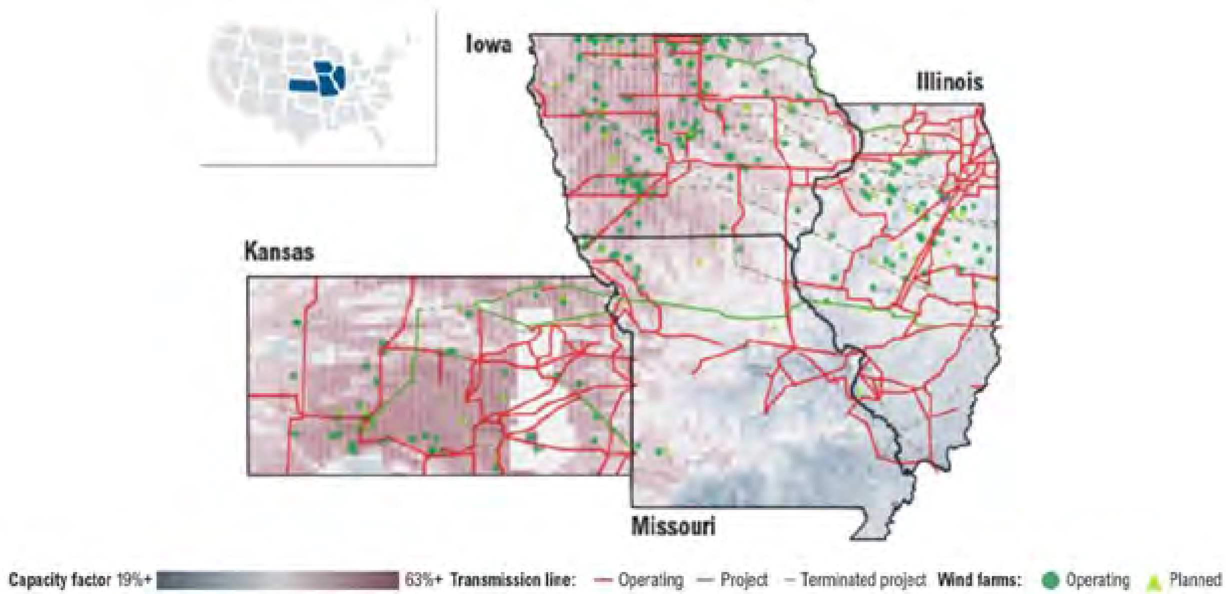
Figure 6.6 U.S. Wind Resource Map – 120 m above surface level[9]



The lower wind resource has translated into fewer wind projects as illustrated in Figure 6.7 below.

[9] https://www.nrel.gov/gis/assets/images/wtk-120m-2017-01.jpg

Figure 6.7 Map of Wind Capacity Factors, Development, and Transmission lines[10]



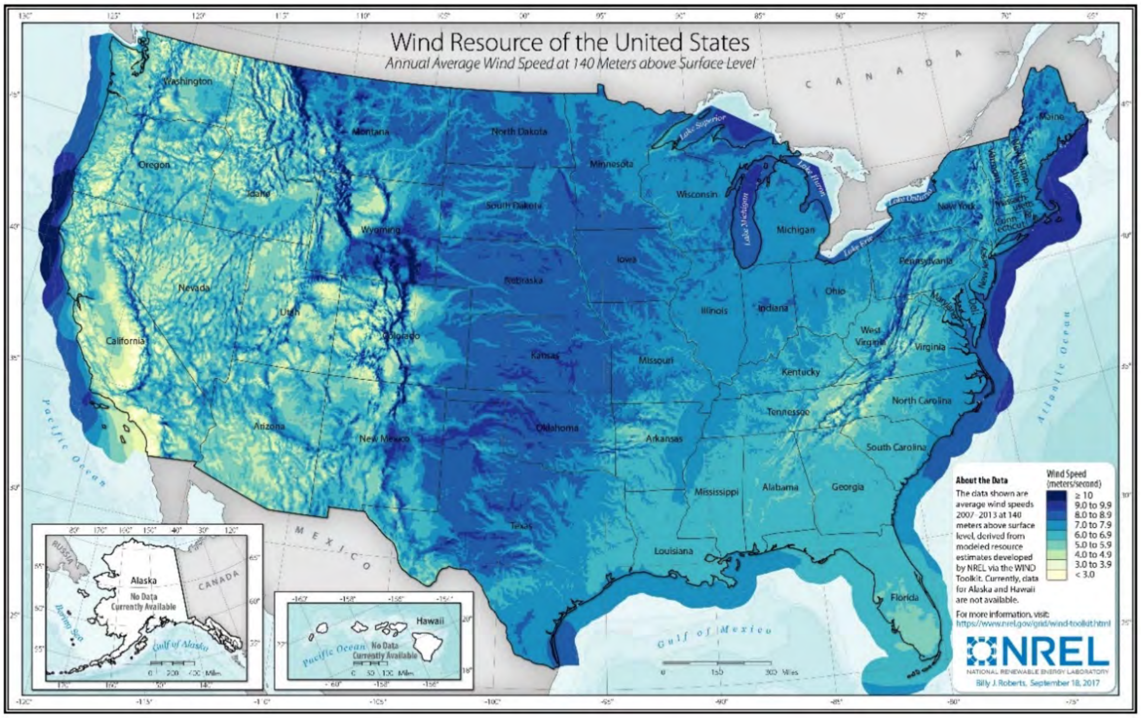
Source: Roland Berger; NREL; S&P Global

However, with the advent of new technologies, modern turbines are getting bigger and can be mounted on higher masts. The height for turbine "hub," the part of the turbine that houses the nacelle, generator, and other ancillary systems has been increasing, with the most recent turbine models at hub heights of 140 meters or more.[11]

The NREL map below, Figure 6.8 shows the wind speed at 140 meter above the surface level.

[10] Roland Berger Market Study: The Risk of Ameren Missouri Delaying Renewable Development; May 2022, pg. 12
[11] https://www.vestas.com/en/products/enventus-platform/v150-6-0

Figure 6.8 U.S. Wind Resource Map – 140 m above surface level[12]



As the map shows, Missouri has considerably more regions of good wind resource (shown in dark blue colors) at the 140-meter height, which may improve future wind generation opportunities in the state.

Ameren Missouri Wind

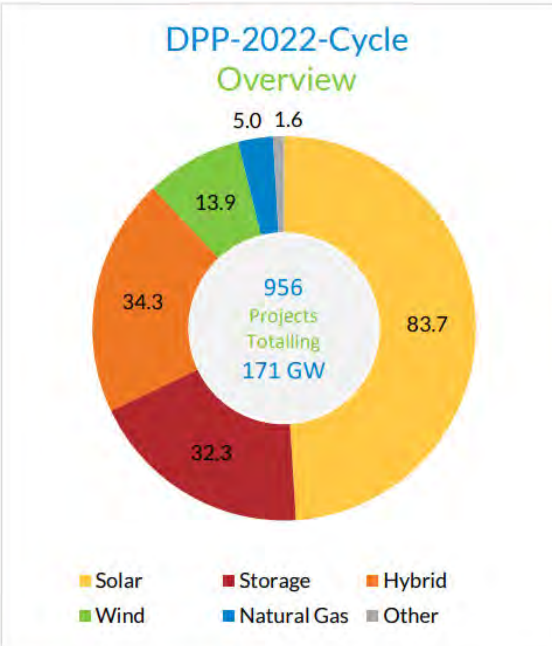
Ameren Missouri currently has two wind facilities in its generation fleet as discussed in Chapter 4: the Atchison Renewable Energy Center, and the High Prairie Renewable Energy Center.

Ameren is evaluating the wind (and solar) projects submitted in response to its request for proposals (RFP) in 2022 and may bring a wind project forward after completing preliminary diligence. In the near-term, wind project opportunities in Ameren Missouri's region appear more limited than solar project opportunities. Lower wind resource, longer wind development timelines, and (until the recent passage of the IRA) declining PTC values combined have likely been driving the relatively slow wind deployment in the region.

[12] https://www.nrel.gov/gis/assets/images/wtk-140m-2017-01.jpg

However, the continued technology evolution for wind together with the recently extended tax credits in the IRA has helped increase interest in wind development in the region, as demonstrated in the MISO GIA queue statistics shown in Figure 6.9.

Figure 6.9 MISO 2022 Generator Interconnection Queue Submissions[13]



Fuel	# of Requests	GW
Solar	469	83.7
Storage	231	32.3
Hybrid	163	34.3
Wind	66	13.9
Natural Gas	21	5.0
Other	6	1.6
Grand Total	**956**	**170.8**

FUEL	# OF REQUESTS	GW
Central	**301**	**54.5**
Solar	137	22.1
Storage	78	13.1
Hybrid	66	14.6
Wind	16	2.9
Natural Gas	4	1.8
East (ATC)	**30**	**4.0**
Solar	10	1.2
Storage	11	1.7
Hybrid	2	0.1
Wind	1	0.2
Natural Gas	6	1.0
East (ITC)	**89**	**14.9**
Solar	57	9.2
Storage	22	3.8
Hybrid	8	1.5
Natural Gas	2	0.3
South	**400**	**71.9**
Solar	222	44.5
Storage	83	7.2
Hybrid	79	15.8
Wind	10	2.6
Natural Gas	1	0.2
Other	5	1.6
West	**136**	**25.4**
Solar	43	6.8
Storage	37	6.5
Hybrid	8	2.2
Wind	39	8.2
Natural Gas	8	1.7
Other	1	0.0
Grand Total	**956**	**170.8**

As Figure 6.9 shows, there are around 5,500 MW of new wind project applications in the 2022 MISO queue for the MISO Central and the MISO South regions providing a reasonably robust medium-term pipeline of wind projects for Ameren Missouri.

[13] https://cdn.misoenergy.org/2022%20GIQ%20Submission%20Statistics626443.pdf

Accordingly, Ameren Missouri will continue to look for opportunities to evaluate and advance wind projects from this medium-term pipeline.

Lastly, Ameren will also be evaluating the potential for new wind (and other technologies) around its retiring generation station using the MISO generator replacement process or combining wind (or solar) with its existing combustion turbine generation facilities to leverage the transmission capacity.

Using market data for available regional wind projects as a reference point, Ameren Missouri subject matter experts revised the cost and operational characteristics of wind resources to be used in the 2023 IRP as can be seen in Table 6.2. Chapter 6 – Appendix A contains more detailed information.

Table 6.2 Forecasted Potential Wind Resources (2023$)

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Ameren Missouri expects that on average the installed cost of wind will continue to decline in real terms, and therefore, is using a declining curve informed by market data and the NREL 2022 Annual Technology Baseline (ATB) data as shown in Figure 6.10.

Figure 6.10 Base Wind Overnight Capital Cost Assumption (2023$)

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6.1.3 Potential Storage Resources[14]

Ameren Missouri has considered a range of storage resource options, including pumped hydro storage, CAES, stacked blocks (gravity storage), liquid air, and a number of BESS technologies. A high-level fatal flaw analysis was conducted as part of the first stage of the supply-side selection analysis for storage resources. Options that did not pass the high-level fatal flaw analysis consist of those that could not be reasonably developed or implemented by Ameren Missouri. Two options passed the initial screen: pumped hydroelectric energy storage, and lithium-ion battery energy storage. Table 6.3 lists primary characteristics of storage resources. Chapter 6 – Appendix A contains detailed resource characteristics.

Pumped Hydroelectric Energy Storage

Pumped hydroelectric energy storage is a large-scale, mature, commercial utility-scale technology used at many locations in the United States and worldwide. Conventional pumped hydroelectric energy storage uses two water reservoirs, separated vertically. During lower priced hours (historically off-peak periods), water is pumped from the lower reservoir to the upper reservoir. During high priced periods, (typically on-peak hours), the water is released from the upper reservoir to generate electricity. Church Mountain, located about midway between Taum Sauk State Park and Johnson Shut-ins State Park, was identified as the potential site for a new 600 MW pumped hydro plant. Multiple design factors can materially impact the costs of a pumped storage facility, including geography, installed capacity, and storage time. Costs used in the 2020 IRP were escalated for inflation, adjusted for transmission interconnection cost, and were used for the LCOE calculation in Table 6.3 Potential Energy Storage Resources.

Battery Energy Storage Systems

Battery Energy Storage Systems have been deployed throughout the United States as both supply-side and demand-side resources. BESS can provide services such as frequency regulation, frequency response, load shifting, and renewable energy smoothing, to name a few. As more intermittent renewable generation is deployed within Ameren Missouri's service territory and the surrounding regions, BESS will become more valuable as a controllable grid resource.

Ameren Missouri continues to analyze different BESS chemistries.[15] Technologies such as sodium-sulfur, while mature, have limited capabilities when compared to emerging technologies, such as lithium-ion and redox flow batteries. Advanced lead-acid batteries

[14] 20 CSR 4240-22.040(1); 20 CSR 4240-22.040(2); 20 CSR 4240-22.040(4)(A); File No. EO-2023-0099 1.G
[15] 20 CSR 4240-22.040(2)(C)2

also continue to improve but face a challenging market with the continued pressure from lithium-ion battery products.

Lead Acid Batteries

Since 2015, Ameren Missouri has been supporting applied research and the actual piloting of this technology at the Missouri University of Science and Technology in Rolla, MO. Today, we are designing, procuring, and deploying this technology at a Managed Charging for Fleet EVs site for Ameren vehicles.

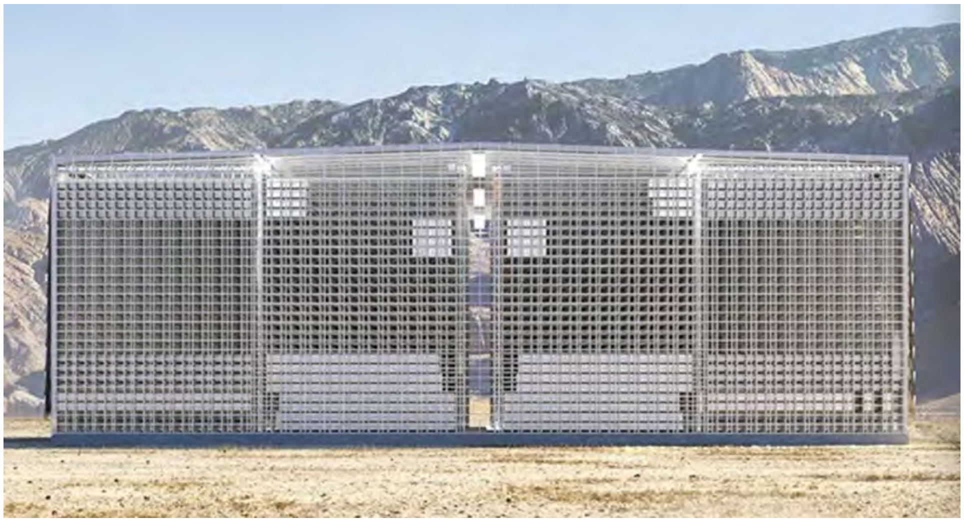
Ameren Missouri is committed to supporting our region's economic development by helping bring to market lead-acid battery products that are mined, processed, manufactured, marketed, and recycled in our state. Through the above-described demonstration project, we will evaluate the safety and techno-economic performance of lead-acid battery technology around the following use cases: resiliency, demand charge management, demand response, and optimum charger dispatch.

Some of the challenges Ameren Missouri has observed for advanced lead-acid batteries include lower energy density as compared to lithium-ion chemistries, larger footprint requirements for similar performance to lithium-ion applications, and performance and cyclic-life limitations. Lead-acid battery technology is very mature and has mature recycling opportunities to address overall performance, however, this application of energy storage has not demonstrated that it is a commercially viable and widely deployed technology for the reasons mentioned above.

Gravitational Energy Storage (GES)

Gravity-based energy storage system consists of thousands of stackable concrete composite blocks, trolleys, reversible hoist motor-generators, sensors and cameras, and control software. Potential energy is stored by lifting the blocks from ground-level to a higher position using the reversible direct-current (DC) hoist motor-generators in motor mode. Kinetic energy is released and converted to electricity when the blocks are returned to the ground by gravity, with the hoist motor-generators operating in generator mode. In essence, the process involves raising many large blocks to charge and subsequently lowering them to discharge. The velocity with which the blocks are lifted and lowered can be varied to control the rate of load absorption and power release, respectively.

Figure 6.11 Concrete Block Storage System – Blocks in a Large Modular Grid[16]



The leading company commercializing this technology is Energy Vault. They offer storage of energy for several hours using low-cost materials that can be locally sourced almost anywhere. Designed to be deployed in 10MWh blocks, the system can be configured for 2-18 hours of storage duration with a round-trip-efficiency of over 80%. A project rated at a nominal 25MW of power and 100MWh of energy started construction in May 2022 and will be completed in late 2023 in China.

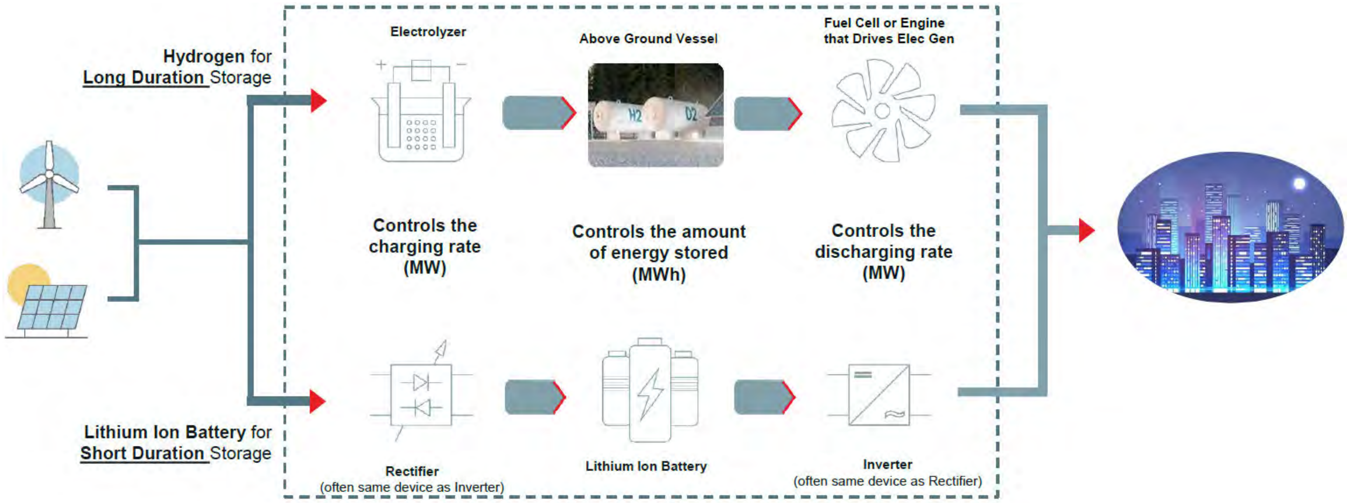
Another GES technology is Advanced Rail Energy Storage (ARES). ARES uses rail technology to harness the power of gravity. ARES' highly efficient electric motors drive mass cars uphill, converting electric power to mechanical potential energy. When needed, mass cars are deployed downhill delivering electric power to the grid quickly and efficiently. Currently, there is only one project under development in Pahrump, Nevada.[17]

Hydrogen Production & Storage

Hydrogen provides long-duration energy storage. Hydrogen can be stored and then consumed when needed by combustion in a combustion turbine, fuel cell, or industrial process. The amount of stored energy will depend on the size of tanks and other equipment. Ameren is investigating the potential application of hydrogen energy storage and planning demonstration projects.

[16] https://www.energyvault.com/ldes
[17] https://aresnorthamerica.com/

Figure 6.12 Equivalency Between Lithium Ion and Hydrogen Storage Systems[18]



Ameren has completed a feasibility study that considered a variety of loads: (1) transportation (hydrogen buses and tractor trailers); (2) blending (to feed into a load that can take natural gas and hydrogen); and (3) hydrogen fuel cell (for electrical loads as shown in the above illustration). The study concluded that it is technically feasible for hydrogen to address all of the above loads. However, commercially available system components have not yet been optimized for wide adoption.

Above Ground/Underground Compressed Air Energy Storage (CAES)

Deployed facilities are comparable to pumped-hydro power plants. In a CAES plant, rather than pumping water from a lower to a higher pond, ambient air is compressed and stored under pressure in an above-ground vessel or underground cavern. When electrical energy is needed, heated and expanded pressurized air is used to power a generator by an expansion turbine.

- Air heats up when compressed from atmospheric pressure to a storage pressure of approximately 1,015 psia (70 bar).
- Standard multistage air compressors use inter- and after-coolers to reduce discharge temperatures to 300/350°F and cavern injection air temperature to 110/120°F.
- The heat of compression therefore is extracted during the compression process or removed by an intermediate cooler.
- In the diabatic storage method, the loss of this heat energy must be compensated for during the expansion turbine power generation phase by heating the high-pressure air in combustors using natural gas fuel, or alternatively, using the heat of a combustion gas turbine exhaust in a recuperator to heat the incoming air before the expansion cycle.

[18] Mitsubishi Power Technical Sales Material

- In the adiabatic storage method, the heat of compression is thermally stored before entering the cavern and used for adiabatic expansion while extracting heat from the thermal storage system.

Large volume storage sites are required because of the low storage density. Underground and above-ground storage are viable options. For larger energy storage requirements, preferred locations include artificially constructed salt caverns in deep salt formations. Salt caverns are characterized by high flexibility, no pressure losses within the storage repository, and no reaction with the oxygen in the air and the salt host rock. If no suitable salt formations are present, it is also possible to use natural aquifers. However, tests must be carried out first to determine whether the oxygen reacts with the rock and with any microorganisms in the aquifer rock formation, which could lead to oxygen depletion or the blockage of the pore spaces in the reservoir. Depleted natural gas fields are also being investigated for compressed air storage; in addition to the depletion and blockage issues mentioned above, the mixing of residual hydrocarbons with compressed air will have to be considered.

Currently, there are only two CAES projects in operation – one in Alabama and the other in Germany.

Liquid Air Energy Storage (LAES)

A large-scale, long-duration energy storage technology that can be installed at the site of demand. Liquid nitrogen or liquefied air (~78% air) is the operating fluid. LAES systems can capture industrial low-grade waste heat/waste cold from co-located operations and exhibit performance traits similar to pumped hydro storage. The systems' size ranges from about 5MW to 100+ MWs, and since capacity and energy are uncoupled, they are ideal for long-term uses.

The LAES process utilizes parts and subsystems that are mature technologies that are readily accessible from significant OEMs, despite being novel at the system level. The technology extensively utilizes established power generation and industrial gas sector processes.

Three fundamental mechanisms comprise LAES:

> Stage 1 - Getting the device charged: The charging device is an air liquefier, which draws air from the environment, cleans it, and then chills it to below-freezing temperatures until the air liquefies. One liter of liquid air is created from 700 liters of atmospheric air.
>
> Stage 2 - Energy store: An insulated tank with low pressure is used as the energy storage, and liquid air is kept there. The use of this apparatus for the bulk storage of LNG, liquid nitrogen, and oxygen is already widespread. The industrial tanks that are used have the capacity to keep GWh of energy.

Stage 3 - Power Restoration: Liquid air is drawn from the tank(s) and pumped to high pressure when electricity is needed. The air is evaporated and superheated to ambient temperature. This produces a high-pressure gas, which is then used to drive a turbine.

In conclusion, LAES offers an output of hundreds of MWs, can be deployed at large-scale, and has an intrinsic capability for long-duration energy storage. To increase system efficiency, LAES systems can use industrial waste heat/cold from thermal generation facilities, steel mills, and LNG terminals. LAES makes use of proven components with established long lifespans (30 years or more), and performance.

Redox Flow Batteries (RFB)

They represent one class of electrochemical energy storage devices. The name "redox" refers to the chemical reduction and oxidation reactions employed in the RFB to store energy in liquid electrolyte solutions which flow through a battery of electrochemical cells during charge and discharge. The energy is stored in the volume of electrolyte, which can be in the range of kilowatt-hours to tens of megawatt-hours, depending on the size of the storage tanks. The power capability of the system is determined by the size of the stack of electrochemical cells. The amount of electrolyte flowing in the electrochemical stack at any moment is rarely more than a few percent of the total amount of electrolyte present (for energy ratings corresponding to discharge at rated power for two to eight hours). Flow can easily be stopped during a fault condition. As a result, system vulnerability to uncontrolled energy release in the case of RFBs is limited by system architecture to a few percent of the total energy stored. This feature is in contrast with packaged, integrated cell storage architectures (lead-acid, Li-Ion, etc.), where the full energy of the system is always connected and available for discharge.

RFBs are suited for applications with power requirements in the range of tens of kilowatts to tens of megawatts, and energy storage requirements in the range of 500 kilowatt-hours to hundreds of megawatt-hours.

Redox flow batteries have one main architectural disadvantage compared with integrated cell architectures of electrochemical storage. RFBs tend to have lower volumetric energy densities than integrated cell architectures, especially in the high power, short duration applications. This is due to the volume of electrolyte flow delivery and control components of the system, which is not used to store energy, so a system is not as compact as other technologies might be for a similar output.

Redox flow batteries show great promise with regard to cyclic life and performance but have not demonstrated commercial viability at the time of this IRP filing. Ameren Missouri continues to monitor and network with other utilities, such as San Diego Gas & Electric (SDG&E), as they operate their vanadium-redox flow battery at their Miguel Substation.

The SDG&E redox flow battery currently tests voltage, frequency and power outage support as well as shifting energy demand.

Lithium-ion Batteries

In addition to electric vehicle and backup systems for residential and commercial applications, lithium-ion (Li-ion) systems have emerged as the preferred choice for new grid-scale storage systems in the United States. Li-ion battery prices have fallen an average of more than 22% year-over-year since 2013.[19] Furthermore, just within MISO, the capacity of energy storage interconnection requests has increased dramatically from 140 MW in 2017 to 32 GW in 2022. Many of the MISO interconnection requests for energy storage are also paired with an intermittent renewable resource, such as solar.

Li-ion batteries have also been deployed in the PJM regional transmission organization and the New York Independent System Operator to provide frequency regulation. The California Independent System Operator (CA-ISO) demonstrates the need for energy storage to provide capacity and demand management. For background, California public utilities expect a capacity shortfall in Southern California and have responded to an order from the California Public Utilities Commission to meet this need. Furthermore, Tesla has received much notice for installing a 100-MW battery in Australia that provides grid stabilizing services.

Table 6.3 shows the energy storage technologies that were evaluated as candidate resource options. Lithium-ion battery energy storage was selected as an energy storage resource to be evaluated in the remaining resource planning process as a major supply-side resource in addition to pumped hydro storage. Ameren Missouri expects that on average the cost of batteries will continue to decline, and therefore has assumed a declining cost curve using Roland Berger and NREL data. Battery system offerings to customers were evaluated in the DSM Market Potential Study and were not found cost effective; therefore, only utility-owned storage systems were evaluated in the analyses discussed in Chapter 9.[20]

[19] *SEPA 2019 Utility Energy Storage Market Snapshot*
[20] File No. EO-2023-0099 1.G

Table 6.3 Potential Energy Storage Resources (2023$)

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Figure 6.13 Base Battery Overnight Capital Cost Assumption (2023$)

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6.1.4 Potential Hydroelectric Projects

Ameren Missouri previously performed studies to identify potential hydroelectric supply-side resources and projects; however, in this IRP, is using generic project characteristics from EIA and NREL. In addition to cost, several factors contribute to the feasibility of these projects, including accessibility of a water resource, environmental constraints, and regulatory definitions that define what types and sizes of hydropower are considered "renewable." For instance, the state of Missouri defines "renewable" hydropower in the Renewable Energy Standard (RES), which states hydropower generators can only be considered renewable energy sources if they meet the criteria, "hydropower (not including pumped storage) that does not require a new diversion or impoundment of water and that has a nameplate rating of 10 megawatts or less."

Table 6.4 contains details of a generic hydroelectric project. Hydro resource was evaluated assuming a 60-year economic life. Because the cost estimates are screening level estimates and because obtaining necessary licenses from the FERC can be complex, a more detailed evaluation of specific projects would be necessary before moving forward with a decision to construct.

Table 6.4 Potential Hydroelectric Resource

Resource Option	Plant Output (MW)	Project Cost with Owner's Cost, Excluding AFUDC ($/kW)	First Year Fixed O&M Cost ($/kW)	First Year Variable O&M Cost ($/MWh)	Assumed Annual Capacity Factor (%)	LCOE without Incentives (¢/kWh)
Hydro	50	$5,704	$99.0	$0.0	60%	19.61

6.1.5 Potential Landfill Gas Projects

Landfill gas (LFG) is produced by the decomposition of the organic portion of waste stored in landfills. LFG typically has methane content in the range of 45 to 55% and is considered an environmental issue. Methane is a potent greenhouse gas, 25 times more harmful than CO_2 by some estimates. In many landfills, a collection system has been installed, and the LFG is being flared rather than being released into the atmosphere. By adding power generation equipment to the collection system (reciprocating engines, small gas turbines, or other devices), LFG can be used to generate electricity. LFG energy recovery is currently regarded as one of the more mature and successful waste-to-energy technologies. There are currently nearly 532 operational LFG energy systems in the United States.[21]

Ameren Missouri continues to operate the Maryland Heights Renewable Energy Center (MHREC) at the IESI Landfill in Maryland Heights, Missouri. Previous studies have identified other landfills within the Ameren Missouri service territory that could support another LFG facility. At this time, however, other renewable resources are more abundant and more cost effective. Ameren Missouri will continue to monitor this technology for opportunities for future deployment.

[21] https://www.epa.gov/lmop/landfill-gas-energy-project-data-and-landfill-technical-data

6.1.6 Potential Biomass Projects

A study on potential biomass project feasibility had previously been conducted for Ameren Missouri. The study included identification of potential sites, technologies, resource locations, characteristics and availability, and costs. Several factors, including resource location and geographical constraints related to potential biomass projects, coupled with the cost structure and technology stagnation, especially in comparison to significant improvements in other renewable technologies, have reduced the focus on biomass as a new supply-side resource in this IRP.[22] Ameren Missouri will continue to monitor this resource potential for technological advancements and cost structure improvements. Any potential future project proposals will be evaluated as they materialize.

6.1.7 Innovative Renewables Deployment[23]

Ameren Missouri is exploring various methods to incorporate and deploy more renewable generation throughout its service territory. Among those methods are:

Community Solar: Ameren Missouri included an application for approval of a permanent Community Solar Program within the electric rate review filed in March 2021. The program features a variety of improvements to enhance the participation experience for customers. This proposal was approved as part of the electric rate review settlement agreement, and, as a result, the permanent Community Solar Program was rolled out to residential and small commercial customers in the latter half of 2022. The program redesign expands access and affordability by (1) lowering the program enrollment fee, (2) enabling customers to match up to 100% of their usage with solar energy, and (3) accelerating new facilities construction timelines.

Renewable Solutions: In 2022, Ameren Missouri filed for approval of a new subscription renewable energy program, the Renewable Solutions Program. Renewable Solutions is a voluntary renewable energy subscription program designed for larger commercial, industrial, and governmental customers. Many of Ameren Missouri's larger customers have publicly expressed their desire for near-term access to renewable energy in the form of sustainability goals for both carbon dioxide emission reduction and renewable energy supply. The program is designed to offer those customers a pathway to meet their sustainability goals with local renewable energy while reducing cost and risk for all Ameren Missouri customers. The Renewable Solutions Program was approved on April 12, 2023 and the first phase of the program, which will be supported by the Boomtown Renewable Energy Center, is fully subscribed.

[22] 20 CSR 4240-22.040(2)(C)2
[23] File No. EO-2023-0099 1.E

6.2 New Thermal Resources

6.2.1 Potential Natural Gas Options

The 2020 IRP included discussion of multiple natural gas supply-side resource options, addressing base, intermediate, and peaking load requirements.

Ameren Missouri previously studied combined cycle technology, including the evaluation of potential combined cycle generating configurations, and potential facility locations. Any future investment will require an updated evaluation to consider the latest technologies, costs, and developments that may impact a new energy center location. For example, since our last IRP, a new 24-inch natural gas pipeline has been constructed, bringing gas from the Rockies Express Pipeline in Illinois into Missouri, through St. Charles and north St. Louis counties. Multiple combined cycle configurations are possible, providing the opportunity and flexibility to tailor a supply-side resource solution to future requirements and constraints in a cost-effective manner. In this IRP, Ameren Missouri also included combined cycle with 98.5% carbon capture as a potential resource.

Table 6.5 contains details of potential natural gas projects. These projects were evaluated assuming a 30-year economic life. Because the cost estimates for these resources are screening level estimates developed from EIA, NREL, EPRI and Roland Berger data, a more detailed scope and evaluation of specific projects would be necessary before moving forward with a decision to construct.

Table 6.5 Potential Natural Gas Resources (2023$)

Resource Option	Plant Output (MW)	Project Cost with Owners Cost, Excluding AFUDC ($/kW-AC)	First Year Fixed O&M Cost ($/kW-year)	First Year Variable O&M Cost ($/MWh)	Assumed Annual Capacity Factor (%)	LCOE without Incentives (¢/kWh)
Greenfield Combined Cycle	1,200	$1,220	$62.0	$2.7	40%-80%	9.8 - 6.77
Greenfield Combined Cycle with CCS	1,135	$2,207	$106.5	$8.4	40%-80%	15.01 - 9.63
Simple Cycle	1,150	$994	$8.1	$5.2	5%	33.02

Project costs in the table include transmission interconnection costs as discussed in Chapter 7, and these costs may be avoided if they are constructed at retired coal energy center sites. It should also be noted that fixed O&M costs for both CC options include firm gas costs. The CC with CCS option also include additional capex and O&M for transportation and storage of captured CO_2 assuming a 100-mile pipeline is needed for transportation. Details can be seen in Table 6.6.

Table 6.6 Carbon Transportation and Storage Cost Assumptions (2023$)

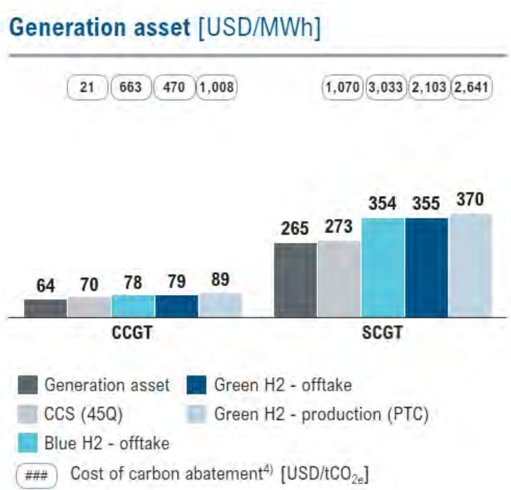
Sequestration Costs	Transportation			Storage	
	Capex ($/mile)	Pipe O&M (% of Capex)	Pump and Other O&M (% of Capex)	Storage Capex ($/ton)	Storage O&M ($/ton)
Transport and Store	750,994	2.3%	4.5%	$5.39	$4.84

Other thermal technologies remain as potential candidates for new supply-side resources, including reciprocating engines. Ameren Missouri will continue to monitor these arenas for technological advancement and cost structure improvements.

Hydrogen[24]

The IRA includes incentives for the production of green hydrogen in the form of production tax credits. Ameren Missouri has evaluated the economics of carbon emission abatement with the help of Roland Berger. The analysis reflects blending hydrogen with natural gas at a rate of 20 percent hydrogen (by volume). This analysis was performed under both an offtake agreement structure and ownership and operation of electrolyzers by Ameren Missouri. The analysis was performed for both CC and SC gas units and compared to the cost of abatement for CCS. The results of the analysis are shown in Figure 6.14 below. Based on these results, Ameren Missouri expects that hydrogen could play a limited role in abatement of carbon emissions from gas generation if hydrogen production for industrial uses can also produce economic green hydrogen for electric generation as an ancillary benefit. It should be noted that hydrogen production in the region is still expected to provide economic benefits by supporting industrial decarbonization for applications that are more difficult to electrify even if hydrogen is not used as a fuel for electric generation.

Figure 6.14 Comparative Economics of Hydrogen Fuel



[24] File No. EO-2023-0099 1.C

6.2.2 Potential Nuclear Resources

Consistent with Ameren Missouri's previous IRP filings, new nuclear was considered in this IRP for carbon-neutral around-the-clock generating capabilities. Ameren Missouri evaluated a conventional nuclear resource and a small modular reactor (SMR). Details are shown in Table 6.7.

Table 6.7 Potential Nuclear Resources

Resource Option	Plant Output (MW)	Total Project Cost Including Owners Cost, Excluding AFUDC ($/kW)	Annual Decommissioning Costs ($1,000)	First Year Fixed O&M Cost ($/kW-year)	First Year Variable O&M Cost ($/MWh)	Assumed Annual Capacity Factor (%)	LCOE (¢/kWh)
SMR	864	$8,492	$13,448	$122.1	$3.86	95%	15.81
AP1000	1,100	$10,109	$17,931	$151	$3.64	94%	19.60

SMRs have a number of characteristics that illustrate the unique role that they can play in our future energy mix: (1) SMRs are relatively small in power output versus large-scale reactors that can have a power output of more than 1,000 MWe; and (2) SMR designs are modular. Unlike traditional reactors, SMRs would be manufactured and assembled at a factory and shipped to the construction site as nearly complete units, resulting in much lower capital costs and much shorter construction schedules. SMRs also permit greater flexibility through smaller, incremental additions to baseload electrical generation, and more SMRs can be added and linked together for additional output as needed.

NuScale Power's SMR received the U.S. Nuclear Regulatory Commission's design certification in January 2023.[25] The NuScale Power Module is a 77 MWe advanced light-water SMR. Each power plant can house up to 12 modules, which will be factory-built and about a third of the size of a large-scale reactor. Its unique design allows the reactor to passively cool itself without any need for additional water, power or even operator action.[26]

DOE is supporting the siting of the nation's first SMR plant at Idaho National Laboratory. First module is expected to begin operating in 2029, with the remaining modules expected to come online by 2030.

6.3 Power Purchase Agreements

After discussions with Ameren Missouri's Asset Management and Trading organization it was determined that there were no pending potential long-term power purchases for

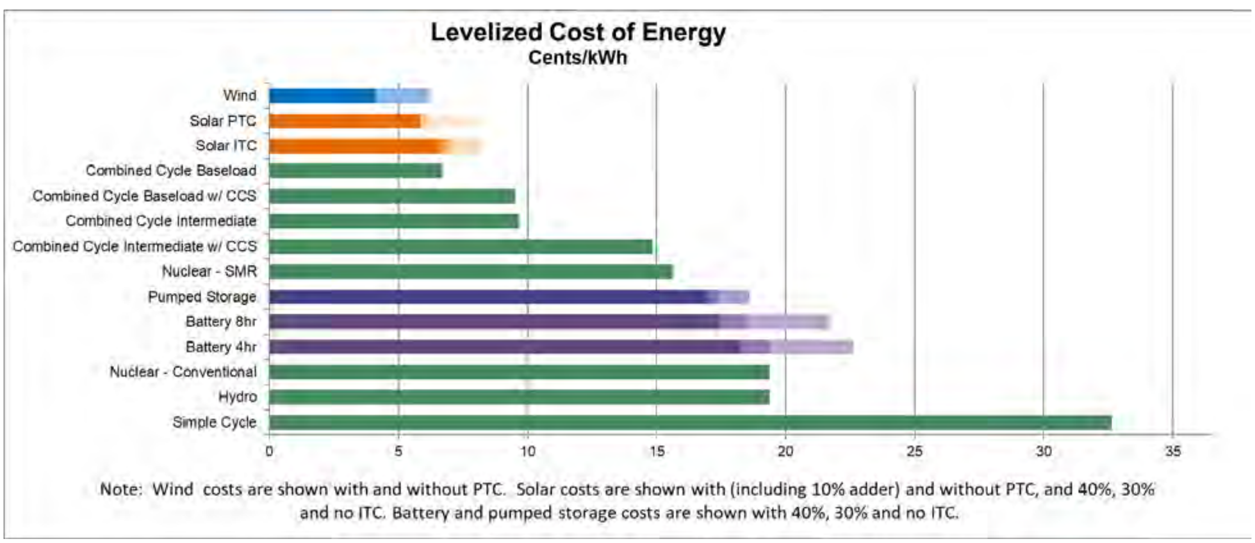
[25] https://www.federalregister.gov/documents/2023/01/19/2023-00729/nuscale-small-modular-reactor-design-certification
[26] https://www.energy.gov/ne/articles/nrc-approves-first-us-small-modular-reactor-design

consideration at the time of the analysis. Furthermore, Ameren Missouri learned from its experience in developing the 2008 and 2011 IRPs that soliciting the market for long-term power purchases or sales is not productive for bidders given the data at this stage of the analysis is generic, and potential respondents are reluctant to share information on potential agreements without a reasonable expectation for an executed contract. Evaluation of generic power purchase agreements would not be expected to yield different results in terms of relative performance of resource types, as the only reasonable assumption that could be made absent specific information would be that such an agreement would be effectively cost-based.

6.4 Final Candidate Resource Options[27]

Figure 6.15 demonstrates the LCOE with incentives (e.g., investment tax credits or production tax credits, if applicable) for a range of potential supply side resources. It is important to note that levelized cost of energy figures, while useful for convenient comparisons of resource alternatives, do not fully capture all of the relative strengths of each resource type. For example, wind resources are intermittent resources and therefore cannot be counted on for meeting peak demand requirements in the same way a nuclear or gas-fired resource can. Similarly, using an energy cost measure to evaluate peaking resources such as simple cycle combustion turbine generators (CTGs) does not fully reflect their value as a capacity resource or their quick-start capability. Table 6.8 shows the component analysis for the levelized cost of energy figures.

Figure 6.15 Levelized Cost of Energy



[27] 20 CSR 4240-22.040(4); 20 CSR 4240-22.040(4)(C)

Table 6.8 Levelized Cost of Energy Component Analysis[28]

Potential Resource	Levelized Cost of Energy (¢/kWh)								
	Capital	Fixed O&M	Variable O&M	Fuel	Resource Specific Cost	CO_2	SO_2	NO_X	Total Cost
Wind[1]	5.03	1.26	0.00	--	-2.13	--	--	--	**4.16**
Solar[1]	7.42	0.80	--	--	-2.09	--	--	--	**6.14**
Solar[2]	6.27	0.80	--	--	--	--	--	--	**7.07**
Combined Cycle: Greenfield	1.90	1.13	0.34	2.73	--	0.65	0.00	0.02	**6.77**
Combined Cycle w/ CCS: Greenfield[3]	3.44	1.85	0.51	3.17	0.62	0.01	0.00	0.02	**9.63**
Nuclear: SMR[4]	11.17	1.95	0.51	1.99	0.19	--	--	--	**15.81**
Nuclear: AP1000[4]	15.07	2.44	0.48	1.42	0.20	--	--	--	**19.60**
Hydro	15.64	3.97	0.00	--	--	--	--	--	**19.61**
Storage: Pumped Hydro[2,5]	10.75	0.27	0.48	--	6.05	--	--	--	**17.56**
Storage: Li-Ion Battery (8h)[2,5]	11.99	1.98	0.00	--	4.76	--	--	--	**18.73**
Storage: Li-Ion Battery (4h)[2,5]	12.21	2.64	0.00	--	4.76	--	--	--	**19.61**
Simple Cycle: Greenfield	24.44	2.37	0.66	4.40	--	1.05	0.00	0.10	**33.02**

1. Resource Specific Cost: Full PTC
2. 30% ITC
3. Resource Specific Cost : Carbon dioxide transportation and storage cost
4. Resource Specific Cost: Decommissioning fund
5. Resource Specific Cost : Battery charging/pump cost

The LCOE for future resource options is an important measure for assessing these options. However, it is not the only factor that must be considered in making resource decisions. Facts and conditions surrounding future environmental regulations, commodity market prices, economic conditions, economic development opportunities, and other factors must be considered as well. A robust range of uncertainty exists for many of these factors, all of which leads to one overriding conclusion – maintaining effective options to pursue alternative resources in a timely fashion is a prudent course of action.

[28] 20 CSR 4240-22.040(2)(B); 20 CSR 4240-22.040(2)(C)1

6.5 Compliance References

10. Strategy Selection

Highlights

- *Ameren Missouri is continuing the transformation of its generation portfolio over the next twenty years while also considering portfolio implications through 2050.*
  - *Our plan includes continued expansion of renewable wind and solar generation, bringing us to over 3,500 MW of wind and solar by the end of 2030 and over 5,400 MW by 2036. This allows us to replace energy no longer generated from coal-fired resources with the lowest cost alternative, clean, emission free renewable energy, while mitigating significant risks associated with changes in energy policy, including policies that establish a price on carbon dioxide (CO_2) emissions.*
  - *Our plan also includes continued customer energy efficiency and demand response program offerings, customer programs for renewable energy, and retirement of nearly three-fourths of our remaining coal-fired generating capacity by 2040, which will be reaching the end of its useful life.*
  - *Our plan results in reductions in CO_2 emissions of at least 60% by 2030 from 2005 levels and 85% by 2040, with a goal of achieving Net Zero CO_2 emissions by 2045.*
- *Our implementation plan for the next three years includes steps necessary to add an additional 1,800 MW of solar generation and 1,000 MW of wind generation to our portfolio by the end of 2030, approval and implementation of energy efficiency and demand response programs beyond our current plan, steps to implement new simple cycle gas-fired generation by the end of 2027 and new combined cycle gas generation by the end of 2032, and actions to preserve contingency resource options and enable us to quickly respond to changing needs and conditions while continuing to ensure safe, reliable and cost-effective service to our customers.*
- *Ameren Missouri will continue to monitor critical uncertain factors to assess their potential impacts on our preferred plan, contingency plans and implementation. These include prices for CO_2 and natural gas and costs for new renewable and dispatchable generating resources.*
- *We will also continue to monitor prices for coal, needs for transmission network infrastructure, and development of carbon-free resources such as large-scale long-cycle battery energy storage, hydrogen-based generation and storage, new nuclear technologies, and generation with carbon capture and sequestration.*

Ameren Missouri has selected its preferred resource plan and contingency options in accordance with its planning objectives and practical considerations that inform our decision making. Our selection process consists of several key elements:

- ✓ Establishing planning objectives and associated performance measures to develop and assess alternative resource plans
- ✓ Creating a scorecard based on our planning objectives and performance measures to evaluate the degree to which various alternative resource plans would satisfy our planning objectives
- ✓ Critically analyzing the most promising alternative resource plans to ensure that we select a plan that best balances competing objectives

We have established an implementation plan for 2024-2026 that allows us to begin implementing the resource decisions embodied in our preferred resource plan and to preserve contingency options to allow us to effectively respond to changing needs and conditions while continuing to ensure safe, reliable, and cost-effective electric service to our customers.

10.1 Planning Objectives

The fundamental objective of the resource planning process in Missouri is to ensure delivery of electric service to customers that is safe, reliable and efficient, at just and reasonable rates in a manner that serves the public interest. This includes compliance with state and federal laws and consistency with state energy policies.[1] Ameren Missouri considers several factors, or planning objectives, that are critical to meeting this fundamental objective. Planning objectives provide guidance to our decision-making process and ensure that resource decisions are consistent with business planning and strategic objectives that drive our long-term ability to satisfy the fundamental objective of resource planning. Following are the planning objectives, established in the development of our 2011 IRP, that continue to inform our resource planning decisions today.

Cost (to Customers): Ameren Missouri is mindful of the impact that its future energy choices will have on cost to its customers. Therefore, minimization of present value of revenue requirements (PVRR) is our primary selection criterion.[2]

Costs alone do not and should not dictate resource decisions. Our other planning objectives are discussed below.

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[1] 20 CSR 4240-22.010(2); 20 CSR 4240-22.010(2)(A)
[2] 20 CSR 4240-22.010(2)(B)

Customer Satisfaction: Ameren Missouri is dedicated to continuing to improve customer satisfaction. While there are many factors that can be measured, for practical reasons Ameren Missouri focused primarily on measures that can be significantly impacted by resource decisions: 1) rate impacts – levelized average rates, 2) supply and service reliability, 3) customer preferences for renewable energy sources and demand-side programs that provide customers with options to manage their usage and costs, 4) availability of programs that allow customers to source more of their energy needs from renewable resources, and 5) reductions in energy center emissions.

Portfolio Transition: While Ameren Missouri has retired and will soon retire additional coal-fired generating resources, coal currently produces the majority of the energy it generates. Ameren Missouri continues to be focused on transitioning its generation fleet to a cleaner and more fuel diverse portfolio. We therefore evaluate alternative resource plans based on the degree and pace of the transition from fossil generation sources to cleaner sources of energy, including reductions in energy consumption resulting from customer energy efficiency programs.

Financial/Regulatory: The continued financial health of Ameren Missouri is crucial to ensuring safe, reliable and cost-effective service for customers in the future. Ameren Missouri will continue to need the ability to access large amounts of capital for investments needed to comply with renewable energy standards and environmental regulations, invest in demand and/or supply side resources to meet customer demand, provide reliable service, and execute our portfolio transition. Measures of expected financial performance and creditworthiness are evaluated along with potential risks.

Economic Development: Ameren Missouri is committed to supporting the communities it serves beyond providing reliable and affordable energy. Ameren Missouri assesses the economic development opportunities, for its service territory and for the state of Missouri, associated with our resource choices. We do this by examining the potential for direct job growth for both construction and operation of resources, which in turn promotes additional economic activity.

Table 10.1 summarizes our planning objectives, the primary measures used to assess our ability to achieve these objectives with our alternative resource plans, and the weighting applied to each objective for scoring the alternative resource plans.

Table 10.1 Planning Objectives and Measures[3]

Planning Objective Categories	Measures	Weighting
Cost	Present Value of Revenue Requirements	30%
Customer Satisfaction	Customer Preferences, Levelized Rates	20%
Portfolio Transition	Resource Diversity, CO_2 Emissions, Probable Environmental Costs	20%
Financial/Regulatory	Free Cash Flow, Financial Ratios, Stranded Cost Risk, Transaction Risk, Cost Recovery Risk	20%
Economic Development	Direct Job Growth (FTE-years)	10%

These planning objectives are consistent with Ameren's overall sustainability efforts. In early May 2023, Ameren Corporation released its corporate sustainability report – Powering a Smart, Sustainable Tomorrow. The report details Ameren's commitment to sustainability and environmental stewardship and offers a comprehensive view of the actions taken on key matters. In the report, Ameren addresses the following key topics:

- ✓ Environmental Stewardship
  - o Accelerating the transition to a cleaner and more diverse generation portfolio
  - o Significant transmission investment supporting cleaner energy
  - o Decade-long investment in gas infrastructure to reduce leaks
- ✓ Social Impact
  - o Delivered value to customers in 2022 while focused on safety
  - o Socially responsible and economically impactful financial support
  - o Supporting core value of DE&I both inside Ameren and in our communities
- ✓ Governance
  - o Diverse board of directors focused on strong oversight
  - o Board oversight aligned with ESG matters
  - o Executive compensation supports sustainable, long-term performance
- ✓ Sustainable Growth
  - o Constructive frameworks for investment in all jurisdictions

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[3] 20 CSR 4240-22.060(2); 20 CSR 4240-22.060(2)(A)1 through 7

- Strong long-term infrastructure investment pipeline
- Expect future dividend growth to be in line with long-term EPS growth expectations

10.2 Assessment of Alternative Resource Plans

Ameren Missouri uses a scorecard to evaluate the performance of alternative resource plans with respect to our planning objectives and measures described above. The scorecard and measures include both objective and subjective elements that together represent the trade-offs Ameren Missouri's management considers in balancing these competing objectives. It is important to keep in mind that the scorecard is a tool for decision makers and does not, in and of itself, determine the preferred resource plan. The selection of the preferred resource plan is informed by the scorecard and by a more critical analysis of the relative merits of alternative resource plans, including an assessment of any risks or other constraints.

10.2.1 Preliminary Scoring of Alternative Resource Plans[4]

To score each of the alternative resource plans, we employed a standard approach to scoring for each planning objective on a 5-point scale and determined a composite score by applying the weightings shown in Table 10.1 to each planning objective. As Cost is the primary selection criterion, it was given the greatest weight – 30% -- just as it was in the scoring performed for all of our IRP filings since 2011.[5] The scoring approach for each planning objective is as follows:

Cost – The 23 alternative resource plans were separated into five groups according to probability weighted average PVRR results from the risk analysis discussed in Chapter 9. The lowest cost group of plans were given a score of 5, the next lowest cost group a score of 4, and so on, with the highest cost group of plans receiving a score of 1.

Customer Satisfaction – Alternative resource plans were evaluated based on levelized annual average rates for a portion of the score. As was done with the PVRR results, the alternative resource plans were separated into five groups according to the probability-weighted average levelized annual average rate results produced from our risk analysis. The plans resulting in the lowest rates were given a score of 5, the next lowest rate group a score of 4, and so on, with the highest rate group of plans receiving a score of 1. Plans that yielded a score greater than 3 for rates were given 2 points in the overall scoring for

[4] 20 CSR 4240-22.010(2)(C); 20 CSR 4240-22.010(2)(C)1; 20 CSR 4240-22.010(2)(C)2; 20 CSR 4240-22.010(2)(C)3; 20 CSR 4240-22.070(1); 20 CSR 4240-22.070(1)(A) through (D)

[5] 20 CSR 4240-22.010(2)(B)

Customer Satisfaction. Plans that yielded a score of 3 were given 1 point. Plans were given one additional point for each of the following:

- ✓ Inclusion of demand-side programs
- ✓ Early retirement of coal generation
- ✓ Addition of significant renewables (beyond those needed to comply with legal mandates)

Portfolio Transition – Alternative resource plans were awarded points for each plan attribute contributing to greater resource diversity and/or environmental impact in terms of emission reductions. Plans were awarded one point for each of the following:

- ✓ Inclusion of demand-side programs
- ✓ Addition of nuclear generation
- ✓ Early retirement of coal-fired generation (1 point per 2 large units)
- ✓ Addition of significant renewables (beyond those needed to comply with legal mandates)
- ✓ Displacement of fossil resources with additional storage and/or renewables
- ✓ Addition of low-emission efficient gas generation

Financial/Regulatory – Scoring for Financial/Regulatory is based on a default score of 5 with deductions for risks and financial impacts that may detrimentally affect Ameren Missouri's ability to continue to access lower cost sources of capital. Plans that would result in relatively lower free cash flow (i.e., less than 3 out of 5 points) were reduced by one point. Plan scores were also reduced by one point each for potential risks associated with:

- ✓ Lack of any DSM programs beyond currently approved programs
- ✓ Nuclear construction, financing, and operating risks
- ✓ Risks associated with a heavy concentration of gas-fired generation
- ✓ Risks associated with recovery of coal-fired generation investment (including those resulting from potential changes in environmental and climate policies and regulations)

Economic Development – Alternative plans were scored based on direct job creation, including construction and ongoing operation. Construction and operating jobs were translated into full-time equivalent years (FTE-years). Alternative plans were ranked based on FTE-years and divided into five groups based on relative rank. The group of plans resulting in the highest FTE-year values were given a score of 5 points each, the next highest FTE-year group a score of 4, and so on, with the lowest FTE-year group of plans receiving a score of 1.

Table 10.2 Alternative Resource Plan Preliminary Scoring Results[6]

Plan	Description	Composite Score
O	Labadie 2039	4.40
L	Pumped Hydro w/ MAP LF	4.30
B	Sioux Retired 2028	4.20
M	SC	4.00
P	Labadie 2036	3.90
A	Sioux Retired 2030	3.80
C	RAP - Renewable Expansion	3.80
R	RAP LF	3.80
H	MAP LF-RES Compliance	3.70
T	All Renewables	3.70
Q	Labadie 2031	3.70
D	Labadie SCR	3.50
U	SC instead of First CC	3.50
K	Renewables for Capacity Need	3.30
V	CCS on 1st CC	3.30
E	MAP	3.20
S	MAP LF	3.20
W	RAP 80%	2.80
N	SMR w/ RAP LF	2.60
F	RAP-RES Compliance	2.30
G	MAP-RES Compliance	2.30
I	No Additional DSM	1.70
J	No Additional DSM-RES Compliance	1.40

[6] Plans include RAP-level DSM and Renewable Expansion portfolio unless otherwise noted.

Table 10.2 shows the composite scores for each of the 23 alternative resource plans. The full scorecard with scores for each planning objective for each alternative resource plan is shown in Appendix A. Based on the scoring results, the alternative resource plans were separated into three tiers – Top, Mid, and Bottom. Plans with scores greater than 3.7 were placed in the Top Tier. Plans with scores between 3.3 and 3.7 were placed in the Mid-Tier. Plans with scores below 3.3 were placed in the Bottom Tier. All Top Tier plans include energy efficiency and demand response at the realistic achievable potential (RAP) level and the Renewable Expansion portfolio discussed in Chapter 9.

10.2.2 Renewable Resource Expansion

One of the key conclusions from our evaluation of alternative resource plans is that the inclusion of a sustained long-term expansion of renewable energy resources is beneficial across all of our planning objectives. It steadily transforms our portfolio to one that is cleaner and more diverse while enhancing customer affordability and providing much needed clean energy jobs for our communities and the state of Missouri. It also does something to help ensure our ability to accomplish these goals – it mitigates risks inherent in our existing portfolio as we manage the transition away from fossil fuels while relying on the reliability and economic benefits they continue to provide and supplementing them with new dispatchable resources to partner with renewable resources to provide reliable and sustainable energy services at a reasonable cost.

Resource planning has traditionally focused on the balance of generating capacity with customer demand and reserve margin requirements. While that remains important, transforming our generation portfolio requires that we carefully consider all the implications of how we effectuate that transformation. This includes the following considerations, which are discussed in more detail in this section:

1. **Aging Coal Fleet –** Ameren Missouri will need energy as well as capacity resources to meet customer demand and reserve margin requirements as its coal-fired generators are retired at the end of their useful lives. That need is also driven by the risk of reduced output from coal-fired generation due to existing or proposed environmental requirements or other causes even before the coal units retire. Due primarily to recent and expected coal unit retirements and these other risks, Ameren Missouri has a clear, present, and ongoing need to add energy resources to its generation portfolio to address the dramatic shift in the Company's energy position that will occur over the next several years and continue over the next twenty years. Ameren Missouri expects to experience an energy shortage as early as 2029 assuming normal loads and generation, a dramatic change from the approximately 15-20% energy buffer from which customers have typically benefited, although at times that buffer has been a high as approximately 10 million

MWhs. Such a shift could expose our customers to reliability challenges and high market price risk.

2. **Low Cost, Emission-Free Energy –** Renewable resources represent the lowest cost, and emission-free, sources of replacement energy, as shown in Chapter 6.

3. **Increasing Environmental Regulations –** The large-scale expansion of renewable resources provides significant risk mitigation to Ameren Missouri's portfolio, particularly with respect to additional environmental regulations that could become law, other changes in climate policy and carbon dioxide (CO_2) prices, and other factors that may significantly affect the operating costs and benefits of its existing coal-fired resources. The industry is actually seeing these risks come to fruition now with the effectiveness of new rules regulating emissions of nitrous oxides (NO_x), plus additional proposed regulations targeted specifically at CO_2, among others.

4. **Reliability and Resilience –** Ameren Missouri's addition of diverse new renewable resources during continued operation of its existing fleet, and addition of new dispatchable resources, is a prudent approach and ensures reliable, resilient, and affordable energy for our customers under varying scenarios during the transition.

5. **The Risk of Inaction –** Delaying the inevitable shift to renewables creates significant implementation risk. The transition will require a very large-scale expansion of renewable generation at the same time that other utilities and states are pursuing the same. A task of this magnitude must be implemented over time to be successful. This is the case since each renewable energy project takes 5 to 8 years to develop and construct, requires geographical diversity of projects for reliability, and requires navigating several implementation risks, such as delays in the development or completion of projects, lost opportunities for more viable projects, and the potential for financing constraints and increases in financing costs.

6. **Availability of Significant Tax Credits -** Initiating renewable resource builds in the nearer term provides the ability to realize significant tax incentives for customers and thus lower the overall cost of adding needed renewables, making addition of these necessary resources more affordable for all customers. Because federal law and policy can change, taking advantage of such incentives sooner and while the better projects are available provides greater certainty of benefits to customers.

Ameren Missouri's Need for Energy Resources

Ameren Missouri's existing generation fleet has a total net capability of 9,986 MW. Of this, 45% is coal, 12% is nuclear, 15% is hydroelectric and other renewables, and 28% is gas or oil-fired peaking generation. In contrast, coal currently provides approximately 66% of the energy produced by our fleet, with nuclear providing roughly 23% and renewables providing another 10%. Gas and oil-fired resources provide approximately 1% of the energy produced by our existing fleet. As coal-fired resources are retired or as their level of production decreases as a result of changes in operating efficiencies, CO_2 prices, other market conditions, regulatory constraints, or other factors, new energy resources will be needed to supplement the remaining generation. While the peaking generation will continue to provide capacity to meet peak demand and reserve margin needs, it will not be able to make up for the loss of coal-fired energy on its own. In fact, it is likely the production levels from current coal-fired energy assets will remain relatively low in the future as they are dispatched in the Midcontinent Independent System Operator (MISO) market and as they are operated in compliance with environmental permit constraints. The continued availability of these affordable coal-fired energy assets, along with new dispatchable resources, does allow Ameren Missouri to maintain reliability as increasing amounts of renewable energy is integrated into the system to meet customer needs.

Figure 10.1 Energy Position With and Without Renewable Transition – Low CO_2 Price

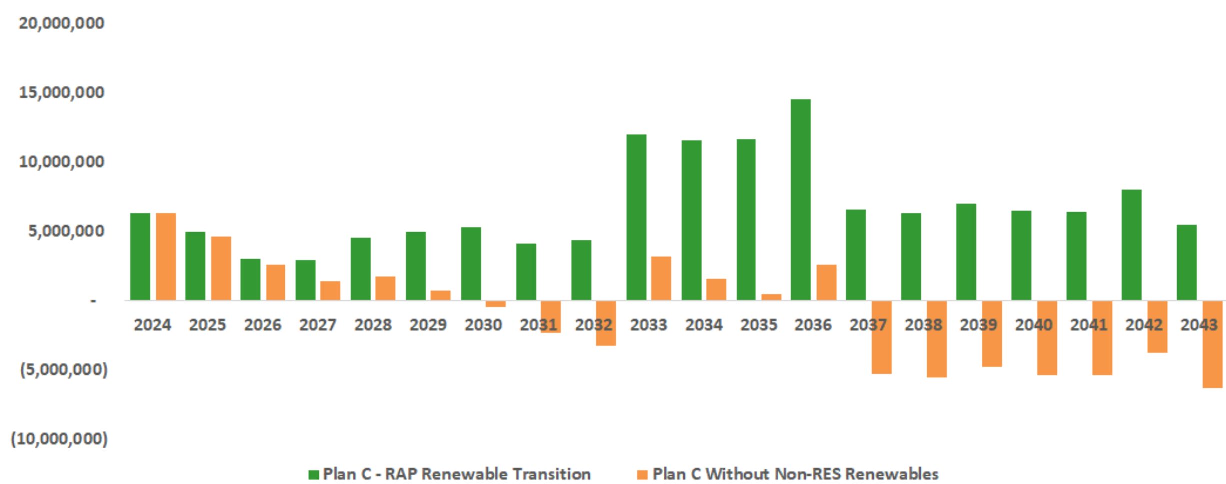


Figure 10.1 shows a comparison of the Company's expected energy position (generation minus sales) with and without renewable transition under our Low CO_2 price scenario. Figure 10.2 shows a similar comparison of energy production for several alternative plans under our High CO_2 price scenario, which results in reduced levels of generation from coal resources (and also gas to a lesser extent) compared to the levels of production under the Low CO_2 price scenario. The chart shows that for Plan C (RAP – Renewable Transition) without renewable resources beyond those needed for renewable energy

standard (RES) compliance, Ameren Missouri would be generating less energy than its customers use by 2028 and that this shortfall would grow to over one-third of total load by 2038. Any acceleration of coal energy center retirements would further exacerbate this issue. This is also true if retail sales are higher, as shown in Figure 10.3.

Taken together, the charts in Figures 10.1, 10.2, and 10.3 highlight a key consideration in the approach to our renewable resource expansion. There is significant uncertainty regarding the level of production from our existing fleet of resources. Differences in future CO_2 prices is only one source of this uncertainty, but it helps to highlight the broader issue. Other sources of uncertainty include natural gas prices, power prices, environmental regulation, and potential changes in climate policy. All of these factors and perhaps others could impact coal-fired resources and result in a much earlier need for new energy generation. Waiting until such needs are certain may result in suboptimal solutions and potential higher costs to customers. It could also result in an unintended but necessary increase in reliance on fossil-fueled generation like natural gas combined cycle, and potentially deferring or displacing some renewable resource additions.

Figure 10.2 Energy Position With and Without Renewable Transition – High CO_2 Price

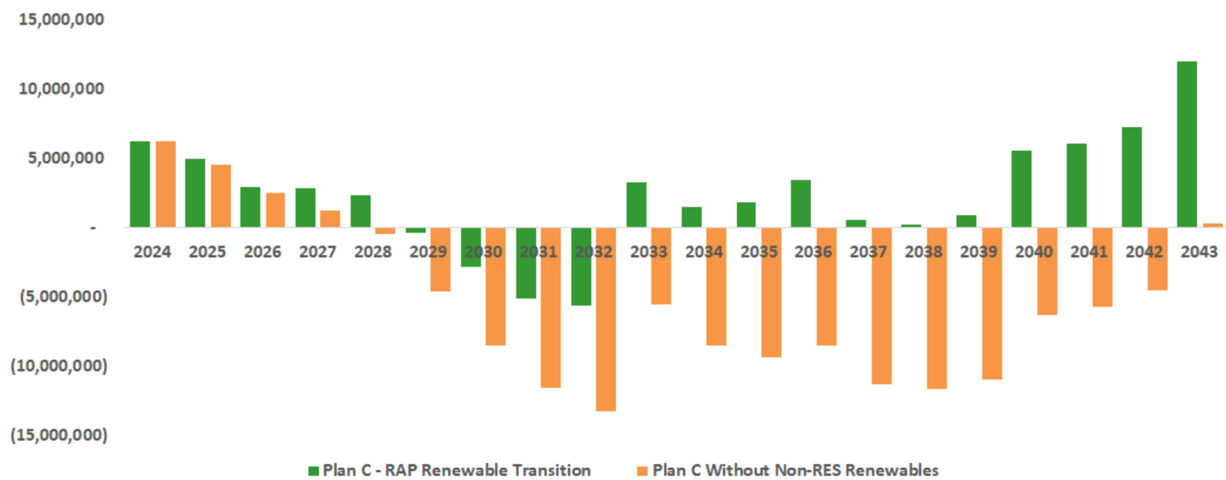
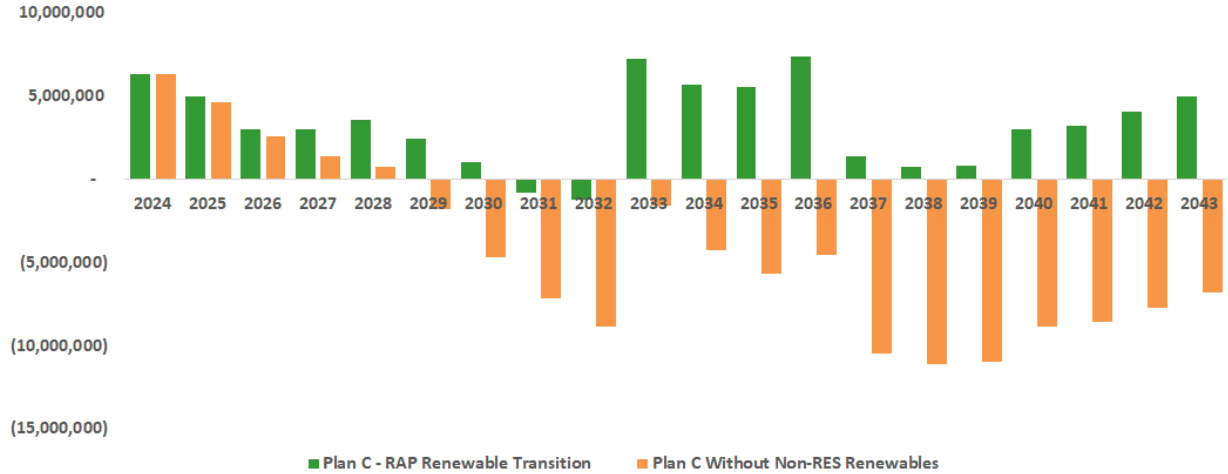


Figure 10.3 Energy Position With and Without Renewable Transition – High Load



The energy position charts in Figures 10.1-10.3 represent "economic" energy, or energy generated based on economic dispatch in the MISO market. This is important because it does not represent a constraint to the ability for units to generate at any given time, which means there is some flexibility to operate at higher levels if needed.[7] At the same time, Ameren Missouri's fleet is increasingly subject to constraints in its ability to operate units across seasons or across the year. This mainly affects the Company's remaining fleet of coal-fired generation at the Sioux and Labadie Energy Centers. In addition to assumed prices on CO_2 emissions, our modeling assumes allowance prices for NO_x emissions consistent with US EPA's Good Neighbor Rule, described in Chapter 5. As a result, forecast coal generation declines beginning in the latter part of this decade and continues to decline until units are retired. In addition, the natural gas combined cycle generators included in the PRP are forecast to run at high-capacity factors (80% or more). When added to our portfolio of high capacity factor nuclear generation and weather-dependent hydro, wind and solar generation, the ability to generate significantly more energy is somewhat limited. This further highlights the importance of the energy position analysis presented above and the vital role of new renewable additions in ensuring sufficient energy to meet customer needs. While assumptions for key variables, like CO_2 price and customer load, and constraints of further environmental regulation may change, and almost certainly will, planning to meet energy needs under such assumptions is vital to ensure reliable energy supply under a range of potential future conditions.

Risk Mitigation Benefits of Renewable Expansion

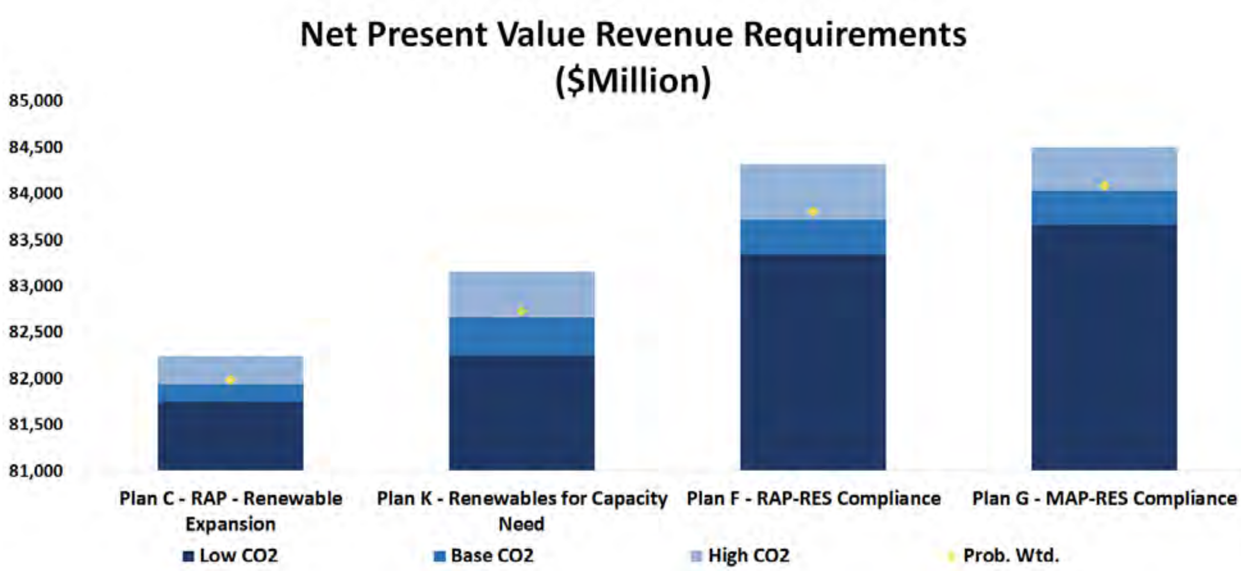
Our analysis shows that higher CO_2 prices have a beneficial impact on the economics of renewable resources and a detrimental effect on the economics of coal-fired resources,

[7] Ameren Missouri would expect to be compensated by the market in such instances.

a decidedly unsurprising result. The impact on coal is somewhat obvious in that the CO_2 prices impose a cost directly on the energy production from coal generators. It is this cost imposed on coal and gas generators that also manifests itself in power market prices, as illustrated in Chapter 2. The higher the CO_2 price, the higher the power price. Wind and solar generation, along with other non-carbon-emitting generating sources like hydro and nuclear, therefore see a benefit from CO_2 prices through the revenue they receive in the market. In contrast, the absence of a CO_2 price results in maximal benefits to coal-fired generation and minimal benefits to renewables, nuclear and hydro.

By expanding the share of renewable resources in our portfolio, we improve the balance of resources that from an economic perspective perform better as CO_2 prices rise and resources whose performance diminishes as CO_2 prices rise. This is not unlike the diversification of personal investments like those many hold in retirement funds like a 401(k) plan. By investing in a variety of resources, each of which perform well under different conditions, the overall risk of the portfolio can be mitigated. To illustrate this effect in the context of resource planning, we can simply examine how various alternative resource plans perform under different levels of CO_2 price. Figure 10.4 shows the PVRR results for several plans with different levels and timing of renewable energy resources under the three different scenarios for CO_2 price used in our risk analysis.

Figure 10.4 PVRR Results for Selected Plans by CO_2 Price Scenario



As the chart in Figure 10.4 shows, the steady addition of wind and solar resources represented by Plan C provides not only the lowest PVRR among the plans, but also provides risk mitigation around the range of CO_2 prices used for risk analysis, with the range of costs to customers across the different CO_2 price scenarios being significantly narrower than for those without the steady buildout. In fact, PVRR for Plan C under all scenarios for CO_2 price is lower than the lowest cost to customers for any of the other plans shown. This CO_2 price risk mitigation is in addition to the risk mitigation highlighted by the discussion of energy needs above. Specifically, the steady addition of renewable resources mitigates risk with respect to numerous factors that could impact the production of coal-fired resources, including market prices for energy, environmental regulations, and other energy policies.

Customers continue to express an increasing preference for energy supplied by renewable resources. One way to meet this growing demand is to offer programs that allow customers to increase the share of their energy needs that is supplied by renewable resources. Ameren Missouri has done just this with the implementation of its Renewable Solutions Program, approved by the Missouri Public Service Commission (MPSC) in April 2023, which will provide 150 MW of solar generation to some of the Company's largest customers. The Company also has completed projects to support its Neighborhood Solar and Community Solar programs, as described in Chapter 4. In addition to such programs, there has also been a growing sentiment that greater levels of renewable generation should be available to all customers. This is the sentiment that drove the adoption of Missouri's RES in 2008. Ameren Missouri continues to implement the resources necessary to comply with the full requirement of the RES, having received MPSC approval for the planned 200 MW Huck Finn solar project, which follows the Company's acquisition of 700 MW of wind generation projects in Missouri in 2020 and 2021. The passage of the Inflation Reduction Act (IRA) in 2022 has also provided unprecedented incentives to enhance customer affordability for both the deployment of renewable resources and the development of domestic industry to support that deployment. While the advancement of further policies supporting renewable energy development remains uncertain, the trend in recent years has been one of greater and greater support for the use of renewable energy resources.[8]

Reliability and Resiliency Benefits of Renewables

The Company's plan to transition to a "new fleet," featuring renewable and low-carbon resources, reflects some meaningful operating overlap with the "old fleet" resources, comprised of primarily coal-fired resources. The term "old fleet" refers to Ameren Missouri's existing (and legacy) coal-fired generation resources. These resources have served as the backbone of Ameren Missouri's generation fleet for several decades but are now approaching the end of their useful lives, with increasing maintenance challenges for key equipment (such as energy piping, boilers, and turbines) and increasing pressure from existing and new environmental regulations. Three of the Company's four coal-fired energy centers will be retired within the next ten years: the Meramec Energy Center in 2022, the Rush Island Energy Center by 2025 and the Sioux Energy Center by 2032.

[8] File No. EO-2023-0099 1.C; File No. EO-2023-0099 1.E

These retirements will result in a dramatic swing in the Company's energy position over the next few years, from its historically abundantly long position (as many as 10 million MWhs annually) to having a shortage of energy starting in 2029, assuming normal generation and load, absent the addition of new energy resources. The shortage grows steadily thereafter. A significant shift in the Company's energy position is already underway with the recent retirement of the Meramec Energy Center, and it will continue to shift when the Rush Island Energy Center is retired. The term "new fleet" refers to the Company's planned future resource portfolio, which includes a diverse mix of zero or low-carbon resources, primarily renewable resources like solar, wind and hydroelectric, along with zero-carbon nuclear and supported by dispatchable energy storage and natural gas resources.

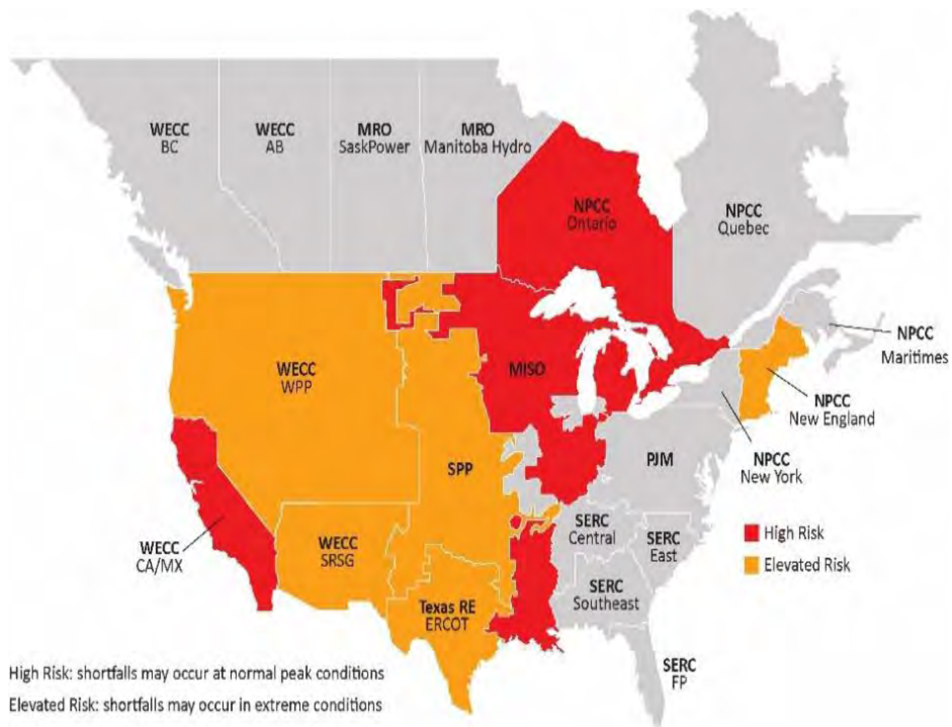
The overlap between the old fleet and the new fleet is necessary to address reliability risks during the transition period between the old fleet coming offline, and the new fleet being fully implemented. These risks are driven by myriad planning uncertainties, such as:

- Uncertainty in system load, including as industry and transportation electrify, and also driven by the potential for more frequent and intense severe weather;
- Uncertainty in the energy or demand savings, or both, from planned energy efficiency and demand-response programs;
- Uncertainty in whether and to what extent Ameren Missouri can expect to (or should) rely on the MISO market to meet customers' reliability needs;
- Uncertainty in the reliability contribution of new renewable resources;
- Ever increasing environmental regulations for existing fossil generation;
- Unplanned generation outages or other unanticipated events; and
- Material variances between our optimized generation forecasts or weather-normalized loads used for planning purposes and what happens in reality.

Taken as a whole, it is unwise to wait until some predetermined amount of capacity of coal-fired generation retires to add corresponding capacity of renewables to plug the capacity gap, or to wait until that coal capacity can no longer provide significant energy. Over the last five years, the Company's customers have benefited from an annual energy buffer of approximately 5 million MWhs. This energy buffer has mitigated the risk that the Company's customers face from reliability related emergency conditions resulting in energy shortages on the electric system. The buffer over the past roughly 5 years translates to an energy position approximately 15-20% above our retail customers' needs, which mitigates customers from the risk of adverse MISO reliability and market conditions as well as price spikes (price risk), while generating meaningful excess market revenues for the benefit of customers.

Likewise, it would not be prudent to rely on the MISO market more heavily for near-term energy needs. Just like Ameren Missouri, the entire MISO footprint is undergoing a transition from dispatchable fossil resources to a much greater reliance on renewable resources; in fact, MISO's modeling indicates that MISO as a whole is expected to move at a faster pace than Ameren Missouri. Therefore, it has become riskier to rely on the MISO market in moments of system stress than it has been in the past.

Figure 10.5 NERC Risk Area Summary, 2023-2027



As detailed in the North American Reliability Corporation's (NERC's) 2022 Long-Term Reliability Assessment, MISO's anticipated capacity reserves are alarmingly low and energy risks are expected to increase starting in 2024, especially in June through August when MISO's demand peaks. The NERC report lists MISO as a "high risk" region of the country in terms of resource adequacy, defined as an area that does not meet resource adequacy criteria, such as the 1-day-in-10-year load loss metric, during periods of the assessment horizon. Figure 10.5 highlights the regions considered high or elevated risk. MISO's "high risk" status indicates that without a concerted effort to begin and sustain our plan to add replacement energy resources, Ameren Missouri and MISO will both be "skating on the edge" from an energy and capacity perspective, putting customer reliability and affordability at risk. As discussed above, although MISO's 2023-2024 Planning Resource Auction results indicate that the North/Central region is expected to have adequate capacity to meet the Planning Reserve Margin during the current planning year, those results do not reflect a "fix" for all long-term capacity concerns. And similarly, NERC's 2023 Summer Reliability Assessment suggested that although the risk of meeting load in MISO was reduced for summer 2023 as compared to 2022, MISO was "at risk of operating reserve shortfalls during periods of high demand or low resource output."

Adding new renewable generation while the Company's coal-fired resources are still online is the ideal approach to ensure continued system reliability during the transition to cleaner energy resources while still enabling the Company to gain critically needed experience with renewable resources. Without that experience, Ameren Missouri risks being unable to reliably manage and operate its renewable generation fleet, and unable to fully understand the backup resource needs that may be required to ensure a reliable supply. Transitioning to renewable energy while more of our coal-fired generation and gas-fired peaking capacity is still in operation will allow us to gain this necessary experience with minimal risk of continuing to provide reliable service to our customers.

By continuing to add new renewable energy in a staged and continuous manner while a significant portion of Ameren Missouri's existing generation fleet remains online, the Company will gain invaluable experience in two areas:

1) The ability to assess when and to what extent renewable energy is truly available over a wide range of weather conditions, which is dependent in large part on the location of the renewable resource, and

2) An understanding of how the existing Ameren Missouri generation fleet may need to be dispatched differently than historical dispatch patterns to provide critical back-up generation during hours that intermittent renewable generation is not available.

By understanding the operational aspects of a significant portfolio of renewable energy resources under different weather conditions over a long period, the Company can also determine the optimal amount of renewable capacity needed to ensure a secure energy supply, ensuring we are not adding too much or too little new renewable energy generation. The Company may also learn how to increase generation through planned and preventative maintenance approaches, and how to optimize equipment selection based on project site characteristics. In addition, the Company can determine the amount of dispatchable generation and battery storage to maintain the reliability of least cost renewable energy. Said simply, by adding significant new renewable generation resources while the Company's coal-fired generation is still operational, Ameren Missouri can learn how to optimally plan and operate its generation fleet in a high renewables future without putting system reliability at risk.

Another important factor to ensure long-term system reliability and resiliency is to pursue a geographically diverse portfolio of renewable energy resources to ensure energy is always available to meet our customers' needs, even during peak energy time periods. Since solar and wind generation are dependent on weather conditions which vary by geographical location, a regionally diverse renewable resource portfolio will be more reliable under varying weather conditions. Over time, as ideal project sites are developed and land availability declines, it will become more challenging to achieve a regionally diverse portfolio of projects. This is another key reason the Company needs to continue to transition to clean energy now and sustain it.

The Risk of Inaction

It is one thing to set forth a plan to meet customer energy needs for the next twenty years. It is quite another thing to execute plans and construct the renewable energy resources to serve those needs. So while we have some time to continue to build out the entire renewable resource portfolio, there are practical considerations that must be taken into account when embarking on the kind of portfolio transformation that Ameren Missouri believes is necessary to best meet our customers' future energy needs, and there are significant risks of inaction or delays in implementation. Renewable energy development is a difficult, lengthy process with successful projects taking five to eight years to reach commercial operation. With each stage of the project lifecycle there is a risk that the project can be delayed, and at times cancelled altogether. The most significant implementation risks are likely to emerge in siting the project location, completing extensive transmission studies, evaluating transmission upgrade costs and completion schedules, completing environmental studies, conservation plans, and compliance requirements, acquiring real estate, obtaining local county permits and community support, qualifying for federal tax credits, evaluating technology options, obtaining financing, receiving regulatory approvals, procuring key equipment in a timely manner, and designing, engineering, and finally constructing, commissioning, and testing of the new renewable energy center. A challenge, delay, or misguided decision can delay and potentially terminate the project. Given the number of renewable energy projects that are needed for a successful transition combined with the length and potential risks within the full lifecycle, it would be impractical, and frankly, irresponsible for the Company to continue to take a "capacity when needed" approach – as there is never a guarantee that each renewable energy project being pursued will come to fruition. We must start and sustain the transition to account for any potential delays. The key project implementation risks include the following:

- Land (i.e., renewable site) availability
- Project permitting and construction
- Supply chain constraints
- Transmission interconnection
- Technology costs
- Financing costs
- Financing constraints

One of the most critical reasons for Ameren Missouri to pursue a controlled but sustained transition that starts immediately is to ensure the Company can acquire the best available project sites in our region. The lengthy development, permitting, regulatory approval and construction cycle challenges described above, along with the myriad of development risks involved to successfully develop a good renewable energy project site, means that the best renewable energy sites are the first to be developed. Ameren Missouri is now also in competition with large technology firms from outside its service territory who are purchasing renewable energy projects in and around Missouri and Illinois for their announced sustainability goals and are equally as eager to find the best available project sites. An ideal project site will feature good renewable resource, favorable topography, good community relations, access to a favorable transmission interconnection point, and minimal environmental risk. This means that as the availability of suitable land declines, both the cost of the planned facility and the risks of not being able to obtain necessary permissions or not being able to construct the project at all are likely to increase.

Placing a renewable energy project into service requires a series of preceding permits – these include but are not limited to environmental, construction, county, state, federal and other governmental permits. These activities require a great deal of lead time and if not obtained, could delay project construction, or even terminate a project. For example, to obtain the appropriate environmental permits, we must first complete several environmental studies to determine and mitigate any potential adverse impacts to the environment (e.g., water, land, natural habitat, etc.). These studies can take years to complete as they require extensive data collection and analysis. In some cases, the studies might indicate a fatal flaw in the project site. A fatal flaw would result in a change in project site – making it important to pursue a pipeline of potentially suitable projects simultaneously to pivot to a more suitable project site from an environmental permitting perspective.

Prior to starting construction, local and county permits might be required. If there is a delay in receiving these permits, the construction schedule can be put at risk. A delay in schedule can jeopardize the in-service date, ultimately impacting the Company's ability to receive federal tax incentives or at times, preventing project implementation altogether.

Building community support and engaging with key stakeholders early in the project development lifecycle will allow the Company to quickly identify potential delays and adjust accordingly. But navigating these permitting issues takes a great deal of time, and navigating them simultaneously with the large number of projects that would be needed all at once if we wait to add renewable capacity when the capacity need is here would be extremely difficult, if not completely impractical.

Once all necessary environmental and local government permits have been received, projects must be designed, engineered, and then constructed in a manner to provide at least 30 years of reliable energy. The design and engineering phase typically takes about a year. While recently performing due diligence on a solar project in an advanced stage of development (land acquisition, permitting and environmental assessment were all completed), Ameren Missouri discovered that the project was sited on land above a historical mine that potentially may be unsuitable for construction. Ameren Missouri had to place the project on hold until suitable geotechnical due diligence could be completed to ensure that the project can be constructed and operated in a reliable manner.

The construction phase itself for solar and wind projects can take one to two years to complete. During this time there is heavy construction traffic on smaller local county roads that can be subject to weather delays. The supply chain for solar and wind generation is global and there are numerous opportunities for delays in manufacturing, shipment, and delivery. As with any large construction projects, actual construction may face challenges from an electric and mechanical component perspective, and therefore testing of the final project after completion of construction is critical. For the High Prairie and Atchison Renewable Energy Centers, the Company experienced several months of delay before achieving successful testing and commissioning and ultimately bringing the projects online.

Supply chain constraints can occur due to labor shortages, political upheaval (globally or otherwise), commodity supply and price changes, transportation challenges, or quality control issues. Challenges in the supply chain can lead to project delays, cost increases, or ultimately an inability to construct a project at all. Since supply chain problems can meaningfully disrupt the timing and costs of renewable energy projects, it is important to have a long implementation timeframe to maintain flexibility in the generation transition. By developing long-term strategic partnerships with key renewable equipment manufacturers as well as established renewable energy developers, we ensure a greater certainty of supply of key renewable project equipment. But to develop such strategic partnerships, we need a long-term and defined transition plan with a known stream of projects for which equipment can be acquired in a timely manner. The same dynamic exists when we have ongoing relationships with national renewable energy developers for new projects, so they can plan ahead for completing projects in a timely manner. Given the 5- to 8-year life cycle for successful renewable energy project development, such partnerships are much more difficult to develop if a transition plan is not defined at least 10 years in advance to ensure certainty of equipment supply.

Transmission interconnection and upgrade costs remain one of the most important and, it is fair to say, challenging aspects of renewable energy development. This includes the challenge of navigating MISO's Generator Interconnection Queue. The larger utility scale renewable energy projects must go through a transmission interconnection queue to determine the timing and cost of transmission upgrades that may be required for interconnection. This is not only challenging, but time-consuming. In MISO, generator interconnection at the transmission level is a three-phase process that can generally take up to three years to complete. The transmission upgrade costs are a function of the number of projects in the queue, and the location and size of the projects. Generally, projects that are earlier in a queue can interconnect at a lower cost. It is also important to note that after Phase 2, a non-refundable 20% payment is due for expected transmission upgrades for a renewable energy project. As such, only the best projects with the most favorable locations and queue positions make it to the final Phase 3. Other projects are rejected due to high transmission costs in Phase 2, or at times even in Phase 3, as cost estimates can change throughout the process until it is clear which projects will proceed to construction.

At any point in the process, projects that the Company may be relying on could be terminated due to exorbitant interconnection costs, forcing the Company to start the 3-year cycle once again. Over the last ten years, generally less than a third of the projects that enter the MISO Generator Interconnection Queue make it to start of construction. Ameren Missouri has first-hand experience with projects in which a great deal of time and effort was expended only to see the project fail due to no fault of the Company. The Brickyard Hills wind project, for which the Commission granted Ameren Missouri a CCN in 2019 and which had likely been under development for approximately 10 years, ultimately had to be terminated due to unacceptably high transmission costs. As future queues get more and more constrained with new renewable energy projects, new transmission buildout will be needed. However, building new transmission lines to interconnect new renewable energy projects is generally a 6- to 10-year endeavor, if not longer. Although ideally transmission buildout will keep pace with renewable energy project buildout, projects later in the queue may have significantly higher transmission interconnection costs or may not be able to operate at full output. This poses a real risk caused by delay because the energy from the generation we will ultimately place in service may be more costly or less reliable.

The Company can best manage transmission interconnection risks, first and foremost, by continuing to proceed with the planned renewable transition now and sustaining it. Second, we must act on good projects when they are available, including smaller utility-scale projects like the Vandalia and Bowling Green Projects currently before the MPSC, which were not required to navigate the difficult and lengthy MISO generation interconnection queue since they will connect to the distribution system. Third, we must be flexible regarding the best renewable project acquisition approach for each specific project – whether we use a build-transfer, development-transfer, or self-development approach. The Company needs to maintain a renewable project pipeline with at least twice the number of projects needed for the inevitable transition to renewable energy and use the most appropriate acquisition approach for each project. To have a pipeline of twice the number of projects needed for our generation transition, we need to constantly be looking for – and acting on – good renewable projects in Missouri and surrounding states. Without a large pipeline and a phased approach, we are likely to face delays in project interconnection to the grid, significantly higher costs, or both, thus rendering our generation transition less reliable and more costly than it would have been had we obtained good project earlier in the transition process.

Although Ameren Missouri hopes that renewable technology costs will ultimately decline, the last several years served as a reminder that cost declines are far from a guarantee. It is tempting to point to some possible declining cost curve forecasts for wind and solar and recommend the Company wait until such declines materialize before proceeding with renewable development. But it is critical to remember that declines that are forecasted by some are not certain. Waiting for costs to decline is also a risky approach, because if those declines do not materialize customers could be exposed to higher costs for less ideal sites later. By adding investments steadily over time, we engage in a form of "dollar cost averaging" similar to that used in financial investing, while continuing to progress towards a prudent energy buffer.

Financing costs are also a key risk. Investors are increasingly focused on concerted efforts by utility companies to transition their portfolios to cleaner and more sustainable resources as they make decisions about which companies to invest in and what kind of return on investment they expect based on their assessment of risk. This increased focus is expected to result in differences in cost of capital between those utilities that are making concerted and consistent efforts to transition their portfolios and those that are not. Deferring implementation of renewable resources may require that Ameren Missouri invest huge amounts of capital in a short period of time, risking substantial deterioration to our credit metrics and impairment of our ability to cost-effectively and timely finance investments in the renewable generation we need when we need it. Staging the transition with a steady stream of additions over several years therefore reduces the expected financing costs associated with the renewable resources the Company needs to add.

Capturing the Value of Available Tax Credits

In 2022, Congress passed the IRA. Among its many impacts, the IRA extensively modifies provisions of the tax code for renewable energy projects. The IRA extends both the investment tax credit (ITC) and production tax credit (PTC), creates additional wage and apprenticeship requirements that projects must meet to qualify for the full ITC or PTC value, and adds additional bonus credit amounts for domestic content and project location. The IRA enables solar projects to utilize the PTC or the ITC (previously solar projects could only elect the ITC) and allows taxpayers the ability to transfer tax credits to unrelated parties for cash. Certain projects may be eligible for bonus tax credits, such as the energy community bonus incentive, which increases the value of the ITC from 30% to 40% or increases the PTC credit value in a given year by 1.1 times. Projects that are located in a community with a retired coal mine or coal generating facility are eligible.

While the benefits of the IRA are significant and expected under the law to apply for projects completed into the next decade, it is important to avoid complacency with regard to securing these benefits for customers. Although the IRA extends available tax incentives for renewable resources into the early 2030s, they are still not expected to be available forever. If the Company were to wait to add renewable resources, these new and enhanced tax benefits could be unavailable. Moreover, there is no guarantee that Congress may not change the law in such a way that the tax credits under the IRA become unavailable earlier than 2032. Implementing a sustained and planned transition to renewable resources enables the Company to capture the IRA incentives and pass them back to customers, helping maintain customer affordability while transitioning to a cleaner generating fleet.

Weighing the Considerations Together

In accounting for the foregoing considerations and in conjunction with our rigorous risk analysis of alternative resource plans, we conclude that a continued buildout of renewable wind and solar resources throughout the planning horizon yields significant real and potential benefits for our customers with limited downside. It provides us with valuable risk mitigation regarding CO_2 prices and other factors, and valuable flexibility in managing the transformation of our generation portfolio.

10.2.3 Reliability Needs and New Dispatchable Generation

While renewable wind and solar resources are vitally important to meet customers' energy needs, we also need dispatchable resources that are available on demand to partner with those renewable resources and ensure reliable and affordable service, both now and as we continue to transition our resource portfolio. As explained in Chapter 2, the nature of resource planning has changed from one in which we plan for meeting the annual peak demand (typically in the summer) with dispatchable resources that can meet energy needs in any hour to one that is far more complex. Resource planning must account for the need to blend non-dispatchable, intermittent energy resources like wind and solar with the need for dispatchable capacity to ensure reliability in all hours, and it must do so for all seasons and under the most extreme weather conditions. The need for energy resources is discussed in section 10.2.2.

To assess capacity needs, we must account for both the expected operation of resources in the real world and also how those resources will be compensated in MISO's capacity market. MISO's seasonal resource adequacy (RA) construct aims to promote reliability and ensure fair value for resources that are available when they are needed to meet load. In doing so, MISO has designed a process for capacity accreditation that accounts for each generator's historical performance in each season, including the degree to which each generator was available at time when it was needed most to ensure reliability. MISO establishes planning reserve margin (PRM) requirements for each season that accounts for generator performance as well as load forecast uncertainty under normal conditions. While this framework is necessary and important for promoting reliability and fair value for resources across the MISO footprint, it is not by itself sufficient for examining resource adequacy needs at the utility level over all timeframes.

Capacity Positions – Operating View

To examine resource adequacy needs more rigorously, Ameren Missouri has used what it has learned about reliability needs from its work with Astrapé Consulting, from trends in the industry, and from the operation of its own units in MISO under real operating constraints such as those imposed by the Climate and Equitable Jobs Act (CEJA) in Illinois. We have done this by also examining capacity needs under what we call an "Operating View." This view accounts for the real-world constraints like those of CEJA and is defined by the following characteristics:

- Most Illinois CTGs are limited to a short period of operation (rolling 12 months) and/or emergencies; unit capacity is therefore set to zero – Units in this category are Pinckneyville Units 5-8, Venice Units 2-4, and all units at the Goose Creek, Racoon Creek, and Kinmundy Energy Centers.
- All gas-only CTGs are subject to fuel availability constraints during cold weather, including at time of normal winter peak demand; gas-only CTG unit capacity is therefore set to zero for winter capacity position – Units in this category are Pinckneyville 1-4, Venice Unit 5, and all units at the Audrain Energy Center.
- Wind, solar and storage set to ELCC values (current MISO transitioning to calculated ELCC)[9]
- All other units set to full unit capability by season based on Ameren Missouri's most recent assessment of monthly unit capabilities.[10]

[9] See discussion of wind and solar capacity credits in Chapter 2.
[10] Monthly unit capabilities are reviewed and revised annually based on unit testing and operation.

- Planning reserve margin requirement set to output of largest unit (Callaway) – Approximately 1,200 MW, which corresponds to ~17% of summer peak demand and ~20% of winter peak demand.

It should be noted that MISO's new seasonal construct, which took effect with the 2023-2024 planning year, results in an interdependent set of unit accreditations and planning reserve margins. As a result, the planning reserve margins determined by MISO for use in its seasonal capacity construct cannot be applied in the Operating View described here. As a reasonableness check, it is useful to compare the planning reserve margin requirements for the Operating View describes above with historical planning reserve margin requirements based on an installed capacity (ICAP) view, which similarly uses unit capabilities unadjusted for availability. The ICAP-based planning reserve margin requirements used by Ameren Missouri, and previously set by MISO under its annual RA construct, were typically in the range of 15-20%. The planning reserve margin requirements for the Operating View are comparable to this historical range.

Using the Operating View described above, Ameren Missouri has examined the capacity position for its PRP as well as variations from the PRP to assess the contribution of certain resource additions. These variations include the following and correspond to the subsequent figures as noted:

- Winter operating view capacity position with no new simple cycle generation, batteries or non-RES renewables – Figure 10.6
- Winter operating view capacity position for the PRP – Figure 10.7
- Summer operating view capacity position with no new solar resources beyond those for which the Company has received a CCN (i.e., the Boomtown and Huck Finn projects) – Figure 10.8
- Summer operating view capacity positions for the PRP – Figure 10.9

Figure 10.6 Winter Operating View Capacity Position Without New Simple Cycle, Batteries, or Non-RES Renewables

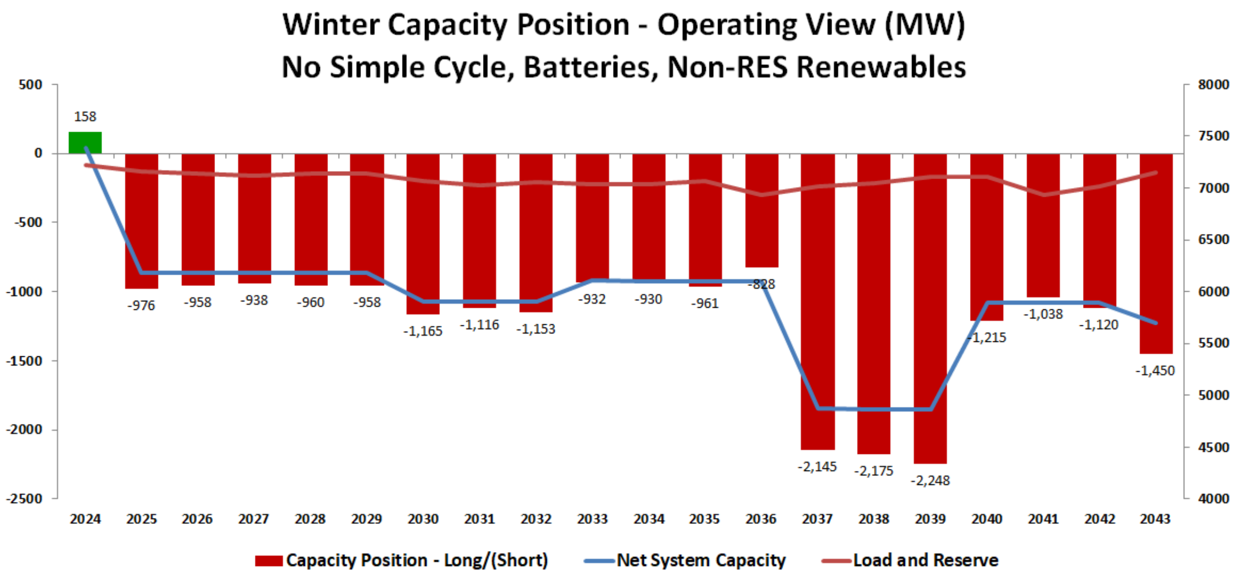


Figure 10.7 Winter Operating View Capacity Position – Preferred Resource Plan

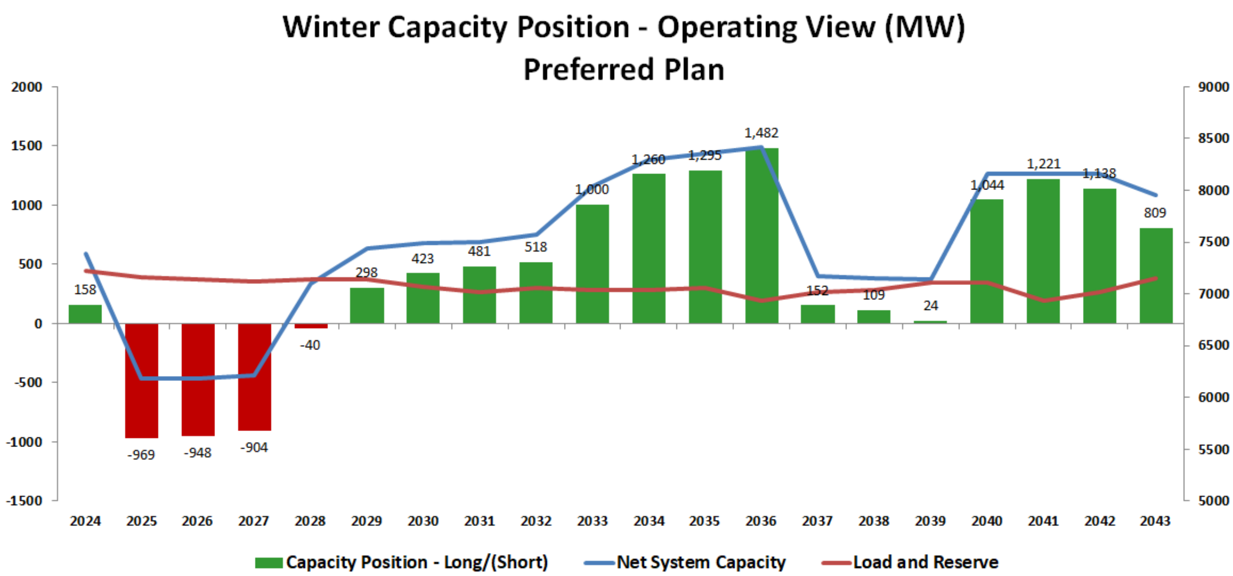


Figure 10.6 shows that without new simple cycle generation, batteries and non-RES renewables, Ameren Missouri would be roughly 1,000 MW short of its PRM in most years and roughly 2,000 MW short for the three years following the retirement of the first two units at Labadie Energy Center. Including the simple cycle generator, batteries, and planned wind and solar resources in the PRP results in Ameren Missouri achieving its PRM in all years starting in 2029, with only a slight shortfall in 2028 following the addition

of the new simple cycle generation. For the years 2025-2027, Ameren Missouri expects to be dependent on MISO to meet demand and/or the ability to operate CTG units in Illinois under emergency conditions.

Figure 10.8 shows Ameren Missouri's summer capacity position without new solar resources beyond those for which it has received a CCN, and Figure 10.9 shows Ameren Missouri's summer capacity position with additional new solar resources. Figure 10.9 shows how near-term capacity needs are reduced with the addition of additional new solar projects, such as those for which the Company is currently seeking CCNs, particularly in 2027. As with the winter capacity position shown in Figure 10.7, Ameren Missouri expects to be dependent on MISO to meet some of its near term needs and/or the ability to operate CTG units in Illinois under emergency conditions.

Figure 10.8 Summer Operating View Capacity Position With No Additional Solar

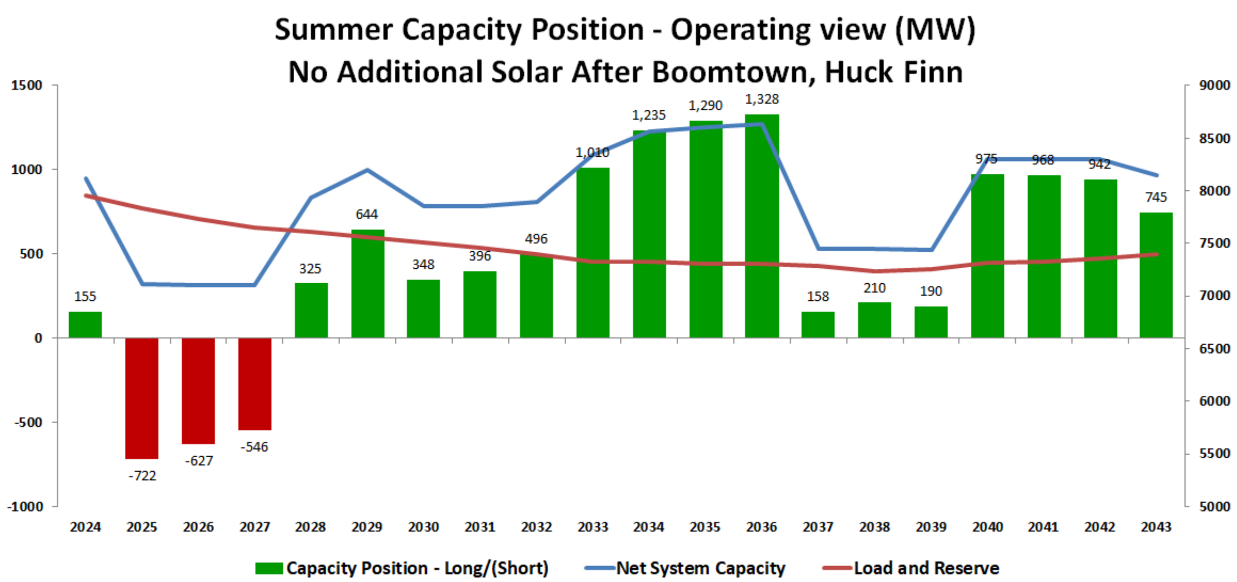
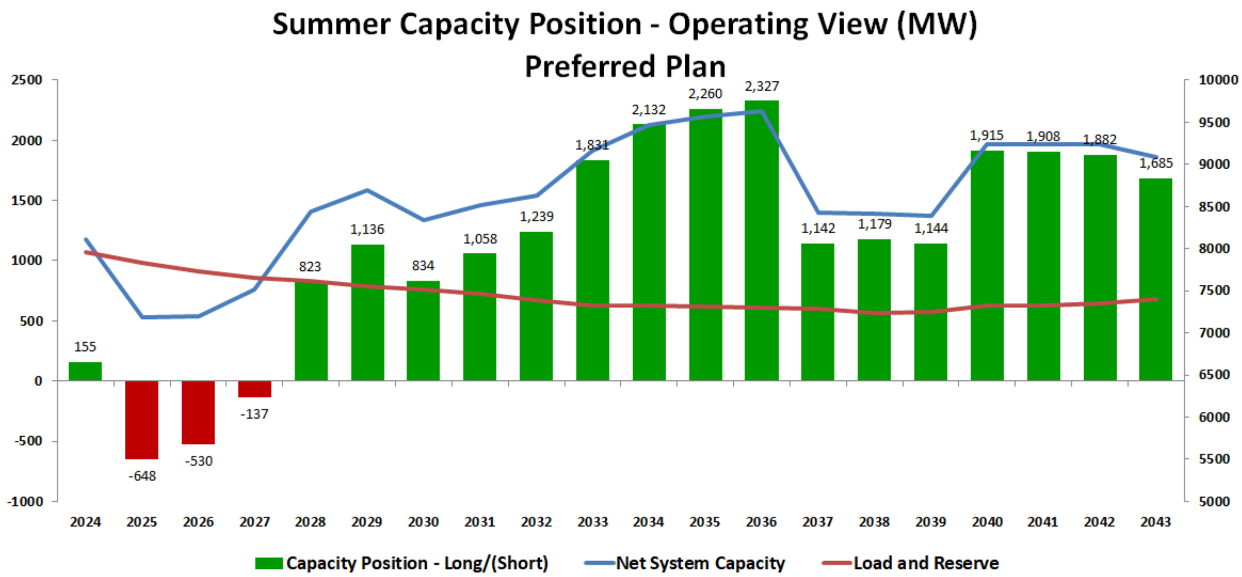


Figure 10.9 Summer Operating View Capacity Position – Preferred Resource Plan



Capacity Positions – MISO Resource Adequacy View with Extreme Weather[11]

In addition to the Operating View capacity positions shown above, Ameren Missouri has also examined its capacity position under MISO's seasonal construct and under extreme weather conditions. For convenience, and to distinguish this view from the Operating View, we refer to this as the "MISO RA View." The MISO RA View is characterized by the following:

- All units reflected at MISO seasonal accredited capacity (SAC) values
- Planning reserve margins set to MISO seasonal values[12]
- Assessment with extreme weather assumes limited use units (i.e., Illinois CTGs) are available for emergencies only
- Extreme weather reflects incremental peak demand of 600 MW in winter and 800 MW in summer based on recent extreme weather events[13]

Using the MISO RA View described above, Ameren Missouri has examined the capacity position for its PRP as well as variations from the PRP to assess the contribution of certain

[11] 20 CSR 4240-22.070(1)(D); 20 CSR 4240-22.030(8)(B)

[12] See Chapter 2 for a full discussion of seasonal PRM requirements.

[13] Summer peak load addition of 800 MW based on approximate midpoint of values calculated and presented in the extreme weather sensitivity analysis in Chapter 3. Winter peak load addition of 600 MW based on approximate increase in peak demand above normal peak experienced during winter storm Elliott in December 2022.

resource additions. These variations include the following and correspond to the subsequent figures as noted:

- Winter capacity position with no new simple cycle generation, batteries or non-RES renewables – Figure 10.10
- Winter capacity position for the PRP – Figure 10.11
- Summer capacity position with no new solar resources beyond those for which the Company has received a CCN (i.e., the Boomtown and Huck Finn projects) – Figure 10.12
- Summer capacity positions for the PRP – Figure 10.13

Figure 10.10 Winter MISO RA View Capacity Position Without New Simple Cycle, Batteries, or Non-RES Renewables

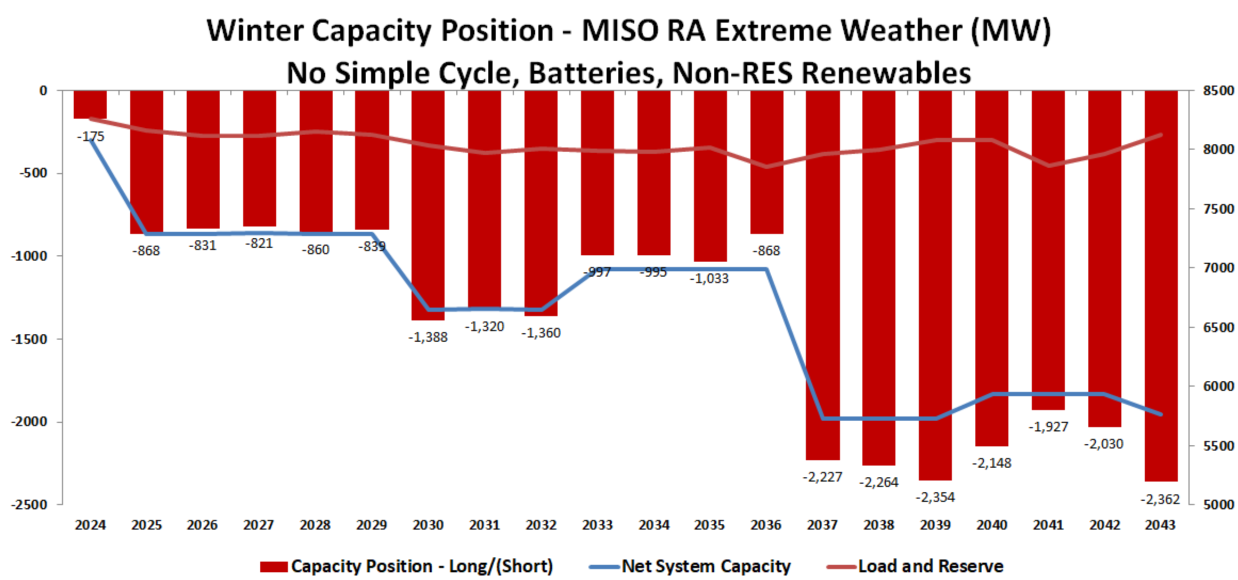
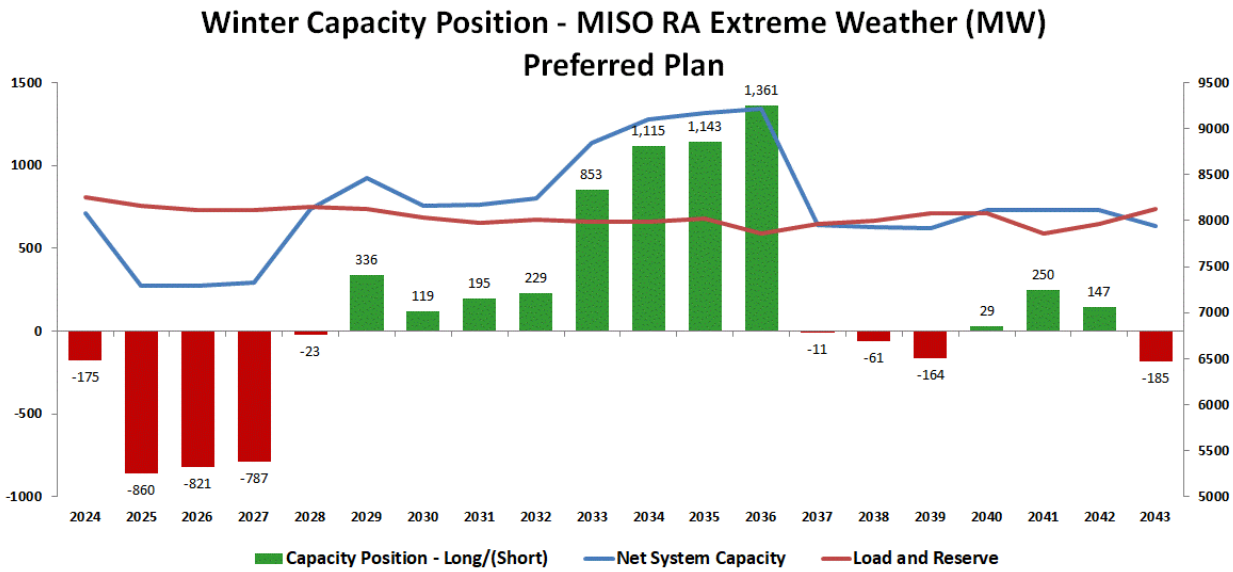


Figure 10.11 Winter MISO RA View Capacity Position – Preferred Resource Plan



Under extreme weather conditions, the MISO RA view for winter shows a capacity shortfall in all years absent the simple cycle generation, batteries and non-RES renewable additions included in the PRP, as shown in Figure 10.10. With those resources, as shown in Figure 10.11, Ameren Missouri expects to have sufficient resources in most years beginning in 2029, with a slight deficit in 2028 and relatively small deficits beyond 2036, following the retirement of the first two units at the Labadie Energy Center. Ameren Missouri could be dependent on MISO for capacity under extreme weather conditions between now and 2027.

Figure 10.12 shows that Ameren Missouri expects a relatively small capacity deficit in the summer under extreme weather conditions in 2024 and 2026 in the absence of additional solar resources. Figure 10.13 shows that this near-term deficit is resolved by the inclusion of additional solar resources, including those for which the Company is currently seeking CCNs.

Figure 10.12 Summer MISO RA View Capacity Position With No Additional Solar

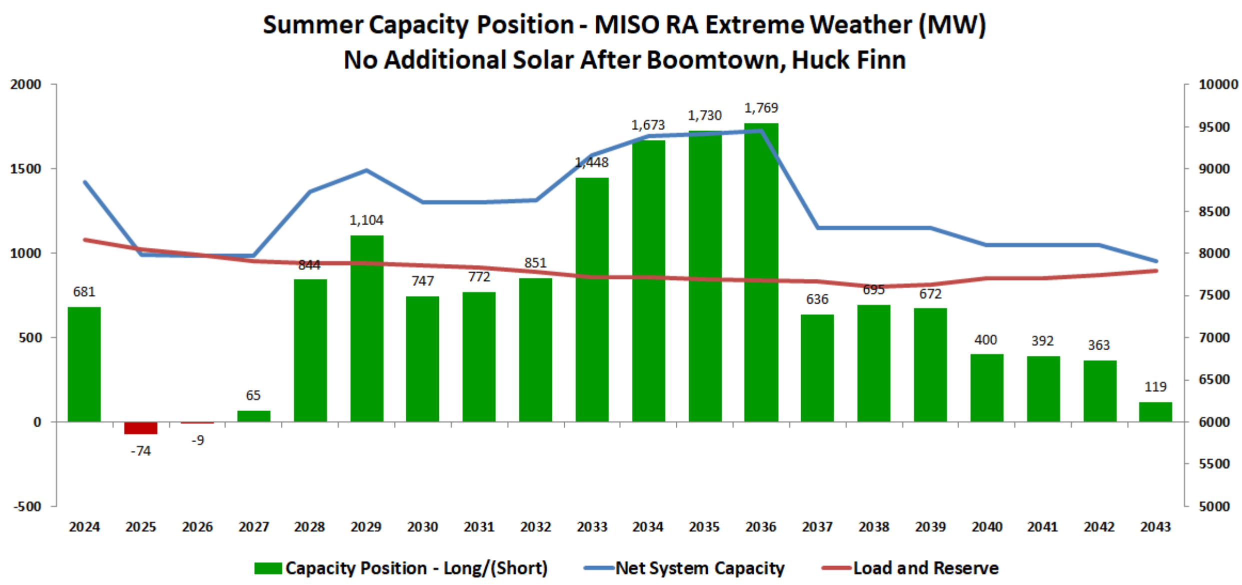
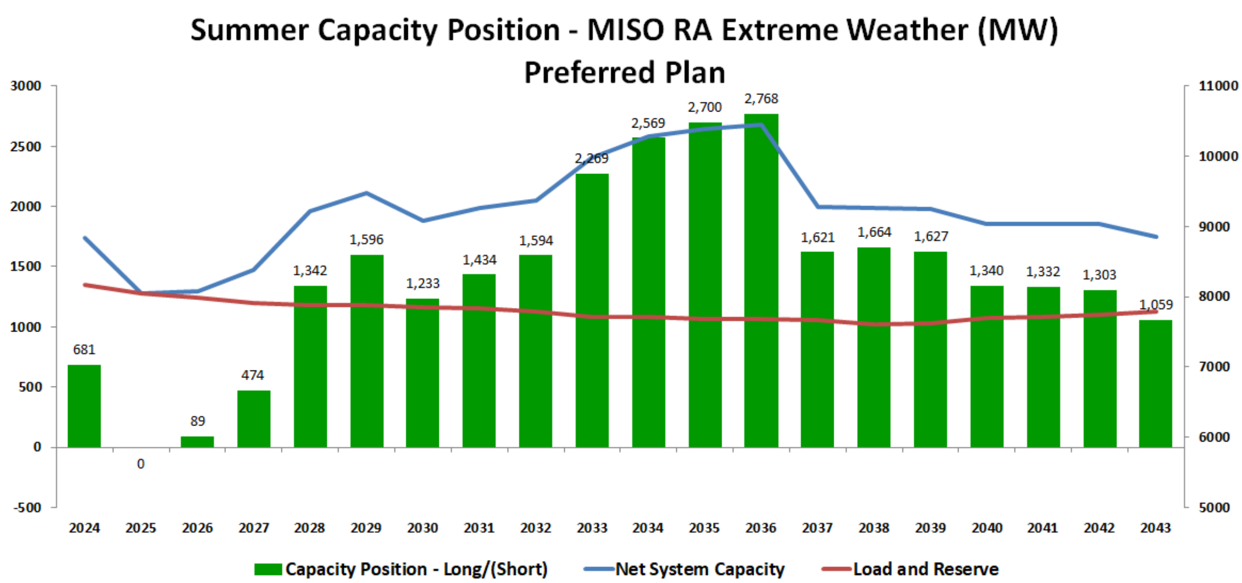


Figure 10.13 Summer MISO RA View Capacity Position – Preferred Resource Plan



Additional Reliability Analysis

As discussed previously, Ameren Missouri will need new dispatchable resources that can produce at any hour to partner with new renewable resources and other dispatchable resources in Ameren Missouri's fleet to ensure reliable energy for customer. Wind and solar resources are not dispatchable. Batteries can provide dispatchability over short periods, but they need to be charged, and therefore their value on the grid is determined by finding an optimal charging and discharging cycle over time. Gas-fired resources, on the other hand, can generate on demand in any given hour and ensure reliability of the overall portfolio in a way that renewables and storage alone cannot.

To illustrate this, the Company used Astrapé Consulting to analyze three different portfolios at or near the end of the Company's 20-year planning horizon. In each of these portfolios, all of Ameren Missouri's existing coal-fired resources are assumed to have been retired. One portfolio (marked as Case 2 in Table 10.3 below) reflects renewable resources included in the Company's PRP. Case 1 shows an alternative portfolio in which no further renewables (or battery storage) are added beyond the Company's existing and approved wind and solar resources (including the Huck Finn and Boomtown solar projects). That portfolio shows the need for 1,800 MW of additional natural gas-fired generation to achieve the same level of reliability, shown in terms of the Loss of Load Expectation (LOLE) – 0.04 in both cases. Case 3 shows an alternative portfolio in which no new gas resources are added. Case 3 includes a combination of wind (7,400 MW), solar (6,500 MW), and battery storage (4,000 MW) to attempt to achieve the same LOLE as Case 2. As the table shows, this still falls short from a reliability perspective, with an LOLE of 0.14. Further increments of wind, solar, and storage could be added to achieve the 0.04 LOLE achieved by Cases 1 and 2 but would simply result in even higher (and more unrealistic) levels of such resources. As discussed previously in this chapter, there are significant, but not insurmountable, challenges to implementing the renewable resources in the Company's PRP. To attempt to pursue the levels of renewable resources and battery storage shown in Case 3 would simply not be realistic, and even if they were available, it would require a much quicker pace of implementation in the near term than what the Company is currently seeking to execute.

Cases 4-7 show portfolios with and without further renewable resources under the PRP in 2026 and 2031, which each follow the retirement of significant coal-fired generation – Rush Island by 2025 and Sioux by 2030.[14] Cases 4 and 6 shown years 2026 and 2031, respectively, including the renewable additions in the PRP, and cases 5 and 7 show those same years, respectively, without renewable additions beyond those already approved. Differences from the PRP are highlighted in green.

[14] Note that this analysis was completed prior to the final selection of the Company's PRP.

Table 10.3 Astrapé Reliability Analysis Results

Year	2043	2043	2043	2026	2026	2031	2031
Case	*1*	*2*	*3*	*4*	*5*	*6*	*7*
Rush Island	-	-	-	-	-	-	-
Sioux	-	-	-	974	974	-	-
Battery Storage	-	800	4000	-	-	-	-
CCGT	4200	2400	-	-	-	1200	1200
Labadie	-	-	-	2372	2372	2372	2372
CT Gas	788	788	-	2711	2711	2058	2058
DR	704	704	704	704	704	704	704
Hydro	370	370	370	370	370	370	370
Nuclear	1236	1236	1236	1236	1236	1236	1236
PSH	440	440	440	440	440	440	440
Purchases	2200	2200	2200	2200	2200	2200	2200
Solar	350	2700	6500	900	350	1800	350
Wind	400	2400	7400	400	400	1400	400
LOLE	0.04	0.04	0.14	0.09	0.13	0.01	0.08

For 2026, the addition of 550 MW of solar resources, which is the total combined capacity of the solar projects currently before the MPSC, results in an improvement in LOLE from 0.13 (Case 5) to 0.09 (Case 4). For 2031, the addition of 1,450 MW of solar and 1,000 MW of wind resources results in an improvement in LOLE from 0.08 (Case 7) to 0.01 (Case 6). While renewable resources are intermittent and alone cannot provide all the necessary capacity to ensure a reliable system, they are integral to meeting reliability needs throughout the near, intermediate, and long term in partnership with existing and new dispatchable resources in the Company's fleet.

Hourly Energy Contribution of Renewable Resources

In addition to the annual energy analysis described previously in this chapter, Ameren Missouri has analyzed hourly energy needs and expected generation during key times of the year, which highlights the value of the Company's renewable additions in meeting customer energy needs.[15] This was done by taking the Company's 2023 IRP load forecasts and showing an explicit build-up of energy resources compared to the load.

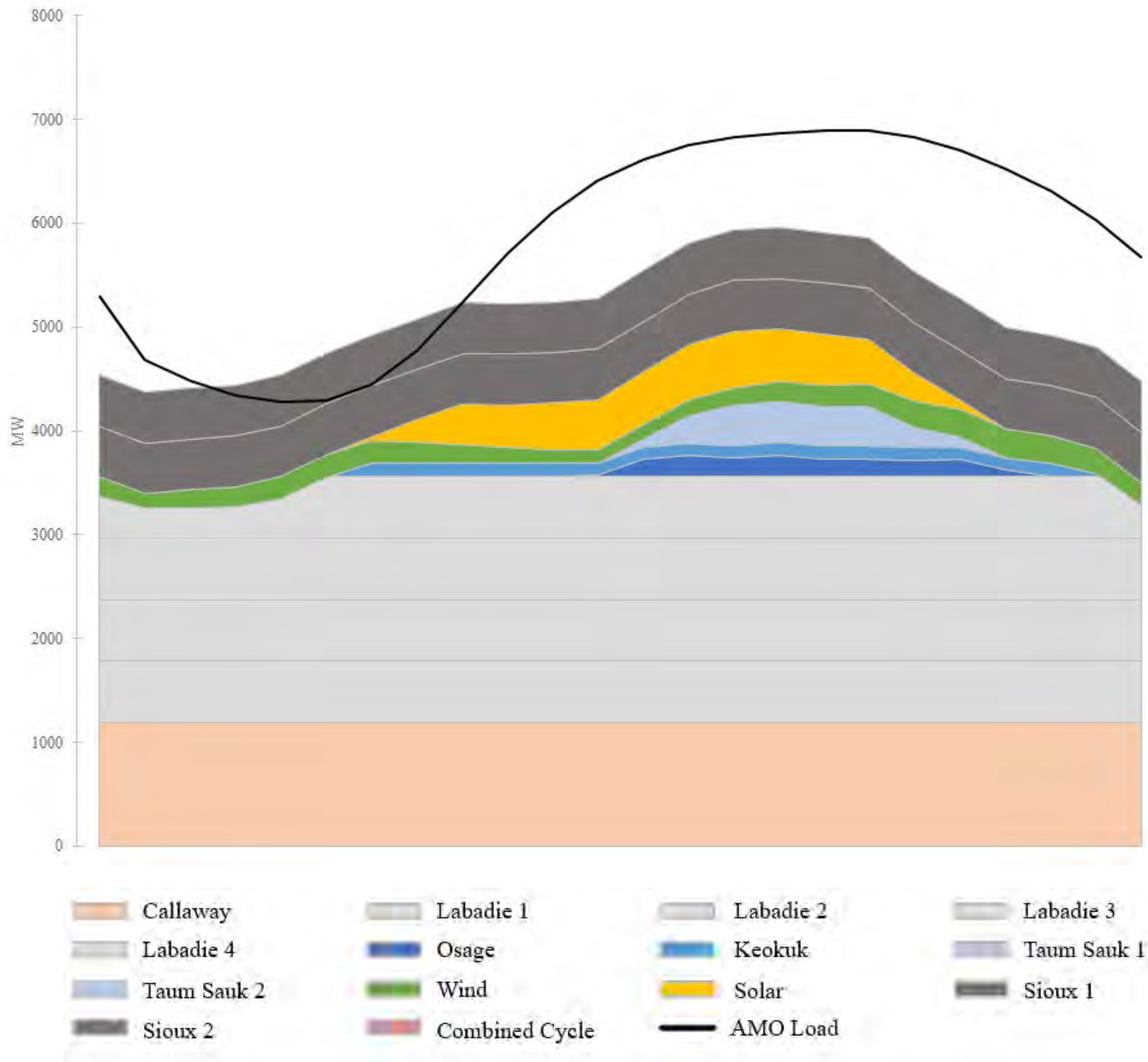
[15] More granular hourly and sub-hourly analysis is among the recommendations made by NERC in its 2022 Long-term Reliability Assessment, as discussed in Chapter 2.

Specific time periods were evaluated, including summer and winter peak conditions, for several key timeframes during the 20-year planning horizon.

The hourly analysis shows that renewable resources are expected to contribute significantly to meeting customer energy needs in the short-, intermediate- and long-term and that the Company's planned solar projects in particular are valuable in meeting customer energy needs in the near term, especially during the summer. The importance of the value provided by the solar projects in the near term is further heightened by the CSAPR rule changes affecting coal generation during the summer months and proposed rules regulating CO_2 emissions.

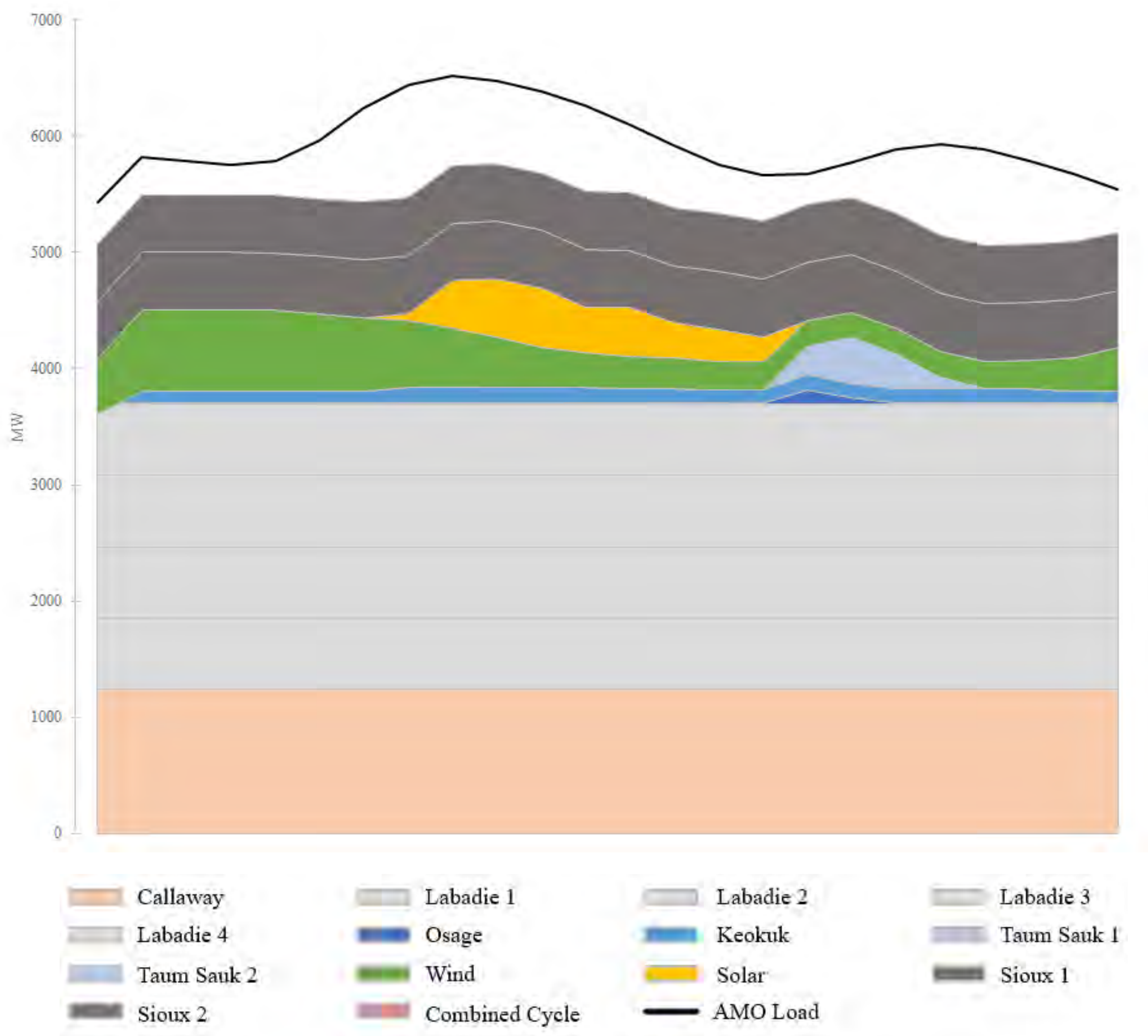
Figure 10.14 shows peak day energy resources and load for July 5, 2026. The solar resources, shown in yellow on the chart, are contributing energy production primarily during the peak period, while wind resources, shown in green generate primarily in the off-peak period. Figure 10.15 shows a similar view for December 23, 2026. This shows much higher production from wind resources in winter than in summer, and primarily in the early morning hours, while solar resource still generate during the middle of the day. Note that in both summer and winter, there is still a need for other energy to meet load, as is the case in the annual energy positions discussed previously. This could be met by a combination of resources, including peaking resources in the Company's fleet and other available resources within MISO and the broader market.

Figure 10.14 Summer Peak Day Energy – PRP 2026



Schedule MM-S3

Figure 10.15 Winter Peak Day Energy – PRP 2026



Figures 10.16 and 10.17 similarly show the summer and winter, respectively, energy production and load for the same days in 2033, following the retirement of Sioux Energy Center, the addition of 1,200 MW of combined cycle gas generation and renewable additions that bring total wind generating capacity to 2,100 MW and total solar generating capacity to 2,200 MW. These charts show the higher contribution of solar during the summer and wind during the winter, while also showing that both provide generation during both seasons. The charts also demonstrate the important role of new dispatchable generation in meeting customer energy needs when total wind and solar generation are lower.

Figure 10.16 Summer Peak Day Energy – PRP 2033

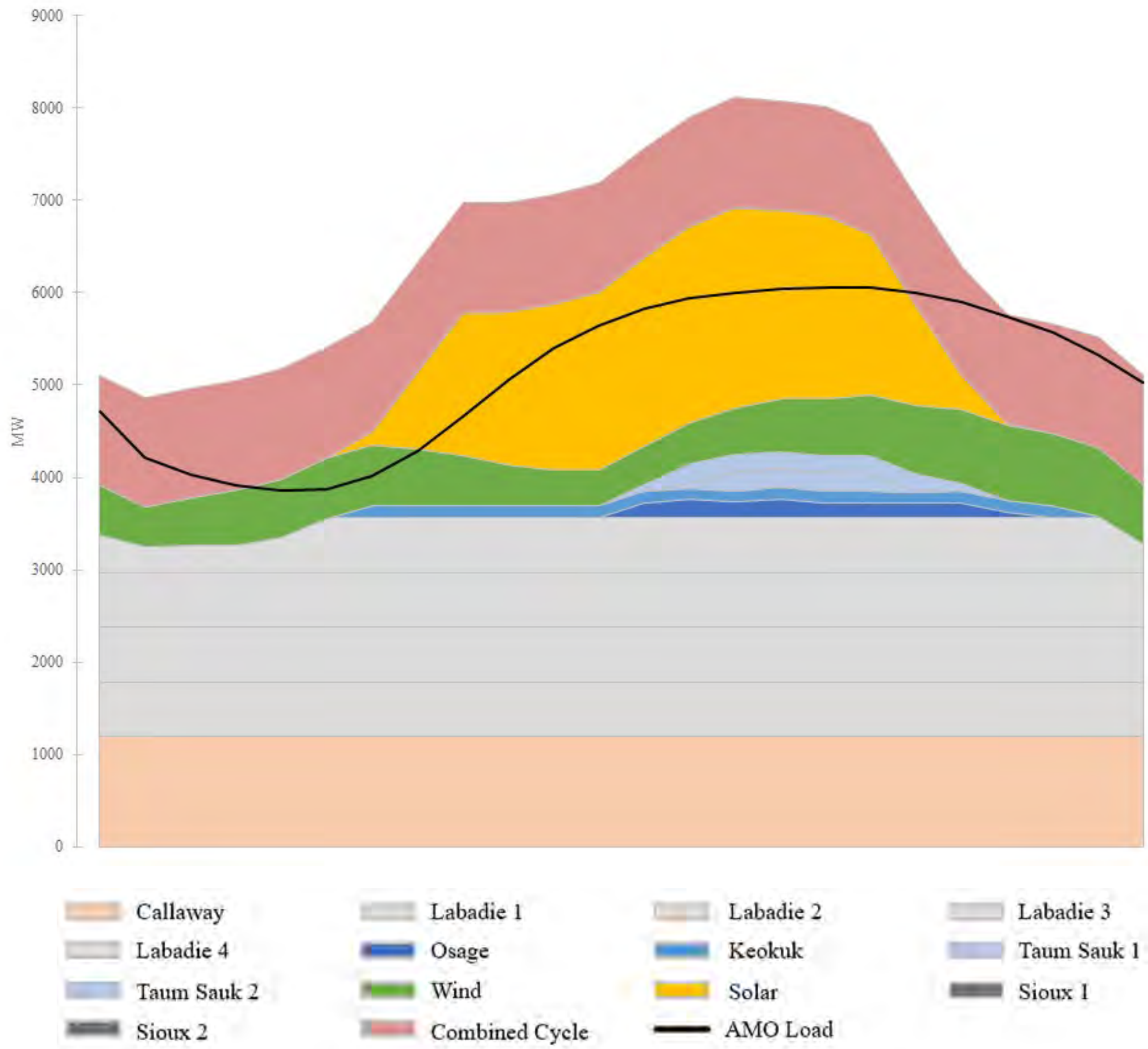
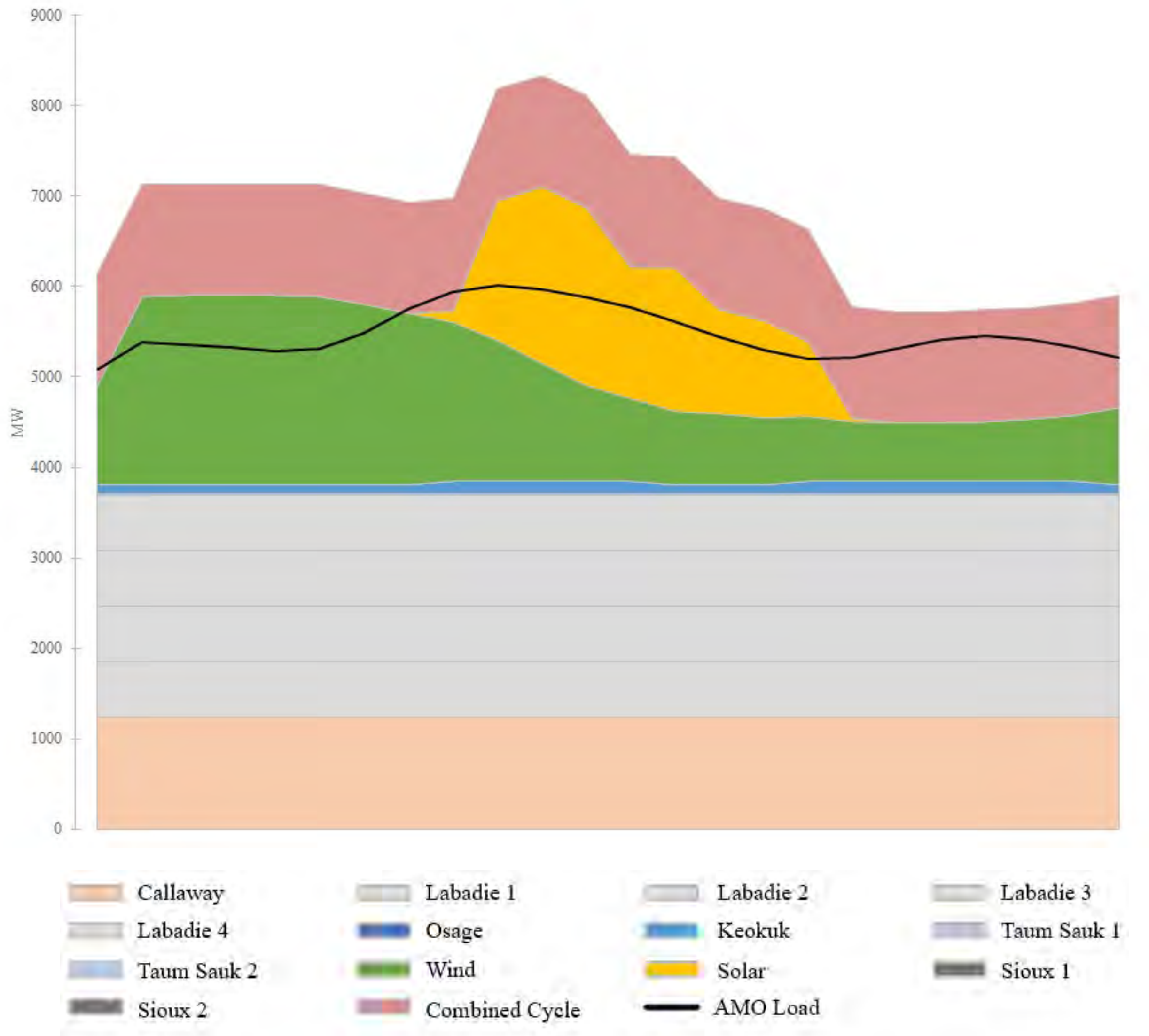


Figure 10.17 Winter Peak Day Energy – PRP 2033



Following the retirement of two Labadie units in 2036, renewable additions bring total wind and solar generating capacity to 5,400 MW. The charts in Figures 10.18 and 10.19 again show summer and winter peak days, respectively, and the generation needed to serve load in 2040, following the addition of 1,200 MW of clean dispatchable generation.[16] Once again, these charts show the important role of renewable resources in producing energy to meet load and the role of dispatchable resources to partner with renewables and ensure reliability in all hours.

[16] For analysis purposes, the clean dispatchable resource is modeled as combined cycle gas. However, the Company plans to make the decision in the future as to exactly what type of clean dispatchable generation is ultimately deployed.

Figure 10.18 Summer Peak Day Energy – PRP 2040

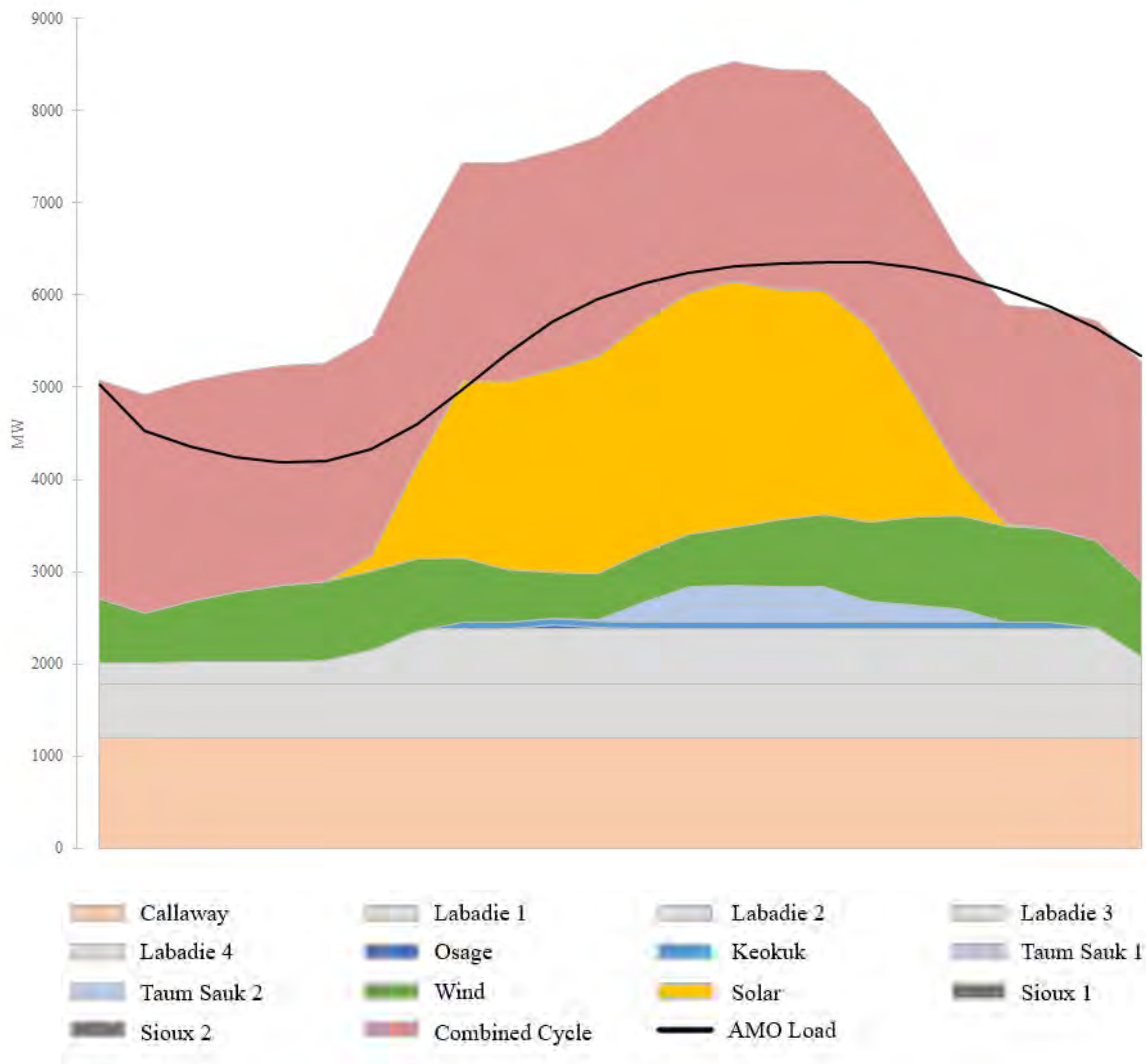
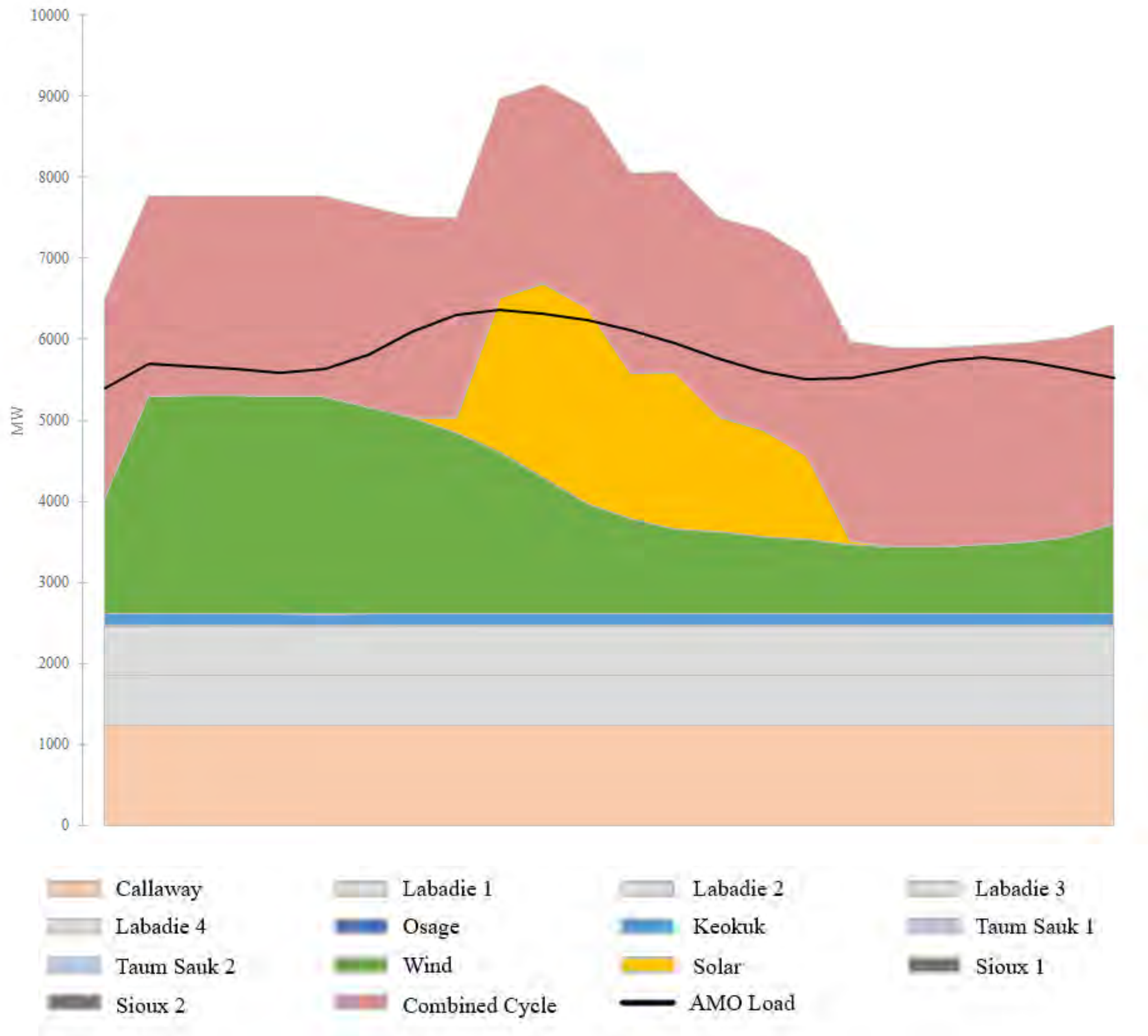


Figure 10.19 Winter Peak Day Energy – PRP 2040



10.2.4 DSM Portfolio Considerations

The continued transition from our old fleet to our new fleet has placed an even greater emphasis on the potential role of demand-side resources, which compete directly with supply-side resources in the alternative plans described and analyzed in Chapter 9. We have seen the gap between the costs of the RAP and MAP portfolios increase in terms of the cost per kWh saved. As a result, the incremental cost of the MAP portfolio does not result in savings from the deferral of supply side resources that justify this cost, as evidenced by our PVRR analysis. At the same time, achievement of energy savings at levels less than that reflected in the RAP portfolio give rise to the need for more supply side resource additions, also resulting in higher costs for customers. For these reasons, the Company believes it is appropriate to continue to target energy and demand savings based on the RAP portfolio.

In addition to its traditional evaluation of demand side programs, the Company also evaluated the potential for additional load flexibility, as described in Chapter 8. While inclusion of this potential (see Plan R in Chapter 9) results in higher PVRR, it may still prove to be a useful contingency option for meeting reliability needs, particularly in the winter. The Company will continue to evaluate the potential for additional load flexibility.

Pursuing the Policy Goal of MEEIA

The stated goal of MEEIA is to achieve all cost-effective demand-side savings by aligning utility incentives with helping customers to use energy more efficiently. Ameren Missouri has demonstrated its commitment to pursuing this goal by implementing the largest utility energy efficiency program in Missouri history. And while we believe this is a goal worth pursuing, it cannot be quantified with any degree of accuracy for the next twenty years. Rather, it is a goal that will constantly be shaped and reshaped through continuous implementation, evaluation, research, testing and readjustment.

As noted in Chapter 8, Ameren Missouri has conducted a DSM Potential Study, prepared by a nationally recognized independent contractor team. The primary objective of the study was to assess and understand the long-term technical, economic, and achievable potential for all Ameren Missouri customer segments. Assuming regulatory treatment that reflects the requirements of MEEIA, RAP represents all cost-effective energy efficiency because, by definition, it represents a forecast of likely customer behavior under realistic program design and implementation.

10.3 Preferred Plan Selection[17]

In selecting its Preferred Resource Plan, Ameren Missouri decision makers[18] relied on the planning objectives discussed earlier in this chapter and the considerations reflected in the scoring and comparison of alternative plans highlighted in the previous sections. As was noted previously, the Top Tier plans identified through scoring include the RAP DSM portfolio, a significant expansion of renewable and storage resources, and the addition of dispatchable resources in the selection of the preferred resource plan.

[17] 20 CSR 4240-22.010(2)(C); 20 CSR 4240-22.010(2)(C)1; 20 CSR 4240-22.010(2)(C)2
20 CSR 4240-22.010(2)(C)3; 20 CSR 4240-22.060(3)(A)5; 20 CSR 4240-22.070(1); 20 CSR 4240-22.070(1)(A) through (D)

[18] Names, titles and roles of decision makers are provided in Appendix B.

Figure 10.20 Comparison of Top Tier Plans

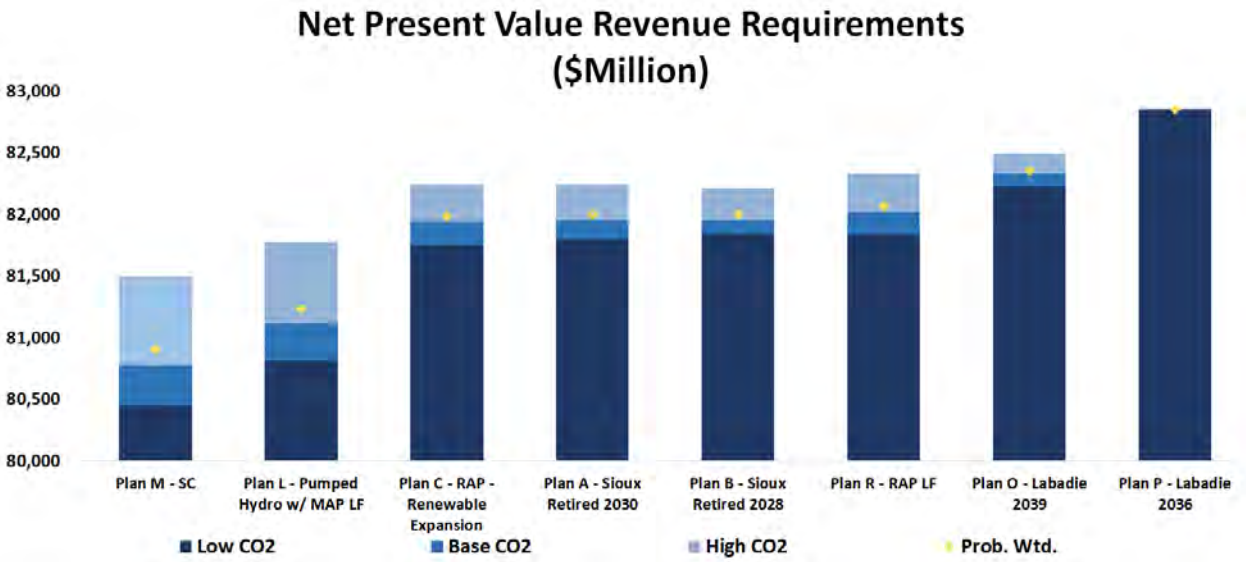
Performance Objectives	Customer Cost (PVRR) (30%)	Customer Sat. (incl. Reliability) (20%)	Financial and Regulatory (20%)	Resource Diversity (20%)	Econ. Dev. (Direct Jobs) (10%)
Plan C – Sioux Retired 2032; Clean Dispatchable (CC-CCS) 2040/2043	No Relative Advantage/Disadvantage	No Relative Advantage/Disadvantage	Relative Advantage	Relative Advantage	No Relative Advantage/Disadvantage
Plan A – Sioux Retired 2030; Clean Dispatchable (CC-CCS) 2040/2043	No Relative Advantage/Disadvantage	No Relative Advantage/Disadvantage	Relative Disadvantage	Relative Advantage	No Relative Advantage/Disadvantage
Plan B – Sioux Retired 2028; Clean Dispatchable (CC-CCS) 2040/2043	No Relative Advantage/Disadvantage	Relative Disadvantage	Relative Disadvantage	Relative Advantage	Relative Disadvantage
Plan R – Sioux Retired 2032; Clean Dispatchable 2040/2043; Additional Load Flexibility	No Relative Advantage/Disadvantage	No Relative Advantage/Disadvantage	Relative Advantage	Relative Advantage	No Relative Advantage/Disadvantage
Plan M – Sioux Retired 2032; Simple Cycle 2040; Clean Dispatchable 2043	Relative Advantage	No Relative Advantage/Disadvantage	Relative Advantage	No Relative Advantage/Disadvantage	Relative Disadvantage
Plan L – Sioux Retired 2032; Pumped Hydro 2040; Clean Dispatchable 2043	Relative Advantage	No Relative Advantage/Disadvantage	No Relative Advantage/Disadvantage	No Relative Advantage/Disadvantage	Relative Advantage
Plan O – Sioux Retired 2032; Labadie Retired 2039; Clean Dispatchable 2040x2	Relative Disadvantage	No Relative Advantage/Disadvantage	No Relative Advantage/Disadvantage	Relative Advantage	Relative Disadvantage
Plan P – Sioux Retired 2032; Labadie Retired 2036; Clean Dispatchable 2037/2039	Relative Disadvantage	Relative Disadvantage	Relative Disadvantage	Relative Advantage	Relative Disadvantage

Relative Advantage — No Relative Advantage/Disadvantage — Relative Disadvantage

To facilitate the selection of the preferred plan, an additional assessment was made of the top tier resource plans. Figure 10.20 presents the comparison of the top tier plans based on further assessment of Ameren Missouri's planning objectives. By isolating the top tier plans, we can assess their relative advantages with more specificity. This also means that the ratings applied in the scorecard in Table 10.2 do not constrain this comparison. Following is a description of the consideration of each planning objective for the top tier plans.

PVRR – Figure 10.21 summarizes the PVRR results for the top tier plans by CO_2 price scenario and for the probability weighted average. Based on these results, Plans M and L were rated as having a relative advantage compared to the other plans. Plans O and P were rated as having a relative disadvantage. All other plans were rated as having no relative advantage or disadvantage.

Figure 10.21 Results for Top Tier Plans[19]



Customer Satisfaction – Plans B and P were judged to have a relative disadvantage due to risks to the accelerated need for gas-fired generation and risks to reliability if new generation is delayed. Plan P also reduces flexibility to take advantage of new clean resource technology development. The other plans were judged to have no relative advantage or disadvantage. While Plan A also results in a slight acceleration of coal generation retirement (i.e., Sioux Energy Center), the risks to reliability are not elevated as with Plan B.

Financial and Regulatory – Plans A, B, and P were judged to have a relative disadvantage given the acceleration of retirement for coal-fired energy centers and the resultant accelerated need for gas-fired generation. The potential implications of EPA's proposed rule for greenhouse gas emissions under Section 111 of the Clean Air Act weighs significantly in the consideration of regulatory risk since they affect not only coal-fired generation, but also new gas-fired generation. Should the proposed rule take effect in a form other than that proposed, or not take effect at all, this risk would be reconsidered. Plan O was judged to have no relative advantage or disadvantage. While Plan O carries regulatory risk associated with the licensing and permitting of new pumped hydro generation, the risk is far enough in the future as to not constitute a relative disadvantage. Should policy changes reduce the regulatory risk associated with licensing and permitting new pumped hydro generation, this risk would be reconsidered. Plan L was judged to have no relative advantage or disadvantage. Like Plans A, B, and P, Plan L carries some risk associated with accelerating gas-fired generation. However, this risk is far enough in

[19] Plans include RAP-level DSM unless otherwise noted.

the future so as not to constitute a relative disadvantage. All other plans were judged to have no relative advantage or disadvantage.

Portfolio Transition – Plans L and M were judged to have no relative advantage or disadvantage since the alternative resources that differentiate them – simple cycle gas and pumped hydro – would not be expected to provide replacement energy for retiring coal. This could also result in the need to retain remaining coal-fired generation and/or operating coal and gas-fired generation at higher levels to meet energy needs. Because this risk is far in the future, this did not result in a finding that they exhibited a relative disadvantage. All other plans were judged to have a relative advantage in that they result in significant energy transition. It should be noted that changes in technology and other factors may diminish the relative advantages of various resources in the period 2040 and beyond. Ameren Missouri will continue to monitor such developments as part of its ongoing planning process.

Economic Development – Plan L was judged to have a relative advantage based on the jobs associated with pumped hydro resource construction. Plans B, O and P were judged to have a relative disadvantage based on the earlier elimination of jobs at coal-fired energy centers. Plan M was also judged to have a relative disadvantage due to the reduced labor intensity of simple cycle gas. All other plans were judged to have no relative advantage or disadvantage.

Along with these objectives, we have considered the costs and benefits of the specific components that define an integrated resource plan. These include consideration of DSM programs, the addition of renewable energy resources, and the retirement of existing generation resources, particularly coal-fired generation. These components define the transformation of our portfolio that we believe best achieves and balances the objectives discussed above.

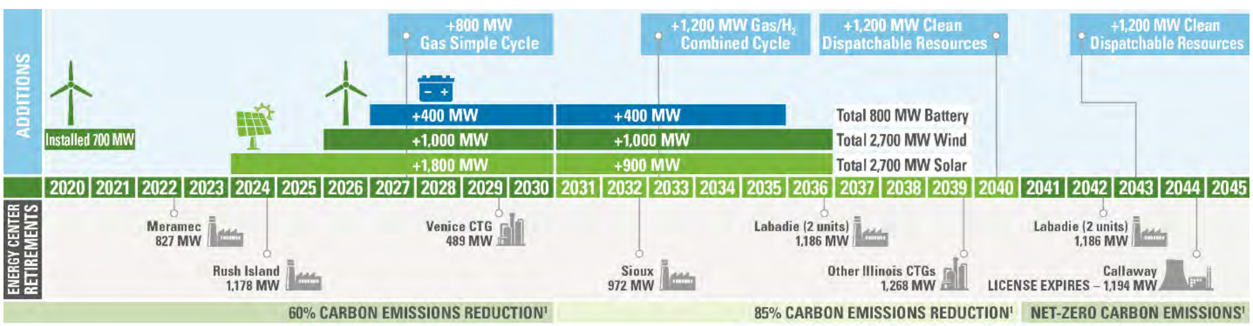
DSM Portfolio – Including energy efficiency and demand response based on RAP DSM potential in our preferred resource plan allows us to continue to offer highly cost-effective programs to customers at a reasonably aggressive level of annual spending while also allowing the potential for increased savings if our experience and expectations indicate they could be achieved in a cost-effective manner. Identifying such opportunities will depend on the results of program implementation and periodic updates of our market research.

Renewable Resources – One of Ameren Missouri's planning objectives is to transition our generation portfolio to one that is cleaner and more fuel diverse in a responsible fashion. For the reasons set forth in this chapter, we believe that the appropriate course of action is to continue the transition to greater levels of renewable energy today in a sustained and controlled manner. Doing so will address both near-term and long-term risks and ensure flexibility in the face of uncertainty and changing conditions. These could include changes in environmental regulations, coal generation economics, and changes in policy that require or can be satisfied by the addition of renewable energy resources.

Coal Retirements and Replacements – We evaluated various alternatives for earlier retirement of coal-fired generation as well as a delay of the retirement of Sioux Energy Center. Delaying the retirement of Sioux Energy Center to 2032 yields benefits in terms of customer costs while also addressing risks associated with potential policy changes and changes in market conditions that affect not only coal generation economics but also the economics and risk associated with replacement gas-fired generation. In particular, EPA's proposed GHG rule introduces risks associated with new gas fired generation, particularly non-peaking gas-fired generation. Making these changes now will ensure we can address recovery of the cost of these investments in way that is consistent with our objective to ensure affordability.

Based on our consideration of all these objectives and factors and consideration of the results of our thorough analysis of a wide range of options, we have selected Plan C as our preferred resource plan. Figure 10.22 shows the major resource additions and retirements defined by Plan C.

Figure 10.22 Preferred Resource Plan



10.4 Contingency Planning[20]

Because any assumptions about the future are subject to change, we must be prepared for changing circumstances by evaluating such potential circumstances and options for providing safe, reliable, cost-effective and environmentally responsible service to our customers. We have identified several cases which could significantly impact the performance of our preferred resource plan.

10.4.1 DSM Cost Recovery and Incentives

As stated previously, MEEIA provides for cost recovery and incentives for utility-sponsored demand-side programs to align utility incentives with helping customers to use

[20] 20 CSR 4240-22.070(4)

energy more efficiently. In September 2023, the MPSC approved the third one-year extension of our third cycle of MEEIA programs and supporting cost recovery, and incentives. Our preferred resource plan is based on the expectation that supporting cost recovery and incentives will continue to be approved in the future. If such alignment is not achieved, it may be necessary for Ameren Missouri to change its preferred resource plan. We have therefore included a contingency plan, Plan W, for this circumstance.

Ameren Missouri expects to file an amended multi-year MEEIA 4 application with the MPSC for approval of a new portfolio of demand-side programs that would become effective starting in 2025. Costs are expected to be recovered through our Rider Energy Efficiency Investment Charge (Rider EEIC). In our request, we will also seek recovery of costs associated with the so-called “throughput disincentive.”

In addition to recovery of program costs and addressing the throughput disincentive, MEEIA also mandates that utilities be provided with timely earnings opportunities that serve to make investments in demand-side resources equivalent to investments in supply-side resources. Ameren Missouri will seek such incentives in its upcoming MEEIA filing.

10.4.2 Renewable Subscription Program

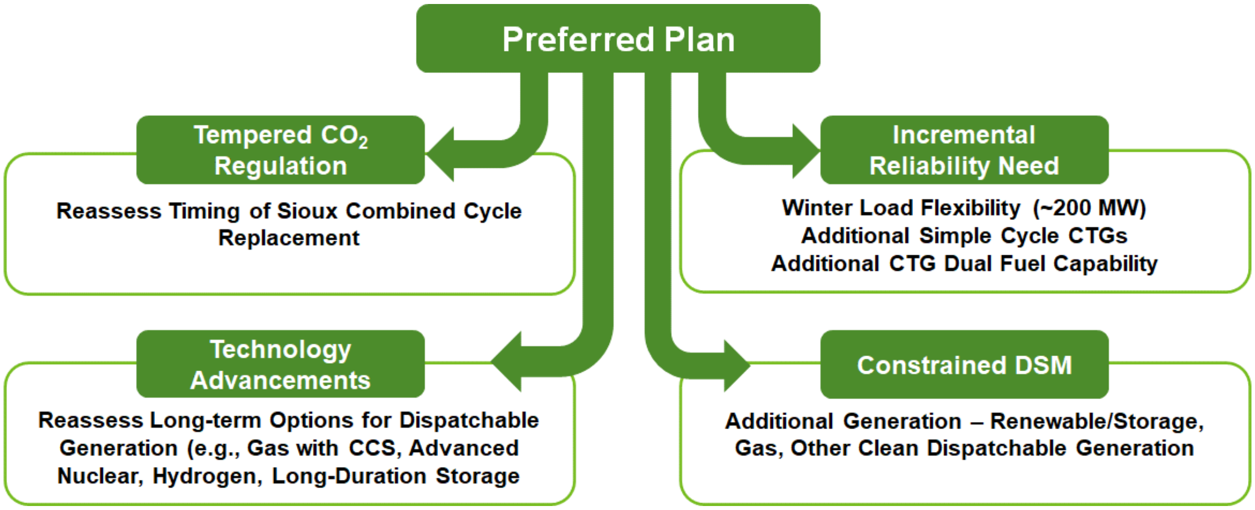
Our preferred plan includes our Renewable Solutions Program to offer commercial and industrial customers and communities the means by which they can source more of their electric energy needs from renewable resources. While further resources have not been designated for this program, some planned resources may be designated for the program in the future depending on customer demand and project economics.

10.5 Resource Acquisition Strategy[21]

Our resource acquisition strategy has three main components. First is the Preferred Resource Plan, which is discussed in more detail in Section 10.5.1. The second component of the resource acquisition strategy is contingency planning. Figure 10.23 shows the contingency options the Company has considered and the events that could lead to a change in our preferred plan. The final component of the resource acquisition strategy is the implementation plan, which includes details of major actions over the next three years, 2024-2026.

[21] 20 CSR 4240-22.070(1); 20 CSR 4240-22.070(1)(A) through (D); 20 CSR 4240-22.070(2); 20 CSR 4240-22.070(4); 20 CSR 4240-22.070(4)(A) through (C); 20 CSR 4240-22.070(7); 20 CSR 4240-22.070(7)(A) through (C)

Figure 10.23 Contingency Options



10.5.1 Preferred Plan

As discussed in Section 10.3, our Preferred Resource Plan includes energy efficiency programs based on the RAP portfolio potential discussed in Chapter 8, 4,700 MW of wind and solar generation by 2036, 800 MW of battery storage by 2035, retirement of the Fairgrounds, Mexico, Moberly, Moreau and Venice Energy Centers by the end of 2029, retirement of Rush Island Energy Center by the end of 2024, retirement of Sioux Energy Center by the end of 2032, retirement of two of the four units at Labadie Energy Center by the end of 2036, retirement of the remaining CTG energy centers in Illinois by the end of 2039, and retirement of the remaining two units at Labadie Energy Center at the end of 2042. It also includes the addition of 800 MW of simple cycle gas generation by the end of 2027, 1,200 MW of combined cycle gas generation by the end of 2032, and 1,200 MW of clean dispatchable resources in each of 2040 and 2043.

Demand-Side Resources

The preferred plan includes energy efficiency and demand response programs based on the RAP portfolio potential discussed in Chapter 8. Program spending for the 20-year planning horizon (after the current cycle of MEEIA programs) is approximately $2.5 billion. Cumulative peak demand reductions approaching 1,600 MW by 2043 (not including planning reserve margin), and cumulative annual energy savings (at the customer meter) over 4.1 million MWh.

Renewables and Storage

We are continuing a transformation of our generation portfolio, and one of the key components of that transition is the continued significant expansion of renewable wind and solar generation resources, with a total of 4,700 MW of new wind and solar generation by 2036 and 2,800MW by 2030, and the addition of 400 MW of battery storage by 2030 and another 400 MW by 2034. As discussed earlier in this chapter, these renewable energy resources will be necessary to ensure the energy supply that our customers need and do so in a way that is environmentally responsible and ensures affordability for our customers. Battery storage resources, along with other dispatchable resources in our fleet, will partner with these renewable resources to ensure reliable energy supply during and after the transition of our portfolio.

Supply-Side Resources

The Preferred Resource Plan calls for the retirement of Rush Island by the end of 2024, retirement of Sioux Energy Center by the end of 2032, retirement of two of the four units at Labadie Energy Center by the end of 2036, and retirement of the remaining units at Labadie Energy Center by the end of 2042. It also calls for the retirement of four older oil-fired CTGs and the gas-fired Venice Energy Center by the end of 2029 and the remaining Illinois gas-fired units at the Goose Creek, Racoon Creek, Pinckneyville and Kinmundy Energy Centers by the end of 2039. To ensure sufficient dispatchable resources to partner with the above-mentioned renewable and storage resources, we also plan to add 800 MW of gas-fired simple cycle combustion turbine generation by the end of 2027, 1,200 MW of gas-fired combined cycle generation by the end of 2032, and 1,200 MW of additional clean dispatchable generation in each of 2040 and 2043.

10.5.2 Contingency Plans[22]

Figure 10.5 presents our key contingency options. In the event that Ameren Missouri's interests are not aligned with helping customers use energy more efficiently, as required by MEEIA, we have included a contingency option that reflects a discontinuation of demand side programs after our current MEEIA cycle programs expire. The contingency option therefore also includes the installation of an additional 1,200 MW of combined cycle gas generation in 2028 and another 1,200 MW of clean dispatchable generation in 2043. Should the EPA's current proposed regulation of CO_2 take effect in a different form or not take effect at all, the Company may reevaluate the timing of the retirement of its Sioux Energy Center and the planned addition of combined cycle gas replacement generation. Should the development of clean dispatchable resource technologies advance more quickly or result in resource options that provide a more favorable combination of reliability and affordability, Ameren Missouri will reevaluate its planned generation additions. This could also include further consideration of simple cycle gas generation and/or pumped hydro energy storage resource, which scored well in our assessment of alternative plans. Should additional resources be needed for ensuring reliability, the Company will reassess the role of additional load flexibility resources.

[22] 20 CSR 4240-22.070(4)

10.5.3 Expected Value of Better Information

After selecting the preferred plan, Ameren Missouri conducted an expected value of better information (EVBI) analysis to assess the performance of its preferred resource plan under the range of values defined for the critical uncertain factors and to inform its on-going research and implementation activities. Table 10.4 displays the results of the EVBI analysis as measured by PVRR. Under most critical uncertain factor values, the preferred plan results in the lowest PVRR. Plan M results in the lowest PVRR under certain values for critical uncertain factors – low CO_2 prices, low or base gas prices, and high project costs. Because the difference between the preferred plan and Plan M is the addition of simple cycle gas in 2040 instead of the placeholder clean dispatchable resource, incurring additional expenditures for the better information needed is not expected to resolve that choice. Instead, we have time to monitor conditions and engage in continued planning analysis until a decision must be made. For all other values of critical uncertain factors, Plan T results in the lowest PVRR. For the reasons discussed in Section 10.3, Plan T is not considered to be a feasible or desirable path. As a result, procuring better information, regardless of the cost, would not bear on plan selection.

Table 10.4 EVBI Analysis Results

Alternative Resource Plans		PVRR Without Better Info	Carbon Price			Natural Gas Price			Load Growth			Project Cost		
			Low	Base	High	Low	Base	High	Low	Base	High	Low	Base	High
A	Sioux Retired 2030	82,002	81,799	81,953	82,241	81,358	81,821	82,388	80,603	82,040	83,286	80,434	81,922	84,209
B	Sioux Retired 2028	82,003	81,839	81,955	82,215	81,341	81,810	82,409	80,604	82,041	83,287	80,416	81,923	84,226
C	RAP - Renewable Expansion	81,985	81,748	81,937	82,243	81,353	81,814	82,356	80,586	82,023	83,269	80,434	81,905	84,178
D	Labadie SCR	82,668	82,426	82,619	82,931	82,041	82,499	83,037	81,269	82,707	83,953	81,008	82,581	85,025
E	MAP	82,680	82,541	82,633	82,879	82,027	82,512	83,054	81,281	82,719	83,965	81,129	82,600	84,873
F	RAP-RES Compliance	83,807	83,344	83,711	84,314	82,537	83,439	84,583	82,407	83,845	85,091	82,129	83,724	86,147
G	MAP-RES Compliance	84,087	83,657	84,023	84,499	82,861	83,750	84,815	82,688	84,125	85,371	82,514	83,991	86,429
H	MAP LF-RES Compliance	82,080	81,352	81,933	82,870	80,960	81,791	82,721	80,681	82,118	83,364	80,814	82,012	83,891
I	No Additional DSM	86,656	86,718	86,690	86,537	85,707	86,344	87,283	85,257	86,694	87,940	84,487	86,543	89,725
J	No Additional DSM-RES Compliance	87,002	86,618	86,972	87,305	85,573	86,554	87,919	85,603	87,041	88,286	84,961	86,891	89,932
K	Renewables for Capacity Need	82,721	82,248	82,658	83,157	81,894	82,516	83,184	81,322	82,759	84,005	81,178	82,634	84,964
L	Pumped Hydro w/ MAP LF	81,238	80,819	81,118	81,778	80,648	81,100	81,559	79,839	81,277	82,522	79,803	81,181	83,135
M	SC	80,907	80,448	80,777	81,493	80,296	80,756	81,248	79,508	80,945	82,191	79,507	80,849	82,768
N	SMR w/ RAP LF	84,840	84,584	84,775	85,148	84,442	84,762	85,037	83,440	84,878	86,124	82,784	84,714	87,903
O	Labadie 2039	82,356	82,226	82,331	82,495	81,693	82,167	82,759	80,957	82,394	83,640	80,759	82,271	84,634
P	Labadie 2036	82,848	82,853	82,852	82,837	82,137	82,633	83,294	81,449	82,886	84,132	81,199	82,757	85,226
Q	Labadie 2031	83,758	83,985	83,767	83,599	82,923	83,468	84,330	82,359	83,796	85,042	81,978	83,689	86,093
R	RAP LF	82,067	81,834	82,016	82,331	81,421	81,894	82,445	80,668	82,106	83,352	80,516	81,987	84,260
S	MAP LF	82,813	82,679	82,760	83,020	82,136	82,641	83,197	81,414	82,851	84,097	81,262	82,733	85,006
T	All Renewables	80,808	80,816	80,767	80,901	80,945	80,953	80,592	79,409	80,846	82,092	78,895	80,708	83,516
U	SC instead of First CC	82,020	81,507	81,892	82,635	81,404	81,887	82,341	80,621	82,058	83,304	80,367	81,907	84,576
V	CCS on 1st CC	82,963	82,725	82,916	83,219	82,336	82,794	83,331	81,564	83,001	84,247	81,254	82,869	85,430
W	RAP 80%	83,749	83,680	83,756	83,773	83,008	83,534	84,202	82,350	83,787	85,033	81,967	83,648	86,340
Minimum PVRR among plans			80,448	80,767	80,901	80,296	80,756	80,592	79,409	80,846	82,092	78,895	80,708	82,768
Plan with Minimum PVRR			M	T	T	M	M	T	T	T	T	T	T	M
Subjective Probability			15%	60%	25%	10%	50%	40%	20%	60%	20%	10%	80%	10%
Expected Value of Better Info			1,300	1,170	1,342	1,057	1,059	1,764	1,177	1,177	1,177	1,539	1,196	1,410

10.5.4 Implementation Plan[23]

As mentioned earlier, the implementation plan outlines the major activities to be completed during the next three years, 2024-2026. Below is a description of those major activities.

Demand-Side Resources Implementation

Ameren Missouri continues to implement its third cycle of approved MEEIA programs, which run through 2024. Ameren Missouri expects to file an updated multi-year MEEIA 4 application with the MPSC in the first quarter 2024 for approval of demand-side programs and associated cost recovery and incentive mechanisms to be implemented beginning in 2025. Such a proposal will be consistent with the preferred resource plan which includes the RAP portfolio.

Renewables

Our preferred resource plan includes the addition of 2,800 MW of new wind and solar generation by the end of 2030. Ameren Missouri will be engaging in activities during the implementation period to support the development of the new wind and solar generation, including bid solicitation, contractor selection, applying for certificates of convenience and necessity, and construction. A new request for proposal process for wind resources will be initiated by the first quarter of 2024. CCN applications are currently before the MPSC for four solar projects totaling 550 MW. Additional solar project CCN applications are expected to be filed with the MPSC in the second quarter of 2024. Concurrently, Ameren Missouri continues with implementation of the Huck Finn solar project to satisfy RES requirements and the Boomtown solar project to support the Company's Renewable Solutions program, with each resource also contributing to meeting the Company's energy and capacity needs apart from the RES or the Renewable Solutions Program. Both projects were granted CCNs by the MPSC earlier in 2023, and the Renewable Solutions program was approved in that same timeframe.

New Simple Cycle Gas Generation

Our preferred resource plan includes the addition of 800 MW of simple cycle CTG generation with dual fuel (natural gas and oil) capability by the end of 2027 to provide periodic generation during times of peak demand or when wind and solar generation are diminished. The Company will be taking steps to implement this new dispatchable resource starting in 2023 and over the next few years. These include site selection, permitting, engineering, and procurement, as well as steps to secure interconnection within MISO. The Company expects to seek approval by the MPSC for a CCN for this resource sometime in 2024.

[23] 20 CSR 4240-22.070(6); 20 CSR 4240-22.070(6)(A) through (D)

New Combined Cycle Gas Generation

Our preferred resource plan also includes the addition of 1,200 MW of natural gas-fired combined cycle generation by the end of 2032 to replace the existing coal-fired generation at the Sioux Energy Center. The Company will begin taking steps to implement this new dispatchable resource over the next few years. These include site selection, permitting, engineering, and procurement, as well as steps to secure interconnection within MISO.

Rush Island and Sioux

Ameren Missouri will be taking steps to retire the units at Rush Island Energy Center by the end of 2024, including construction of new transmission facilities to ensure grid reliability. Ameren Missouri continues to operate the units at Rush Island pursuant to an SSR agreement with MISO until the units are retired. While the retirement of Sioux Energy Center has been delayed to 2032, the Company will continue to prepare for its retirement and thereby maintain flexibility to further revised retirement plans in the event conditions warrant a review of the current plans and Ameren Missouri management decides it is appropriate to make a change.

Competitive Procurement Policies[24]

Ameren Missouri assigns a Project Manager to lead the activities necessary to ensure the successful completion of its acquisition and development of supply-side resources. In general, a project team comprised of a Project Manager and various lead engineers will identify all items to be procured and will coordinate with the Strategic Sourcing and Purchasing departments within Ameren to ensure proper contract structures are considered and used for each procurement activity. A Contract Development Team (CDT) is assembled and assists in collecting material and labor estimates based on the overall project design. Strategic Sourcing, CDT and the project team work to set up a number of components as Ameren stock items that are the basis for ordering materials. A detailed procurement matrix is developed to identify the major purchases that are anticipated to be required as part of the project. Projects make use of stock items where appropriate. Where material has not been established as a stock item, the CDT determines potential vendors, collects quotes, and scores the potential vendor to make the best selection. Ameren Missouri will be following Ameren's Project Oversight Process, which is provided in Appendix C, for monitoring the progress of projects that fulfill its Preferred Resource Plan.[25]

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[24] 20 CSR 4240-22.070(6)(E)
[25] 20 CSR 4240-22.070(6)(G)

10.5.5 Monitoring Critical Uncertain Factors[26]

Ameren Missouri will be monitoring the critical uncertain factors that would help determine whether the Preferred Resource Plan is still appropriate and whether contingency options should be pursued. Below is a description of how Company decision makers will be monitoring the factors most relevant to future resource decisions.

Climate Policy

Ameren Missouri senior management and its Environmental Services organization will continue to monitor and evaluate developments on efforts to regulate greenhouse gas emissions, including EPA's current proposed rule, as well as state and industry efforts aimed at reducing greenhouse gas emissions. The Company reviews its assumptions for climate policy and CO_2 prices as part of its IRP annual update process.

Natural Gas Prices

Ameren Missouri evaluates natural gas prices at least annually, and a review of natural gas price assumptions is included as part of its IRP annual update process.

Generation Project Costs

Ameren Missouri will continue to monitor project pricing for various resources through industry sources and through its own resource acquisition activities, such as RFPs and competitive bidding. This includes wind, solar, storage, and natural gas-fired resources (both simple cycle and combined cycle) as well as environmental controls such as SCRs, and carbon capture and sequestration. Evaluation of project costs will continue to be included as part of the Company's IRP annual update process.

[26] 20 CSR 4240-22.070(6)(F)

10.6 Compliance References

2022
Change in Preferred Plan

INTEGRATED RESOURCE PLAN

Ameren MISSOURI

Schedule MM-S4

Notification of Change in Ameren Missouri's Preferred Resource Plan

Executive Summary

Ameren Missouri's senior management has concluded that the Preferred Resource Plan presented in its 2020 Triennial Integrated Resource Plan ("IRP") (File No. EO-2021-0021) is no longer appropriate and should be revised. This conclusion was reached as a result of several key events and changes in the planning environment:

- Rush Island NSR Litigation – An appellate court decision resulted in a subsequent decision by Ameren Missouri to retire the coal units at Rush Island Energy Center within the next few years rather than install expensive pollution control technology.
- Illinois Energy Legislation – Legislation passed by the Illinois General Assembly to transition away from carbon-emitting electric generation shortens the operating life of simple cycle gas combustion turbine generators ("CTGs") owned by Ameren Missouri and operated in Illinois.
- Winter Capacity Needs – In the wake of Winter Storm Uri, Ameren Missouri has placed additional focus on winter reliability. The Midcontinent Independent System Operator ("MISO") has also filed a proposal with the Federal Energy Regulatory Commission ("FERC") to include consideration of seasonal capacity needs and capabilities as part of proposed resource adequacy reforms.
- Enhanced Reliability Focus – In addition to considering winter capacity needs, Ameren Missouri has engaged Astrapé Consulting to evaluate long-term reliability implications of the Company's resource decisions through rigorous reliability modeling and has incorporated insights from this analysis into the development of its revised Preferred Resource Plan.

In addition to the above factors, Ameren Missouri has revisited key assumptions affecting the performance of its Preferred Resource Plan – natural gas prices, carbon prices, and costs for wind, solar, storage and gas-fired generation technologies. 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.

Ameren Missouri also strives to ensure specific 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).
- Mitigate Financial/Regulatory Risk.
- Economic Development.

Given these objectives and the planning environment changes noted above, Ameren Missouri has updated its Preferred Resource Plan as shown in Figure 1. Figure 2 shows Ameren Missouri's actual 2021 generation mix and its expected future generation mix under the new Preferred Resource Plan.[1]

Figure 1: Preferred Plan Resource Timeline

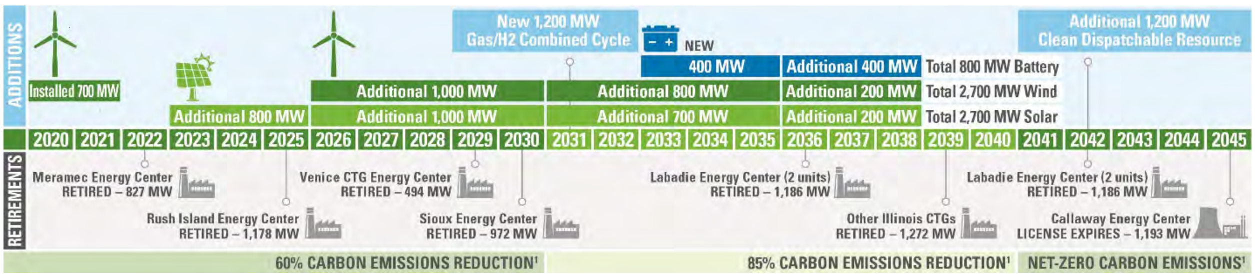
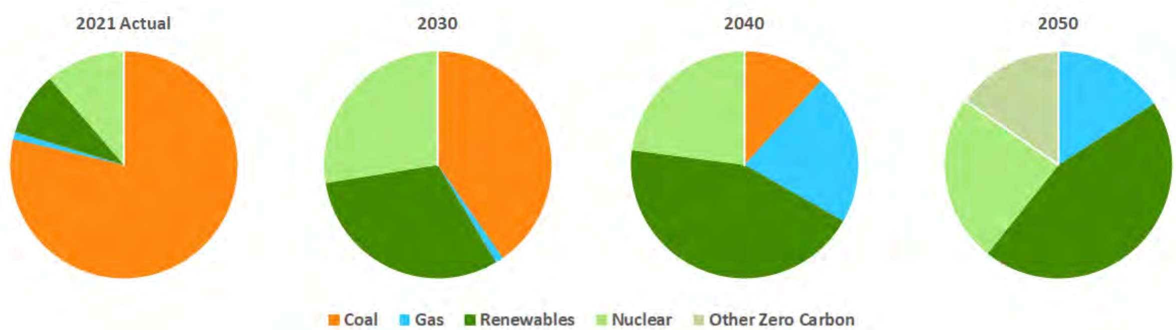


Figure 2: Preferred Plan Generation Mix



The Preferred Resource Plan reflects the following key changes from the 2020 IRP preferred plan:

- Acceleration of the retirement of Rush Island Energy Center from 2039 to 2025[2].
- Retirement of Venice Energy Center by the end of 2029.
- Delay in the retirement of Sioux Energy Center by two years from 2028 to 2030.

[1] Gas generation in 2050 is assumed to include a combination of hydrogen blending and carbon capture and sequestration to eliminate CO_2 emissions that might otherwise result. Other zero carbon generation may be a combination of gas-fired generation with hydrogen blend and carbon capture, utilization and storage ("CCUS"), advanced nuclear, renewables with long-duration storage, or other new zero-emitting technologies. 2021 actual generation reflects a prolonged outage of the Callaway Energy Center.

[2] At the time of preparation of this notification, final resolution of the retirement date for the Rush Island Energy Center had not been reached. Changes in the retirement date are expected to have no material impact on other resource decisions represented in the updated Preferred Resource Plan.

- Addition of 1,200 MW of natural gas-fired combined cycle ("NGCC") generation in 2031, with plans to switch to hydrogen fuel and/or blend hydrogen fuel with natural gas and install carbon capture technology by 2040.
- Changes in the timing of wind and solar additions, still resulting in total renewable generation additions of 5,400 MW[3].
- Addition of 800 MW of battery storage resources.
- Retirement of the remaining Illinois CTGs by the end of 2039 – Goose Creek, Raccoon Creek, Pinckneyville, and Kinmundy Energy Centers.
- Increase from 800 MW to 1,200 MW of clean dispatchable resources in 2043.

Ameren Missouri's new Preferred Resource Plan represents an acceleration of the Company's portfolio transition that results in the retirement of approximately 3,000 MW[4] of coal-fired generation by the end of 2030, accelerated retirement of approximately 1,800 MW of gas-fired generation, total renewable generation of 3,500 MW by 2030, the addition of flexible battery storage, and the deployment 1,200 MW of clean-burning NGCC generation, with an expectation for technology development to eliminate remaining carbon emissions in the long term. This accelerated transition allows Ameren Missouri to achieve greater reductions in carbon emissions by 2030 – 60% compared 2005 levels versus the previous goal of 50% – maintain the goal of an 85% reduction in carbon emissions by 2040, and accelerate the Company's net zero emissions goal to 2045 from 2050.[5] Table 1 shows the acceleration of the transition by comparing key elements of the new Preferred Resource Plan to the 2020 IRP preferred plan.

Table 1: Transition Timing Comparison

	2022 Preferred Plan	2020 IRP Preferred Plan
Coal Retirement Acceleration	**3,000 MW by 2030** 5,400 MW by 2042	1,800 MW by 2030 5,400 MW by 2042
Natural Gas Retirement Acceleration	**500 MW by 2030** **1,800 MW by 2040**	None
Renewable Additions	**3,500 MW by 2030** **5,000 MW by 2035** 5,400 MW by 2040	3,100 MW by 2030 4,300 MW by 2035 5,400 MW by 2040
Battery Storage Additions	**400 MW by 2035** **800 MW by 2040**	None
Carbon Emission Reduction (CO_2e)	**60% by 2030** 85% by 2040 **Net Zero by 2045**	50% by 2030 85% by 2040 Net Zero by 2050
Natural Gas Additions	**1,200 MW (2031)**	None
Other Clean Dispatchable Additions	**1,200 MW (2043)**	800 MW (2043)

[3] Includes 700 MW of wind generation resources added in 2020 and 2021.
[4] Includes 240 MW of generation at Meramec Energy Center that was switched from coal-fired operation to gas-fired operation in 2016.
[5] Ameren Missouri's carbon reduction goals are focused on CO_2 equivalent (CO_2e) emissions, including methane, nitrous oxide and sulfur hexafluoride and include both Scope 1 and Scope 2 emissions. Achieving net zero is contingent on the availability of some combination of developing technologies, such as CCUS, hydrogen fuel/energy storage, advanced nuclear, long-duration battery storage, and other developing or potential technologies.

As mentioned above, Ameren Missouri is accelerating its carbon reduction goals to achieve a 60% reduction from 2005 levels by 2030, 85% by 2040, and net zero emissions by 2045. This accelerated reduction in carbon emissions means that cumulative emissions over the planning horizon will be substantially reduced compared to the 2020 IRP preferred plan. As was the case with the previous 2050 net zero goal announced in 2020, the 2045 net zero goal depends on the development of new clean energy technologies that will allow the Company to ensure reliability while eliminating carbon emissions. Figure 3 shows the decline in total carbon emissions under the new Preferred Resource Plan. Figure 4 shows expected carbon intensity, carbon emissions per MWh generated, for the new Preferred Resource Plan compared to the prior preferred plan.

Figure 3: Expected Carbon Emissions

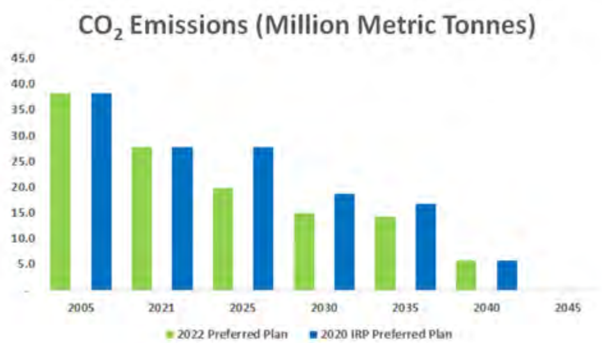
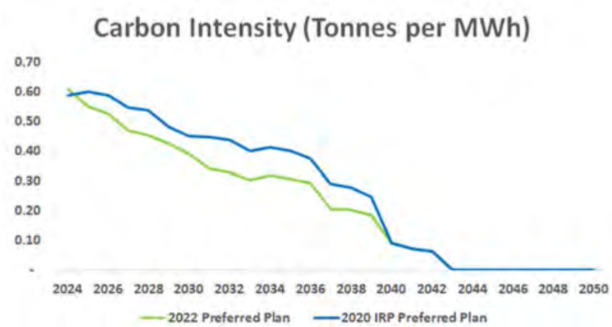


Figure 4: Expected Carbon Intensity



It should be noted that Ameren Missouri has updated its plan to include the cost to Ameren Missouri of expected future transmission system investments in MISO to integrate a significantly higher penetration of renewable wind and solar generation resources based on MISO's Long Range Transmission Planning ("LRTP") effort, the first iteration of which was published by MISO in early 2021. These investments will be critical to achieving broader decarbonization across the economy, including the electrification of transportation, industrial processes, and other uses of fossil fuels.

The Company has also performed rigorous analysis to ensure that its new Preferred Resource Plan will deliver the reliable service customers count on. This includes ensuring that the plan meets the expected requirements of MISO's proposed seasonal capacity construct, which considers differences in customer demand and electric resource capabilities on a seasonal basis in addition to the annual summer peak that has traditionally been the focus of resource adequacy. This is particularly important as the Company reflects on the challenges that were presented by Winter Storm Uri in early 2021. It also includes insights gained through the analysis of Ameren Missouri's system performed by Astrapé Consulting. This analysis looks specifically at Ameren Missouri's system and its expected reliability with different mixes of resources, accounting for the intermittent nature of wind and solar resources, operating constraints for other resources in Ameren Missouri's fleet, and support from MISO, as well as the benefits of energy efficiency and demand response. While MISO's proposed seasonal capacity construct has not yet been adopted, a focus on seasonal reliability will be critical to ensuring reliable service to customers under a wide range of weather and system conditions and constraints.

One of the hallmarks of Ameren Missouri's planning process is maintaining flexibility and developing prudent long-term plans to mitigate energy supply and reliability risks. This often ensures preferred plan provisions that reduce risk to customers and investors alike. The portfolio transition represented by the new Preferred Resource Plan is designed to maintain flexibility and mitigate risks that could otherwise result in increased costs to customers, particularly if the addition of renewable resources were delayed until a specific need for capacity was imminent. In December 2021, Ameren Missouri filed with the Missouri Public Service Commission ("MPSC") its analysis of the relative risks to customers and shareholders of the planned renewable transition in the 2020 IRP preferred plan when compared to a planned transition that reflects renewable additions only when a need for new capacity is identified. To further quantify these risks and to assist with updating the Company's assessment based on the revised timing of renewable additions in the new Preferred Resource Plan, Ameren Missouri engaged Roland Berger. Roland Berger's analysis identified a number of key risks associated with a delayed renewable transition. Certain of these risks – those that were determined to be quantifiable and significant – were quantified and included in the results of the Company's plan analysis.

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

- Submitting applications for Certificates of Convenience and Necessity ("CCNs") to the MPSC for solar generation projects.
- Applying for the creation of a Renewable Solutions program to help communities and large customers meet their sustainable energy goals.
- Issuing a new Request for Proposals ("RFP") to identify additional wind and solar project opportunities to support planned additions.
- Finalizing plans for the retirement of Rush Island Energy Center:
    - Completing the Attachment Y process with MISO.
    - Receiving a revised decision from the U.S. District Court reflecting early retirement as the means of compliance.
    - Finalizing plans for operation of the units until retirement.
    - Completing transmission system upgrades necessary to ensure reliability after retirement of the units.
- Adjusting depreciation expense for Sioux Energy Center to reflect retirement by the end of 2030 as part of the Company's next rate review.
- Filing an application with the MPSC to securitize the remaining balance in rate base and other transition costs associated with the Rush Island Energy Center.
- Conducting preliminary work for the development of new NGCC generation, including site studies, permitting, and engineering[6].

[6] Ameren Missouri intends to seek a CCN for the new NGCC generation at some time after the filing of the Company's 2023 triennial IRP, which is due by October 1, 2023.

- Continuing to provide energy efficiency and demand response programs to customers to help them manage their energy costs and reduce the need for new generation resources.

As Ameren Missouri considers new wind and solar projects to fulfill the resource needs identified in the new Preferred Resource Plan, it will be focused on ensuring a regionally diverse portfolio to mitigate any potential impacts on energy supply due to variations in weather conditions across geographical locations. With strategic and proper siting, geographic diversity allows for a smoothing effect across variable energy resources, allowing for improved reliability. Further, a geographically diverse energy portfolio is more resilient during unplanned events that would otherwise negatively impact the electrical system. With a host of viable solar generation projects currently under consideration, Ameren Missouri will also be focused on wind generation additions after 2025 to ensure a balanced portfolio designed to mitigate the variations in generating performance of wind and solar technology. This variation is due to the times when renewable energy resources are available in Missouri and surrounding states. Wind is typically available more at night and during non-summer months while solar is typically available more during the day and summer months. This difference in availability allows for more hours that energy is produced when wind and solar are combined to provide a more predictable energy generation profile. The Company will also continue to look for opportunities to pair storage resources with renewable resources to enhance reliability and flexibility.

With respect to demand-side resources, Ameren Missouri continues to evaluate the potential for additional energy efficiency and demand response resources to help customers better manage their energy consumption and to ensure that the Company is able to meet all customers' electric energy needs reliably and affordably. The Company recently commissioned a new market potential study to identify further potential for energy efficiency and demand response. As part of that market potential study, Ameren Missouri will also be evaluating the benefits of load flexibility to further enhance and ensure reliability at a reasonable cost.

As Ameren Missouri begins the initial work to add new natural gas-fired generation, it will continue to ensure that it maintains flexibility that allows the Company to alter plans as new and better information becomes available. This includes new information regarding technology, energy policy, market conditions, and changes in expected demand.

In making changes to the preferred plan, the Company’s management is mindful of how the many variables that can influence long-term resource planning may change over time. These variables include power prices, carbon prices, fuel prices, environmental regulations, load growth, generation technology costs, transmission infrastructure costs, interest rates and allowed returns on equity, retirements of generators in the U.S. power markets, and other economic and market conditions that affect the various resource alternatives. While the Company conducts robust risk analyses to account for potential changes in such variables, sometimes changes are of such a magnitude that they fall outside the expected range and could result in a significant change in the Company's preferred plan in the future. There are also other factors that must be considered, such as the presence of an enabling regulatory cost recovery framework or expectations for environmental regulation that impact the cost-effectiveness of Ameren Missouri's existing generation fleet and necessitate the consideration of options such as unit retirement or conversion. Ameren Missouri must periodically consider all these factors as it makes and adjusts its long-term resource plans.

Planning Environment

A key element of Ameren Missouri's resource planning process is monitoring the planning environment and assessing the potential impact of changes in various factors on the preferred resource plan. Since the filing of Ameren Missouri's 2020 IRP, a number of factors that may influence the complexion and performance of the Company's preferred resource plan have emerged or changed. These include policy changes, market changes, and the outcome of litigation involving Ameren Missouri generating units. Following is a discussion of each of the factors that have been considered in the Company's change to its preferred resource plan.

Rush Island NSR Litigation

In August 2021, the U.S. Court of Appeals for the Eight Circuit upheld in part a U.S. District Court finding that Ameren Missouri had violated the New Source Review ("NSR") provisions of the Clean Air Act and that a portion of the associated remedy ordered by the lower court was lawful. Specifically, the appellate court upheld the lower court's order to install flue gas desulfurization ("FGD") equipment, commonly referred to as "scrubbers" on the Rush Island coal units. The appellate court subsequently denied petitions for rehearing submitted by both the Company and the United States. In December 2021, the Company announced in a filing with the Securities and Exchange Commission its intent to seek a modification to the District Court order, allowing the Company to retire the Rush Island coal units in lieu of adding scrubber technology. That process is ongoing at the time of this filing. While the final resolution of the case is still pending, the Company expects the units to be retired within the next few years and has assumed retirement of the units at the end of 2025 for purposes of this new Preferred Resource Plan. The final retirement date will depend in part on the completion of the Attachment Y process with MISO, which is used to determine the need for new transmission infrastructure necessary to ensure reliability upon retirement of generating units and to determine the need for continued operation of generating units until such transmission infrastructure has been placed into service. Ameren Missouri does not expect any differences in the final timing for unit retirement to affect other resource decisions included in its new Preferred Resource Plan. The Company expects to file an application with the MPSC to securitize the remaining balance for the Rush Island Energy Center and other appropriate energy transition costs in the second half of 2023. Because the details of such a filing have yet to be determined, the economic impact of securitization has not been included in the Company's planning analysis. Since such an assumption would be common to all plans evaluated, this would not result in relative differences in economics between the plans evaluated.

Illinois Legislation

In September 2021, the Illinois General Assembly passed Senate Bill 2408, the Climate and Equitable Jobs Act ("CEJA"), and Governor Pritzker signed it into law on September 15, 2021. Among other things, CEJA provides for the elimination of fossil-fueled generation in Illinois by 2045. This includes approximately 1,800 MW of gas-fired simple cycle CTGs owned and operated by Ameren Missouri within the state of Illinois. While the headline date of 2045 applies to some fossil-fueled generators, Ameren Missouri's Illinois CTGs are subject to specific provisions that are expected to result in retirement of these units more quickly. First, the law requires generators owned by investor-owned utilities to be retired by January 1, 2040. Second, the law requires generators to reduce CO_2 equivalent emissions by half starting January 1, 2035. Third, the timeline for retirement is accelerated for generators in close proximity to statutorily designated Environmental Justice Communities. Of Ameren Missouri's CTG facilities in Illinois, Venice Energy Center is the only facility that is subject to this requirement. As a result, the Company expects Venice to be retired by January 1, 2030. In addition to the accelerated retirements, the Illinois CTGs are subject to emission limits in any rolling 12-month period equal to the average annual actual emissions during the calendar years 2018-2020. These limits are included in the reliability modeling performed by Astrapé Consulting and described later in this report.

Seasonal Capacity Needs

In the wake of Winter Storm Uri, the electric power industry has placed increased focus on seasonal reliability. Ameren Missouri has included consideration of seasonal capacity needs as part of its analysis supporting the selection of its new Preferred Resource Plan. On November 30, 2021, MISO filed with FERC proposed reforms to its resource adequacy construct, including the establishment of seasonal capacity accreditation and capacity auctions for each of four distinct seasons. Ameren Missouri has reviewed the proposed framework and included evaluation of the Company's capacity position for both winter and summer seasons, including assumed differences in seasonal capacity accreditation for its existing fleet of generators, using the framework proposed by MISO as an appropriate basis for consideration. For example, Ameren Missouri's CTG fleet frequently experiences gas supply constraints during the winter season that result in lower assumed capacity accreditation for those units during the winter. Capacity positions were not developed for fall and spring given the expectation that those seasons could be adequately covered if summer and winter requirements were met. FERC is expected to act on MISO's proposed reforms by the end of 2022. Ameren Missouri will continue to monitor the proceedings at FERC and incorporate any changes to the Company's resource planning process as appropriate. It is important to note that regardless of the outcome of proceedings at FERC regarding MISO's proposed seasonal capacity construct, seasonal capacity needs will continue to be a vital consideration in Ameren Missouri's resource planning process.

Capacity Prices

In April 2022, MISO released the results of its capacity auction for planning year 2022-2023, indicating that capacity prices were set to the cost of new entry ("CONE") for the North and Central regions. In the development of its 2020 IRP, Ameren Missouri adopted an approach to estimating annual market prices for capacity based on a long-term expectation for "residual pricing" that reflects the predominantly vertically integrated nature of the MISO membership. That is, because MISO members are predominantly vertically integrated utilities with IRP or other planning mechanisms designed to ensure sufficient capacity to meet resource adequacy requirements, market prices for capacity will typically reflect prices for capacity that is in excess of the aggregate demand and reserve margin requirement. These assumed market capacity prices are used to monetize long and short capacity positions in the alternative resource plans evaluated through the Company's integration and risk analysis. It is important to note that this approach does not presume that periodic spikes in capacity prices of the kind experienced in the recent MISO auction cannot occur, but rather reflects an expectation that high capacity prices will not be the norm. It is also important to note that with imminent generator retirements in Ameren Missouri's fleet, that long capacity positions are expected to be lower than they have been historically and that the Company's resource planning process is designed to minimize any short positions to less than 300 MW. As a result, assumed capacity prices are not expected to have as significant a potential impact on the relative economics of alternative resource plans as they have in the past. Ameren Missouri will continue to evaluate the potential for changes to its approach for developing assumptions for market capacity prices.

MISO Long-Range Transmission Planning

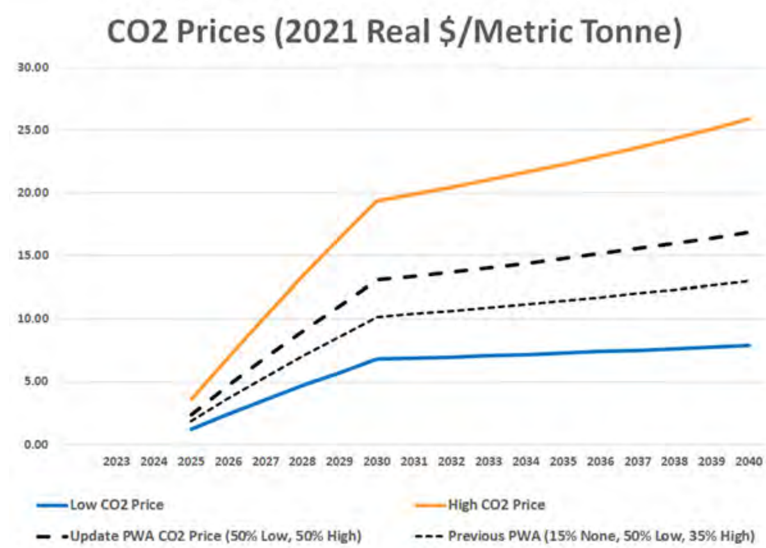
In early 2021, MISO published results of its LRTP effort, which evaluated the need for transmission infrastructure to support high levels of penetration of renewable wind and solar resources within MISO. Given expectations for continued policy direction at the state and federal levels to support greater levels of decarbonization and greater levels of renewable resources, Ameren Missouri has included estimated costs associated with the transmission infrastructure needs identified by the LRTP in its planning model assumptions. This assumption reflects an expectation that Ameren Missouri will be allocated a share of the costs of this transmission infrastructure in a manner similar to that used to allocate costs of Multi-Value Projects ("MVPs") over the last decade. As a result, this assumption is common to all the plans evaluated in the analysis and does not result in differences in costs between plans. However, it is important to recognize the potential impact of these costs on future rates, which are included in the results highlighted in this report.

CO_2 Prices

As part of the analysis to support the preferred plan change, Ameren Missouri revisited the assumptions for carbon pricing used in the 2020 IRP. In the 2020 IRP, the Company's management had assigned a 15% probability to the scenario with no carbon price, a 50% probability to the low carbon price scenario and a

35% probability to the high carbon price scenario. Following management review and discussion, management has revised the probabilities to reflect a 50% probability on each of the high and low carbon price scenarios with zero probability for the no carbon price scenario. The carbon price scenarios and the probability weighted average price under the prior and updated probabilities are shown in Figure 5.

Figure 5: Carbon Dioxide Emission Price Assumptions

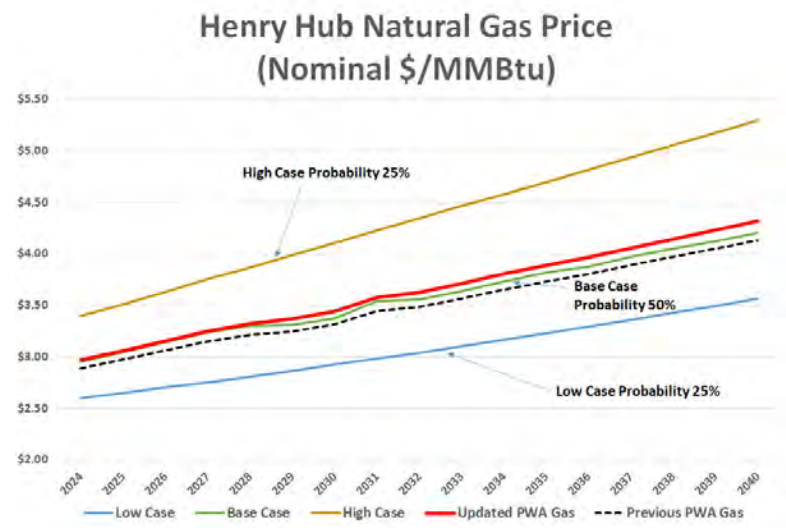


Note that as described in the 2020 IRP, the assumptions for carbon price do not presume a particular mechanism (e.g., carbon tax, cap-and-trade program, etc.) by which the carbon price is implemented. It can be explicit or implicit and may reflect expectations regarding potential regulations, including 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 it assumptions for natural gas prices, particularly in light of recent price increases. Based on management review of supply and demand fundamentals and the risk of a shift in market dynamics due to recent geopolitical events, Ameren Missouri's management has shifted the probabilities for the high, base and low gas price scenarios. Figure 6 shows the three price scenarios, the revised probabilities, the new probability-weighted average price, and the prior probability-weighted average price. Ameren Missouri continues to monitor factors that may affect assumptions for natural gas prices.

Figure 6: Natural Gas Price Assumptions



The changes in probabilities for natural gas prices and carbon prices carry through to joint probabilities for resultant power prices and are reflected in the analysis of plans described later in this report.

<u>Other Potential or Emerging Factors</u>

In addition to the planning environment factors described above, Ameren Missouri continues to monitor other factors that may influence plan performance and planning decisions. One such factor is the potential for federal energy legislation. During 2021, a number of proposals were considered in Congress to support the decarbonization of the electric industry. These included proposals for carbon taxes, clean energy standards with varying timelines and penalties/incentives, incentive programs for expansion of clean energy, and extension and expansion of tax credits for clean energy projects. While such proposals have not yet been passed by Congress, the Company continues to monitor potential legislative policies.

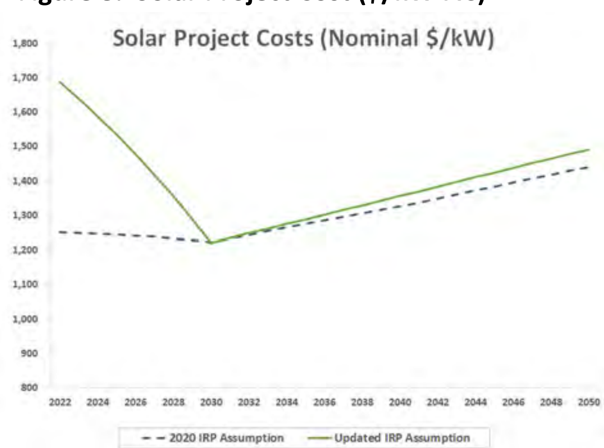
On the federal regulatory front, Ameren Missouri also continues to follow efforts to promulgate changes in regulation of power plant emissions. This includes the Environmental Protection Agency's ("EPA") recently proposed changes to the Cross-State Air Pollution Rule ("CSAPR") with respect to ozone season NOx emissions. The Company is closely following this proposed change through the review and comment period and is evaluating the potential impact of requirements on its existing fleet and the potential options for mitigation. Upon the release by EPA of a final rule, the Company will determine whether and to what extent further changes to its preferred resource plan may be warranted. As described later in this report, the Company's planned addition of solar generation provides a measure of mitigation for potential impacts to coal-fired generation during the summer ozone season, when expected solar production is higher.

Supply Side Resources

Ameren Missouri continues to monitor changes and potential changes in the market for renewable energy projects, both through its own engagement with developers and through evaluation of secondary information sources. Based on the most recent such information, Ameren Missouri has updated the assumptions for wind and solar project costs. For its updated cost assumptions, Ameren Missouri used the most recent Annual Technology Basis ("ATB") assumptions from the National Renewable Energy Laboratory ("NREL"), starting with the moderate cost scenarios for each technology and shifting the cost curves to ensure consistency with current market costs. The updated assumptions for wind and solar resources are shown in Figures 7 and 8, respectively, along with the assumptions that were used in the 2020 IRP for comparison. Both show a relatively consistent long-term cost path after 2030, with higher prices in the near term. While the assumptions for both wind and solar show an expected decline, future costs are subject to certain risks. These risks have been described and quantified by Roland Berger, as explained later in this report.

Figure 7: Wind Project Cost ($/kW)

Figure 8: Solar Project Cost ($/kW-AC)



The Company also reviewed its assumptions for battery storage costs and performance and determined that the 2020 IRP assumptions were still appropriate. In addition to changes in the assumptions for the cost of renewable resources, Ameren Missouri has also updated its assumed overnight cost for NGCC generation to $1042/kW from $1245/kW in the 2020 IRP (both in 2019 dollars).[7] This cost change reflects expectations for design and scale optimization based on review by internal subject matter experts. The alternative plans analysis described later in this report also reflects the cost of firm gas transportation to ensure reliable operation of the units in all seasons. In considering the addition of NGCC generation during the planning horizon, Ameren Missouri is mindful of the benefits and risks associated with this resource type. Following is an overview of the benefits and risks associated with NGCC generation.

[7] The 2020 IRP assumed NGCC capacity of 824 MW. Updated analysis reflects 1,200 MW.

Benefits

- Proven highly efficient technology that can produce on demand.
- Superior flexibility to fill in gaps in wind/solar production and respond to rapid changes in load and renewable production.
  - Lower minimum operating levels than coal.
  - Faster ramping response than coal – 75 MW per minute for a new H Class combined cycle plant vs. 5 MW per minute for the existing Sioux coal units.
- Less than half the carbon emissions per MWh produced compared to coal – 0.34 metric tons per MWh for a new combined cycle plant vs. 1.0 metric tons per MWh for the Sioux coal units.
- Capability to burn hydrogen blended with natural gas (20-30% hydrogen by volume today with increases expected).
- CO_2 emissions may be mitigated in the future through addition of CCUS (currently in demonstration phase).

Risks

- Exposure to regulation of CO_2 emissions (absent hydrogen and/or CCUS).
- Permitting may become more challenging over time (can be mitigated with early start).
- Requires firm fuel transportation (i.e., pipeline capacity) to ensure reliability.
- Fuel price volatility.

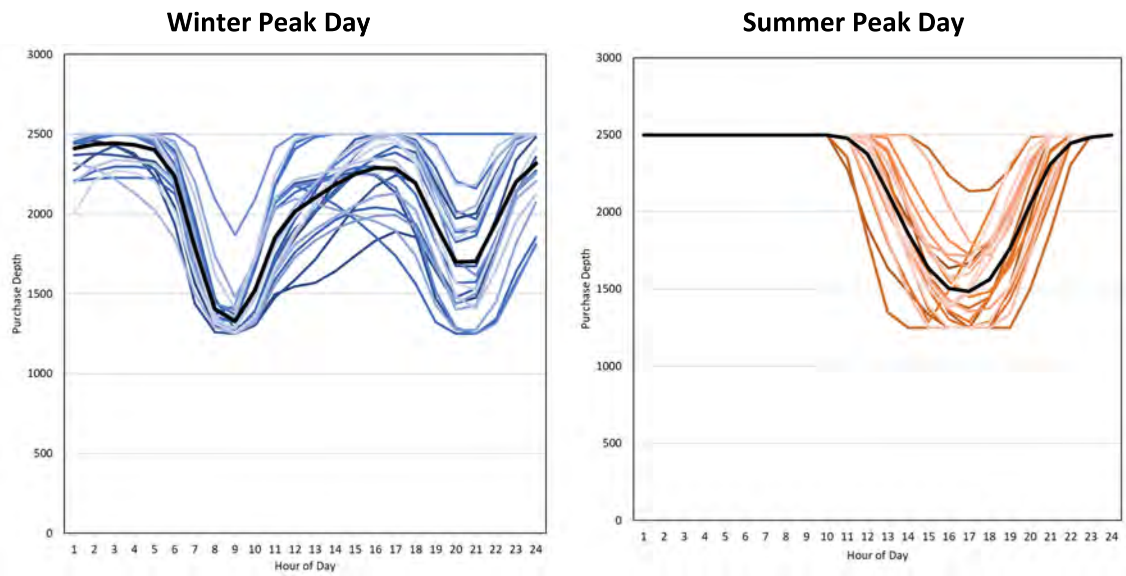
Depending on the continued development of low and no-carbon technologies, changes in fuel and power markets, and changes in climate and environmental policy, the level of operation of new NGCC and its resultant emissions could vary significantly in the future. Regardless of such potential variations in the planning environment and expected outcomes, the reliability and flexibility benefits of firm, dispatchable resources are critical to ensuring reliable and affordable electric service. The next section discusses the Company's latest analysis of reliability needs and the relative benefits of different types of resources in the context of Ameren Missouri's system.

Reliability Analysis

As dispatchable coal and gas-fired resources continue to be retired and actual and expected additions of intermittent wind and solar resources continue to rise, it has become increasingly important in resource planning to conduct more rigorous analyses of expected system reliability. To help Ameren Missouri evaluate and consider the reliability implications of resource decisions, it has engaged Astrapé Consulting to evaluate the reliability of different mixes of resources and any potential associated risks or gaps. Astrapé uses its proprietary Strategic Energy Risk Valuation Model ("SERVM") to evaluate reliability in terms of the loss-of-load expectation ("LOLE"). The SERVM model is based on a resource adequacy framework which uses history as a guide for estimating future reliability. It uses up to 40 synthetic weather scenarios developed using neural networks, Monte Carlo generator outage draws, and economic commitment and dispatch on hourly or sub-hourly (5-minute) time steps. Astrapé has provided consulting and modeling services using SERVM in multiple Regional Transmission Organizations ("RTOs") and regions across the U.S. and Canada, including MISO, Southwest Power Pool, Tennessee Valley Authority, and the California Independent System Operator.

For its analysis, Astrapé modeled the Ameren Missouri system with planned loads, including energy efficiency and demand response and an assumed level of available resource support from the rest of MISO. Ameren Missouri supplied assumptions regarding the performance characteristics of its existing resources, including forced outage rates and constraints on emission and fuel supply. Fuel constraints are most notably applied to the operation of Ameren Missouri's CTG fleet during the winter heating season when gas may not be available on the coldest days when winter peaks are highest. CTGs were assumed to be unavailable for dispatch below 20 degrees Fahrenheit. Emission constraints include the constraints on Ameren Missouri's Illinois CTG fleet pursuant to CEJA, which limits emissions of each generator during any 12-month period to the actual annual average emissions during the calendar years 2018-2020. All cases analyzed reflect market support from MISO of up to 2,500 MW off peak and 1,500 MW on peak, with separate shapes for market support in winter and summer periods as illustrated in Figure 9. Market support varied as a function of weather – summer or winter extreme days saw lower periods of external support, whereas mild weather benefitted from greater amounts. The black line in each chart represents the average market support.

Figure 9: Summer and Winter Peak Day Market Support



A base case, Case 0, was calibrated to achieve an LOLE of 0.1, which corresponds to the standard of one day in ten years used by RTOs and other reliability organizations as the basis for establishing resource adequacy metrics such as MISO's planning capacity reserve margin. This was done to provide a baseline of reliability against which to measure reliability risks for other cases and does not necessarily indicate an absolute measure of current reliability for Ameren Missouri's system.

To isolate the reliability implications of anticipated resource decisions for Ameren Missouri's resource portfolio, Astrapé evaluated ten cases, with each case focused on a given year during the planning horizon and variations of resource mix in that year. Table 2 lists the ten cases that were evaluated. Cases were designed to evaluate relative reliability risks associated with different combinations of resources and determine the magnitude of additional resources that would be needed to achieve an LOLE of 0.1. Unless stated otherwise, all incremental battery additions were assumed to be 4 hours in duration.

Table 2: Cases Evaluated for Reliability Risks

Case Name	System Year	
Case 0	2022	Current System (Callibrated to 0.1 LOLE)
Case 1	2025	Rush Island Retired; 1,200 MW Solar Added
Case 2	2025	Rush Island Retired; No Solar Added
Case 3	2030	Sioux and Venice Retired; 1,200 MW Combined Cycle; 3,100 MW total Wind and Solar
Case 4	2030	Venice Retired (Sioux Operating, No CC); 3,100 MW total Wind and Solar
Case 5	2035	Sioux and Illinois CTGs Retired; 1,200 MW CC; 4,200 MW total Wind and Solar
Case 6	2040	Sioux, 2 Labadie Units and IL CTGs Retired; 1,200 MW CC; 354 MW Batteries; 5,400 MW total Wind and Solar
Case 7	2040	Sioux, 2 Labadie Units and IL CTGs Retired; 1,800 MW CC; 354 MW Batteries; 5,400 MW total Wind and Solar
Case 8	2040	Sioux, 4 Labadie Units and IL CTGs Retired; 2,400 MW CC; 354 MW Batteries; 5,400 MW total Wind and Solar
Case 9	2040	Sioux, 4 Labadie Units and IL CTGs Retired; 3,000 MW CC; 354 MW Batteries; 5,400 MW total Wind and Solar
Case 10	2040	Sioux, 4 Labadie Units and IL CTGs Retired; 1,200 MW CC; 1,540 MW Batteries; 5,400 MW total Wind and Solar

Cases 1 and 2 were designed to test the reliability contribution of adding solar generation to Ameren Missouri's portfolio in the near term. Cases 3 and 4 were designed to test the relative reliability contributions of the existing Sioux coal units and new NGCC generation, which the Company's capacity position analysis indicated are needed upon the retirement of Sioux. Case 5 examines the incremental impact on reliability of retiring the remaining Illinois CTGs beyond Venice and adding incremental renewable generation, relative to Case 3. Cases 6 and 7 were designed to examine the further reliability implications of retiring two Labadie units and adding incremental renewables and storage to the portfolio. Finally, cases 8, 9 and 10 were designed to examine reliability contributions of different combinations of storage and NGCC generation once all coal is retired, and the full renewable buildout is complete.

The results of Astrapé's modeling are summarized in Table 3. For each case, results are shown for LOLE as well as the "Deficit Found" – i.e., the magnitude of continuously available, fully dispatchable generation, or "perfect resources,", needed to achieve 0.1 LOLE – and, alternatively, the amount of 4-hour battery storage that would be needed to achieve 0.1 LOLE. It is important to note that conditions and assumptions may change that would alter the absolute LOLE results, so the Company focuses primarily on the comparative results across cases for each timeframe. Alternative plans continue to be designed to meet capacity reserve margin requirements, including consideration of winter capacity needs under MISO's proposed seasonal capacity construct. The absolute LOLE results do, however, serve as a measure of potential reliability risk for a given case and set of assumptions.

Table 3: Astrapé Analysis Summary

Year	2022	2025	2025	2030	2030	2035	2040	2040	2040	2040	2040
Case	*0*	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
Rush Island	-	-1,178	-1,178	-1,178	-1,178	-1,178	-1,178	-1,178	-1,178	-1,178	-1,178
Sioux	-	-	-	-974	-	-974	-974	-974	-974	-974	-974
Battery Storage	-	-	-	-	-	-	354	354	354	354	1,540
CCGT	-	-	-	1,200	-	1,200	1,200	1,800	2,400	3,000	1,200
Labadie	-	-	-	-	-	-	-1,186	-1,186	-2,372	-2,372	-2,372
CT Gas	-	-	-	-491	-491	-1,765	-1,765	-1,765	-1,765	-1,765	-1,765
Solar	-	1,205	5	1,605	1,605	2,000	2,700	2,700	2,700	2,700	2,700
Wind	-	700	700	1,499	1,499	2,200	2,700	2,700	2,700	2,700	2,700
LOLE	**0.1**	0.7	1.2	0.3	1.3	0.7	1.5	0.4	1.0	0.2	2.1
Deficit Found	-	696	858	346	999	488	907	417	709	196	817
4-Hr Battery Equivalent	-	766	963	346	1,195	488	1,458	488	1,178	196	N/A

In comparing the results of Cases 1 and 2, one can see that the inclusion of 1,200 MW of solar generation provides a measure of reliability risk mitigation, reducing LOLE from 1.2 in Case 2 to 0.7 in Case 1 and reducing the need for perfect resources by 162 MW. This implies an effective load carrying capability ("ELCC")[8] of 13.5% (162 MW divided by 1,200 MW) for the 1,200 MW of solar added in Case 1. This result reflects the fact that Ameren Missouri's system is subject to potential reliability challenges during winter morning and evening periods, as illustrated in Table 4, which presents a "heat map" of LOLE by month (horizontal axis) and hour (vertical axis) under normal conditions with Ameren Missouri's fleet as constituted in 2020.[9]

Table 4: LOLE by Month and Hour (2020)

Month

2020	1	2	3	4	5	6	7	8	9	10	11	12
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

[8] ELCC is a measure of the dependable capacity output associated with a resource and is commonly used by MISO and other RTOs to determine capacity credit values assigned to wind and solar resources.
[9] The values shown in Table 4 represent the contribution to total LOLE of each hour for all days in each month.

The heat map also shows potential reliability challenges during summer peak conditions. While the addition of solar resources does improve reliability, the benefits during winter peaks is limited. Note that this limitation is also reflected in the capacity credit assigned to solar resources in the winter capacity position.

Turning to Cases 3 and 4, one can see a significant reliability benefit from the replacement of the Sioux coal units with new NGCC generation, with LOLE improving from 1.3 in Case 4 to 0.3 in Case 3. This improvement can be attributed to a combination of the greater output capability of the gas generation (1,200 MW vs. 974 MW) and better reliability (equivalent availability over 95% for gas vs. 65% for the Sioux coal units by 2030). The new gas units also provide significantly greater flexibility, with the ability to ramp output up and down more quickly than the coal units, which becomes increasingly valuable as more intermittent wind and solar generation are added to Ameren Missouri's fleet and within MISO. The results for Case 5 indicate a potential increased risk associated with the retirement of the remaining Illinois CTG fleet as more wind and solar generation are added.

Cases 6 and 7 provide an indirect comparison of gas-fired generation with battery storage resources. Case 7 starts with the same portfolio analyzed in Case 6 and adds 600 MW of NGCC generation. The result is an improvement in LOLE – 0.4 for Case 7 vs. 1.5 for Case 6. The amount of perfect resources needed is reduced by 490 MW (417 MW in Case 7 vs. 907 MW in Case 6), and the equivalent amount of incremental 4-hour battery storage is reduced by 970 MW (488 MW in Case 7 vs. 1,458 MW in Case 6). This indicates that the ELCC for additional batteries beyond the 842 MW (354 MW plus 488 MW) included in Case 7 is roughly 50% (490 MW divided by 970 MW) of the maximum rated output for the batteries. This highlights an important consideration with respect to the deployment of battery storage, the reliability benefit of which depends on the net load shape (load less wind and solar generation) for a given system.

Figure 10 shows net load for a summer day and a winter day for the modeled 2030 renewable portfolio (~3,100 MW of wind and solar) with variations in output based on 39 historical weather years. The expected net load is indicated by the solid black line in each chart. The winter net load shape indicates a more limited role for storage resources than is indicated by the summer net load shape, with a relatively flatter net load, and thus a reduced opportunity to shift load to other times of day. As a result, one can see diminishing returns in terms of reliability for additional battery storage past a certain point. These diminishing returns are illustrated more explicitly in Figure 11, which shows the marginal and average ELCC for battery storage as a function of installed 4-hour battery capacity with a total of 5,400 MW of wind and solar resources. Figures 12 and 13 show samples of the variations in solar and wind production, respectively, for the first week in August across 39 weather years that underlie the summer and winter peak day net loads shown in Figure 10.

Figure 10: Summer/Winter Day Net Load with ~3100MW Renewables (2030)

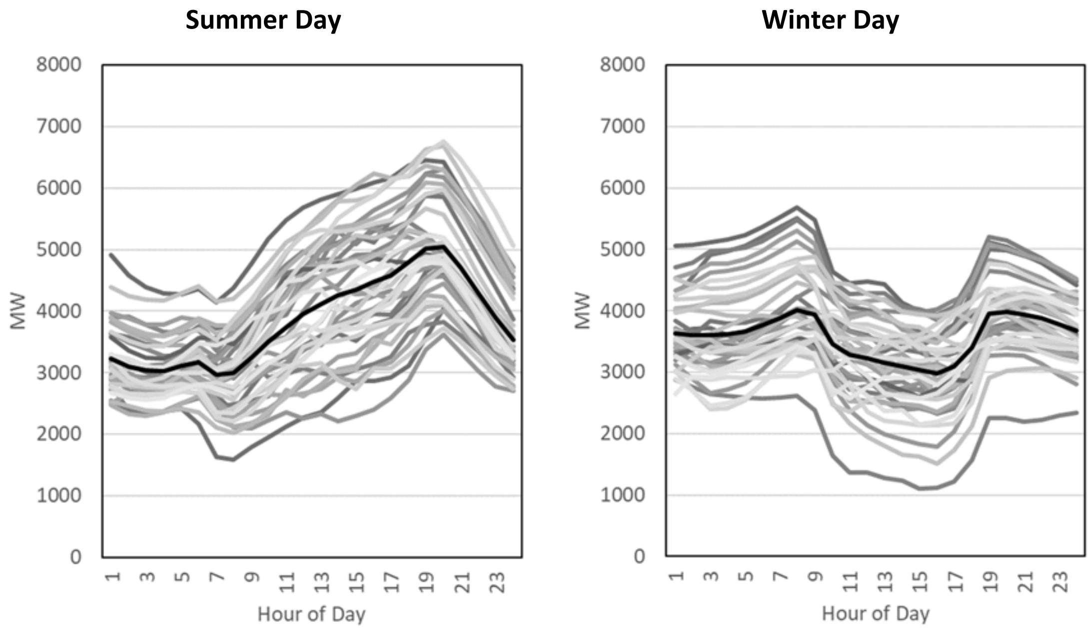
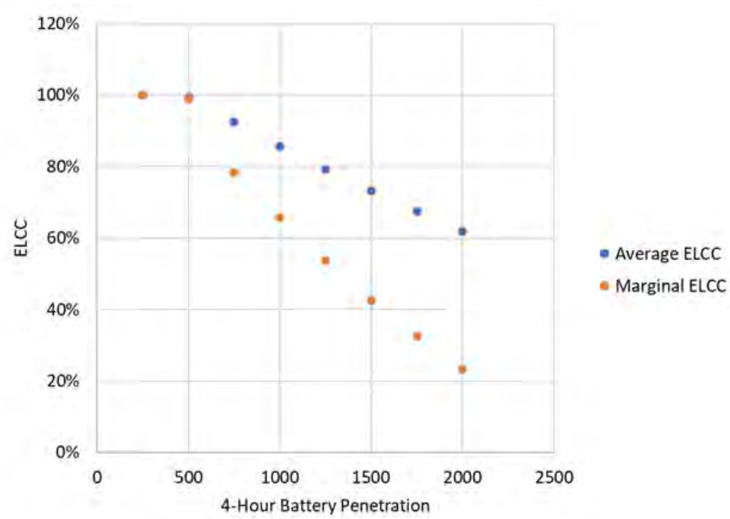


Figure 11: Benefit from Additional Battery Storage



As Figure 11 shows, once aggregate battery capacity reaches about 500 MW, the marginal benefit of additional battery storage begins to decline. As a result, meeting further reliability needs with battery storage as additional renewable resources are added and dispatchable resources are retired becomes increasingly more costly and/or dependent on significant improvements in battery storage technology. The insights discussed here on the diminishing returns of battery storage can also be applied to the incremental benefits of demand response and rate structures like time-of-use rates. These insights also indicate the potential for benefits of such programs and rate structures, along with battery storage resources, to "cannibalize" one another. That is, deployment of one such resource may reduce the potential benefits of other similar resources. This will be a focus area for continued resource planning efforts.

Figure 12: Solar Generation – First Week of August

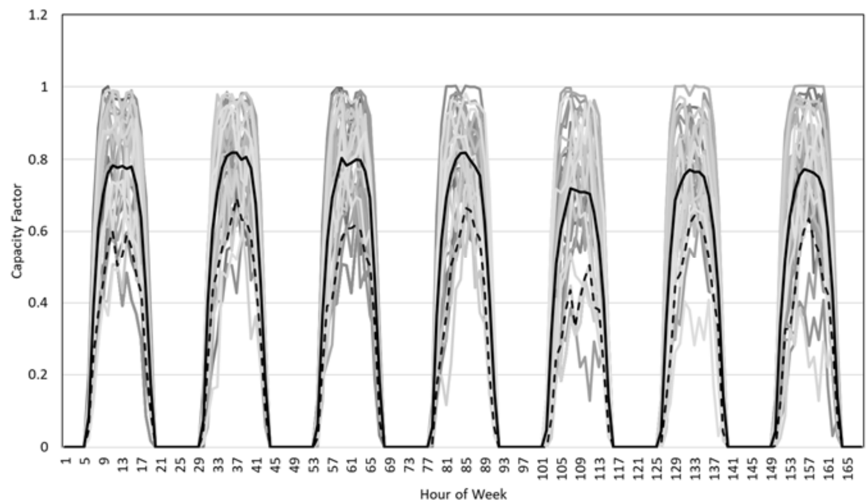
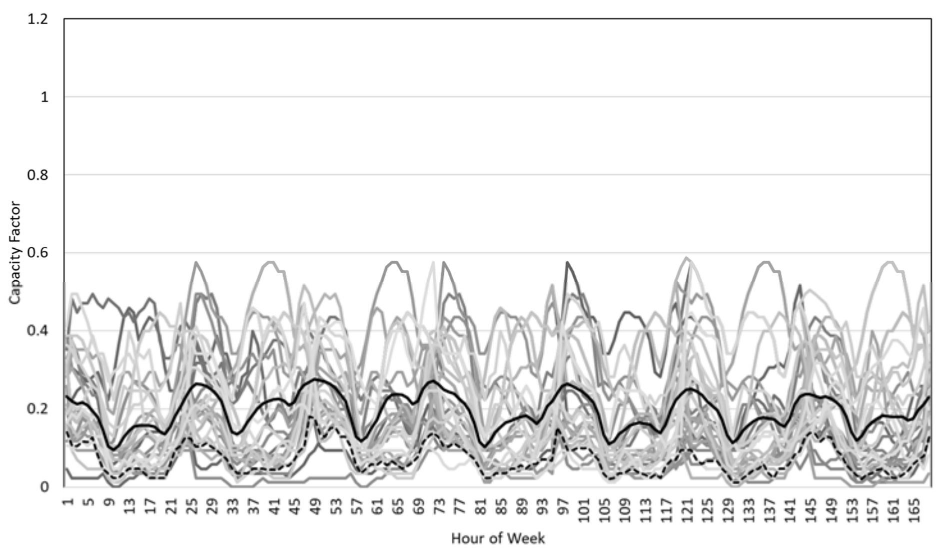


Figure 13: Wind Generation – First Week of August



Turning to the last set of cases, Cases 8-10, the Company examines the relative reliability benefits of gas-fired resources and battery storage in the context of the full deployment of renewable resources and the retirement of all coal-fired generation in Ameren Missouri's fleet. Case 9 starts with the portfolio modeled in Case 8 and adds 600 MW of NGCC generation, resulting in an improvement in LOLE from 1.0 to 0.2 and a reduction in the need for perfect resources by 513 MW. In contrast, Case 10 limits NGCC capacity to 1,200 MW and includes a total of 1,540 MW of battery storage, increasing LOLE to 2.1 and increasing the amount of perfect resources needed to 817 MW. Notably, the SERVM model could not solve for sufficient additional battery storage to achieve 0.1 LOLE, further demonstrating the limits of benefits resulting from greater levels of short-duration (i.e., 4-hour) battery storage and the benefits of dispatchable resources such as NGCC generation. It is clear that given this storage penetration on the Ameren Missouri system, firm resources or longer duration battery storage will be necessary to achieve resource adequacy targets.

The reliability analysis described here provides useful insights and guidance as the Company thinks about the continued transition of Ameren Missouri's resource portfolio. Ameren Missouri will continue to employ this kind of rigorous reliability analysis to inform Ameren Missouri's resource planning efforts, including the evaluation of reliability benefits of demand-side resources. Ameren Missouri will also continue to engage with MISO's resource adequacy efforts to ensure that the framework continues to provide necessary reliability for customers and useful guidance for long-term resource planning.

Renewable Transition Risk Analysis

Renewable resources will play a critical role in the transition of Ameren Missouri's generation portfolio. Renewable resources are an abundant source of clean energy and can be deployed in manageable increments. The 2020 IRP indicated a need for 5,400 MW of new wind and solar generation, and the new Preferred Resource Plan retains that key element of portfolio transition. The 2020 IRP described a host of risks inherent in waiting until Ameren Missouri is nearing a capacity shortfall and then attempting to rapidly deploy thousands of megawatts of renewable energy resources. In December 2021, Ameren Missouri filed additional analysis of the relative risks to customers and shareholder of such a large and rapid deployment. To support further investigation and quantification of the risks faced by customers, Ameren Missouri engaged Roland Berger, a consulting firm with extensive experience in electric utility planning and analysis. Ameren Missouri has integrated the results of Roland Berger's work into its resource plan analysis, as described later in this report. In this section, the Company describes its updated assessment of transition risks and the work performed by Roland Berger to characterize and quantify certain of these risks. Roland Berger's report is attached to this report as Appendix A.

The key question at hand in performing the transition risk assessment is whether customers, investors, communities, and the environment are best served by a continuous and incremental deployment of renewable resources over time or by an approach in which renewable resources are only added at the time of a need for capacity to meet load and planning reserve margin requirements. As was the case with the 2020 IRP, Ameren Missouri has evaluated two different alternative resource plans – one representing each of these two different approaches to renewable transition. These plans formed the basis for the Company's updated risk analysis and the basis for the risk assessment performed by Roland Berger. The resource timelines in Figures 14 and 15 illustrate, respectively, the key elements of the two plans – the "Renewable Transition Plan" and the "Capacity Need Plan" – with the key difference between the two plans being the timing of renewable additions.

Figure 14: Renewable Transition (Preferred) Plan Resource Timeline

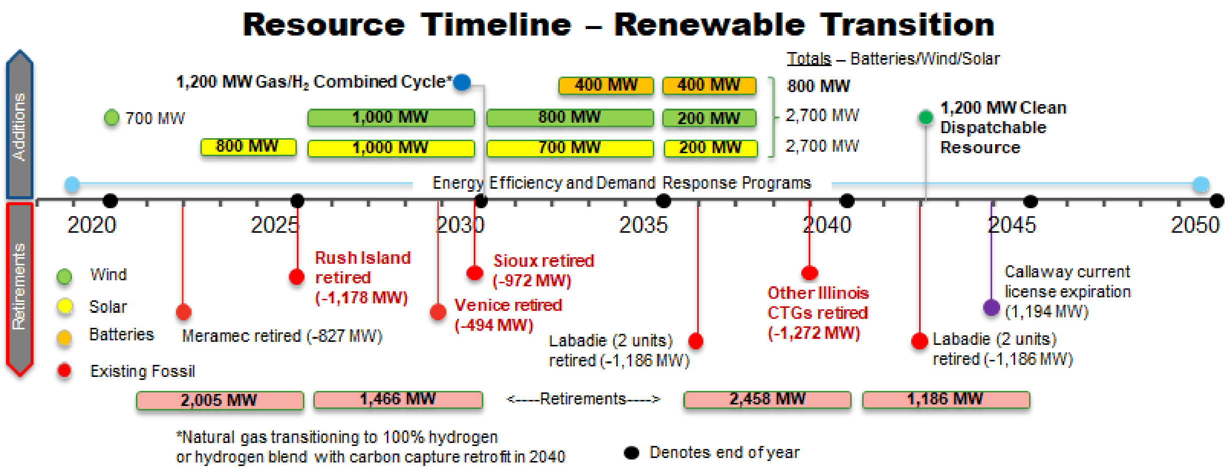
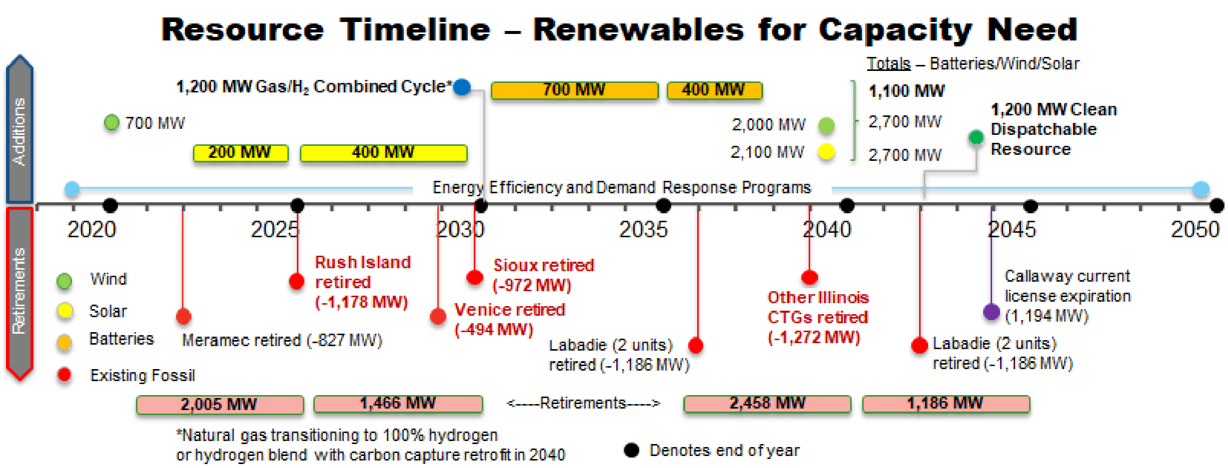


Figure 15: Capacity Need Plan Resource Timeline



The Renewable Transition Plan includes a sustained series of investments in wind and solar generation resources over the next 20 years. This sustained approach provides substantial mitigation of risks associated with the inevitable transition of Ameren Missouri's generation portfolio to cleaner sources of electricity. Such risks include risks associated with expectations of a price on carbon emissions and the resulting impact on the market price for power. They also include risks of implementation, including project development and construction, and siting and construction of enabling transmission investments, all of which are complex and challenging, as experience in the industry has shown. A sustained transition also provides opportunities to capitalize on more attractive projects that may not be available in the future, and guards against rapid changes to other portions of the generation portfolio that may result from changes in energy policy or market conditions, such as a federal clean energy standard, increased requirements under Missouri's Renewable Energy Standard, or changes in regulations targeting coal generation emissions. Another benefit of a sustained transition is the potential for financing cost advantages available to utilities that demonstrate a commitment to portfolio transition, including the potential for green bonds. Finally, a sustained transition supports ongoing operational learnings to ensure continued system reliability as Ameren Missouri and the entire U.S. power industry significantly increase their reliance on intermittent renewable resources and reduce overall carbon emissions. The risk mitigation provided by the planned sustained transition could not be provided by a plan that reflects deployment of new renewable resources only when new capacity is expected to be needed, which the new Preferred Resource Plan estimates would not occur until more than 15 years from now.

To provide important context regarding the Company’s risk assessment, it is important to think about the rationale for the planned transition represented in the Renewable Transition Plan and the risks of delaying that transition. While certain risks may prove over time to be more significant than others, the approach represented in the Renewable Transition Plan addresses them collectively and in a manner that ensures flexibility to adjust to changing conditions so the Company can continue to ensure reliable and affordable electric service for its customers. The key risks are:

- Changes in Energy Policy – The Biden administration has maintained a focus on transitioning the U.S. power system to net zero carbon emissions by 2035 through a combination of legislative and regulatory action. The enactment of federal or state policies, such as Clean Energy Standards ("CES"), changes to state Renewable Energy Standards ("RES"), or the imposition of an explicit price or tax on carbon emissions continues to receive serious attention. Such policies, which could be enacted in any number of combinations, would likely further accelerate the need for renewable resources and challenge the supply chains for labor, equipment and other goods and services that are needed for the deployment of renewable resources. They could also necessitate further acceleration of the retirement of coal-fired resources, resulting in a need for new energy resources much sooner than otherwise expected. While the outcome of potential legislative efforts at the federal level remains uncertain, the appetite for policies, both legislative and regulatory, encouraging a more rapid transition continues to remain strong. Policy changes could also be implemented through regulation under existing law. One example is the proposed revision to the CSAPR ozone season NOx regulations, which is expected to be finalized later this year. Ameren Missouri will be evaluating compliance options once a final rule is published. Finally, renewable tax credit extension and/or expansion has been considered in legislative proposals and could provide additional economic benefits for a more distributed transition to renewable resources.

- Carbon Pricing – As demonstrated in the Company's 2020 IRP filing, the economics of various resources are sensitive to assumptions for carbon emission prices and may drive consideration of changes to the timing of resource retirements and additions. This is particularly true for coal-fired resources but is also significant for renewable resources which benefit from the inclusion of such charges in the market price of power. In light of this reality, while the Renewable Transition Plan represents a purposeful balance of risks and benefits based on reasonable assumptions today, that may change. The carbon price assumptions used for the Company's resource plan analysis are shown in the Planning Environment section of this report.

- Implementation Risks – The potential challenges of deploying over 5,000 MW of wind and solar resources should not be underestimated, and such challenges have been evident in the Company's implementation of new resources already. Potential challenges are present in every stage of implementation, including project planning, siting, permitting, contract negotiation, construction, commissioning, testing and transmission interconnection. Waiting to begin the deployment of renewable resources allows these potential challenges to compound, particularly in the context of any nationwide clean energy policies that may be enacted. As previously mentioned, the Biden administration has maintained a focus on transitioning the U.S. power system to net zero carbon emissions by 2035 through a combination of legislative and regulatory action. Should those efforts or subsequent such efforts be successful, the challenges of implementation will be further magnified. Waiting to begin deployment of renewable resources also risks lost opportunities with respect to higher quality projects that may not be available later.

- Reliability Risks – Deployment of over 5,000 MW of new wind and solar resources also requires a particularly deep focus on integration and reliable operation of these new renewable generation resources to ensure the Company can continue to provide the reliable energy supply upon which all its customers depend. The experience of Texas and other regions during the winter of 2020-2021 highlights the need to ensure that resources, systems, regulatory processes, and market mechanisms are in place and properly coordinated to ensure reliability of critical energy services to customers. Other lower probability, high impact events must be considered to ensure reliability at the most critical times. It is therefore vitally important to deploy new renewable generation in a continuous and balanced manner to allow for operational learnings over an extended period, while existing coal-fired generation is available to provide reliability services. Through that methodical deployment of new renewable resources, the Company can fully understand how best to optimally and reliably operate the renewable generation portfolio that will replace much of its current generation portfolio, and system operators and regulators can implement necessary measures to ensure reliability with confidence.

- Financing Risks – Investors and financial analysts continue to be focused on utility company plans and progress on portfolio transition and sustainability. Access to lower cost debt may become increasingly tied to a utility's ability to demonstrate concrete plans and progress on transition and establishing and meeting sustainability goals. At the same time, we see indications that financing costs are likely to rise in the future, so taking advantage of lower cost financing in the near term can provide economic benefits to customers over the long term. Ameren Missouri has included consideration of financing cost risks in its transition risk analysis and economic analysis of alternative plans, as described later in this report.

As mentioned previously, Ameren Missouri engaged Roland Berger to analyze, and where possible quantify, key risks associated with a delayed transition. Table 5 lists the risks evaluated by Roland Berger and the extent to which quantification of each could impact PVRR. Note that some risks could have a more significant impact on revenue requirements and rates than has been quantified, but the ability to quantify them to a greater degree is limited. For example, as more and more renewable projects are executed in

MISO, the challenges of ever greater needs for transmission infrastructure could limit the ability to connect new projects. Transmission congestion issues can also fluctuate over time as new generation and transmission infrastructure are added to the grid.

Table 5: Key Risks of Delayed Transition

Variable		Assessment	Estimated Impact on PVRR
Renewables costs	Land availability	• We expect lower capacity factors for wind and solar in the "Capacity when needed" plan given expectation that more attractive areas are limited and will continue to be built out	●
	Financing costs	• Ameren will likely face higher financing costs under its "Capacity when needed" plan due to limited investor willingness to finance CO2 heavy generation portfolios	●
	Tax credits	• The proposal in the Build Back Better plan to extend the PTC and ITC may still pass separately	●
	Equipment costs	• Solar and wind equipment cost declines likely to be less pronounced than what NREL ATB predicts • Assumed step-change in wind technology performance not be applicable to high-capacity factor areas such as the U.S. Midwest	◕
	Interconnection costs	• Available MISO and SPP interconnection data indicate a range of $50 / kW to $200 per kW • We expect longer interconnection distances as more attractive land near transmission is developed over time	◑
	MISO congestion	• The relationship between congestion and transmission capacity appears to be inconclusive • SMEs suggest that there are multiple drivers for congestion beyond transmission capacity and project development • Our analysis of congestion pricing indicates a low potential impact to PVRR	◔
	Labor costs and availability	• The relationship between labor shortfalls and construction and O&M costs is not significant enough to change CapEx or O&M assumptions	○
	Operational learnings	• The relationship between operational efficiency and O&M costs is not significant enough to change operating cost assumptions	○

○ Low Impact ● High Impact

Table 6: Incremental Cost of Delayed Transition

Risk Variable	Description	Change in PVRR[10]
Financing Costs	Fossil-heavy generation portfolios likely to have higher financing costs than cleaner and less carbon-intensive portfolios	$ 292 million
Land availability	Continued renewable build out will make "good land" scarcer over time, limiting capacity factors for wind	$ 247 million
Wind equipment Cost	Wind equipment cost declines and performance improvements may be less pronounced than NREL ATB assumes	$ 122 million
Solar equipment cost	Onshoring of solar PV equipment manufacturing as consequence of trade relations with China may result in higher costs	$ 59 million
Tax Credits	Extension of ITC and PTC per the proposal in the Build Back Better plan done through separate congressional action	$ 339 million

Table 6 shows the estimated impact on relative PVRR of the Capacity Need Plan (i.e., wait until there is expected to be a capacity shortfall and then rapidly build-out large quantities of renewables) compared to the Renewable Transition Plan (as reflected in the new Preferred Resource Plan). The risks and PVRR

[10] Positive PVRR change indicates that the Capacity Need Plan gets relatively more expensive than the Renewable Transition Plan over study period.

impacts shown in Table 6 are described in detail in Roland Berger's report in Appendix A. The first four risks listed – all but "Tax Credits" – are included in the Company's economic analysis of alternative plans. The PVRR impact of "Tax Credits" was excluded since it is contingent on action by Congress. Should Congress pass tax credit extensions, the value of extended tax credits will mean there are additional benefits from following the Renewable Transition Plan.

A key element of Ameren Missouri's resource planning process is the assessment of risks that could affect the costs of resource decisions for customers. Ameren Missouri analyzes such risks in accordance with the Commission's IRP rules, specifically the risk analysis provisions set forth in 20 CSR 4240-22.060, and describes the assumptions, analytical approach and results of this analysis in Chapters 9 and 10 of the 2020 IRP filing. The 2020 IRP risk analysis considered a number of variables, or uncertain factors, which might have a significant impact on the performance of the various alternative resource plans the Company evaluated. The Company considers both dependent and independent uncertain factors. Dependent uncertain factors are those that exhibit a strong interdependent relationship with other uncertain factors. These generally include variables that have a direct bearing on the market price of power – natural gas prices, prices on carbon emissions, and the growth of demand across the market. Independent uncertain factors are those that do not exhibit a strong interdependence with other uncertain factors. These generally include financing costs (interest and equity returns), capital costs for new resources, resource operating characteristics (e.g., forced outage rates, variable O&M expense), DSM costs and energy savings, and prices for non-carbon emissions (e.g., SO_2, NOx). Of the uncertain factors evaluated, several were found to be critical to the comparative evaluation of alternative resource plans. They include dependent uncertain factors – natural gas prices and carbon emission prices – that together define nine scenarios for power market prices. They also include two independent uncertain factors – load growth and DSM program costs. Ameren Missouri continues to include these uncertain factors as part of the analysis of plans in support of this Preferred Resource Plan change notification. For more on the testing and selection of critical uncertain factors, see Chapter 9 of the 2020 IRP.

Shareholder Risks[11]

IRP risk analysis is focused on risks from a customer perspective. Investor risks are considered in the assessment of plans through the financial and regulatory risk objective included in the Company’s scorecard evaluation of alternative resource plans using both quantitative and qualitative factors. These factors include quantification and comparison of free cash flows and qualitative assessments of risks associated with financing and recovery of potential stranded costs. To provide more direct quantification of shareholder risks associated with the planned portfolio transition, the Company can consider categories of risks to return of and return on the investment by shareholders. Key categories of such risks are:

- Project Management Risk – the risk of mismanagement of project execution resulting in disallowances from rate recovery.

[11] The Company also addressed these risks in its December 15, 2021*, Response Regarding Detailed Analysis Required by the Commission's Order Regarding 2020 Integrated Resource Plan*, File No. EO-2021-0021.

- Retail Sales Risk – the risk that retail sales through which investment returns are realized do not materialize as expected.
- Regulatory Risk – the risk that inefficiencies in the regulatory and ratemaking processes will prevent full realization of expected and/or allowed rates of return.

Shareholder risk can be quantified in general by considering the capital revenue requirements associated with the investments. The PVRR for the investment component of the planned renewable transition is approximately $4.5 billion. A recovery loss of 2-5% of this revenue requirement would be $90-225 million.

For additional context, the first-year revenue requirement for the capital costs of a wind project with a 30-year economic life is approximately 13% of the initial investment, and the average annual capital revenue requirement over the life of the wind project is approximately 8% of the initial investment. This indicates that even small delays in the recovery of new wind resource investments could have significant impacts on investor returns even absent the other risks described above. The same would be true for solar resource investments. While shareholder risks cannot be more specifically defined or estimated with any degree of confidence, the analysis presented here provides an indication of the potential magnitude of the collective range of risks to shareholders that can be compared to the customer risks described earlier in this document.

Alternative Plans and Risk Analysis

To assess key alternatives in light of the planning environment changes described earlier in this report, Ameren Missouri has evaluated several alternative resource plans. In addition, the 2020 IRP preferred plan was also analyzed under the updated assumptions described in this report for comparison to the new Preferred Resource Plan across the various performance measures. The plans analyzed are:

A. 2020 IRP Preferred Plan
B. Renewable Transition with Sioux retired at the end of 2028 and 1,200 MW NGCC generation in service at the beginning of 2029
C. Renewable Transition with Sioux retired at the end of 2030 and 1,200 MW NGCC generation in service at the beginning of 2031
D. Renewable Transition with Sioux retired at the end of 2033 and 1,200 MW NGCC generation in service at the beginning of 2034
E. Renewables for Capacity Need with Sioux retired at the end of 2030 and 1,200 MW NGCC generation in service at the beginning of 2031
F. Renewable Transition with Maximum Achievable Potential ("MAP") demand side management ("DSM"), Sioux retired at the end of 2030 and 1,200 MW NGCC generation in service at the beginning of 2031

Each of Plan B, C, D and F include the renewable additions shown in Figure 12. Plan E includes the renewable additions shown in Figure 13. Retirement of Rush Island Energy Center was assumed at the end of 2025 for analysis purposes, pending final action by the U.S. District Court. Variation from that retirement date is not expected to affect other resource decisions. Plans A, B, C, D and E each include Realistic Achievable Potential ("RAP") DSM. Plans B, C, and D were used to inform decisions around the concurrent retirement of the existing Sioux coal units and the addition of NGCC generation in light of the results of the reliability analysis performed by Astrapé and described earlier in this report. The decisions regarding that concurrent timing include consideration of the time needed to implement new NGCC generation and the risks of operating the Sioux coal units beyond the prior expected retirement date of 2028.

It should be noted that Plan F included NGCC generation in 2031 just as Plans C and E do because the additional load reduction from MAP DSM is not sufficient to avoid the NGCC addition. Ameren Missouri has initiated a new DSM market potential study, which is expected to be completed in the first quarter of 2023 and will be a key input for the Company's 2023 IRP, which is due by October 1st of that year. As part of the 2023 IRP analysis, Ameren Missouri will assess the need for new capacity under a range of options for demand-side resources, including MAP energy efficiency and demand response. Whether or not higher levels of DSM than that reflected in the Company's most recent estimates of RAP DSM are both achievable and sufficient to defer, reduce, or eliminate the need for dispatchable generation resources, Ameren Missouri expects the need for significant new renewable energy resources to remain.[12]

Table 7: PVRR Results ($ Million)

	PVRR and PVRR Differences ($MM)	0%	50%	50%	<<<Probabilities
		No CO_2 Price	Low CO_2 Price	High CO_2 Price	Prob. Wtd.
A	2020 IRP Preferred Plan	75,361	76,594	78,946	77,770
B	Renewable Transition - Sioux 2028	77,277	78,172	79,934	79,053
C	Renewable Transition - Sioux 2030	77,181	78,116	79,933	79,024
D	Renewable Transition - Sioux 2033	77,092	78,085	79,973	79,029
E	Renewables for Capacity Need	77,307	78,502	80,811	79,656
F	Renewable Transition - Sioux 2028 - MAP	78,302	79,157	80,804	79,981
	Difference (Plan C vs. Plan E)	(126)	(386)	(878)	(632)

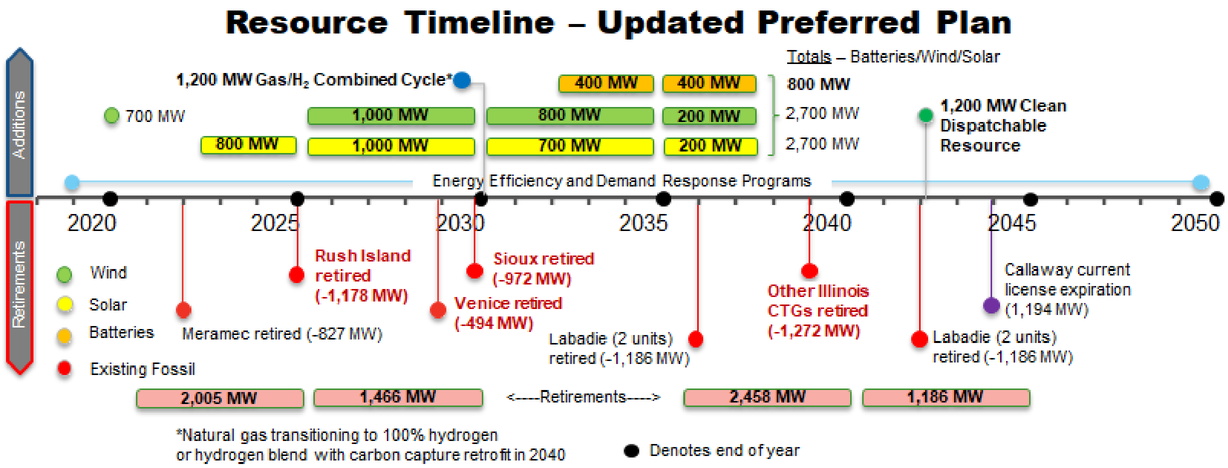
PVRR results for the six plans are shown in Table 7. Also shown is the difference in the PVRR results for Plans C and E, which differ by the timing of renewable additions, with all other resource retirements and additions being the same. Note that results are shown with no carbon price for reference only. As discussed previously in this report, management has updated the carbon price assumptions to reflect a 50% probability for each of the High and Low Carbon Price scenarios. As the PVRR differences show, the Renewable Transition Plan (Plan C) results in lower costs than the Capacity Need Plan (Plan E).

Preferred Resource Plan and Implementation

Based on the analysis of alternative plans and consideration of Ameren Missouri's planning objectives, management has selected Plan C as its new Preferred Resource Plan as shown in Figure 16.

[12] Assessing sufficiency must also include the need for resource flexibility, which Ameren Missouri will continue to evaluate through its current DSM market potential study and its ongoing reliability analysis.

Figure 16



Notifications of changes in a utility's Preferred Resource Plan are governed by 20 CSR 4240-22.080(12). This section requires that an electric utility notify the PSC in writing when its Preferred Resource Plan and/or Acquisition Strategy is no longer appropriate and that the notification must include the following:

- A description of all the changes to the Preferred Resource Plan and/or Acquisition Strategy.
- The impact of each change on the present value of revenue requirement and all other performance measures specified the last filing pursuant to 20 CSR 4240-22.080.
- The rationale for each change.

The Company is also required to file for review a revised Resource Acquisition Strategy, including specification of the ranges or combinations of outcomes of critical uncertain factors that define the limits within which the new Preferred Resource Plan remains appropriate.

Following is the specific information required for inclusion with the notification of a change in Preferred Resource Plan and/or Acquisition Strategy.

Description of (and Rationale for) Changes in Preferred Resource Plan and/or Acquisition Strategy

- **Early retirement of Rush Island Energy Center** – Ameren Missouri announced in December 2021 that it would seek a revised order from the District Court to change the required remedy resulting from the NSR litigation to retirement of the units rather than adding FGD equipment. Because the outcome of this process was not known at the time analysis for this Preferred Resource Plan change was performed, the retirement date was assumed to be the end of 2025. Any variance from this assumption is not expected to affect the other resource decisions reflected in the new Preferred Resource Plan.

- **Accelerated retirement of Venice Energy Center** – Pursuant to the requirements of Illinois law under CEJA, including the fact that Venice is located near an Environmental Justice Community as defined in the law, the units at Venice will be retired by the end of 2029.
- **Accelerated retirement of other Illinois CTGs** – Also pursuant to the requirements of CEJA, Ameren Missouri plans to retire the remaining Illinois CTGs by the end of 2039. This includes the units at the Goose Creek, Raccoon Creek, Pinckneyville and Kindmundy Energy Centers.
- **Delayed retirement of Sioux Energy Center** – In conjunction with the addition of NGCC generation and in light of the reliability risks identified and described herein, Ameren Missouri has chosen to delay in the retirement of Sioux Energy Center by two years from 2028 to 2030.
- **Addition of 1,200 MW of new NGCC generation** – To meet capacity planning needs and ensure reliability and flexibility of Ameren Missouri's portfolio to integrate the included wind and solar additions, the new Preferred Resource Plan includes the addition of 1,200 MW of NGCC generation in 2031, with plans to switch to hydrogen fuel and/or blend hydrogen fuel with natural gas and install carbon capture technology by 2040.
- **Changes in the timing of wind and solar additions** – To reflect current market conditions, available projects, and a more sustained plan for project implementation, the timing of wind and solar additions has been updated. The planned additions still result in total renewable generation of 5,400 MW, including the 700 MW of wind placed in service in 2020 and 2021.
- **Addition of 800 MW of battery storage resources** – To ensure sufficient capacity while limiting risks associated with additional gas-fired generation and recognizing the unique contributions of storage resources, Ameren Missouri has included 800 MW of battery storage resources in its new Preferred Resource Plan. Future IRP analyses will include comparisons of load-shifting resources, including energy storage, demand response, and demand-side rates to ensure a reasonable mix and aggregate deployment of such resources.
- **Increase from 800 MW to 1,200 MW of clean dispatchable resources in 2043** – While outside the 20-year planning horizon, Ameren Missouri is mindful of the need for new resources in the longer term as the last remaining coal-fired units are retired. With the Company's goal of achieving net zero carbon emissions by 2045, Ameren Missouri has assumed new resources added in this timeframe will be zero-emitting resources. The need for dispatchable capacity to ensure reliability and flexibility necessitate the increase from 800 MW in the prior preferred plan to 1,200 MW in the new Preferred Resource Plan.

Impact of Changes on Present Value of Revenue Requirements (PVRR) and Other Performance Measures

Ameren Missouri modeled its updated Preferred Resource Plan using the same model setup used for its 2020 IRP with updated assumptions as described in this report. A summary of the results for key performance measures for the new vs. prior Preferred Resource Plan is shown in Table 8. As the table shows, PVRR for the 2023-2050 period is increased by approximately $1.2 billion, or about 1.6%.

Table 8: Performance Measures Comparison

Performance Measures (2023-2050)	Prior Preferred Plan 2020 IRP	New Preferred Plan 2022 Update	Change	% Change
PVRR, $MM	$77,770	$79,024	$1,254	1.6%
Levelized Annual Rates, $/kWh	$18.66	$18.96	$0	1.6%
PV of Free Cash Flow, $MM	$6,638	$6,356	-$281	-4.2%
Cumulative CO_2 Emissions, Million Metric Tons	342	285	-57	-16.8%
PV of Probable Environmental Costs, $MM	$2,594	$2,524	-$70	-2.7%
Energy Savings, GWh	95,296	95,296	0	0.0%
Direct Jobs, FTE-Years	34,356	40,284	5,928	17.3%

(Note: "Net Jobs" reflects the total FTE-Years across the planning horizon for all direct jobs associated with implementation of new resources, including construction and operation {1 job over 10 years = 10 FTE years}; this measure does not reflect the number of new jobs produced at any particular point in time, which would be much lower)

Detailed Description of Revised Preferred Resource Plan and Acquisition Strategy

As discussed in the Company's 2020 IRP filing, the Resource Acquisition Strategy includes three main elements – the preferred resource plan, contingency planning, and an implementation plan for the years 2022-2024. The Preferred Resource Plan is described above.

Contingency Planning and Critical Uncertain Factors

Contingency plans may be triggered by either a change in critical uncertain factors or a change in other considerations that are critical to meeting the fundamental objective of the resource planning process. Based on prior analysis completed for the Company's 2020 IRP, critical uncertain factors include carbon prices, natural gas prices, load growth and DSM costs/performance. The new Preferred Resource Plan includes several near-term actions that will be pursued as part of the Company's implementation plan prior to the filing of the next triennial IRP filing (due by October 1, 2023). In light of this, contingencies are limited pending that new triennial filing.

Because implementation of renewable projects is subject to unique uncertainties and risks, Ameren Missouri seeks to maintain a steady pipeline of potential projects for implementation to mitigate these risks. This is consistent with the evaluation of transition risk described earlier in this report and for which Roland Berger has provided quantitative analysis. Regarding demand-side resources, Ameren Missouri has initiated a new DSM market potential study that will be a key input for the Company's 2023 IRP and is currently seeking new estimates of near-term demand-side resource potential through a direct market solicitation. These actions will continue to ensure that Ameren Missouri is identifying demand-side resource potential on a timely basis and is able to evaluate any impacts on other aspects of its resource acquisition strategy. Finally, the addition of NGCC generation is closely tied to the retirement of the existing coal units at Sioux Energy center. As implementation proceeds, it may be necessary to modify the final timing of unit retirements and additions to ensure system reliability during the transition. As shown in the PVRR analysis of alternative plans, changing the timing of Sioux retirement and NGCC additions has a relatively small impact on PVRR.

Because Ameren Missouri will be making its next triennial IRP filing in 2023, and because significant changes have been made to the preferred plan, a full revised Expected Value of Better Information ("EVBI") analysis including comparisons to the full range of alternative resource plans identified in the Company's 2020 IRP was not performed. Instead, comparisons have been made between the new Preferred Resource Plan and the prior Preferred Resource Plan across the ranges of values of the critical uncertain factors along with a small but meaningful set of other alternative plans. A table summarizing the Company's analysis of EVBI is presented in Table 9. Based on the analysis, the new Preferred Resource Plan is appropriate across most values for critical uncertain factors, with two exceptions. Under either low carbon prices or high gas prices, the PVRR is slightly lower ($30-35 million) for Plan D, which delays the retirement of Sioux and addition of NGCC generation by three years. Ameren Missouri will continue to monitor critical uncertain factors and provide updates through its regular IRP filings, including its next IRP annual update due by October 1st of this year.

Table 9: EVBI Analysis

Alternative Resource Plans		PVRR Without Better Info	Carbon Price		Natural Gas Price			Load Growth			DSM		
			Base	High	Low	Base	High	Low	Base	High	Low	Base	High
A	2020 IRP Plan	77,770	76,594	78,946	77,682	77,755	77,887	76,532	77,908	78,595	77,473	77,750	78,227
B	Renewable Transition-Sioux 2028	79,053	78,172	79,934	78,784	79,013	79,402	77,815	79,191	79,878	78,756	79,033	79,510
C	Renewable Transition-Sioux 2030	79,024	78,116	79,933	78,779	78,988	79,343	77,786	79,162	79,849	78,728	79,004	79,481
D	Renewable Transition-Sioux 2033	79,029	78,085	79,973	78,814	78,996	79,309	77,791	79,167	79,854	78,732	79,009	79,485
E	Renewables for Capacity Need	79,656	78,502	80,811	79,234	79,604	80,183	78,418	79,794	80,481	79,359	79,636	80,113
F	Renewable Transition-MAP	79,981	79,157	80,804	79,803	79,952	80,216	78,743	80,119	80,806	79,368	79,905	81,201
Minimum PVRR among plans			78,085	79,933	78,779	78,988	79,309	77,786	79,162	79,849	78,728	79,004	79,481
Plan with Minimum PVRR			D	C	C	C	D	C	C	C	C	C	C
Subjective Probability			50%	50%	25%	50%	25%	20%	60%	20%	10%	80%	10%
Expected Value of Better Info			31	0	0	0	34	0	0	0	0	0	0

Implementation Plan

Ameren Missouri's revised implementation plan for years 2022-2024 includes the following:

- Submitting applications for CCNs to the MPSC for solar generation projects.
- Applying for the creation of a Renewable Solutions program to help communities and large customers meet their sustainable energy goals.
- Issuing a new RFP to identify additional wind and solar project opportunities to support planned additions.
- Finalizing plans for the retirement of Rush Island Energy Center:
    - Completing the Attachment Y process with MISO.
    - Receiving a revised decision from the U.S. District Court reflecting early retirement as the means of compliance.
    - Finalizing plans for operation of the units until retirement.

    - Completing transmission system upgrades necessary to ensure reliability after retirement of the units.
- Adjusting depreciation expense for Sioux Energy Center to reflect retirement by the end of 2030 as part of Ameren Missouri's next rate review.
- Filing an application with the MPSC to securitize the remaining balance in rate base and other energy transition costs for Rush Island Energy Center.
- Conducting preliminary work for the development of new NGCC generation, including site studies, permitting, and engineering.
- Continuing to provide energy efficiency and demand response programs to customers to help them manage their energy costs and reduce the need for new generation resources, including any approved modifications to the Company's programs and budgets through 2024.

MARKET STUDY

The Risk of Ameren Missouri Delaying Renewable Development

Mike Granowski, Director; Ben Lowe, Principal

May 2022

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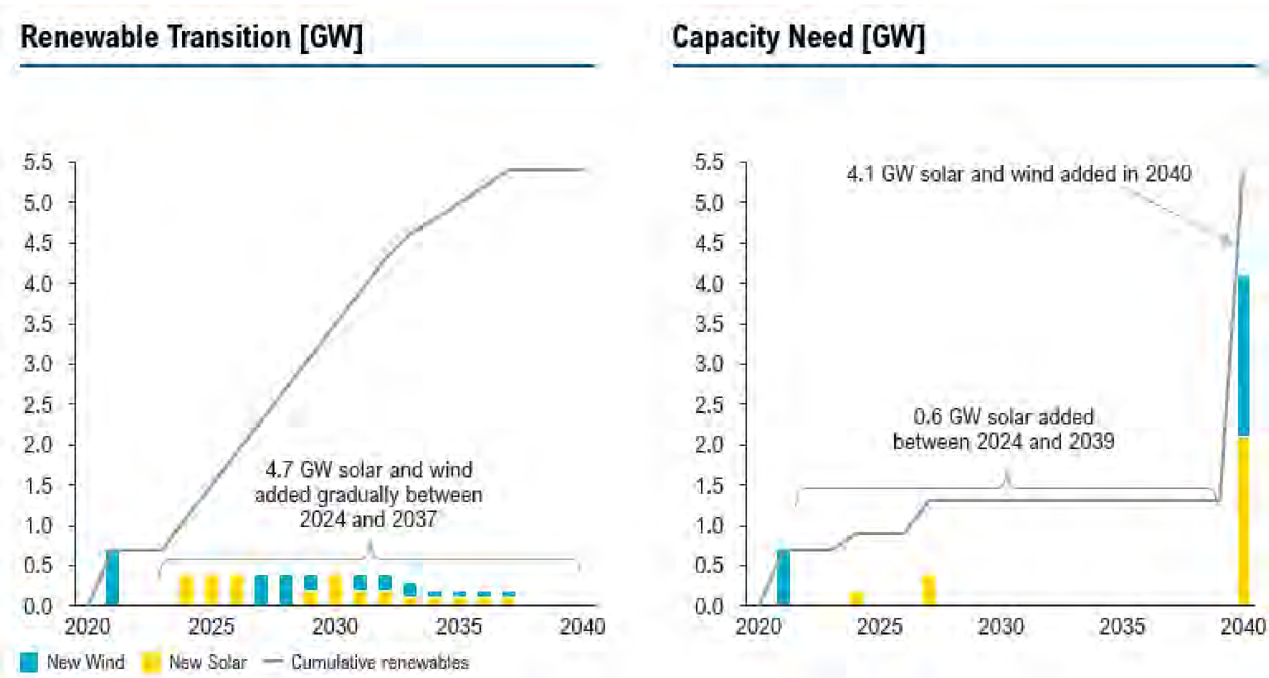
1. Executive Summary

Ameren Missouri retained Roland Berger to analyze, and where possible quantify, the potential risks associated with delaying renewable energy deployment in Ameren Missouri's generation portfolio. The central analysis quantified the incremental difference in revenue requirement between Ameren Missouri's two proposed build plans from its new Preferred Resource Plan: Renewable Transition and Capacity Need.[1] Our analysis assessed the present value of the incremental change in revenue requirement for each of these cases broken out by individual risk variable.

Both plans include 4.7 GW of solar and wind additions, but they differ in timing and pace of deployment. The Renewable Transition plan builds solar and wind generation gradually from the early 2020s to the late 2030s, while the Capacity Need plan adds almost all new renewable capacity (4.1 GW) in 2040, when there is a capacity shortfall. Both build plans assume that solar and wind plants would be built in or near Ameren Missouri's service territory; Missouri, Illinois, Kansas, and Iowa are all potential locations and would be considered based on the best available project economics. Figure 1 details the capacity installed over time of the two build plans.

Figure 1: Ameren Missouri 2022 Change in Preferred Resource Plan Alternative Renewable Build Plans



Source: Ameren Missouri

Across the United States and in MISO in particular, the transition to cleaner renewable energy sources has been underway for many years. Initially, the transition was largely driven by renewable portfolio standards and generous subsidies both at the federal and local levels. More recently, as the cost of renewable resources has declined, the transition has been driven more by economic considerations and demand from commercial and industrial customers. The last 10 years has seen 17.4 GW of wind and 3.7 GW of solar constructed in MISO representing compound annual growth rates of 8.9% and 49%, respectively. Although it is likely that less than half will see operation, the current MISO interconnection queue is dominated by renewable resources, with 15 GW of wind and 78 GW of solar (92.7 GW including solar + storage hybrid assets). Figure 2 details the growth of renewables over the last 10 years and the resources that currently comprise the MISO interconnection queue.

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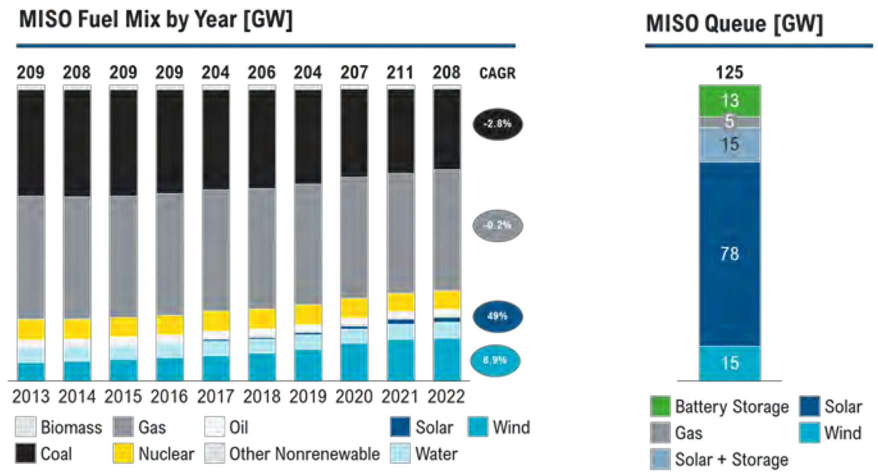
[1] Ameren Missouri 2022 Change in Preferred Resource Plan

Figure 2: MISO Historical Fuel Mix and Interconnection Queue



Source: S&P Global MI, MISO, Roland Berger

The fuel mix and generation queue in MISO indicate that the transition is accelerating. For this reason, we assessed potential risk factors that could impact project development costs and plant operational performance over time. We analyzed multiple risk variables and were able to quantify four key risks: financing costs, land availability, tax credits, and equipment costs. We were unable to quantify several other risk variables but addressed them qualitatively in the body of this report. Figure 3 below summarizes risk variables we were able to quantify and their potential impact on Ameren Missouri's renewable build alternatives (PVRR change between the Capacity Need and Renewable Transition plans). The Capacity Need plan is much more exposed to these risks than the Renewable Transition plan.

Figure 3: Risk Variables Impacting Ameren Missouri's Alternative Renewable Build Plans

Risk Variable	Description	Change in PVRR[2]
Financing Costs	Fossil-heavy generation portfolios likely to have higher financing costs than cleaner and less carbon-intensive portfolios	$ 292 million
Land availability	Continued renewable build out will make "good land" scarcer over time, limiting capacity factors for wind	$ 247 million
Wind equipment Cost	Wind equipment cost declines and performance improvements may be less pronounced than NREL ATB assumes	$ 122 million
Solar equipment cost	Onshoring of solar PV equipment manufacturing as consequence of trade relations with China may result in higher costs	$ 59 million
Tax Credits	Extension of ITC and PTC per the proposal in the Build Back Better plan done through separate congressional action	$ 339 million

Source: Roland Berger

[2] Positive PVRR change indicates that the Capacity Need plan gets relatively more expensive than the Renewable Transition plan over study period.

Further analysis breaking out the individual impacts of each risk variable on the incremental revenue requirements of each renewable plan, the underlying assumptions, and the third-party information on which we relied are discussed in Section 3 of the report.

2. Analytical Approach

2.1.1 Overview

Our analysis evaluated the central risks and uncertainties in Ameren Missouri's build plans and assumptions underlying its 2020 Integrated Resource Plan ("IRP") filing, and build plans and assumptions reflected in the 2022 Change in Preferred Resource Plan. We assessed market data and trends in MISO and the four states of primary interest (Kansas, Missouri, Iowa and Illinois). We articulated key risk variables that could impact Ameren Missouri's alternative renewable build plans from its recent IRP and assessed each using quantitative and qualitative methods. We aligned with Ameren Missouri on its base assumptions related to cost and operational performance for the "Renewable Transition" and "Capacity Need" plans. Through our independent financial and market modeling, we were able to quantify the incremental difference in revenue requirement for each case broken out by individual risk variable. After quantifying the impact of the risk variables, each variable was applied to both renewable build plans equally.

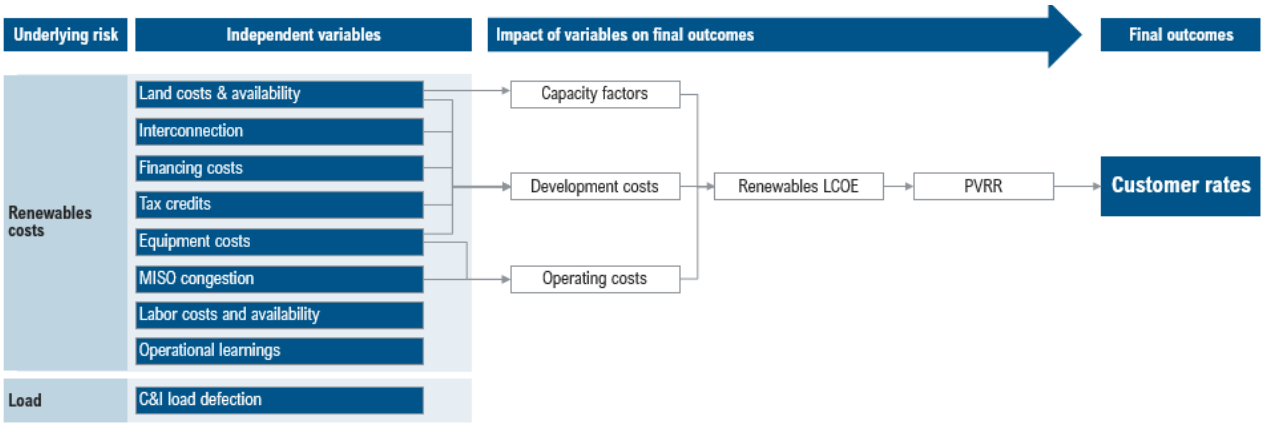
In developing our results, we utilized a range of public resources and databases, Ameren Missouri-specific data and subject matter expertise to inform our analysis. We interviewed experts in renewable project development, MISO power market operations, and renewable technology. We layered in data from energy organizations like the Energy Information Administration (EIA), the National Renewable Energy Laboratory (NREL), International Energy Agency (IEA), and the U.S. Department of Energy (DOE). Using this information and our own expertise and analysis, we developed an objective view of the potential outcomes related to the key risk variables.

2.1.2 Methodology

In framing the analysis, Roland Berger reviewed and summarized existing Ameren Missouri materials, including its 2020 IRP filing and related documents. We accounted for updates since its last IRP, including commodity price forecasts, avoided costs, and options for fossil-fueled power plant retirements (e.g., Rush Island). Using Ameren Missouri's input, we aligned on the planning horizon for the study and identified key assumptions like load growth and generation capacity supply and demand balance.

Having aligned on the base assumptions, Roland Berger identified key risk variables over the planning horizon that could impact the economics of Ameren Missouri's planned renewable deployment. During this phase of the study, we leveraged Ameren Missouri inputs on operational and financial data, internal and external subject matter expertise and primary source inputs to begin quantifying variables with direct and indirect impacts on Ameren Missouri's alternative renewable plans. As shown below in Figure 4, we connected risk variables to specific inputs (e.g., renewable output, operational cost assumptions, capacity factors) and developed preliminary scenarios and assumptions for the Renewable Transition and Capacity Need plans.

Figure 4: Renewable risk variable and revenue requirement impact flow chart



Source: Roland Berger

As we researched each of the potential risk variables to delayed renewable deployment, we prioritized the most important, quantifiable variables and de-prioritized variables that did not have material impacts on the revenue requirement analysis. Our internal research, corroborated by external subject matter experts, concluded that land availability, equipment costs, tax credits and financing costs materially affected the cost to build renewables over the planning horizon. Factors like interconnection costs, congestion and potential load defection could still have economic impacts, however, they are much harder to quantify objectively. During this part of the analysis, we tested and refined our hypotheses regarding the prioritization of risk variables with Ameren Missouri. Figure 5 summarizes the risk variables that we assessed and qualitatively illustrates the weighted impact on PVRR results.

Figure 5: Renewable risk variable prioritization framework

	Variable	Assessment	Estimated Impact on PVRR
Renewables costs	Land availability	• We expect lower capacity factors for wind and solar in the "Capacity when needed" plan given expectation that more attractive areas are limited and will continue to be built out	●
	Financing costs	• Ameren will likely face higher financing costs under its "Capacity when needed" plan due to limited investor willingness to finance CO2 heavy generation portfolios	●
	Tax credits	• The proposal in the Build Back Better plan to extend the PTC and ITC may still pass separately	●
	Equipment costs	• Solar and wind equipment cost declines likely to be less pronounced than what NREL ATB predicts • Assumed step-change in wind technology performance not be applicable to high-capacity factor areas such as the U.S. Midwest	◕
	Interconnection costs	• Available MISO and SPP interconnection data indicate a range of $50 / kW to $200 per kW • We expect longer interconnection distances as more attractive land near transmission is developed over time	◑
	MISO congestion	• The relationship between congestion and transmission capacity appears to be inconclusive • SMEs suggest that there are multiple drivers for congestion beyond transmission capacity and project development • Our analysis of congestion pricing indicates a low potential impact to PVRR	◔
	Labor costs and availability	• The relationship between labor shortfalls and construction and O&M costs is not significant enough to change CapEx or O&M assumptions	○
	Operational learnings	• The relationship between operational efficiency and O&M costs is not significant enough to change operating cost assumptions	○

○ Low Impact ● High Impact

Source: Roland Berger

After incorporating land availability, equipment costs, renewable tax credits and financing costs into the PVRR model, we calculated the change in revenue requirement for each of the plans for each variable individually and then compared the change between the two plans to see which was more impacted. Although the PVRR impacts are additive, we presented the impacts individually to show the relative impact of each variable.

2.1.3 Data Sources

Databases

- Energy Information Administration 923 dataset for 2021 generation
- S&P Global for historical and pipeline solar and wind build; nuclear retirements; transmission lines and pipeline; mapping
- National Renewable Energy Laboratory (NREL) Geospatial Data Science Wind and Solar supply curve datasets
- 2021 NREL Annual Technology Baseline
- MISO Definitive Planning Phase (DPP) Phase 1 – 3 Reports

Reports

- U.S. Department of Energy, *Solar Photovoltaics – Supply Chain Deep Dive Assessment*, February, 2022
- National Renewable Energy Laboratory, *Land use and turbine technology influences on wind potential in the United States*, Lopez, A. et al., January, 2021
- National Renewable Energy Laboratory, *2021 Standard Scenarios Report: A U.S. Electricity Sector Outlook*, Cole, W. and Carag, J., November 2021
- U.S. Department of Energy, *Land-Based Wind Market Report – 2021 Edition*, August 2021
- International Energy Agency *World Energy Outlook 2021* for U.S. electricity generation growth projection and wind/solar breakdown
- Management Science, *Environmental Externalities and Cost of Capital*, Chava, S., September 2014
- MISO Transmission Expansion Planning Reports: 2019 – 2020
- Oxford University, *The Energy Transition and Changing Financing Costs;* Zhou, X., Wilson, C., Caldecott, B., April 2021

Expert interviews

- Former VP, Development – Central Region, IPP
- Manager, Product High Efficiency Modules, Solar manufacturer
- Chief Commercial Officer – Renewable Developer
- Renewables Director – Renewable Developer
- Software Developer – National Renewable Energy Lab
- Senior Vice President and Chief Customer Officer – MISO
- Product Manager – Solar Developer

Management Interviews

- Renewables Director – Ameren Missouri
- General Executive, Renewables – Ameren Missouri
- Renewable Development Manager – Ameren Missouri
- Market Intelligence Manager – Ameren Missouri
- Senior Director, Transmission Policy – Ameren Missouri
- Senior Director, Asset Management and Trading – Ameren Missouri

2.1.4 Models Used

Ameren Missouri Levelized Cost of Energy (LCOE) Model

We used Ameren Missouri's LCOE model for solar and wind to calculate the annual revenue requirements for the lifespan of the renewable generation assets. The solar and wind models assume 30-year lifespans. Capital cost inputs for wind and solar were based on the 2021 NREL ATB overnight capital cost forecast and vary annually through 2040. Revenue requirement was calculated using the appropriate fixed charge rate and was extracted from the "Total Cost" output, normalized on a USD/MW basis for later use in the PVRR model.

Ameren Missouri Fixed Charge Rate (FCR) Model

Roland Berger incorporated Ameren Missouri's FCR model outputs for wind and solar as levelized fixed charge rates to calculate levelized capital costs in the LCOE model. The FCR model calculates separately for wind and solar and is based on factors such as capital cost, depreciation schedule, financing assumptions, availability of tax credits, etc.

Ameren Missouri Revenue Requirement (PVRR) Model

We assessed the impact of each sensitivity on the revenue requirement for each plan. We did this by calculating the difference in revenue requirement between baseline assumptions and sensitivities developed for each variable. We adapted Ameren Missouri's PVRR model to assess the quantitative impact of variables in the alternative renewable development scenarios. We assumed a present worth discount rate of 6.04% for all cases.[3]

We used the base assumptions for both the Renewable Transition and Capacity Need plan and turned on each of the risk variables. After testing each risk variable, we calculated the forecasted revenue requirements for the Renewable Transition and Capacity Need plans. Next, we compared each scenario to the results with the base assumptions and calculated the difference. For each risk variable, the incremental change in PVRR between the Capacity Need plan and the Renewable Transition plan represents how much more (or less) expensive each build plan is relative to the other.

[3] Revenue requirements are in nominal USD.

3. Risk Variable Analysis

This section details the risk variables that impact Ameren Missouri's alternative renewable build plans. Wind land availability, equipment costs, tax credits and financing (Sections 3.1 – 3.4) were assessed quantitatively and flowed through the LCOE, FCR, and PVRR models as described in Section 2. Interconnection costs, congestion costs, potential for load defection and solar land availability (Sections 3.5 – 3.8) were looked at qualitatively and did not impact the revenue requirement analysis.

3.1 Financing Costs

3.1.1 Overview

As mentioned in the Summary of this report, the transition to renewable energy has been accelerating across the U.S. An element of the economic reasons underlying the acceleration is the increasing preference by energy equity and debt investors for exposure to lower carbon portfolios over higher carbon portfolios. This preference is beginning to take the form of higher return requirements for the more carbon intensive portfolios.

3.1.2 Methodology

We based our analysis on secondary research sources along with an analysis of the market sources of Ameren Missouri's capital to estimate the prospect of higher financing costs for Ameren Missouri under the Capacity Need plan relative to the Renewable Transition. The Sustainable Finance Programme at the University Oxford in April 2021 published a study that found that borrowing costs for coal power plants increased from 2017 to 2020 compared to the same period 10 years earlier. In reviewing available loan transaction data, the Sustainable Finance Programme found that the bank spread for coal power plants increased 38% to up to 365 basis points based on the data they analyzed. We used a separate study to confirm the above findings. In "Environmental Externalities and Cost of Capital", author Sudheer Chava found a positive relationship between a higher cost of capital and known firm environmental characteristics. His conclusions supported our assessment that Ameren Missouri would incur higher borrowing costs by delaying the decarbonization of its generation portfolio.

3.1.3 Impact on Revenue Requirement

We expect that Ameren Missouri will lose the opportunity for borrowing cost savings by delaying its generation portfolio transition. We assume the premium associated with higher carbon portfolios will expand to 200 basis points by 2030 over lower carbon portfolios. This impact applies only to the Capacity Need plan. In the Renewable Transition plan, where Ameren Missouri has a clear and consistent pathway to decarbonization of its generation portfolio, the cost of debt remains stable. Assuming this financing cost impact develops, the Capacity Need plan becomes USD ~292 million relatively more expensive on a PVRR basis than the Renewable Transition plan.

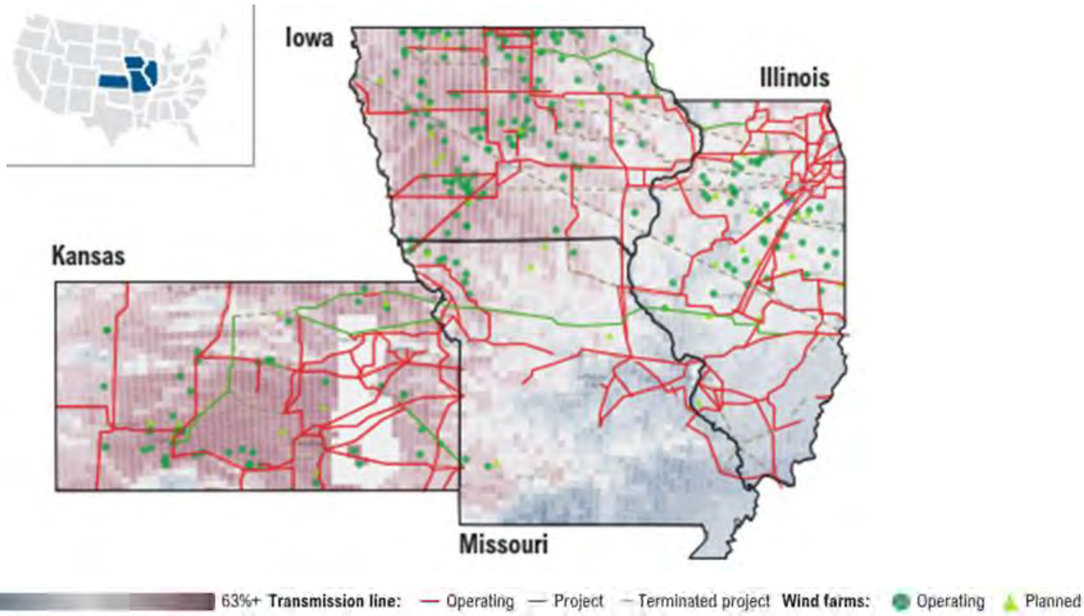
3.2 Land Availability for Wind

3.2.1 Geospatial Analysis

Roland Berger assessed land availability for wind as a potential risk variable associated with delaying renewable deployment. Foundationally, "good" land requires attractive wind resources, transmission access and capacity for interconnection, and available space. Transmission access and interconnection capacity are important considerations for developers but can be addressed through new transmission build over time. Generally, wind projects are sited near existing or planned transmission.

Our analysis showed that wind resources vary over the region, with capacity factors ranging from 19% to over 63%. Overall, the most attractive regions are Kansas, Iowa and Northwest Missouri, highlighted in the wind capacity factor map in Figure 6. We concluded that as land becomes scarce, wind developers will need to build in areas with lower wind resources and pay for longer spur lines, putting upward pressure on levelized wind costs.

Figure 6: Map of wind capacity factors, development and transmission lines



Source: Roland Berger; NREL; S&P Global

According to NREL's 'Limited Access' wind energy supply curve scenario[4], there is potential for 116 GW wind across Missouri, Illinois, Iowa and Kansas – of that total, 50% of the wind potential is in Kansas alone. We summed NREL's estimated potential wind capacity for parcels of land across the four states. Importantly, available land excludes the following: competing land use and associated infrastructure (e.g., roads, buildings), siting topography (e.g., terrain slope, elevation), known protected wilderness, local ordinances related to setbacks, and it does not consider transmission constraints. A summary of exclusions used in NREL's Limited Access scenario is shown below in Figure 7. The primary difference between the Limited Access scenario and the others is the setback provisions. Setbacks for wind have become an increasingly contentious issue across the country as wind farms have encroached on more populated areas. Wind resource availability is based on seven years of generation data and represents a 2030 turbine at 120-meter hub-height as in Annual Technology Baseline Moderate Case; wind capacity potential is based on the available land, assuming 3 MW/km^2.

[4] National Renewable Energy Laboratory wind supply curve datasets, for details see National Renewable Energy Laboratory, Land use and turbine technology influences on wind potential in the United States, Lopez, A. et al., January, 2021

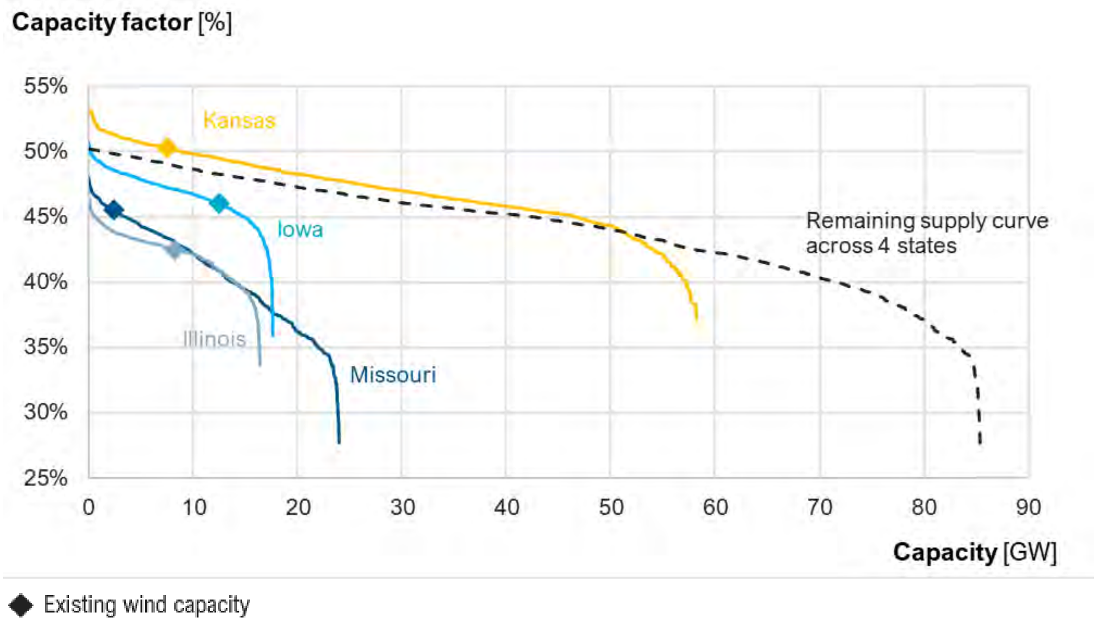
Figure 7: Overview of exclusions used in NREL's siting regimes

Siting exclusion category	Open access scenario	Reference access scenario	Limited access scenario
Infrastructure			
Setbacks to transmission rights-of-way, railroads, roads, building structures	Structure only, no setbacks	Setback = 1.1x wind turbine tip height	Setback = 3x wind turbine tip height
Urban areas and airports	Excluded	Excluded	Excluded
Radar	–	4 km NEXRAD, 9 km SRR/LRR	NEXRAD and SRR/LRR line-of-sight
Regulatory			
Documented state and country setback and height ordinances	–	Applied	Applied
Protected public lands and conservation easements	Excluded	Excluded	Excluded
Other federal lands	–	–	Excluded
Physical			
Slope >25%	–	Excluded	Excluded
Mountainous landforms and high (>9000 ft) elevation	Excluded	Excluded	Excluded
Water and wetlands (with 305-m buffer)	Excluded	Excluded	Excluded

Source: S&P, NREL, Roland Berger

NREL's dataset provides the average capacity factor associated with the potential wind capacity for each parcel of land. We developed a supply curve for each of Missouri, Illinois, Iowa and Kansas by ordering the land from highest to lowest capacity factor and calculating the cumulative potential wind capacity. We then removed the land that has already been used for wind development, assuming the best-resource land has been developed first (this is an imprecise, but conservative assumption). We subtracted the existing, under-construction and advanced development wind capacity from the top of the curve. We then combined the remaining state curves to develop a total *remaining* supply curve for the region and assumed future development will target the best land. The total wind supply curves by state and remaining supply curve across the four-state region are shown below in Figure 8.[5]

Figure 8: Total wind supply curve and existing[6] wind capacity by state and remaining supply curve across Missouri; Illinois; Iowa; Kansas

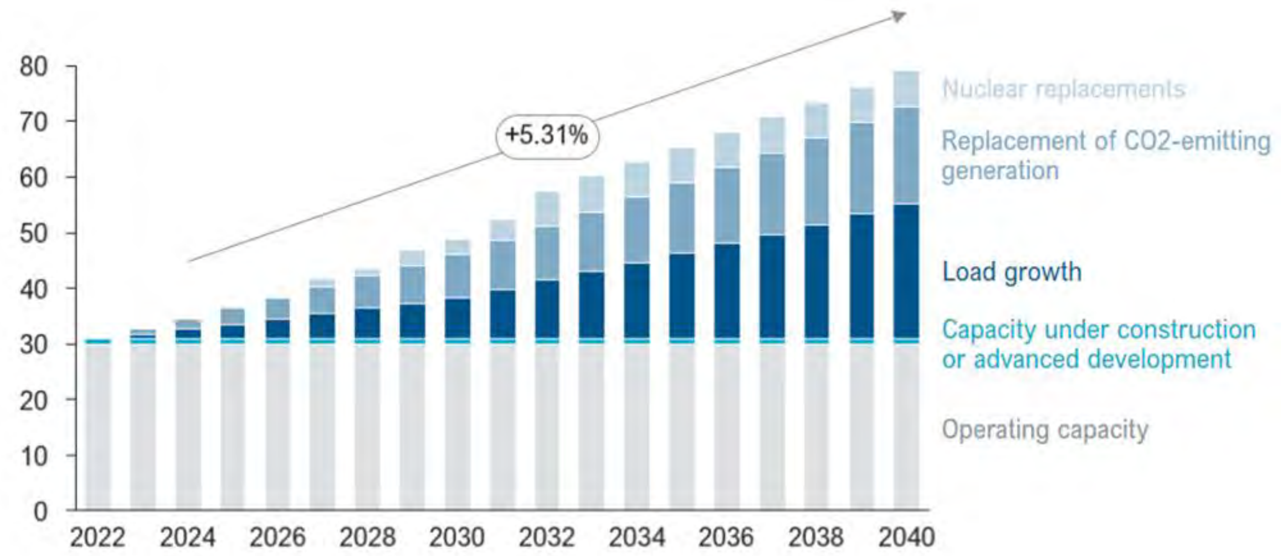


Source: Roland Berger; NREL; S&P Global. Note: 'Existing' wind capacity includes projects currently under construction or under advanced development. State curves show all potential wind capacity, with existing wind marked by a diamond. Dashed black line shows remaining potential capacity across all four states, after existing capacity has been removed.

3.2.2 Projected Wind Build

There is 30 GW of wind capacity already operating across Missouri, Illinois, Kansas and Iowa, and an additional 0.9 GW is under construction or advanced development and expected to be commissioned in 2022. We used the IEA's most recent World Energy Outlook to assess how much wind could be developed in our 4-state region of interest. According to the Announced Pledges Case (Paris Accord zero-carbon by 2050 for the US), 48 GW of new wind capacity would be needed by 2040 to achieve net zero by 2050 across Missouri, Illinois, Kansas and Iowa. The projected wind build represents the capacity needed to meet load growth, replace retiring nuclear plants and replace carbon-emitting generation, shown in Figure 9. Figure 10 summarizes the key inputs to the analysis of how much wind will penetrate the four-state region of interest.

Figure 9: Projected cumulative wind capacity – Missouri, Illinois, Kansas and Iowa [GW]



Source: Roland Berger; S&P Capital IQ; Energy Information Administration-923; International Energy Agency World Energy Outlook; NREL

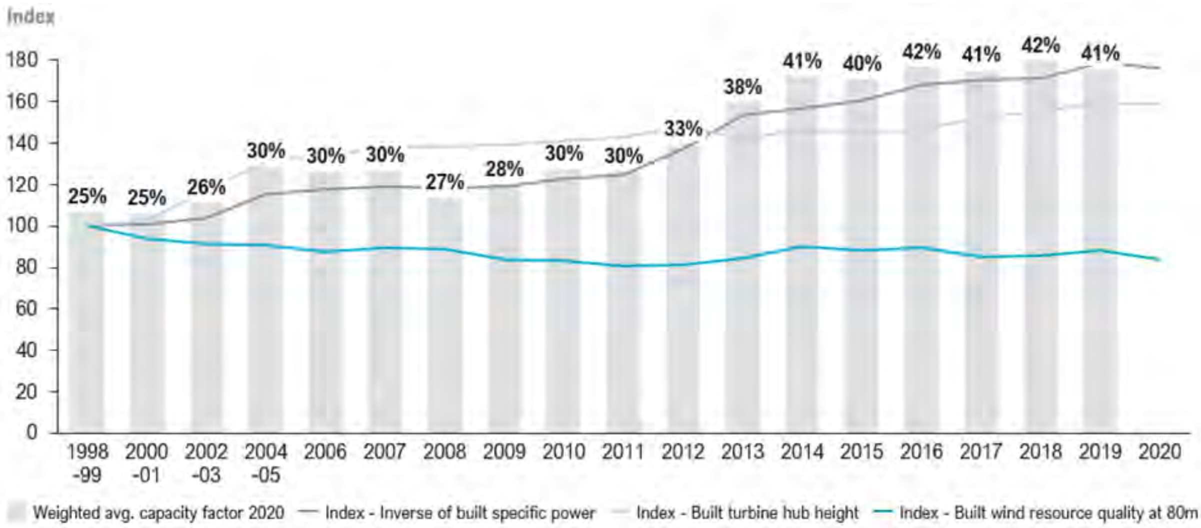
[5] State-specific supply curves are the total before removing already-developed land. The dotted-black line representing remaining supply across the four states nets out land already developed for wind builds.

[6] Existing wind capacity includes operating as well as capacity under construction or advanced development

3.2.3 Projected Wind Capacity Factors

Historically, wind resource quality has declined 16% between 1998 and 2020.[7] Through expert interviews and analysis, we learned that wind resource quality is continuing to deteriorate for built wind because many of the best sites are being taken. At the same time, constructed wind capacity factors have improved from 1998 to 2014[8] and have now flattened, as shown below in Figure 10. Technology improvements have contributed to increasing capacity factors, including specific power and turbine height. However, deteriorating wind resources for constructed wind capacity is expected to put downward pressure on capacity factors.

Figure 10: U.S. built wind: Capacity factors [%], indexed specific power, hub height and wind resource, 1998-2020



Source: EIA; FERC; Berkeley Lab

Mapping wind deployment against the regional supply curve (see Figure 8 on page 13) suggests wind capacity factors could decline approximately 6 percentage points between 2023 and 2040, putting upward pressure on wind LCOEs over time. By taking advantage of higher capacity factors earlier in the study period, less capacity would need to be built to generate the same amount of energy, decreasing build plan costs. Referenced on page 13, Figure 8 details the expected penetration of the supply curve with the expected build and the resulting decline in capacity factors for the four-state region of interest.

3.2.4 Impact on Revenue Requirement

From 2023 to 2040, it is possible that wind capacity factors worsen over time due to reduced availability of good land. In the Capacity Need plan, more of the capacity build will fall in lower capacity factor years (e.g., 2040). This case is therefore expected to be relatively more expensive than the Renewable Transition plan (which builds wind in earlier years presumably on land with better capacity factors). Meanwhile, because of the decline in capacity factors, more wind capacity will be needed in the Capacity Need plan to produce the equivalent output of the capacity deployed in the Renewable Transition plan. It is realistic that the Capacity Need plan will need additional capacity to produce the same output as the Renewable Transition plan, but we did not add additional capacity in the PVRR model. The Renewable Transition plan has an advantage of approximately USD 247 million on a PVRR basis relative to the Capacity Need plan given the land availability risk variable and corresponding declining capacity factors.

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[7] U.S. Department of Energy, "Land-Based Wind Market Report – 2021 Edition," August 2021.

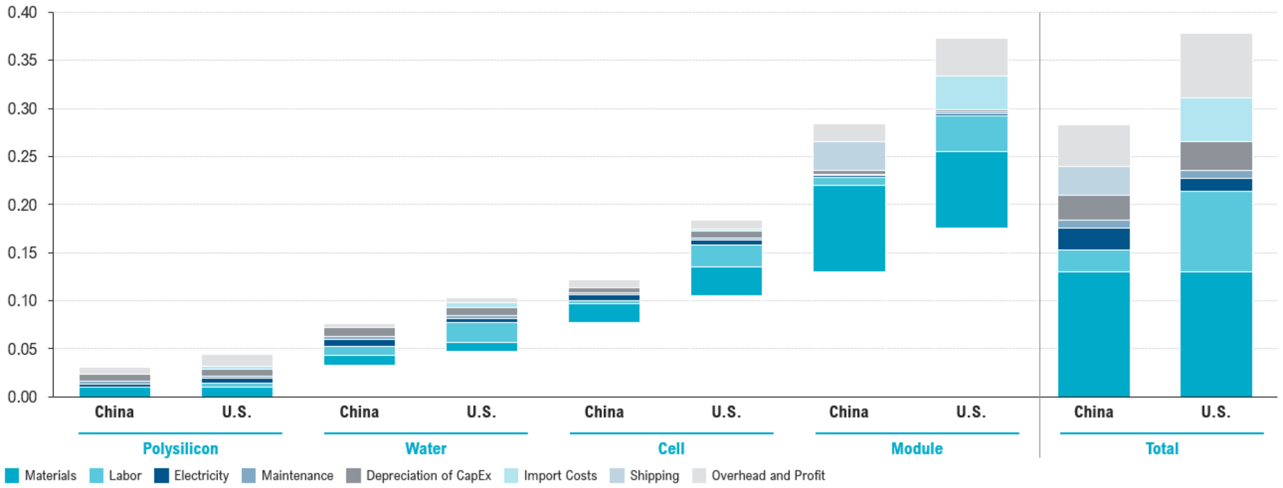
[8] Ibid.

3.3 Equipment Costs

3.3.1 Overview

Solar and wind equipment costs have significant impacts on Ameren Missouri's two alternative renewable build plans. We analyzed the risks for both cases, concluding that the economics are better for the Renewable Transition plan than the Capacity Need plan. Regarding solar, we learned from subject matter expert interviews that there is a considerable likelihood of solar equipment onshoring. Currently, China produces panels ~25% cheaper than the U.S., as illustrated in Figure 11 below.

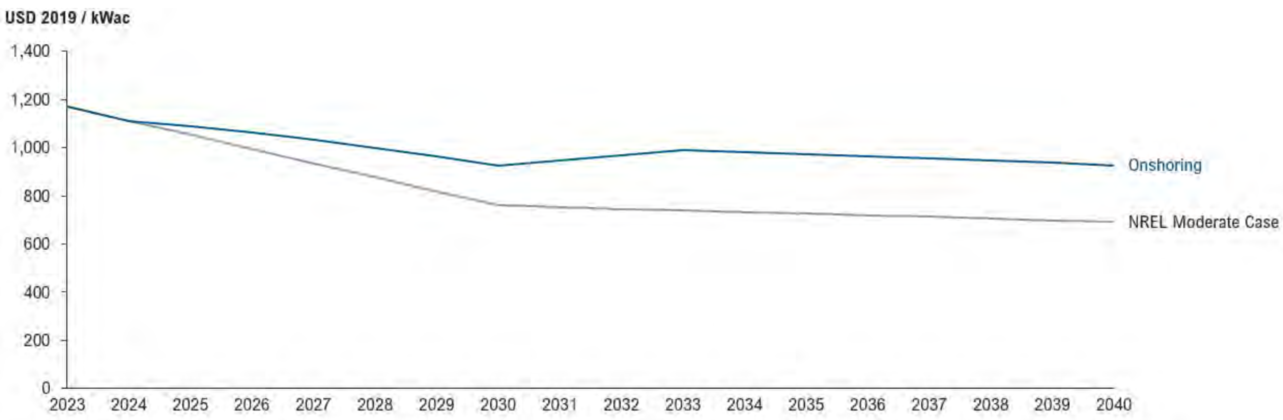
Figure 11: Solar PV production cost in China and U.S. across supply chain [$/Wdc]



Source: Roland Berger; Department of Energy; NREL

Domestic manufacturing would take at minimum 5-7 years to ramp up and mining of input materials for polysilicon would take an additional 5+ years. Overall, it would likely take 10+ years for the value chain to fully onshore. We forecasted solar equipment costs in an Onshoring Case, compared to the NREL ATB Base case assumption for capital costs, shown below in Figure 12. The cost delta could also be applied to Ameren's capital cost base case, which updates NREL's Moderate Case to reflect current market conditions.

Figure 12: Solar overnight capital cost curve comparison: Onshoring Case vs NREL ATB Moderate Case

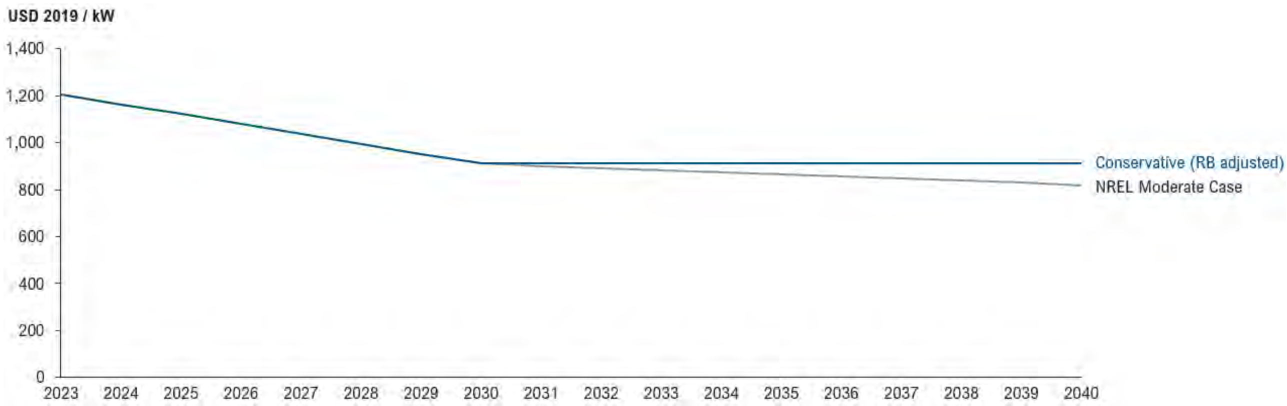


Source: Roland Berger

Solar onshoring is directly related to worsening trade relations with China and lessons learned about overreliance on one region for the solar supply chain. As of this writing, trade relations have intensified under the Biden Administration, which is investigating whether solar manufacturers used factories in Southeast Asia to circumvent U.S. tariffs on solar equipment imports from China. Crystalline silicon solar cells and modules assembled in Cambodia, Malaysia, Thailand and Vietnam could be subject to the same U.S. tariffs imposed on Chinese-made solar components to enforce antidumping and countervailing duties. If onshoring materializes as expected by industry experts, the Renewable Transition plan would benefit more than the Capacity Need plan. Because the Renewable Transition would build solar in the years where solar onshoring is still ramping up, early solar deployments would likely be able to take advantage of relatively cheaper imported equipment while the Capacity Need plan would face higher solar equipment costs by 2040.

Regarding wind equipment costs, we interviewed NREL analysts to better understand their projections.[9] According to NREL, there is risk in their cost decline curves as they rely on certain technological advancements (such as higher module heights) which have the potential to be less impactful in regions such as the Midwest (i.e., in or near Ameren Missouri's territory), which already has good wind potential and output. The national average cost decline curves may, therefore, be less relevant for Ameren Missouri and the ATB's Conservative case may be a better proxy for forecasted wind equipment costs and performance. An equipment cost comparison of the NREL ATB Moderate case and Conservative case is shown below in Figure 13.[10] The ATB's Conservative case benefits the Renewable Transition plan more than the Capacity Need plan due to the reduced cost decline of wind capital costs over the study period. If wind costs develop according to these assumptions, it would be relatively cheaper to build renewables early, as wind plants built later in the forecast would not be advantaged by greater equipment cost declines. The cost delta could also be applied to Ameren's capital cost base case, which updates NREL's Moderate Case to reflect current market conditions.

Figure 13: Wind overnight capital cost curve comparison: Conservative vs NREL ATB Moderate Case



Source: Roland Berger

3.3.2 Impact on Revenue Requirement

From our analysis, we see a strong risk that solar may get more expensive over time due to onshoring. If this plays out as expected, the Renewable Transition plan would be less impacted than the Capacity Need plan by USD ~59 million on a PVRR basis. In addition, when applying the conservative NREL ATB wind assumptions to both alternative renewable build plans, the Capacity Need plan gets relatively more expensive than the Renewable Transition plan by USD ~122 million on a PVRR basis.

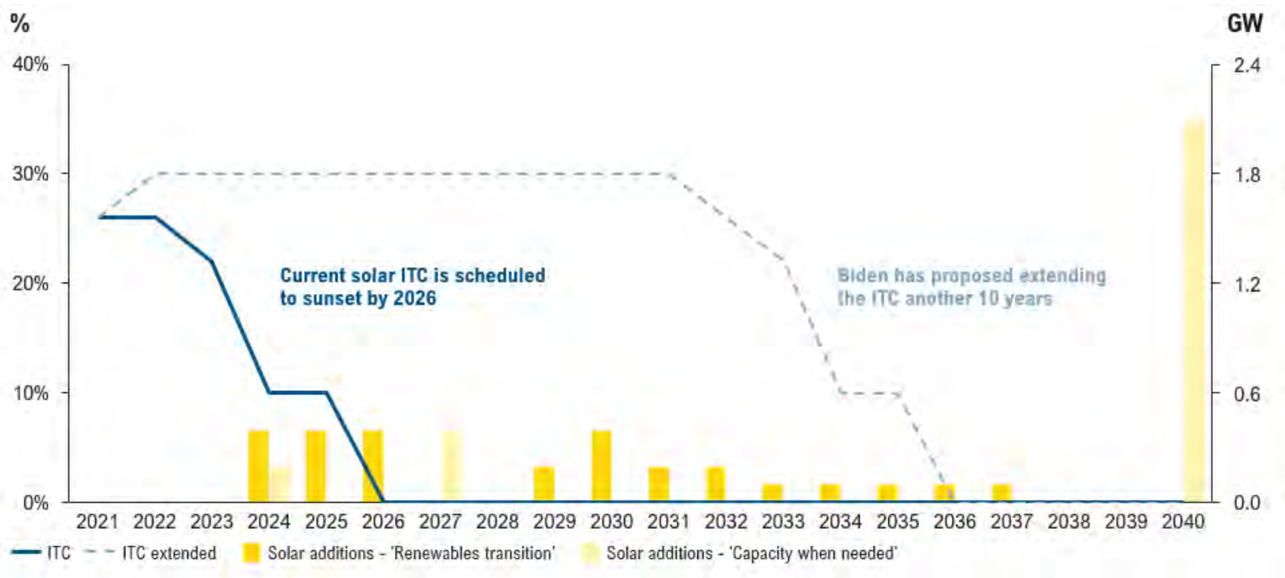
3.4 Tax Credits

3.4.1 Overview

Renewable tax credits are an important risk variable in the revenue requirement analysis. While the production tax credit (PTC) expired in 2021 and the investment tax credit (ITC) is scheduled to step down to 10% by 2024, President Biden has proposed extending the PTC for another 5 years (and including solar in addition to wind) and the ITC for another 10 years.[11] Through the Reconciliation Bill, President Biden has also proposed to expand the ITC at 30% and include an option for "direct-pay" for projects that comply with national content provisions. In addition, President Biden has proposed expanding the PTC rate to USD 0.025/kWh plus a USD .005/kWh bonus, extended through 2026. If both the PTC and ITC are expanded and extended, it will be considerably cheaper to deploy solar and wind while they are available instead of waiting until 2040.

The proposed ITC and PTC extensions would impact a significant portion of the renewable projects deployed in the Renewable Transition plan, while the delayed renewable build plan would only take limited advantage of the cost savings. The current and extended ITC and PTC overlaid against Ameren Missouri's solar and wind build plans are illustrated in Figure 14 and Figure 15 below. As we accounted for the extension of the ITC and PTC in the PVRR model, we used the proposed ITC extension through 2031, sunsetting by 2036. While we assume the PTC would be extended until 2026, we applied the credit to wind projects through 2028, due to the potential grandfathering of new wind additions that begin construction two years prior to the PTC expiration year.[12] The current and extended ITC and PTC overlaid against Ameren Missouri's solar and wind build plans are illustrated in Figure 14 and Figure 15 below. This assumption impacts an additional 800 MW of wind capacity in the Renewable Transition build plan; full PTC and ITC assumptions used in the PVRR model are shown in Figure 16.

Figure 14: Current and extended ITC versus Ameren Missouri solar addition plans



Source: Roland Berger, Ameren Missouri

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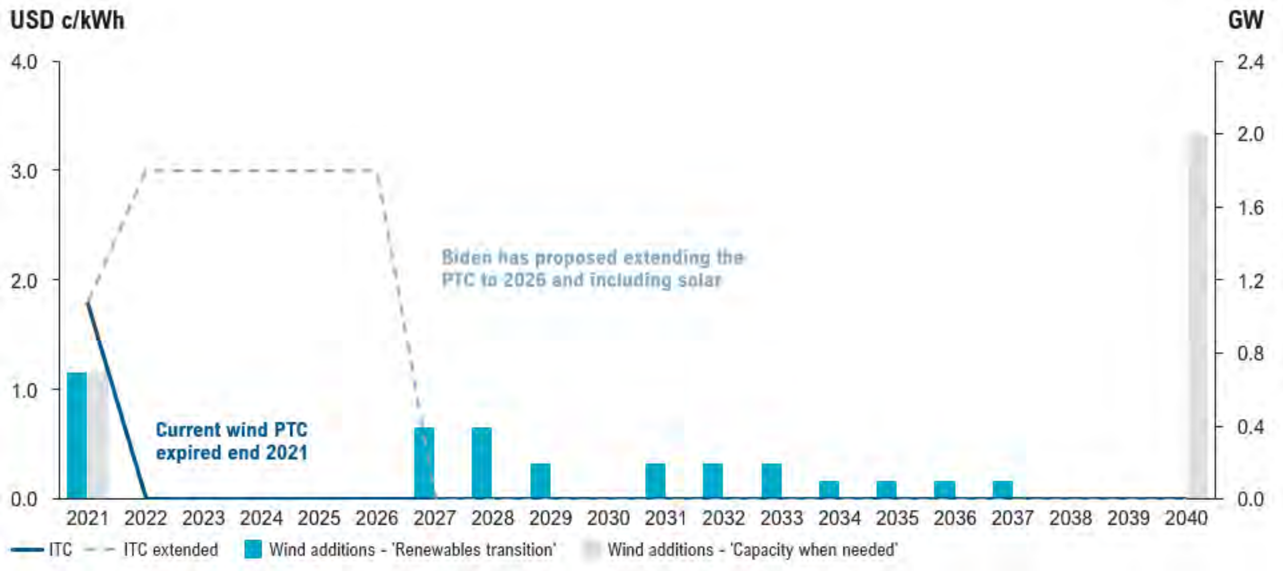
[9] NREL's Annual Technology Baseline (ATB) is widely used in the energy industry to forecast wind and other generation resource costs.

[10] Roland Berger adjusted NREL ATB Conservative Case to reflect NREL's insight on flattening wind equipment costs in the Midwest.

[11] The ITC largely impacts new solar builds while the PTC impacts new wind plants.

[12] Renewable projects can be grandfathered by proving that they have "begun construction" by paying 5% or more of the total cost of the project within two years of the qualifying tax credit year.

Figure 15: Current and extended PTC versus Ameren Missouri wind addition plans



Source: Roland Berger, Ameren Missouri

Figure 16: Ameren Missouri FCR model renewable tax credit assumptions

	ITC	PTC
2023	30%	100%
2024	30%	100%
2025	30%	100%
2026	30%	100%
2027	30%	100%
2028	30%	100%
2029	30%	0%
2030	30%	0%
2031	30%	0%
2032	30%	0%
2033	26%	0%
2034	22%	0%
2035	10%	0%
2036	0%	0%
2037	0%	0%
2038	0%	0%
2039	0%	0%
2040	0%	0%

Source: Roland Berger

3.4.2 Impact on Revenue Requirement

The Renewable Transition plan would take better advantage of the potential extension of the tax credits. This would result in a significantly lower revenue requirement for the Renewable Transition plan and only a slightly lower revenue requirement for the Capacity Need plan, based on the reduced solar build in the 2020's. When extended tax credits are considered as a risk variable, both plans get cheaper, but the Renewable Transition plan becomes an additional USD ~339 million cheaper on a PVRR basis than the Capacity Need plan. If the proposed renewable tax credit extensions are signed into law, a significant amount of solar and wind additions planned in the Renewable Transition plan will cost much less to build than if they were delayed until 2040.

3.5 Interconnection Costs

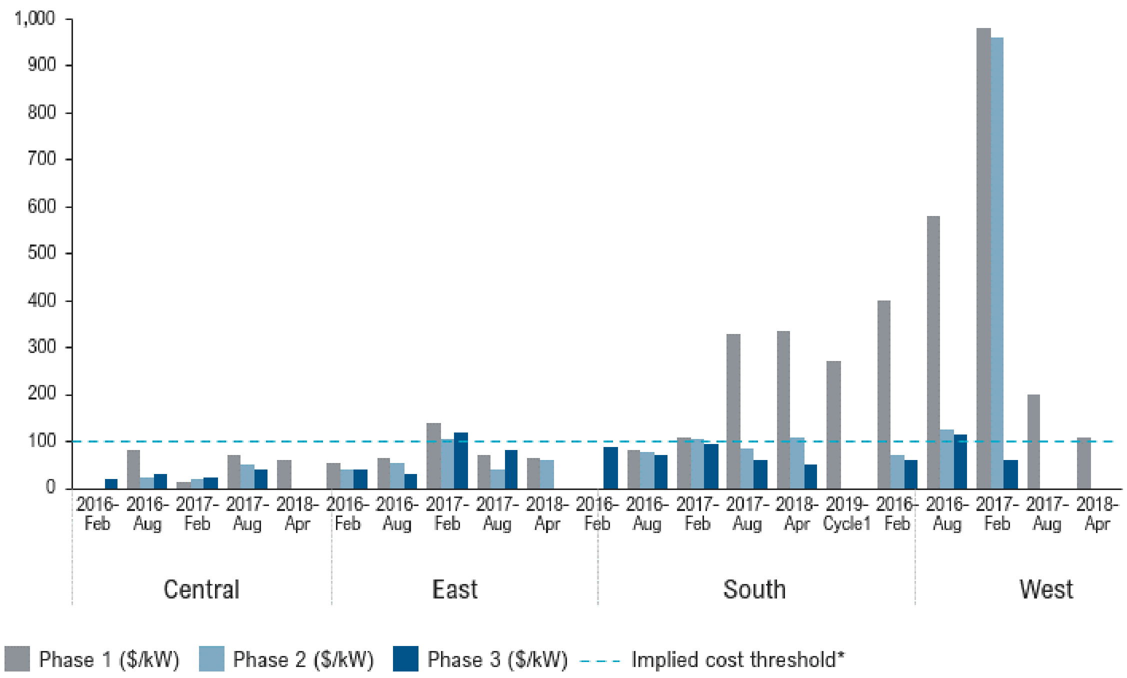
3.5.1 Overview

During the study, we analyzed the relationship between interconnection costs and available transmission capacity in MISO. Interconnection costs include generator tie lines, network upgrades, and make up a relatively small but typically material percentage of project development costs. Transmission capacity correlates strongly with interconnection costs: when there is sufficient transmission capacity, fewer network upgrades are needed, putting downward pressure on costs to generators. However, due to the lumpy, cyclical nature of transmission investment, it is difficult to predict when new capacity will be available and what costs will be passed on to new generators trying to interconnect to the grid. For this reason, we assessed interconnection costs qualitatively and did not quantify the risk factor in our PVRR modeling.

3.5.2 Methodology

We used recent MISO Transmission Expansion Planning (MTEP) reports, MISO Definitive Planning Phase (DPP) report data and MISO Interconnection Queue data to better understand the relationship between interconnection costs and transmission constraints. In addition, we relied on subject matter expert interviews with Midwest renewable developers and MISO operators and managers to corroborate our internal research and interconnection cost hypotheses. Figure 17 shows historical interconnection costs by planning region in MISO.

Figure 17: Historical MISO Interconnection Costs ($/kW)



Source: 2020 MISO MTEP Report, Roland Berger

3.5.3 Key Takeaways

Fundamentally, generator interconnection costs are largely driven by expensive transmission network upgrades, especially for remotely sited renewables in MISO and SPP. Interconnection costs ebb and flow over time depending on the availability of transmission capacity and the number of generators requesting to be interconnected at desirable points of interconnection (POI). For example, while MISO transmission capacity increased significantly through the MISO MVP projects in the 2010's, it was quickly exhausted by new generation from 2015 – 2019, mostly in MISO Central and West.[13] It is common for generators to try to game interconnection strategy, based on our expert interviews. Generators will frequently drop out of the interconnection queue if costs are too high, lowering total cost of new network upgrades and lowering costs for remaining generators, only to return when prospects are better.

Due to the backlog in the MISO interconnection queue, projects may stay in the DPP process for years, incurring study costs until they are forced to drop out. Desirable POIs quickly get saturated as multiple renewable projects attempt to take advantage of available transmission capacity, ensuring their output can reach load, eventually driving the need for new network upgrades. While there is a clear correlation between transmission constraints and higher interconnection costs, the ongoing cycle of GI requests, POI saturation and interconnection queue strategy makes long-term renewable interconnection costs difficult to predict.

3.6 Congestion Costs

Congestion pricing in MISO is unpredictable and not easily manageable. After internal research and analysis, we concluded that it was not a material factor in determining timing of renewables deployment. Congestion pricing depends on the balance of supply and demand for transmission, which varies as plants are added/ retired and transmission lines are added or taken offline temporarily. In addition, fluctuation in congestion prices can be seen in the historical data, which varies greatly over time. It is difficult to forecast congestion prices long-term due to the many uncertain factors that affect prices beyond interconnect requests and transmission availability. Congestion prices are not easily managed due to the difficulty and cost involved in hedging; financial transmission rights (FTRs) or other hedging options can be expensive. During the study, we learned from MISO operations experts that congestion costs do not materially impact developers' decision-making in building renewable resources, which confirmed our preliminary analysis.

3.7 Potential for Load Defection

In analyzing the potential for load defection, we looked at Ameren Missouri's largest commercial and industrial (C&I) customers and assessed risk of lost load if Ameren Missouri delayed renewable deployment. Almost all of Ameren Missouri's top ten largest C&I customers have committed to significant emissions reductions targets, as shown in Figure 18. AT&T, Walmart, AB InBev, General Motors, Bayer AG (Monsanto) and Boeing have all committed to Scope 1 and 2 GHG emissions reductions targets ranging from 25% - 72% relative to base year.[14] Of note, AB InBev has committed to sourcing 100% renewable electricity by 2025 and achieved their 100% renewable goals four years early, in June 2021.[15] Aggressive renewable targets from C&I customers in their footprint pose a potential risk to Ameren Missouri if it pursues the Capacity Need plan. There is additional risk that new business and associated load will not come to Missouri if Ameren Missouri is not greening its generation fleet. While there is some risk that load from these large customers could be lost if they defect and procure energy from other LSEs or move operations to greener regions of the country, it is difficult to predict and quantify.

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[13] 2020 MISO MTEP Report

[14] According to the Greenhouse Gas Protocol, Scope 1 emissions are direct emissions from owned or controlled sources. Scope 2 emissions are all indirect emissions from the generation of purchased energy.

[15] https://www.edie.net/anheuser-busch-meets-100-renewable-energy-goal-four-years-early/

Figure 18: Largest Ameren Missouri C&I Customers' Emissions Reductions Targets

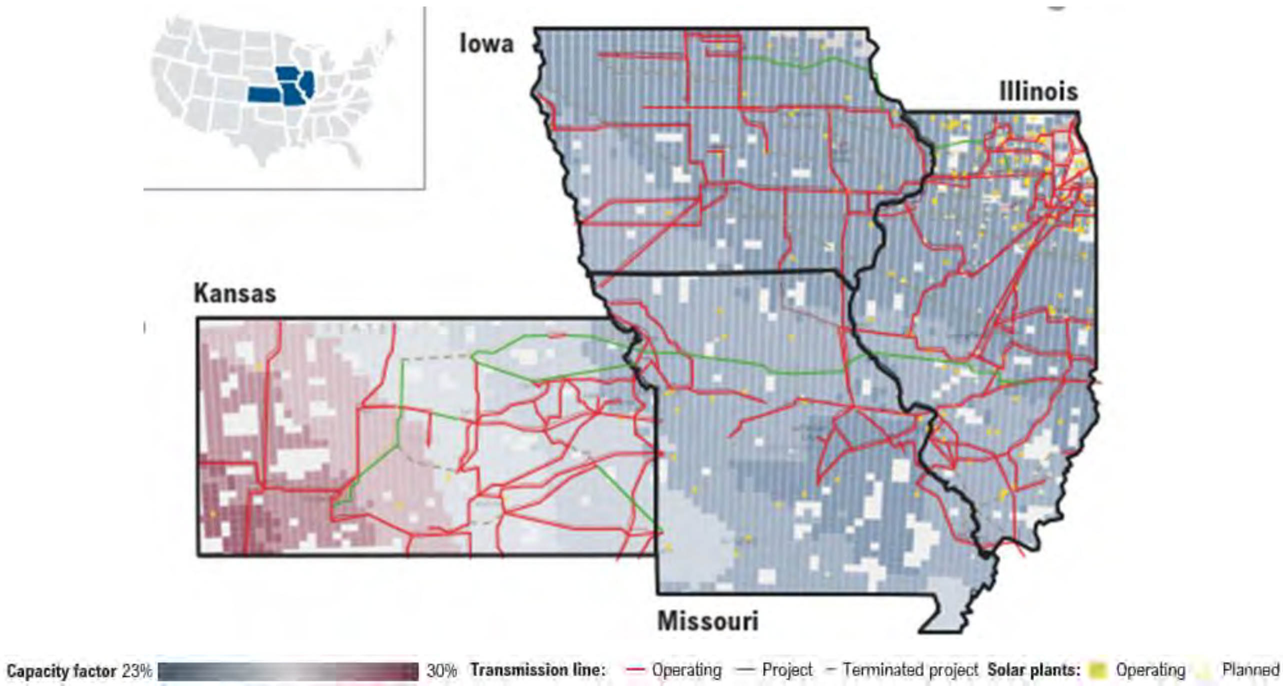
Company	Net-Zero Committed?	Emissions Reduction Target	Additional Green Policies
AT&T	No	Reduce Scope 1 and 2 emissions by 35% by 2025 and 65% by 2030 from 2015 base year	
Walmart	Yes	Reduce Scope 1 and 2 emissions by 35% by 2025 and 65% by 2030 from 2015 base year	
AB InBev	No	Reduce Scope 1 and 2 emissions by 35% by 2025 from 2017 base year	Commits to source 100% renewable electricity by 2025
General Motors	Yes	Reduce Scope 1 and 2 emissions by 72% by 2035 from 2018 base year	
Bayer AG (Monsanto)	Yes	Reduce Scope 1 and 2 emissions by 42% by 2019 from 2019 base year	
Boeing	Yes	Reduce emissions by 25% by 2027, reduce CO_2 by 50% by 2050	Commits to reduce energy consumption by 10% by 2025

Source: Roland Berger

3.8 Land Availability for Solar

In assessing solar land availability, we concluded that solar is less challenging to site than wind and does not have to contend with setbacks, geospatial resource differences and space requirements. Solar projects have a higher power density and can be developed at smaller sized sites than wind; they are more easily connected to distribution grids (e.g., southern Missouri) and can be sited closer to load (e.g., Chicago). Solar capacity factors are less variable across states than wind, as shown below in Figure 19. AC solar capacity factors are less varied locally, instead ranging from 23% in the east to 30% in the west, compared to 19-63% for wind.

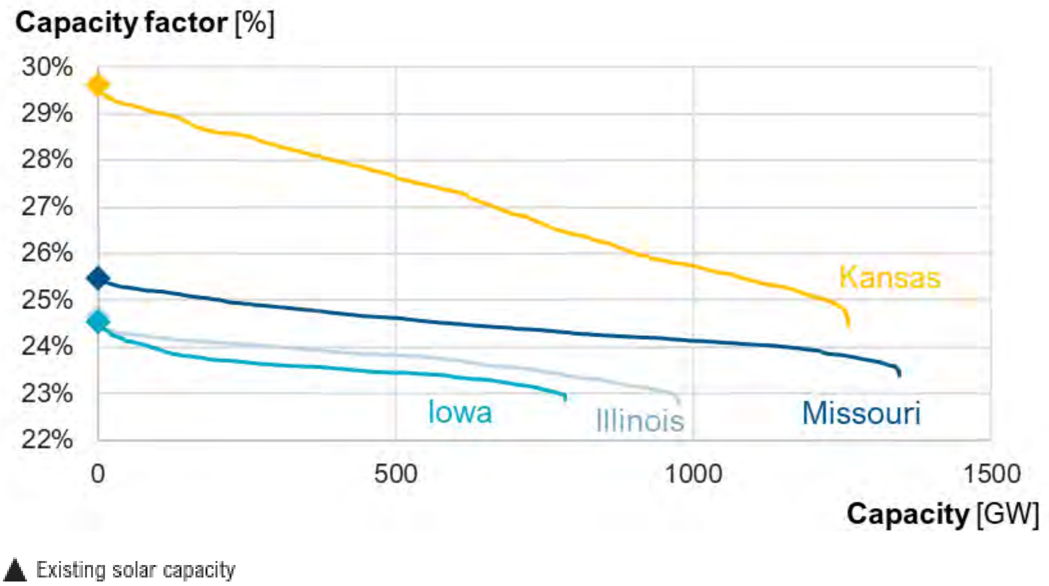
Figure 19: Map of solar capacity factors, development and transmission lines



Source: Roland Berger; NREL; S&P Global. Note: AC capacity factor.

We performed a similar analysis for solar land availability as we did for wind. Because solar additions are not as constrained by land and resource potential as wind, we found that the capacity factor degradation over time as solar is developed on land in the region is minimal. Figure 20 details the solar supply curves under the NREL Limited Availability scenario. NREL's dataset provides the average capacity factor associated with the potential solar capacity for each parcel of land. Solar potential reflects land constraints and resource quality. We developed a supply curve for each of Missouri, Illinois, Iowa and Kansas by ordering the land from highest to lowest capacity factor and calculating the cumulative potential solar capacity.

Figure 20: Solar supply curve and existing solar capacity by state



Source: NREL, S&P Global MI, EIA, Roland Berger

3.9 Conclusion

Figure 21 below summarizes the risk variables we were able to quantify and their potential impact on Ameren Missouri's renewable build alternatives (PVRR change between the Capacity Need and Renewable Transition plans). The Capacity Need plan is much more exposed to these risks than the Renewable Transition plan.

Figure 21: Risk Variables Impacting Ameren Missouri's Alternative Renewable Build Plans

Risk Variable	Description	Change in PVRR[16]
Financing Costs	Fossil-heavy generation portfolios likely to have higher financing costs than cleaner and less carbon-intensive portfolios	$ 292 million
Land availability	Continued renewable build out will make "good land" scarcer over time, limiting capacity factors for wind	$ 247 million
Wind equipment Cost	Wind equipment cost declines and performance improvements may be less pronounced than NREL ATB assumes	$ 122 million
Solar equipment cost	Onshoring of solar PV equipment manufacturing as consequence of trade relations with China may result in higher costs	$ 59 million
Tax Credits	Extension of ITC and PTC per the proposal in the Build Back Better plan done through separate congressional action	$ 339 million

Source: Roland Berger

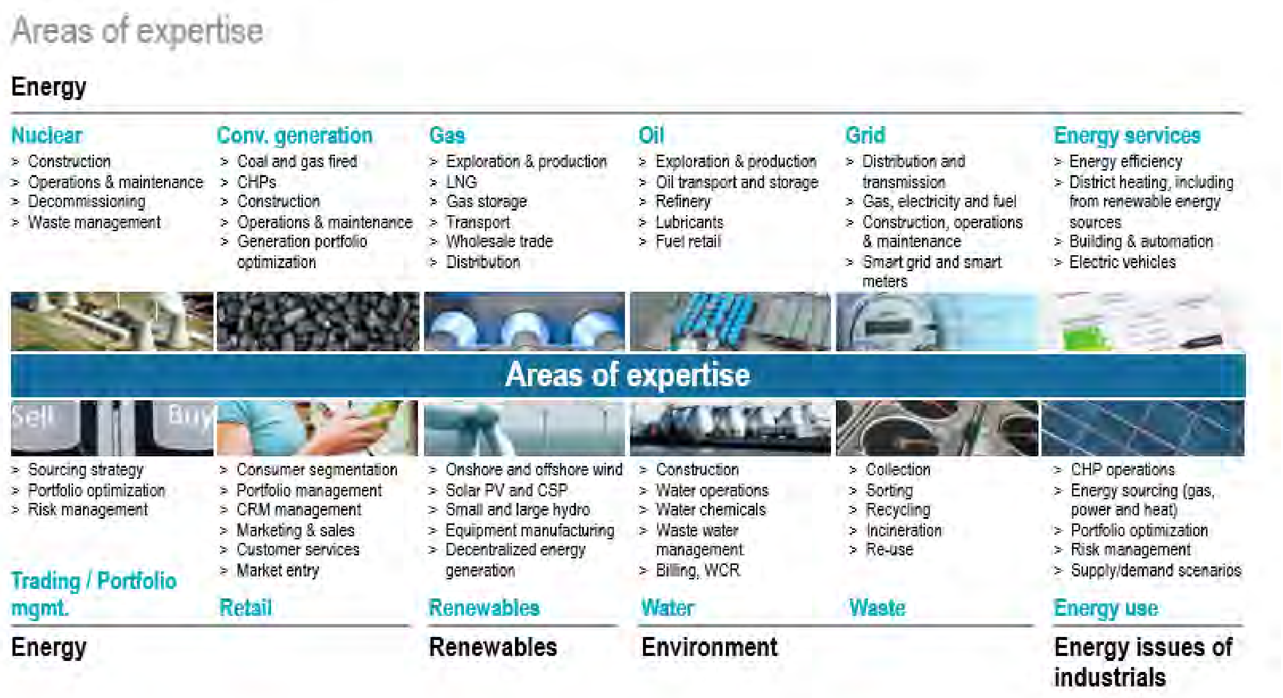
[16] Positive PVRR change indicates that the Capacity Need plan gets relatively more expensive than the Renewable Transition plan over study period.

4. Appendix

4.1 Roland Berger Overview

Founded in 1967, Roland Berger LP is a global management consulting firm that is independently owned by its 250 partners. Roland Berger has 50 offices in 35 countries with 2,400 employees and more than 1,000 international clients. Roland Berger is headquartered in Munich, Germany, and has three offices in the United States: Chicago, Illinois; Detroit, Michigan and Boston, Massachusetts.

Roland Berger's Energy & Utilities practice area has completed more than 1,000 projects for more than 100 clients since 2012. Typical clients include multinational players, energy service specialists, industrial players and investor-owned utilities. In addition to the energy transition, the U.S. Energy and Utilities practice focuses on issues such as market integration and globalization; efficient use of resources; regulation and deregulation; and new technologies / digitization.



4.2 Report Authors

Mike Granowski has over two decades of energy consulting experience. He is a former nuclear engineer and is an expert on utility integrated resource planning, wholesale power markets, power plant valuation, and decarbonization pathways for electric generation fleets. His recent work includes supporting a Midwest transmission utility on energy storage options, a California utility on a multi-decade effort to reimagine the grid to support 100% clean generation, and multiple renewable developer and asset transactions. At Roland Berger, Mike leads the U.S. Digital Analytics practice and is a leader of the U.S. Energy & Utilities practice. Mike earned his MBA from the University of Iowa and earned bachelor's degrees in Nuclear Engineering and in Physics from the University of Wisconsin.

Benjamin Lowe has more than two decades of experience in the electricity sector. He is a former manager at Charlotte-based Duke Energy Corp., where he worked in a number of operational and strategic roles. Ben has worked as a policy director for an energy storage original equipment manufacturer and as the electric utilities reporter for the *Philadelphia Inquirer*. At Roland Berger, Ben advises clients the implications of the renewable transition, focusing on energy market transition with respect to renewables and energy storage technologies. From 2019 to 2021, Ben was on the board of directors of the Energy Storage Association. Ben earned his MBA from Northwestern University's Kellogg School of Management and his B.A. in Economics-Political Science from Columbia University in New York City.