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MISSOURI PUBLIC SERVICE COMMISSION

File No. EA-2023-0286

DIRECT TESTIMONY

OF

MATT MICHELS

ON

BEHALF OF

UNION ELECTRIC COMPANY

d/b/a Ameren Missouri

St. Louis, Missouri
June, 2023

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DIRECT TESTIMONY

OF

MATT MICHELS

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I. INTRODUCTION

Q. Please state your name and business address.

A. Matt Michels, One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

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

A. I am employed by Ameren Services Company as Director of Corporate Analysis. In that capacity, I provide services to Ameren Corporation's operating subsidiaries, including Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company").

Q. Please describe your professional background and qualifications.

A. I joined Ameren Services Company in 2005 as a Consulting Engineer in Corporate Planning. My responsibilities included coordination and monitoring of projects implemented in conjunction with the integration of processes and systems following the acquisition by Ameren Corporation of Illinois Power Company ("Illinois Power") in October 2004. I was subsequently involved in the integration of combustion turbine facilities acquired by Ameren Missouri in 2006. In September 2008, I was promoted to Managing Supervisor of Resource Planning with responsibility for long-range resource planning, including Ameren Missouri’s Integrated Resource Plan filings and associated analyses. In February 2013, I was promoted to Corporate Analysis Manager. In February 2014, I was promoted to Senior Manager of Corporate Analysis. In June 2017, I was promoted to Director of Corporate Analysis. My current responsibilities include long-range resource planning, energy policy analysis, environmental compliance planning analysis, fuel budgeting, and other resource related analysis.

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

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the analytical underpinnings of Ameren Missouri's need for renewable generation resources, including the four solar projects that are the subject of Ameren Missouri’s Application here (the "Solar Projects"). I will first provide details on the Company's development, evaluation, and ultimate selection of the 2022 Preferred Resource Plan ("PRP"), which calls for the addition of significant renewable energy resources. I will then explain why the Solar Projects and execution of the PRP are needed to meet the energy supply shortfall expected in 2028 (under normal planning conditions, or sooner depending on a variety of factors and risks that could arise), help to fill gaps in the Company's winter capacity position, ensure both short-term and long-term reliability, minimize costs to customers, and address other key risks. Finally, I provide an overview of the economics of the Solar Projects.

Q. Please summarize your Direct Testimony.

A. Ameren Missouri has a significant need to add renewable generation resources, both in the short-to-intermediate term (i.e., between 2024 and roughly 2030) and over the next twenty years, so that it can continue to transition its portfolio to greater reliance on cleaner resources. Completing this transition is needed to address and manage several key risks while ensuring continued reliable and affordable service for customers, including via additions of gas-fired generation and battery energy storage over the next several years. The primary conditions underlying this need are as follows:[1]

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 2028 assuming normal loads and generation, a dramatic change from the approximately 15-20% energy buffer from which customers have historically benefited.[2] 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.

3. **Increasing Environmental Regulations** – As noted in my discussion of primary condition 1, 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. We are actually seeing these risks come to fruition now with the

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[1] While Company witness Arora's Direct Testimony and this testimony address all these conditions, my focus is more on the first three, while witness Arora focuses more on the last three.

[2] Future conditions are expected to differ significantly from historical conditions and may warrant a greater buffer. Such future conditions include reduced length from dispatchable resources and a greater reliance on intermittent renewable resources within the Midcontinent Independent System Operator's ("MISO") footprint.

effectiveness of new rules regulating emissions of nitrous oxides ("NO_x"), plus additional proposed regulations targeted specifically at CO_2, among others.[3]

4. **Reliability and Resilience** – Ameren Missouri's addition of diverse new renewable resources during continued operation of its existing fleet 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.

In my Direct Testimony, I discuss the analysis and selection of Ameren Missouri's Preferred Resource Plan, which includes the addition of renewable resources, based on our Integrated Resource Planning ("IRP") process and the considerations outlined above. In doing so, I show that pursuing the addition of renewable resources starting now, and consistently and continuously over the next twenty years, results in savings to customers of over $1 billion, and mitigation of significant risks. I further explain the specific economics of each of the Solar Projects and how they fit into, and are an integral part of, that plan.

[3] These newly adopted and proposed rules are the result of administrative action by the Environmental Protection Agency ("EPA") but as the Commission recognized in its order in the Boomtown case, the U.S. Congress could also "significantly change energy policy and 'drive the need for an imminent and significant expansion of renewable energy resources within an uncomfortably short timeframe'." File No. EA-2022-0245, *Report and Order*, p. 13, ¶ 31.

III. AMEREN MISSOURI'S PREFERRED RESOURCE PLAN

1. Overview

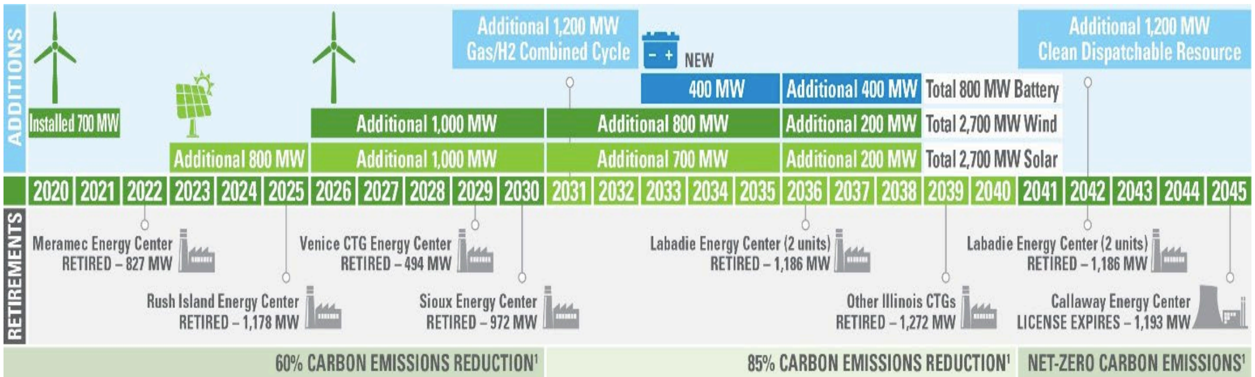
Q. Please provide an overview of Ameren Missouri's current Preferred Resource Plan.

A. On June 22, 2022, the Company filed a Notice of Change in Preferred Resource Plan, which included a new PRP (or "Plan"). The Plan sets forth a transformation of the Company's resource portfolio starting in the near term and continuing over the next twenty years and beyond. It includes the addition of 5,400 MW of wind and solar generation resources, including 2,800 MW between now and 2030,[4] deployment of increasing levels of energy efficiency and demand response, and retirement of all coal-fired generation by 2042, including retirement of the Rush Island Energy Center by the end of 2025 and the Sioux Energy Center by 2030. It also includes the addition of natural gas-fired combined cycle ("NGCC") generation effectively concurrent with the retirement of the Sioux Energy Center coal units to ensure fleet reliability and flexibility. The Plan results in Ameren Missouri's achieving net zero carbon emissions by 2045,[5] with reductions in carbon emissions of at least 60% by 2030 and 85% by 2040 compared to 2005 levels. Figure 1 below shows the Plan to transition from the Company's "old fleet" to its "new fleet," with key additions and retirements, including the addition of new renewable generation.

[4] The Boomtown facility plus the Solar Projects which are the subject of this Application reflect 700 of the 2,800 MW called for by the Plan by 2030.

[5] Assuming sufficient development of clean dispatchable technologies, as discussed in the Company's 2022 Notice of Change in Preferred Resource Plan.

Figure 1



Q. Would you please explain what the phrases "old fleet" and "new fleet" mean, as you are using them?

A. When I use the phrase "old fleet," I am primarily referring 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 no later than 2030: the Meramec Energy Center in 2022, the Rush Island Energy Center by 2025 and the Sioux Energy Center by 2030. 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 2028, 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.

When I use the phrase "new fleet" I am referring to our 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.

Q. Please describe the importance of the IRP process to Ameren Missouri and to its customers.

A. The IRP process is integral to the Company's business planning and essential to its ability to reliably serve its customers. It serves as the foundation for all resource planning decisions. The IRP process directly informs Ameren Missouri's strategic planning process as well as its annual and ongoing business planning process. It also serves as the basis for the Company's assessment of climate and environmental risks and mitigation efforts. Anything and everything that reflects the impacts and risks of resource-related decisions on the business and its customers can be traced back to the Company's IRP process, and it is the primary basis for implementing the resources called for by the Company's PRP and associated implementation plan.

Q. How does the Commission express the importance of the IRP process?

A. As stated in the Commission's IRP rules, "[t]he fundamental objective of the resource planning process at electric utilities shall be to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies."[6]

Q. Has the Commission previously emphasized state energy policy principles regarding the addition of renewable resources?

[6] 20 CSR 4240-22.010(2)

A. Yes. The Commission has specifically recognized that diversifying the state's energy supply through use of renewable resources is the policy of the state, including in its order approving the Company's CCN application for the Boomtown solar project earlier this year in which it concluded that doing so was in the public interest. Company witness Steve Wills discusses Missouri policy regarding renewable resources in his Direct Testimony.

Q. Has Ameren Missouri previously included large-scale generation additions in its IRP implementation plans?[7]

A. Until the Boomtown solar project, the only large-scale generation additions included in the Company's IRP implementation plan have been those needed for compliance with the Missouri Renewable Energy Standard ("RES"). These included the High Prairie and Atchison County wind projects and the Huck Finn solar project. Boomtown – and now the Solar Projects in this docket – are the only major generation additions, other than RES compliance projects, to come out of the Company's IRP process in at least the last ten years.

Q. Is it important to the Company and its customers that Ameren Missouri implement the resources included in its IRP implementation plan?

A. It is vitally important for maintaining reliability and for satisfying the objectives of Missouri's energy policies. In addition to the resources needed for RES compliance described above, the Company has historically relied on the inclusion of demand-side resources in its IRP implementation plan to support its applications under the Missouri Energy Efficiency Investment Act ("MEEIA"). The Commission Staff, Office of Public Counsel and other stakeholders rely on this connection between the IRP and MEEIA applications as well. Importantly and more broadly, the IRP process is *the* process that Ameren Missouri and other Missouri investor-owned utilities

[7] Under the Commission's IRP rules, the Company is required to include an implementation plan for resources called for by its IRP, with the implementation period under the rules defined as the three years subsequent to the filing.

use to assess the need for resources to ensure reliability for customers in a manner that is safe, affordable, and in the public interest. The Company takes the importance of this process seriously and recognizes that the Commission does as well.

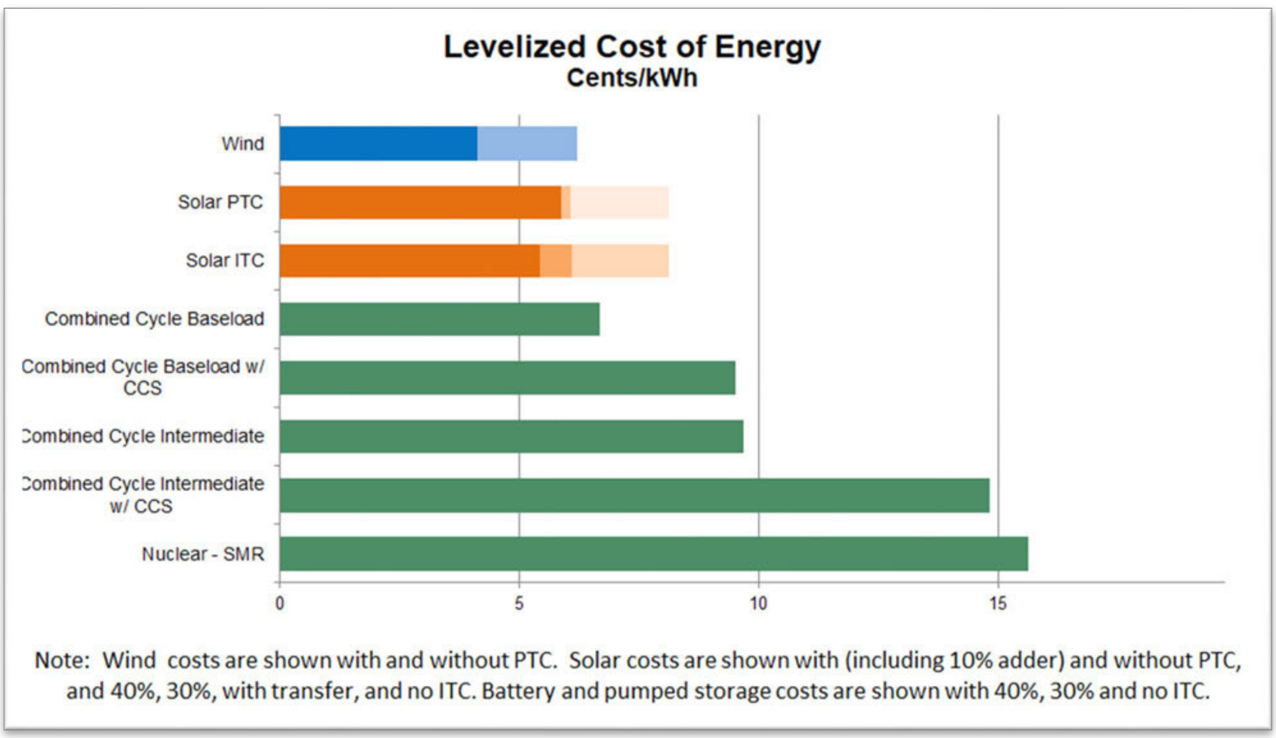
Q. How does Ameren Missouri evaluate different options for meeting customers' electric energy needs?

A. Our IRP process includes the evaluation of numerous resource options, which are combined into alternative resource plans. These alternative resource plans are modeled and compared based on several objectives and supporting measures that include customer costs, customer satisfaction, portfolio diversity, economic development, and financial and regulatory considerations. Our evaluation considers ranges of key variables, or uncertain factors, that may be critical to the performance of the alternative resource plans. A detailed discussion of the development and analysis of alternative resource plans can be found in Chapters 9 and 10 of our 2020 triennial resource planning filing. Chapter 9 of the 2020 filing is attached to my testimony as Schedule MM-D1. Additional discussion of the evaluation of alternative plans can be found in the Company's June 2022 Notice of Change in Preferred Resource Plan, which is attached to my testimony as Schedule MM-D2. For the analysis supporting Ameren Missouri's 2022 Preferred Resource Plan, the Company evaluated a focused set of options based on the insights gained in the development of the 2020 IRP. These options and the results of the Company's analysis are discussed in detail in the Company's Notification of Change in Preferred Resource Plan filing (Schedule MM-D2).

Q. How do options for new resources compare in terms of cost?

A. Ameren Missouri's IRP process includes the evaluation of various candidate supply-side resource options and the selection of supply-side resource options for inclusion in alternative resources plans. The selection process includes evaluation of the levelized cost of energy ("LCOE") for candidate resource options. The Company included such an evaluation in its 2020 IRP and in its 2022 Notice of Change in Preferred Resource Plan (Schedule MM-D2). The Company is in the process of preparing its 2023 triennial IRP submittal, due by October 1st of this year, and has updated its assumptions for the costs of resource options, including wind, solar, and NGCC. Figure 2 presents updated estimates of LCOE for selected supply-side resource options. As the chart shows, solar and wind resources remain the lowest cost supply-side resource options and are easily the lowest cost non-emitting resource options.

<u>Figure 2</u>



Q. Is the LCOE determinative of the economics of various resources?

A. Not by itself, but it does provide a good indication of the cost of energy from various types of resources. Because wind and solar are primarily energy resources, comparison of LCOE provides a good indication of the relative economics of these resources. To examine the economics of different resource options and portfolios more rigorously, the IRP process focuses on an integrated analysis of different portfolios under a range of conditions that are characterized by key variables that can influence the selection of the PRP, with the primary factor being the minimization of cost to customers. Within the Commission's IRP rules and utility IRP filings, these variables are called critical uncertain factors.

Q. What are some of the critical uncertain factors that Ameren Missouri considers in its evaluation of alternative resource plans in its IRP process?

A. Among the most important factors we consider are prices on CO_2 emissions and natural gas prices. These factors in turn affect power prices realized from the sale of generation output into the Midcontinent Independent System Operator, Inc. ("MISO") market. Collectively, our assumptions for CO_2 prices, natural gas prices, and the associated power prices are referred to as "scenarios." These scenarios are used to model the operation of our generation portfolio over the twenty-year planning horizon and for an additional ten years to capture continuing costs and benefits of portfolio changes made during that twenty-year period. Also important are load growth and the cost of demand-side programs. A detailed discussion of our consideration of uncertain factors can be found in Chapter 2 of the Company's 2020 IRP filing (Schedule MM-D3 to my testimony) and Chapter 9 of that filing (Schedule MM-D1). A discussion of updates to assumptions for uncertain factors is included in Schedule MM-D2. In the 2022 Change in Preferred Resource Plan, the Company used the same scenarios for CO_2 prices and natural gas prices, and therefore power prices, that it used in the development of the 2020 IRP, but the probabilities for the scenarios were changed to represent management's updated view based on changed circumstances since the time of the 2020 IRP.

Q. Has the Company updated its assumptions and modeling for its upcoming 2023 IRP filing?

A. Assumptions for natural gas, CO_2 and power prices have been updated for the 2023 IRP, but the analysis is still in process. I discuss the potential effects of these new modeling assumptions on the results of the Plan economic analysis later in my Direct Testimony.

Q. How does Ameren Missouri select its Preferred Resource Plan?

A. The selection of the Preferred Resource Plan is the culmination of discussions with and among Ameren Missouri's senior leadership based on consideration of the analysis referenced above and a scorecard evaluation of alternative resource plans that reflects management's consideration of the key trade-offs among the Company's planning objectives. A detailed discussion of the preferred plan selection process can be found in Chapter 10 of the 2020 filing, which is included in Schedule MM-D4. Additional discussion of preferred plan selection can be found in the Company's Notification of Change in Preferred Resource Plan (Schedule MM-D2). For the Company's Notification of Change in Preferred Resource Plan, which evaluated a focused set of alternative resource plans, the Company relied on the insights gained from the scoring of alternative resource plans in the 2020 IRP and a focus on the primary selection criterion – minimization of present value of revenue requirements ("PVRR").

Q. Is the IRP process, and the PRP in particular, the sole basis for justifying a specific project?

A. Not at all. Projects must be evaluated for their suitability and feasibility for implementation of a utility's resource acquisition strategy as indicated in its PRP, and changes in conditions since the time a utility adopted its PRP should be considered. As Company witness Scott Wibbenmeyer addresses in his Direct Testimony, the Company is striving to locate the best feasible projects at the best cost consistent with meeting the needs of customers. We must and do, however, rely on the rigorous analysis and careful consideration of customer risks and benefits that are embodied in Ameren Missouri's IRP process and reflected in its PRP. The IRP process is not simply a modeling exercise. It is integral to Ameren Missouri's broader business planning and its ability to meet its customers' needs reliably and cost-effectively, and it necessarily reflects considerations that go beyond the basic modeling. It reflects a recognition of the real-world challenges and risks inherent in implementing a true resource acquisition strategy.

2. <u>The Changing Planning Environment</u>

Q. Why is Ameren Missouri starting to place a stronger emphasis on planning for energy needs in its IRP process?

A. Traditionally, Ameren Missouri has focused on capacity needs and assumed continued sufficient resources in the MISO market to ensure that energy needs are met in all hours, with capacity planning reserve margins ("PRM") established annually by MISO. The PRM is still the primary measure for resource adequacy in MISO, including consideration of seasonal capacity needs as described later in my testimony, and is the primary criterion we use for ensuring reliability in the analysis that underlies our 2022 filing. This is reflected in our capacity position, which shows expected accredited resource capacity compared to capacity needs, which include expected demand and the associated PRM requirement.

However, as the utility industry collectively continues to transition away from fossil-fueled generation, renewable resources represent the least cost resources to meet energy needs, in addition to having zero fuel costs and zero carbon emissions. As a result, our ability to rely on underutilized fossil generation resources in the MISO market to provide the energy and flexibility needed to ensure our ability to meet customer needs has continued, and will continue, to diminish. This is especially relevant as more and more of the generation located in MISO will consist of intermittent renewable resources that, while valuable for serving energy needs, do not provide flexible capacity like traditional on-demand, or dispatchable, resources do. As a result, our PRP becomes even more important for ensuring a balanced mix of renewable and dispatchable generation to ensure an affordable and reliable supply of energy.

Q. How has the resource planning environment changed as a result of the considerations you've described?

A. As a result of the market's shift to a mixture of least cost renewable energy resources and dispatchable generation, ensuring adequate capacity relies on a proper analysis of the ability of renewable energy resources to meet hourly energy needs and the ability of dispatchable capacity resources to integrate those intermittent resources. While the capacity position is important, it does not by itself account for all the considerations necessary to ensure proper planning and ensure that resources will be available to provide reliable and affordable service to customers across a range of conditions, including some that may happen in real time as we operate our fleet to serve our customers' needs.

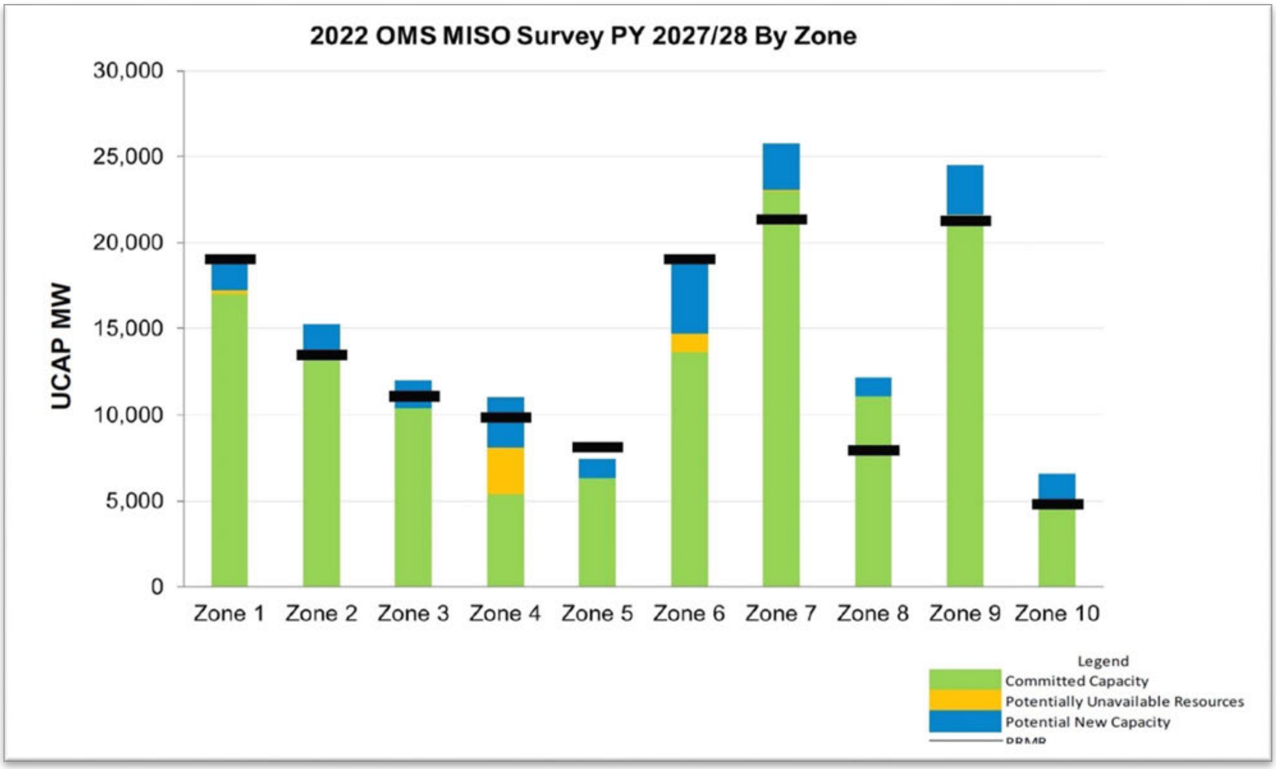
The planning environment has seen a major shift in recent years, moving from one that is characterized by capacity surpluses and the predominance of dispatchable resources to one that is characterized by tight capacity supplies and increasing reliance on intermittent renewable energy resources that replace energy from fossil fuels. In the old environment, utilities could rely to some degree on the availability of underutilized fossil resources owned and operated by other market participants to satisfy some degree of shortfall in resources in their own portfolio. Ameren Missouri itself has historically used a build threshold of at least 300 MW of capacity shortfall before including new generation resources in its plans. In the new environment, such reliance is extremely risky, and therefore inappropriate, since the entire industry is transitioning its fleet and capacity surpluses have all but dried up. In fact, in this new environment it is important to have a planning framework that solves for both capacity and energy in an optimal manner.

Q. Has there been evidence to support the notion that the planning environment has seen the major shift you describe?

A. There has been substantial evidence on multiple fronts. The results of MISO's capacity auction for planning year 2022-2023 (Schedule MM-D5) are a prime example, with the capacity price in all load zones in MISO's North and Central regions set to the cost of new entry ("CONE"). Simply stated, this means that there were not sufficient capacity resources bid into the auction to meet the demand and reserve requirements for those regions.

In June 2022, the Organization of MISO States ("OMS") presented survey results that indicate expected capacity shortfalls within the next five years based on committed capacity resources at that time. Figure 3 below shows the expected capacity position in the 2027-2028 planning year by zone. Note that MISO Zone 5 includes Ameren Missouri. Note also that MISO Zone 4 (Illinois) includes gas-fired generation owned by Ameren Missouri and used by Ameren Missouri to meet its resource adequacy requirement. The full OMS presentation is attached as Schedule MM-D6.

Figure 3



While the results of MISO's 2023-2024 PRA results, published in May 2023 and attached as Schedule MM-D7, show capacity prices that are far less than CONE, MISO cautions that this is not an indication that significant risk no longer exists, indicating the following:

- "The changing resource fleet driven by aggressive member decarbonization strategies continues to dramatically shift the reliability risk profile in our region."[8]
- "Actions taken by Market Participants such as delaying retirements and making additional existing capacity available to the region, resulted in adequate capacity. Many of these actions may not be repeatable and the residual capacity and resulting prices do not reflect the risks posed by the portfolio transition."[9]

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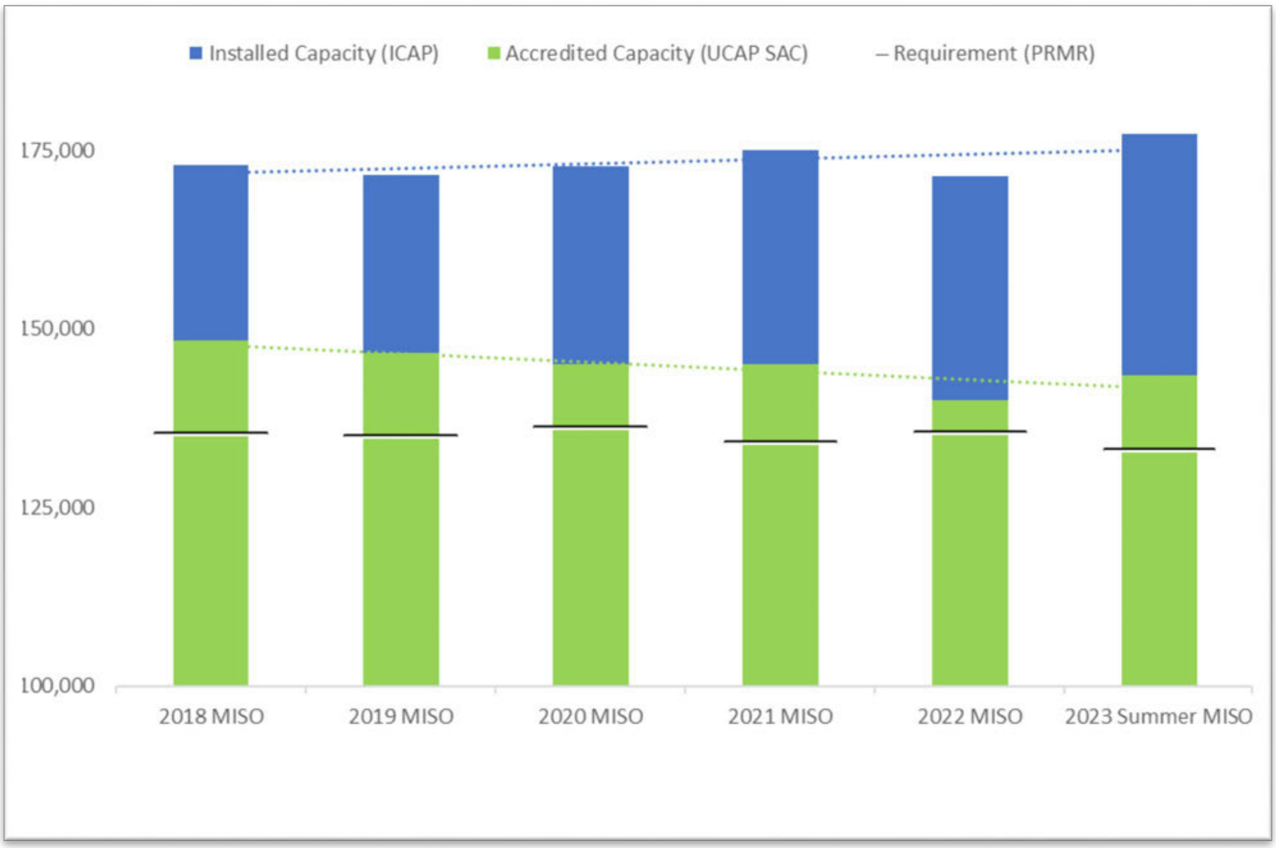
[8] Schedule MM-D7, page 2.
[9] Schedule MM-D7, page 3.

- "Historic trends and projections based on member announced plans show a continued decline in accredited capacity even as installed capacity increases." (see chart in Figure 4 below indicating the ongoing decline in accredited capacity in MISO)[10]

Figure 4



In April of this year, MISO also initiated an effort to examine system reliability needs more broadly, including consideration of an energy-based adequacy plan in addition to the existing capacity-based adequacy plan. This energy-based adequacy plan would address energy gaps as well as voltage support, frequency support, protection enablement and restoration. A presentation from MISO on this effort is attached as Schedule MM-D8.

[10] Schedule MM-D7, page 8.

Q. Has there been evidence on this point beyond what MISO has shown?

A. Yes. NERC[11] issued its reliability assessment for the summer of 2023 (attached as Schedule MM-D9) in May 2023 and stresses the following in its key findings: "Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations."[12] As with MISO's 2023 PRA, this assessment by NERC follows its 2022 summer reliability assessment (attached as Schedule MM-D11) in which NERC indicated that, "System operators in MISO are more likely to need operating mitigations, such as load modifying resources or non-firm imports,[[13]] to meet reserve requirements under normal peak summer conditions," and its 2022 Long-Term Reliability Assessment (attached as Schedule MM-D12), which indicated that MISO, "is facing resource shortfalls across this entire assessment period."[14]

Q. Is this shift likely to reverse?

A. No. The reliability assessments from NERC, together with MISO's assessments and capacity auction results, clearly indicate that the electric industry has already shifted to a new paradigm. At the same time, resource portfolios are increasingly characterized by higher levels of renewables, and with the tax incentives included in the Inflation Reduction Act ("IRA") and the continued tightening of environmental regulations on fossil-fueled generation, that trend is virtually certain to continue. MISO's November 2022 Regional Resource Adequacy Report ("RRA"), attached as Schedule MM-D13, even states, "The (Net Scheduled Interchange) for the future system is projected to become more variable due to the increased penetration of renewables across MISO’s neighbors."[15]

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[11] North American Electric Reliability Corporation.
[12] Schedule MM-D9, page 14. (A summary infographic that accompanied the 2023 assessment is attached as Schedule MM-D10).
[13] Operating mitigations may also include mandatory load shedding under certain conditions.
[14] Schedule MM-D12, page 26.
[15] Schedule MM-D13, page 32; Net Scheduled Interchange is the net sum of all interchange schedules between MISO and neighboring Balancing Authorities.

Q. Has Ameren Missouri seen a similar shift in its own portfolio?

A. Yes. Historically, Ameren Missouri has been a net seller of energy into the MISO market, sometimes in excess of 10 million MWh annually and resulting in additional margins of tens of millions of dollars, which directly offset a portion of costs to customers. This annual energy surplus has been declining as the Company has planned for the retirement of coal units, and as I mentioned previously, Ameren Missouri expects to be in a net purchase (i.e., short) position soon absent the addition of new energy generation resources. Enjoying a net sales (i.e., long) position ensures that Ameren Missouri has a strong ability to serve its customers energy needs. A sufficiently long position also shields customers from the effects of market price spikes (i.e., it acts as a hedge against market exposure) and allows them to benefit from incremental revenues that reduce net energy costs in total. It also improves the Company's ability to ensure customers have the energy they need when they need it.

With the recent retirement of the Meramec Energy Center (at the end of 2022) and the impending retirement of Rush Island Energy Center (by the end of 2025), Ameren Missouri is entering a period of tighter supply relative to demand in terms of both capacity and energy, with deficits in both capacity and energy looming in the absence of new resource additions.

Q. Have Ameren Missouri's customers realized benefits from the Company's historical long position?

A. Yes. Ameren Missouri and its customers have enjoyed the benefits of capacity and energy sufficient to meet their needs under a host of conditions, and the ability to sell capacity and energy into the MISO market in excess of what is purchased to meet customer needs has provided a significant revenue requirement offset for our customers.

Should we experience price spikes in the future, and there is no reason to believe we won't, our customers will be more exposed to the negative effects of such price spikes in the absence of the resource additions in our PRP and will be less likely to see the kinds of benefits they have enjoyed in the past. I provide additional examples of this later in my Direct Testimony.

Q. How have the trends you mentioned changed the way Ameren Missouri and other utilities think about the adequacy of resources to ensure reliable electric supply?

A. These trends have three primary implications for the way in which Ameren Missouri thinks about the adequacy of its resources. First, it requires a more rigorous consideration of reliability and resource adequacy over smaller timeframes. This includes looking at seasonal differences in demand and resource capabilities as well as more granular *hourly* and *sub-hourly* reliability analysis. The days of focusing solely on *annual* peak demand and expecting the required resources to be able to meet demand in all hours of the year are gone.

Second, it requires a recognition that consideration of reliability contributions of intermittent renewable resources is likely to change over time as operational experience is gained and analysis methods improve. This introduces some additional uncertainty that was not previously a significant factor in considering resource adequacy.

Third, it necessitates a more risk-focused view of resource planning to consider potential changes in resource needs and the risk associated with reliance on other market resources to meet demand. Without the benefit of the capacity surpluses MISO and other markets previously enjoyed, there is little or no margin to absorb significant changes in resource needs, whether those needs be annual, daily, hourly, or minute-to-minute. Such changes could be driven by a number of factors, alone or in combination, that may include accelerated retirements or reduced generation due to environmental regulations or economic pressures, reductions in expected demand savings from energy efficiency, increases in demand due to electrification, higher loads due to extreme weather, catastrophic loss of a major resource, increased onshoring of manufacturing, or other factors.

Q. Has NERC indicated a need to examine reliability more rigorously?

A. Yes. In NERC's 2022 Long Term Reliability Assessment, published in December 2022 and attached to my Direct Testimony as Schedule MM-D12, it recognized a need for additional consideration of specific issues affecting reliability. Specifically, NERC indicated a need to consider the following:[16]

- Manage the pace of generator retirements until solutions are in place that can continue to meet energy needs and provide essential reliability services;
- Include extreme weather scenarios in resource and system planning;
- Address IBR[17] performance and grid integration issues;
- Expand resource adequacy evaluations beyond reserve margins at peak times to include energy risks for all hours and seasons;
- Increase focus on DERs[18] as they are deployed at increasingly impactful levels
- Mitigate the risks that arise from growing reliance on just-in-time fuel for electric generation and the interdependent natural gas and electric infrastructure; and
- Consider the impact that the electrification of transportation, space heating, and other sectors may have on future electricity demand and infrastructure.

[16] *See* Schedule MM-D12, NERC 2022 Long Term Reliability Assessment, page 7.
[17] Inverter-based resources.
[18] Distributed energy resources.

Q. Have any jurisdictions incorporated mechanisms to ensure resource adequacy during all hours?

A. Yes. In 2022, the California Public Utilities Commission formally adopted a new resource adequacy framework that includes hourly resource adequacy obligations for a representative day in each month.[19] While California's resource portfolio differs substantially from that of Ameren Missouri and MISO today, this framework represents the kind of rigor that will be increasingly important in ensuring a reliable electric supply for customers as portfolios are transitioned to include greater reliance on renewable resources.

Q. How is Ameren Missouri addressing NERC's recommended actions?

A. Ameren Missouri is focused on making a controlled, reliable, and affordable transition from its "old fleet" to its "new fleet." In short, this approach ensures that there is overlap in the development of the "new fleet" while retaining resources in the "old fleet" to ensure reliability during the transition (NERC's first recommendation listed above). Ameren Missouri also includes the following actions and considerations in its resource planning process:

- Consideration of extreme weather in accordance with the Commission's IRP rules;[20]
- Consideration of the need for operational and system experience to assess the reliability contribution and integration needs of intermittent resources like wind and solar;

[19] https://blog.ucsusa.org/mark-specht/changes-to-californias-resource-adequacy-program-will-have-huge-consequences-for-the-power-grid/
[20] 20 CSR 4240-22.030(8)(B) and 20 CSR 4240-22.070(1)(D)

- Performing granular reliability analysis with the assistance of Astrape' Consulting and its SERVM model to examine hourly and sub-hourly resource needs that are not considered in a traditional capacity-focused assessment of resource needs;
- Assessing a range of potential for customer-owned DER and the potential impacts of FERC Order 2222 and including multiple levels of DER adoption in the range of load forecasts generated for IRP analysis; and
- Inclusion of a range of potential electrification impacts in the range of IRP load forecasts.

Q. How is Ameren Missouri considering resource adequacy over smaller timeframes and the resource contributions of wind and solar resources?

A. Ameren Missouri is examining resource adequacy over smaller timeframes in three ways. First, the Company has incorporated MISO's new seasonal capacity construct for resource adequacy into its planning process. The Company first included a view of seasonal capacity in its analysis supporting its change in PRP filed in June 2022. Since that time, FERC has approved MISO's seasonal construct, and MISO has released information for market participants regarding the seasonal accredited capacity ("SAC") for each generating unit, including new wind and solar resources, and the required PRM for each of the four seasons – summer, fall, winter, and spring. These values were relied upon by market participants in preparing bid submittals for MISO's 2023-2024 planning resource auction, which set capacity prices for each season for the 2023-2024 planning year. Ameren Missouri's planning has focused primarily on the summer and winter seasons to date, since those seasons are expected to drive resource needs.

Second, Ameren Missouri uses detailed hourly and sub-hourly modeling to assess reliability. This has largely been performed by Astrape' consulting with its SERVM model, which is also relied upon by various RTOs, including MISO. In short, the SERVM model examines reliability with robust consideration of uncertainty and volatility – generator outages, load variability, wind and solar output variability, and other factors.

Third, Ameren Missouri is evaluating discrete timeframes under varying conditions to assess the contribution of wind and solar resources. This is done using a combination of historical and forecast data for loads, renewable resource performance, and available dispatchable capacity. The varying conditions evaluated include normal weather and load conditions as well as extreme conditions.

Ameren Missouri's consideration of seasonal resource adequacy, granular reliability modeling, and evaluation of specific timeframes are described in detail later in my Direct Testimony in this case and was also described in our 2022 PRP submission (Schedule MM-D2).

Q. How does Ameren Missouri consider risk with respect to resource adequacy?

A. The main way risk is considered is through examination of different scenarios such as accelerated retirements, constraints on generation output (e.g., as a result of emissions limits and other environmental regulations) and significant changes in demand. I provide examples later in my Direct Testimony.

To account for the implications of these trends, Ameren Missouri explicitly evaluates energy needs, beginning with its 2020 filing and continuing with its current PRP adopted and submitted to the MPSC in 2022 and its ongoing resource planning.

3. The Company's Expected Energy Needs

Q. Please describe how energy needs were evaluated in the analysis that led to the filing of the 2022 Change in Preferred Resource Plan.

A. We analyzed the operation of the alternative plan that became our PRP, and all alternative resource plans, using price scenarios in our IRP production cost model, PowerSimm Planner. This allows us to see the output of generation portfolios and compare the energy generation to our forecast of sales to retail customers. The charts below show comparisons of generation to our forecast of retail sales, or load, for three cases. The first chart, Figure 5, shows a portfolio in which resources are added *only* for a need to comply with the requirements of the Missouri RES. The second chart, Figure 6, shows a portfolio in which renewable resources are added *only* to comply with the RES plus the addition of NGCC in 2031. The third chart, Figure 7, shows a portfolio – the Renewable Transition Plan – in which the resources called for in the PRP are added, including the addition of 4,700 MW of wind and solar resources continuously, starting in the near-term and continuing over the next twenty years. As Figure 5 shows, the No New Non-RES Resources Plan results in total portfolio energy generation that is less than retail load[21] beginning in 2028, with energy deficits growing steadily through 2050 and reaching an annual energy deficit of 24 million MWh. Figure 6, the RES Only Plus CC in 2031 Plan, also shows a need for energy resources starting in 2028 through 2030, a modest annual surplus from 2031 through 2036, and a larger deficit beginning in 2037 and growing to 15 million MWh. In contrast, the Renewable Transition Plan (Figure 7) shows sufficient generation through 2040 and beyond, with an energy buffer comparable to the Company's historical length.[22]

[21] Using normalized loads.
[22] The energy buffer grows to a transient level of 12-15 million MWh annually, under normal load conditions and expected generation levels, between 2031 and 2036 as a result of the addition of NGCC in 2031 prior to the retirement of two units at Labadie Energy Center at the end of 2036.

Figure 5

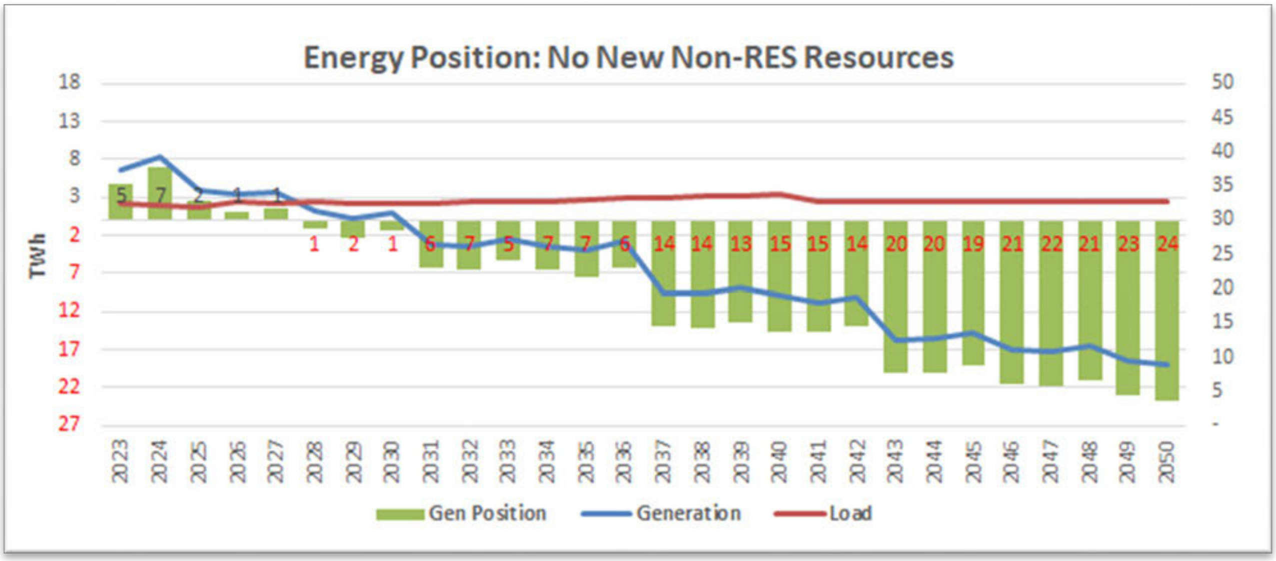


Figure 6

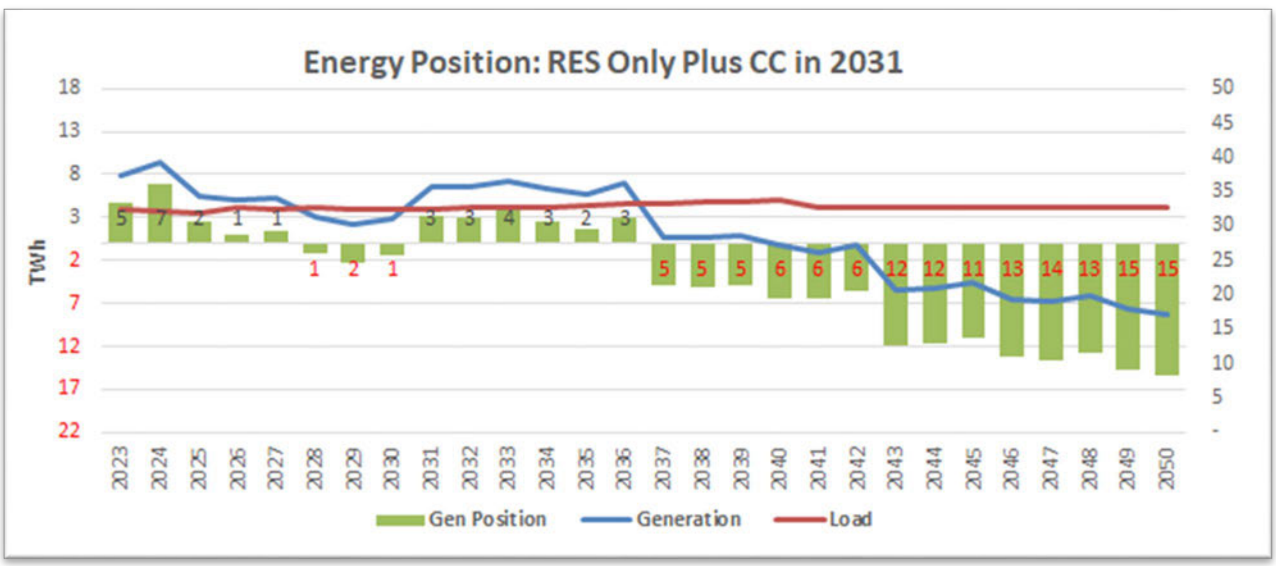
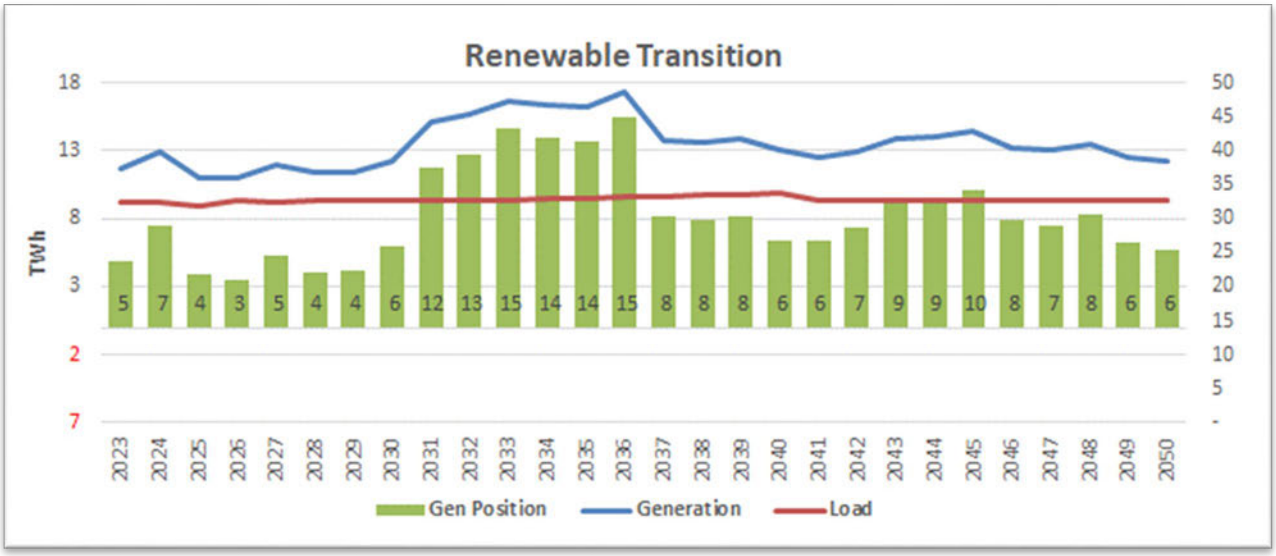


Figure 7



Q. Could the need for energy resources be greater and/or arrive sooner than suggested by the Company's base assumptions?

A. Yes. Planning is always performed in the context of uncertainty, and a number of factors could accelerate our need for energy resources. Examining these risks is an essential part of our IRP process. The need for energy resources becomes even more apparent – and happens sooner – if we consider generation output under a High CO_2 price scenario, as illustrated in the following charts (Figures 8, 9, and 10) showing the same three plans as above but with High CO_2 prices.

Figure 8

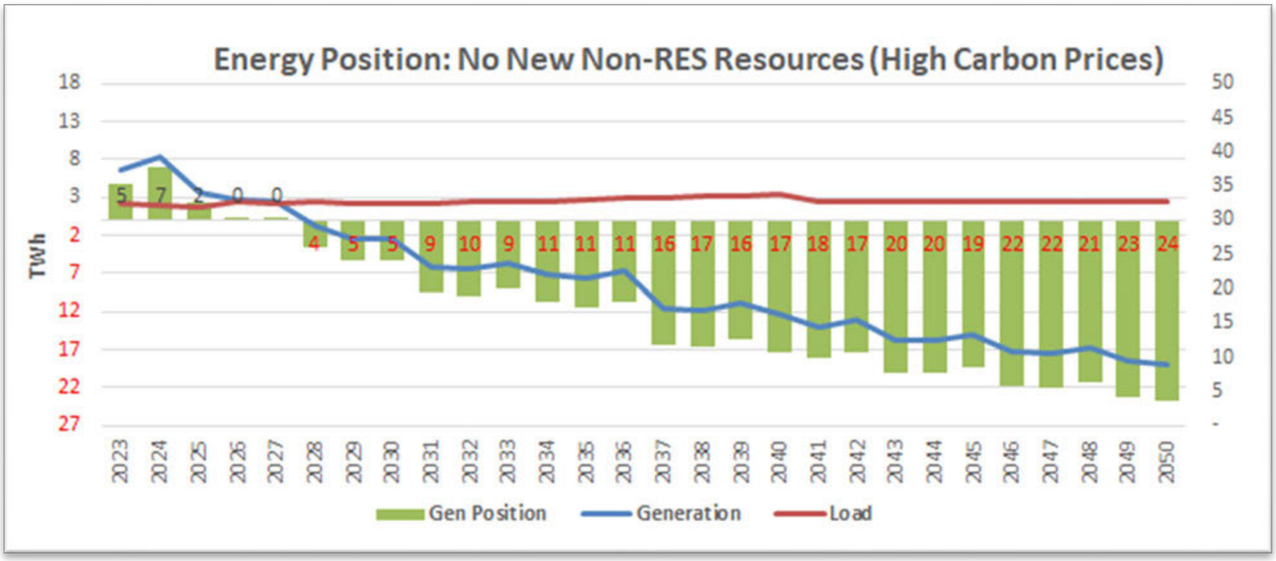


Figure 9

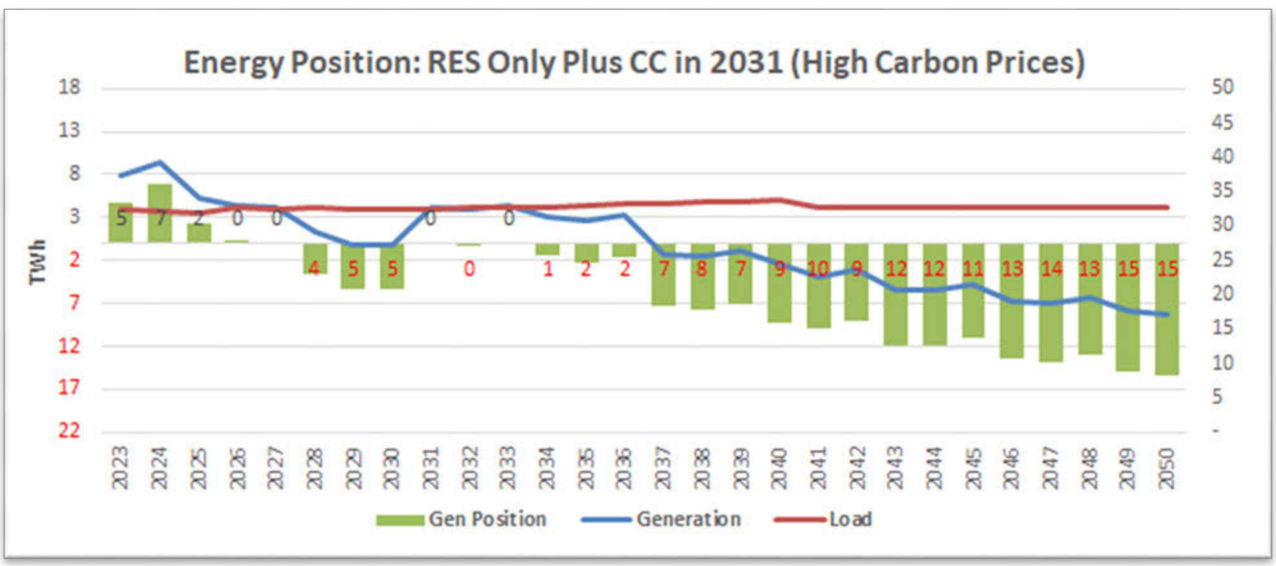
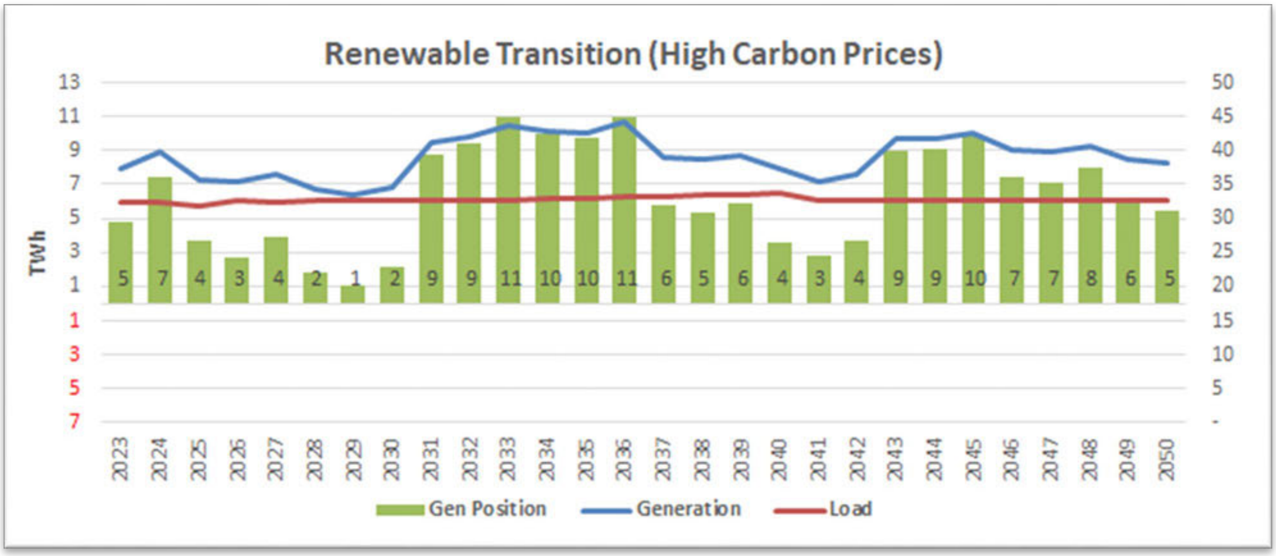


Figure 10



As the charts in Figures 8 and 9 show, the total portfolio generation output without new non-RES renewable resources falls below the total retail load starting in 2028 as it did under the probability weighted CO_2 price results. However, the shortfall is greater in that year and other years. The Renewable Transition Plan, on the other hand, indicates total generation output at or above our forecasted retail load throughout the twenty-year planning horizon. Another risk is the potential for higher than planned loads. The charts below (Figures 11, 12, and 13) show the same three portfolios described above but with both high CO_2 prices and high loads.

Figure 11

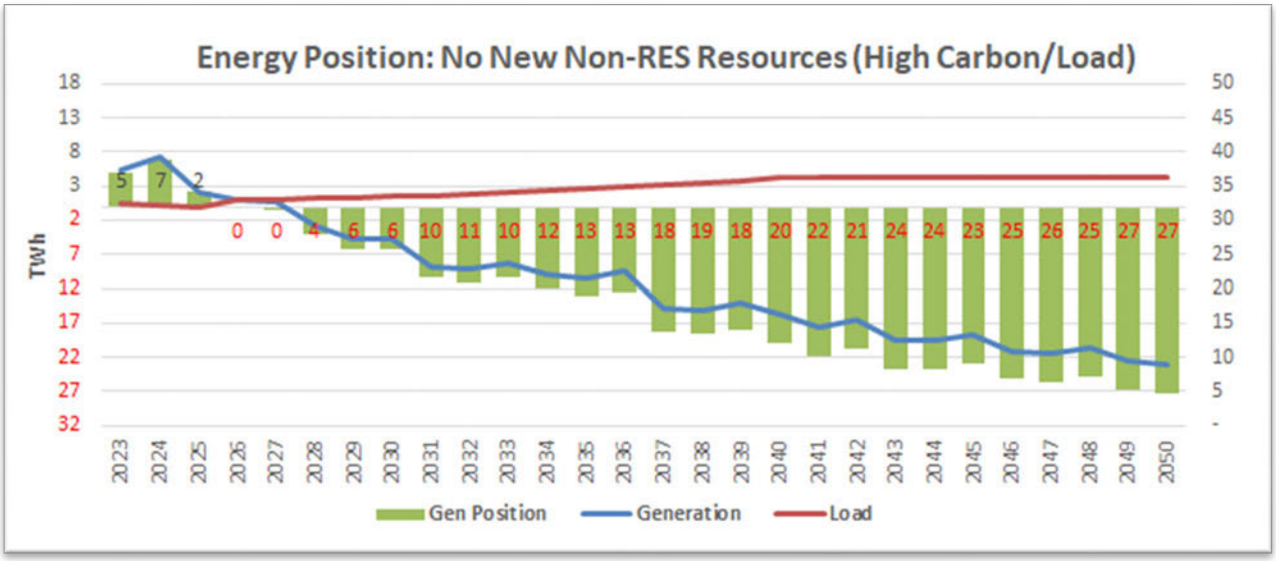


Figure 12

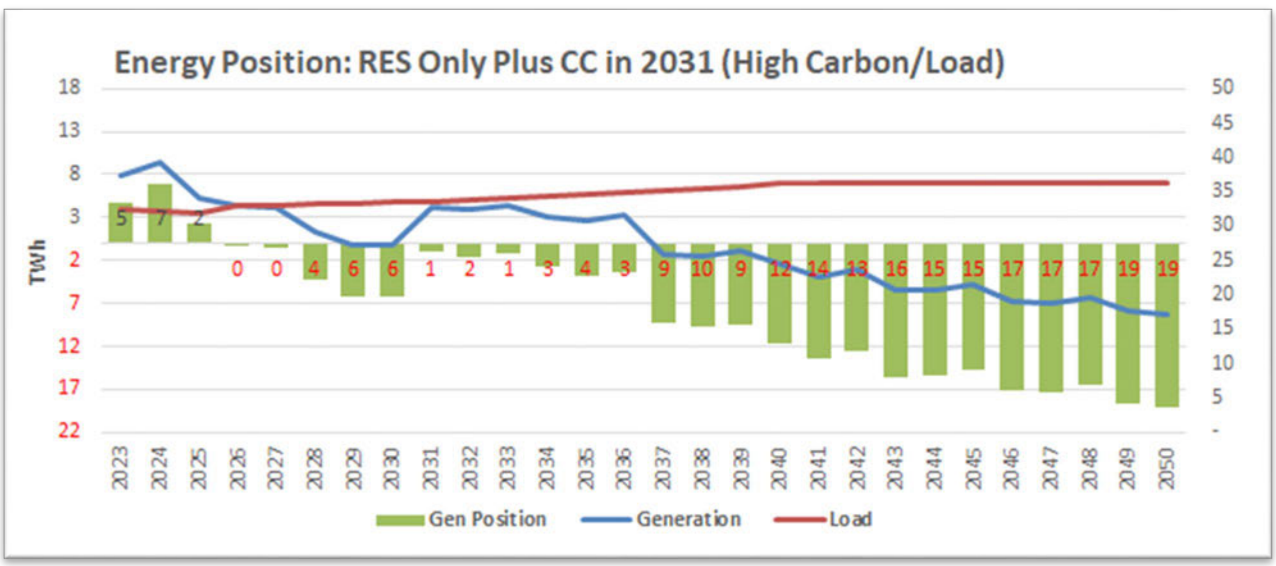
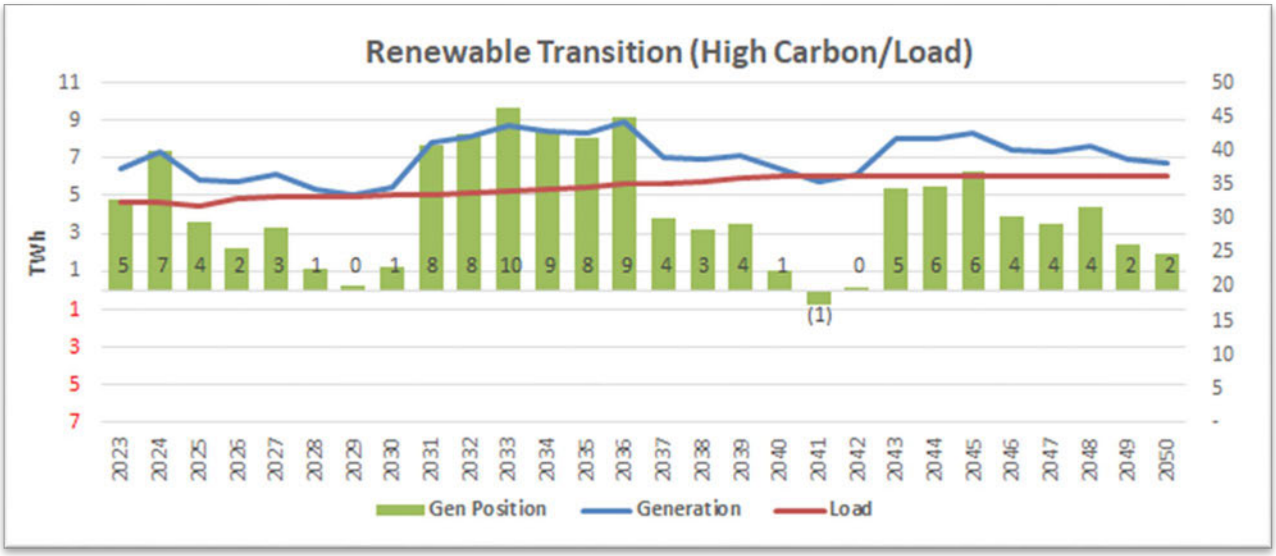


Figure 13



As the charts in Figures 11-13 show, the need for energy would be even greater under these conditions (high load and high carbon prices), and even the addition of the NGCC in 2031 would not be sufficient to meet customer energy needs even for the few years following its in service date. The Renewable Transition Plan (i.e., the PRP) meets energy needs in nearly all years, although there is one year (2041) in which energy needs are not met, and there are several years in which the energy buffer is very small, including in 2028-2030.

Q. Do the energy positions shown above reflect any updates from those you provided in the Boomtown CCN case?

A. No. The Company is currently preparing its 2023 IRP and has not yet finalized its energy analysis. The implications of uncertainty with respect to load and CO_2 prices are expected to remain important factors with respect to considering risks to energy position nonetheless.

Q. Are there further risks to the energy position that highlight the need for energy resources and an energy buffer?

A. Yes. Newly effective and proposed environmental regulations are expected to result in reduced generation from fossil fueled resources, including existing coal and new gas-fired resources. The new and proposed environmental regulations include the Good Neighbor Rule, which establishes more stringent limits for NOx emissions during May through September, and a newly proposed rule limiting CO_2 emissions from coal and gas-fired generators. While dispatchable resources will continue to be vitally important to ensuring reliability, the level of energy production from these resources may be significantly lower in the future as more and more renewable resources are added to the grid.

Q. Is it possible that Ameren Missouri will need more renewable resources than shown in its PRP through 2040?

A. Yes. It is possible that we may need more renewable resources than shown in our PRP. Regardless, we can and will adjust the mix of wind and solar we add throughout the planning horizon, including prior to 2030, as conditions change. That we cannot say for sure exactly how much we will eventually need, and when we will need it, simply highlights the importance of the flexibility that Ameren Missouri maintains as part of its IRP process. As conditions change – technology development, policy changes, market changes – the Company can adjust and refine its planning. Changing conditions will also likely include changes in the resource plans and implementation of other market participants, both in MISO and in neighboring regions.

Rather than wait for such conditions to settle (and they *never* will), it is important that the Company continue to execute the transition of its portfolio based on the best information available, the consideration of risk and uncertainty, and the need to continue to maintain flexibility. Most significantly for the Application in this docket, however, there is a very low chance that the renewable capacity additions our PRP calls for prior to 2030 will not be needed, and there is virtually no chance we won't need at least an additional 550 MW of solar beyond that which has already been approved.

Q. Does the potential need for new energy resources depend entirely on whether and to what extent a price is placed on CO_2 emissions?

A. No. Our consideration of a range of CO_2 prices is just one way to reflect impacts on the operation of existing resources of potential changes in energy policy. Other approaches to energy policy might rely on regulatory mandates that restrict the ability to operate fossil-fueled resources, such as Illinois' Climate and Equitable and Jobs Act or require the addition of expensive environmental controls that may diminish the economic viability of fossil-fueled resources. It is clear that there is a broad and sustained effort to find ways to transition the U.S. power industry away from fossil fuels and toward cleaner resources, such as renewable generation. The question is what form future policy will take. Regardless of its form, we must be prepared to meet our customers' energy needs in an affordable and reliable manner.

Q. Does the addition of solar generation also help to mitigate other risks with respect to the need for energy resources?

A. Yes, it does. Illinois' Clean Energy and Jobs Act ("CEJA") imposed significant limits on our Illinois combustion turbine generators. Environmental regulations recently finalized and additional regulations currently under consideration by the U.S. EPA, if implemented, would limit the Company's ability to operate existing resources. The EPA recently published final revisions to the Cross-State Air Pollution Rule ("CSAPR") that will constrain the generation of Ameren Missouri's coal-fired units absent investment in pollution control equipment. Because the rule revisions are focused on ozone season emissions, these constraints are expected to limit generation during the summer months. Significant generation from solar resources during the summer months would provide a large measure of mitigation. EPA has also announced proposed rules regulating CO_2 emissions from fossil generators. While the proposed rules may change and are not expected to be finalized until next year, the additional mitigation provided by new solar resources can be an inexpensive form of insurance against these or other regulations that might similarly constrain generation from existing resources.

Q. Has the Company evaluated energy needs and the role of solar resources in fulfilling those needs on a more granular basis?

A. Yes. Ameren Missouri has analyzed hourly energy needs and expected generation, which highlights the value of the Solar Projects and the Company's longer-term renewable additions in meeting customer energy needs. This was done by taking the Company's new 2023 IRP load forecasts and showing an explicit build-up of energy resources compared to the load. Specific time periods were evaluated, including summer and winter peak conditions, for several key timeframes during the 20-year planning horizon.

Q. What does that analysis show?

A. In short, 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 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 recently finalized CSAPR rule changes affecting coal generation during the summer months and proposed rules regulating CO_2 emissions.

I described these regulations and their expected implications on energy needs earlier in my Direct Testimony.

The series of charts below, Figures 14-17, show energy needs and generation for the month of July. Analysis results are shown for (a) 2026, following the retirement of Rush Island, with and without the continued investments in renewable resources embodied in the Company's PRP; (b) 2031, following the retirement of Sioux; and (c) 2037, following the retirement of the first two units at Labadie. Resource additions likewise follow the PRP timeline shown in Figure 1. Figures 14 (without the Solar Projects) and 15 (with the Solar Projects) show that the Solar Projects are expected to help meet energy needs during the summer peak period in the relatively near term. This is not the only time solar resources generate electricity, but its value tends to be greatest during these times.

Figure 14 – July 2026 Retail Load and Energy Resource (No New Renewables)

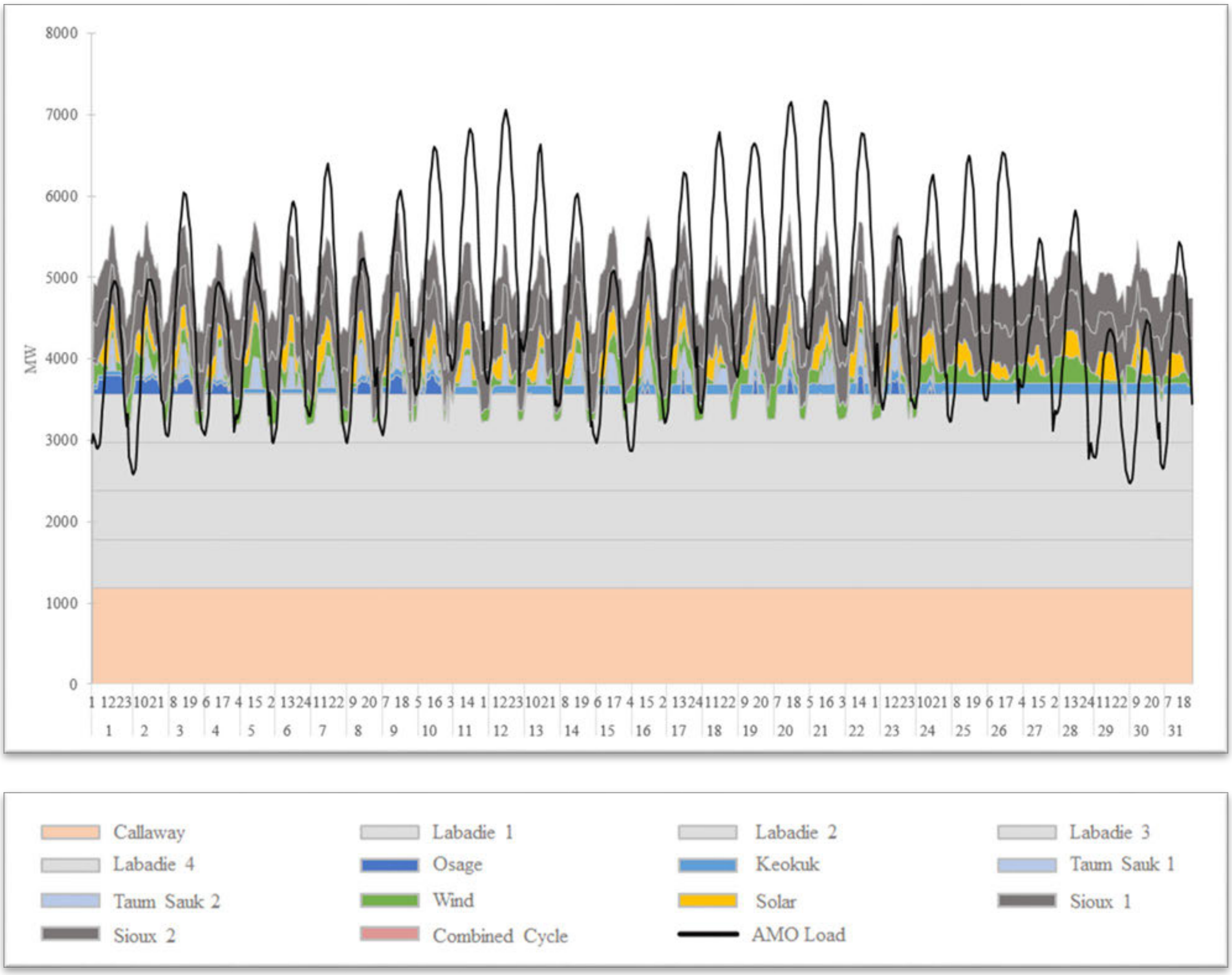
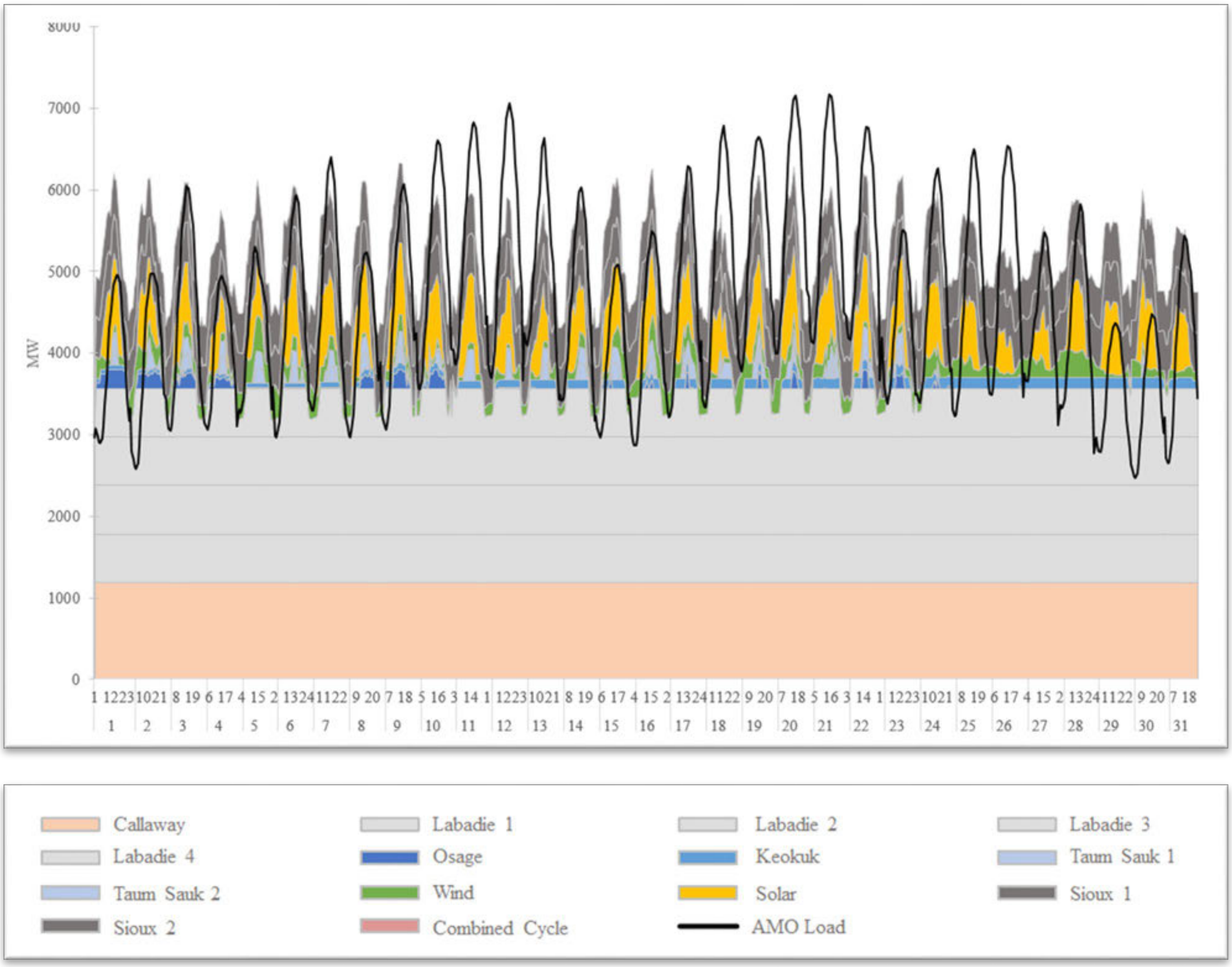


Figure 15 – July 2026 Retail Load and Energy Resource (PRP Renewables)[23]



Similarly, Figures 16 and 17 show the contribution of the PRP renewable additions, including the Solar Projects, in 2031 (after the retirement of Sioux) and 2037 (after the retirement of the first two Labadie Units), respectively. While the charts also reflect the addition of the NGCC addition, any energy generated beyond the needs of Ameren Missouri's native load customers

[23] In this and the following figures, note that the legend should be read left to right by row, with Callaway's generation at the bottom of the stack, followed by Labadie 1 through Labadie 3 in the first row of the legend, then Labadie 4 in the second row, and so on.

results in market revenues that serve to offset the cost of service to customers, either through base rates or through the FAC.

Figure 16 – July 2031 Retail Load and Energy Resource (PRP Renewables)

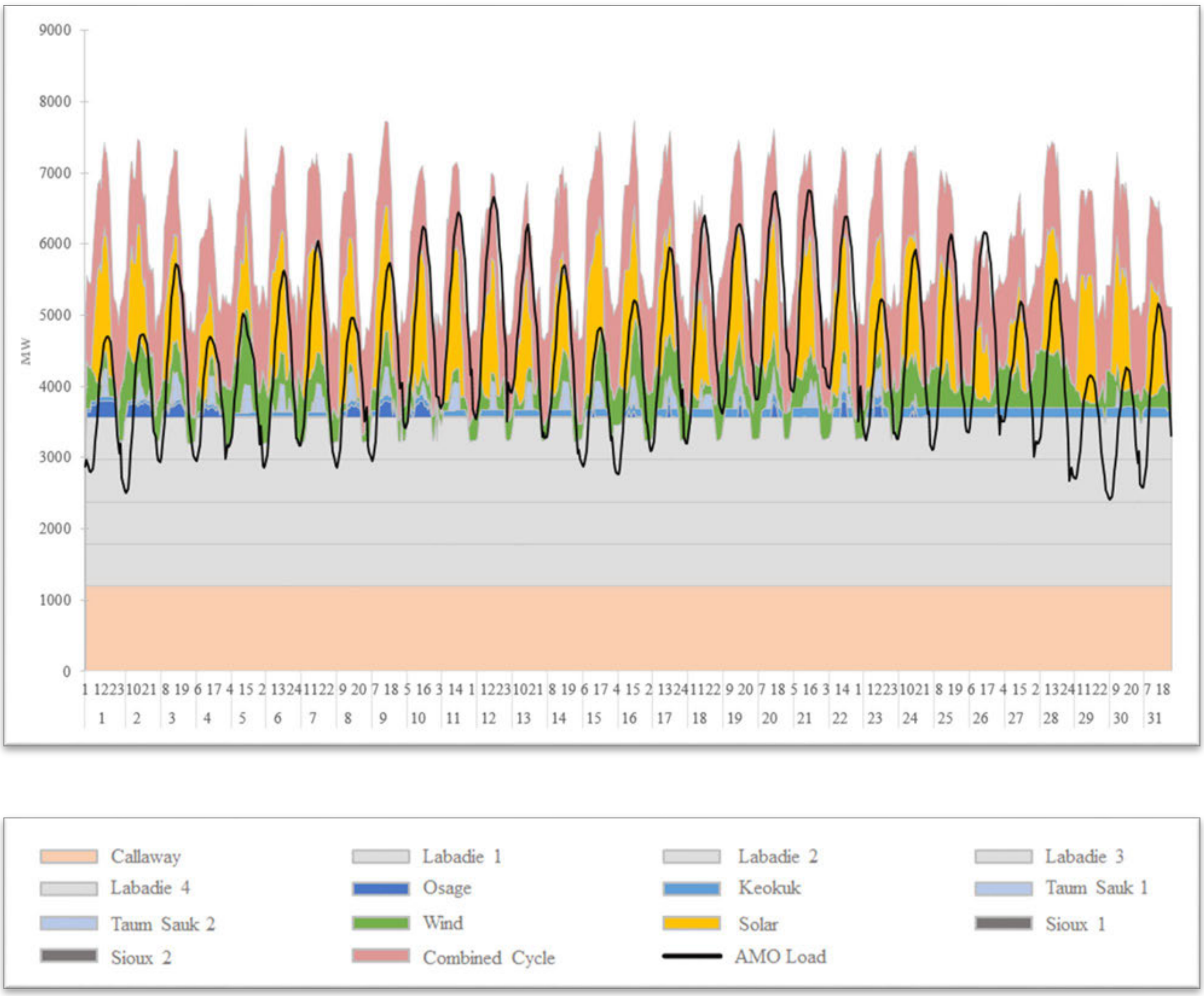
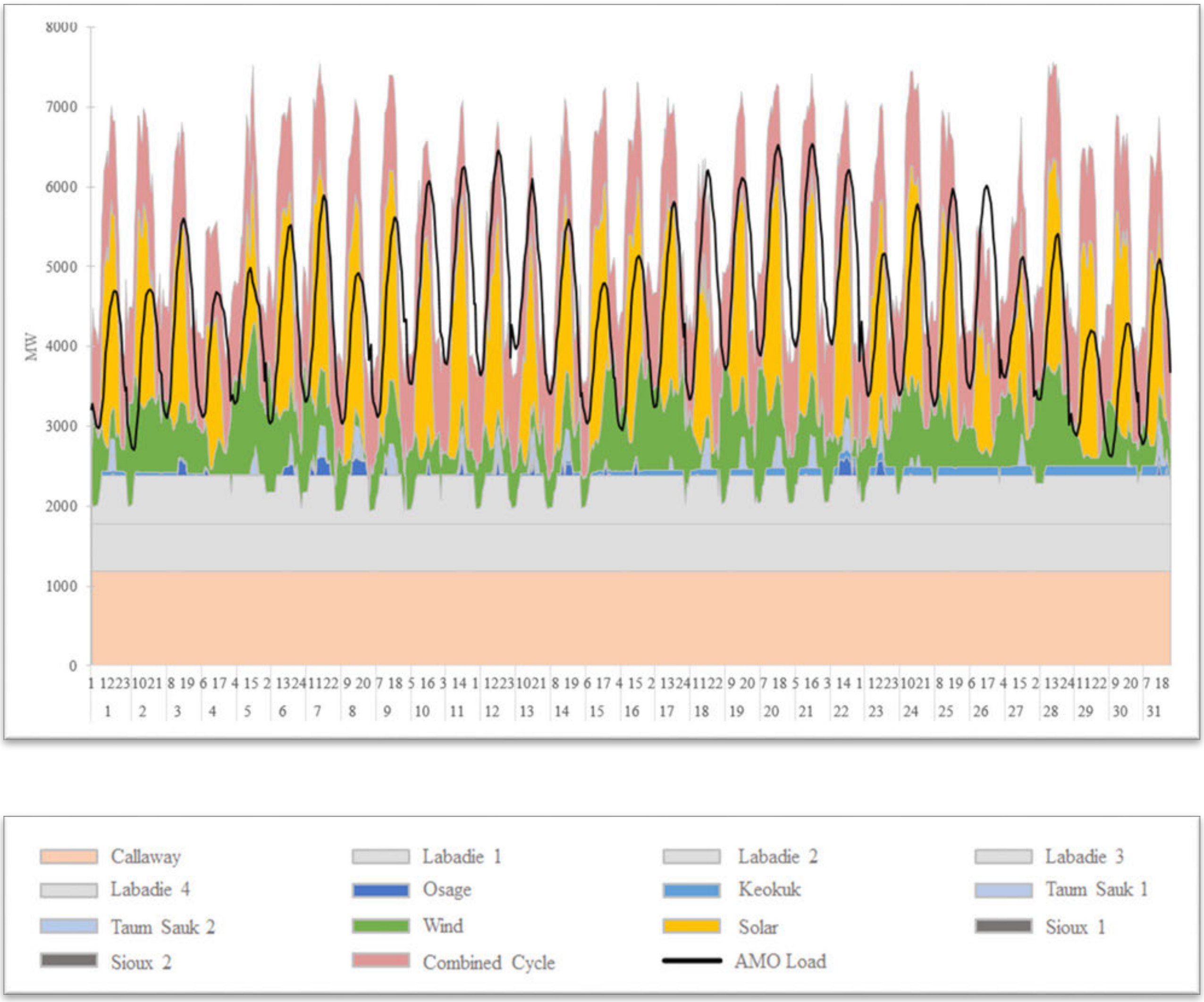


Figure 17 – July 2037 Retail Load and Energy Resource (PRP Renewables)



Q. Please describe in more detail what is shown in Charts 14-17.

A. The charts show retail load (the black line) and expected output of generation resources under normal conditions. Output for wind and solar resources are based on generic historical wind and solar output under normal weather conditions, as is hydroelectric production and pumped hydro (pumping and generation). Thermal resources – nuclear, coal, and NGCC – are shown at their maximum output. Baseload resources (Callaway and Labadie) are shown at the bottom of the stack, followed by hydroelectric and pumped hydro resources, then wind and solar.

Cycling resources – Sioux and NGCC – are shown on the top to reflect their role as capacity reliability resources to fill in gaps when wind and solar production are low, with any generation above the load requirement resulting in off-system sales revenues, which are credited against the retail revenue requirement through base rates or through the FAC. Peaking gas resources are not shown since they are subject to operating limits and typically operate only under peak demand conditions – i.e., because they are capacity resources and not energy resources.

Q. You mentioned that you looked at both summer and winter peak periods. Please discuss your observations for these periods.

A. The next series of charts, Figures 18-21, show a single day for each of the summer and winter peak periods in 2031 and 2037 with the renewable additions in the PRP. These charts illustrate the contribution of renewable resources, including the Solar Projects, to meeting customer energy needs. These charts are based on the actual weather pattern for Ameren Missouri's service territory during 2022 but reflecting expected load changes for those years consistent with the Company's 2023 IRP load forecast.

Figure 18 – July 5, 2031, Retail Load and Energy Resources

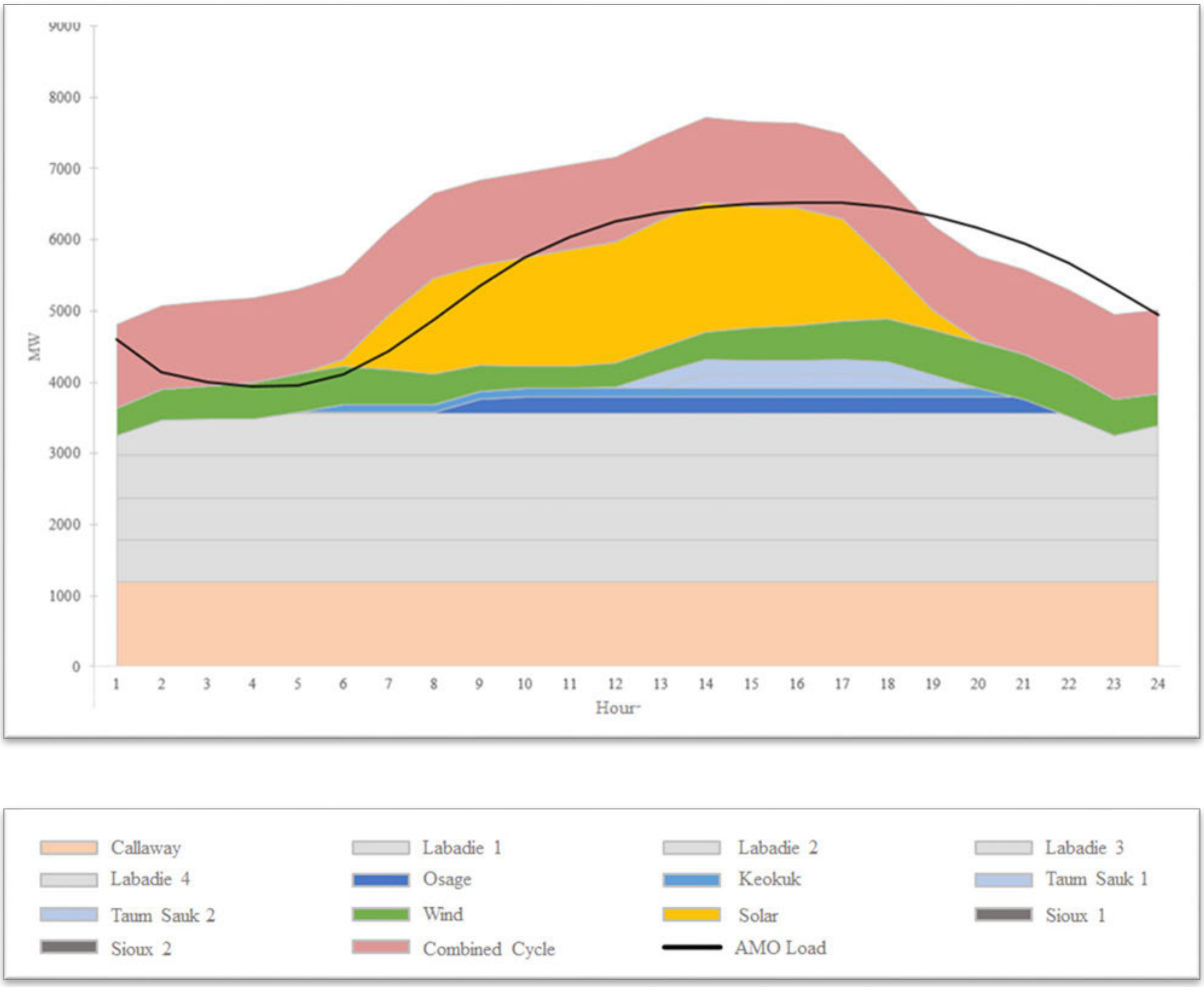
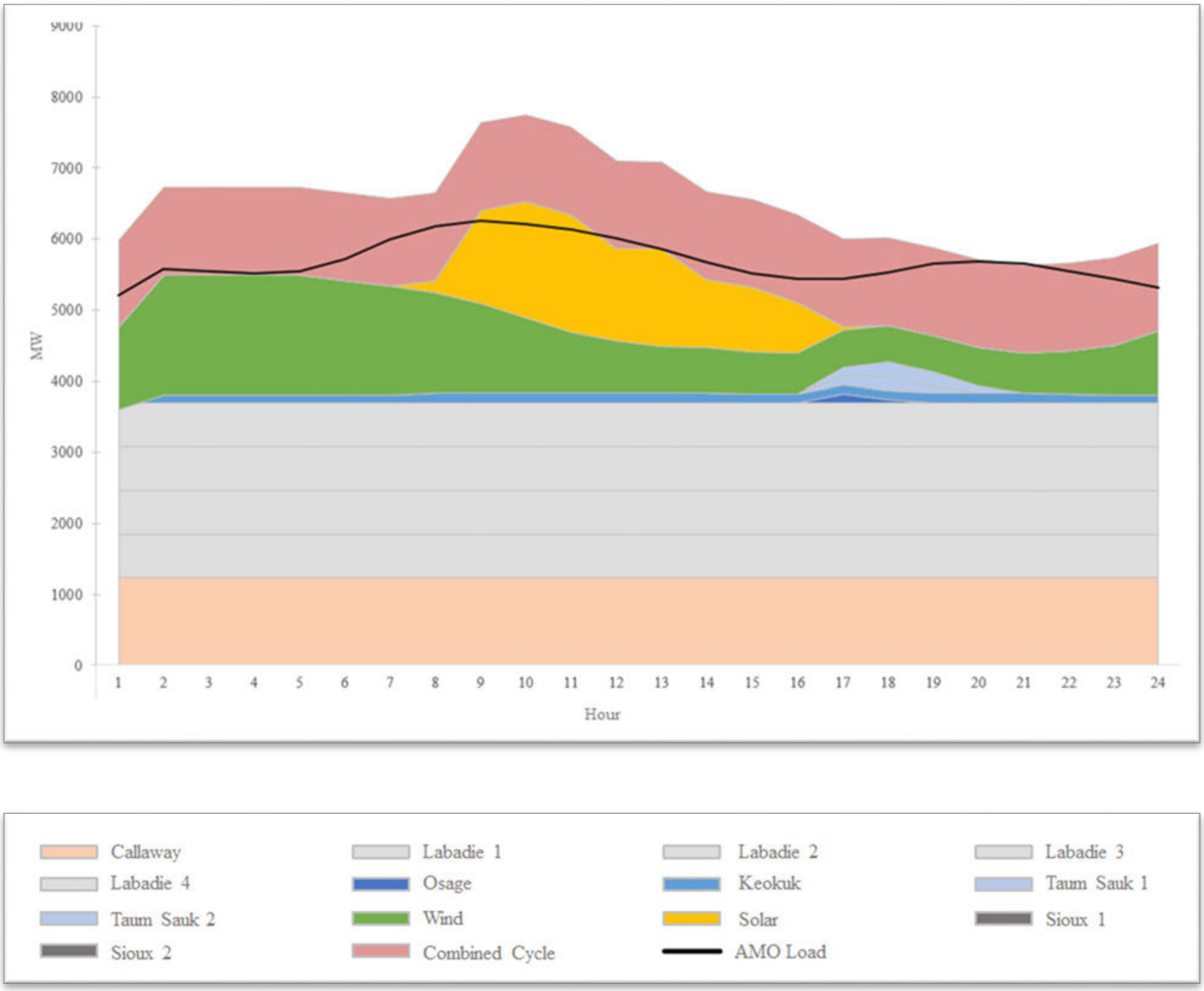
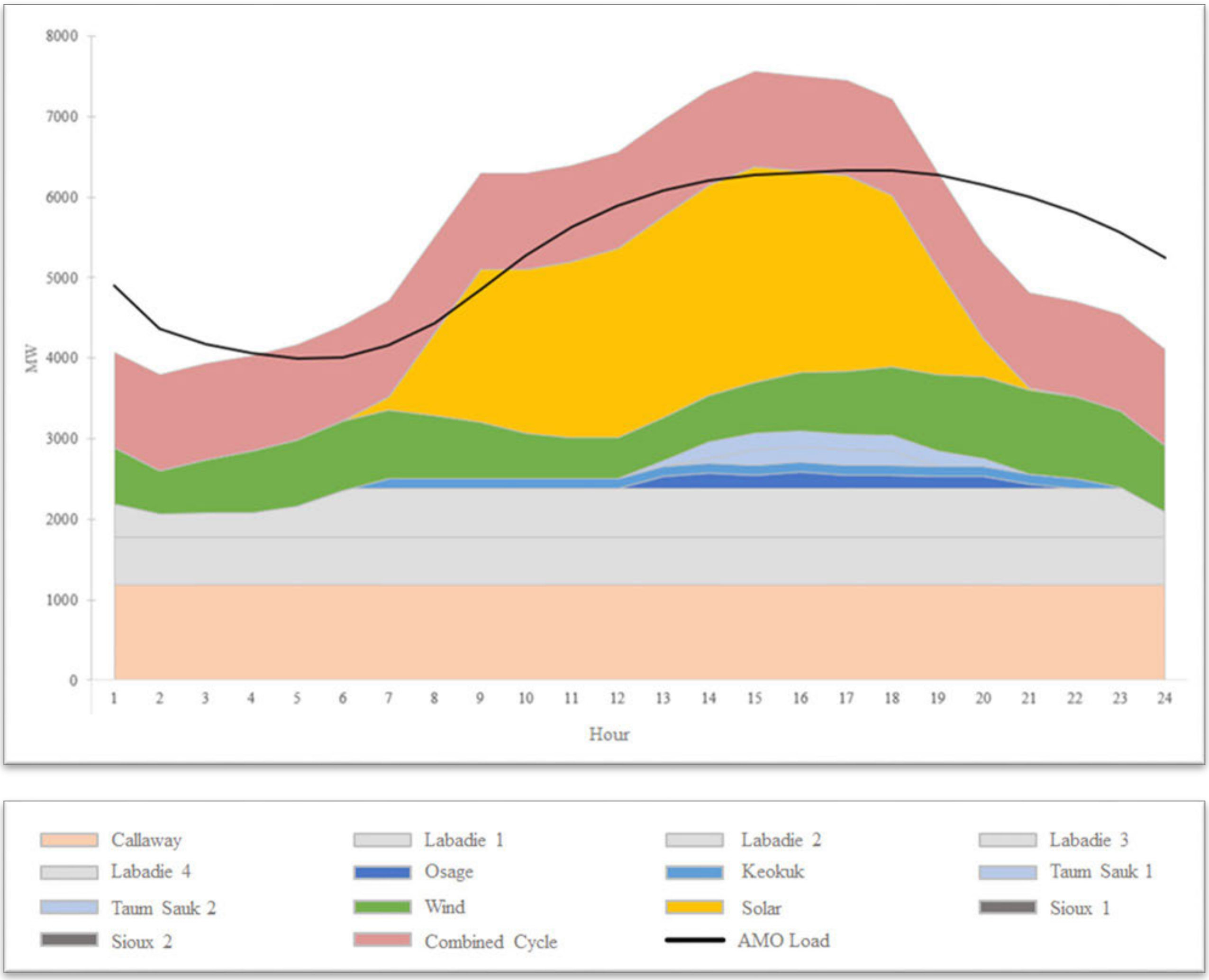


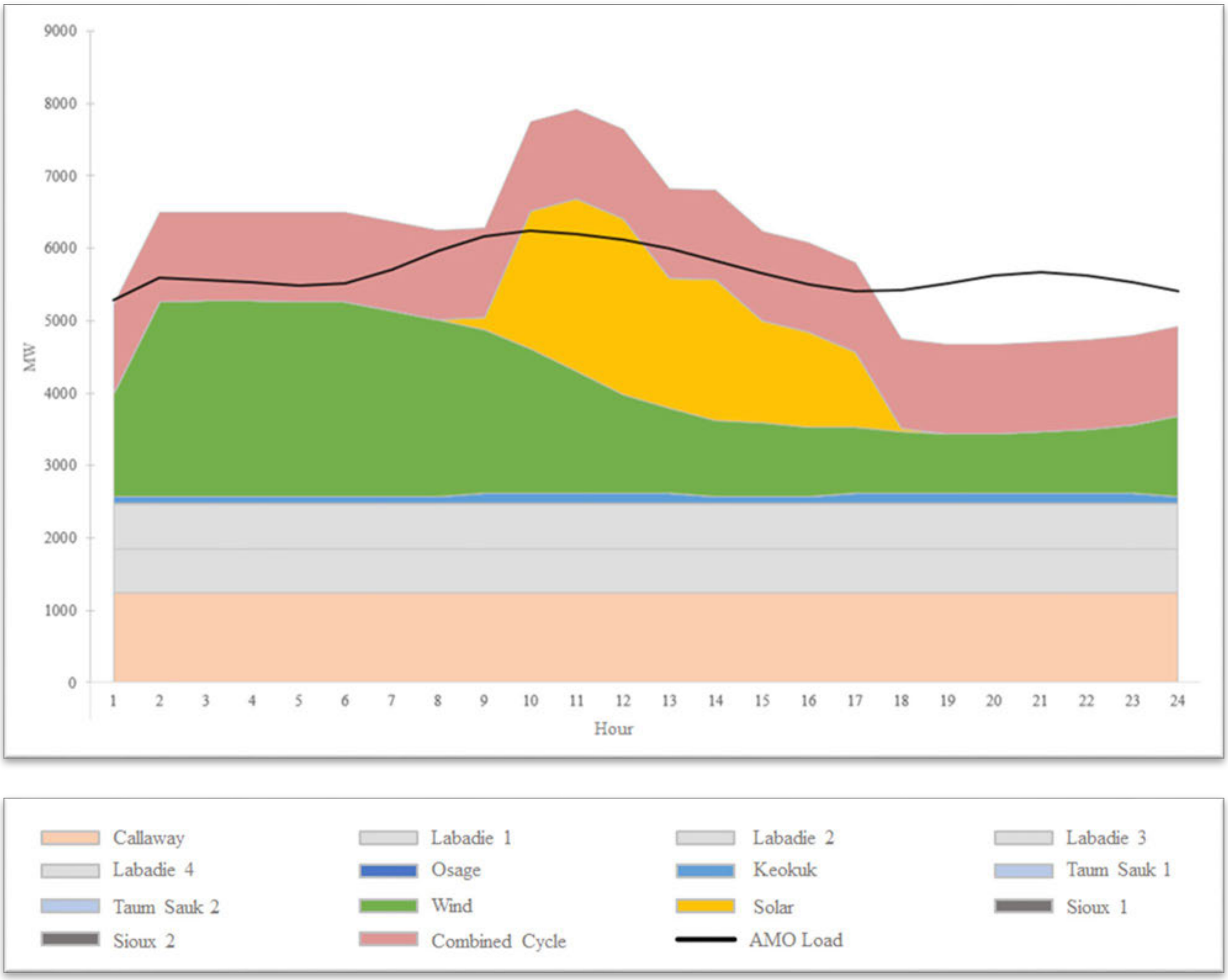
Figure 19 – Dec. 23, 2031, Retail Load and Energy Resources



1 **Figure 20 – July 5, 2037, Retail Load and Energy Resources**



<u>Figure 21 – Dec. 23, 2037, Retail Load and Energy Resources</u>



Note how the contribution of solar resources becomes both greater and more important during summer peak load conditions over time. The high correlation between solar generation and summer peak demand, driven by cooling load, highlights the importance of solar resources, including the Solar Projects. During winter peak periods, as shown in Figures 19 and 21, we see a different dynamic – one in which the somewhat complementary nature of wind and solar resources helps to meet hourly energy needs. Note that the battery storage included in the PRP could be used to shift the energy generated by wind and solar resources to hours later in the day when combined wind and solar generation are lower. Also note the benefits of the NGCC generation, which provides energy on demand. The resource transition reflected in the PRP includes all these elements working in concert as part of the "new fleet" I described previously.

4. The Company's Expected Capacity Needs

Q. Does planning for Ameren Missouri to be a net seller of energy mean that the Company is planning to build more capacity than it needs?

A. No. Ameren Missouri develops an annual capacity position based on forecast peak demand, including demand savings from energy efficiency and demand response, a planning reserve margin set by MISO, and the expected capacity of existing generation resources, including changes in generating capacity due to planned retirements and changes in operations (e.g., the addition of pollution control equipment). Historically, the capacity position has been focused solely on the summer peak demand period. In August 2022, the Federal Energy Regulatory Commission ("FERC") approved MISO's proposal to move to a seasonal capacity construct, whereby Load Serving Entities will be required to meet seasonal capacity requirements. Ameren Missouri has updated its evaluation of capacity need to reflect consideration of seasonal capacity requirements consistent with MISO's latest data for the 2023-2024 planning hear. The charts below (Figures 22 and 23) show the Company's expected capacity position under the Preferred Resource Plan for both winter and summer.[24]

[24] Assumption changes since the Company's 2022 Notice of Change in Preferred Plan filing are listed in Schedule MM-D16.

Figure 22[25]

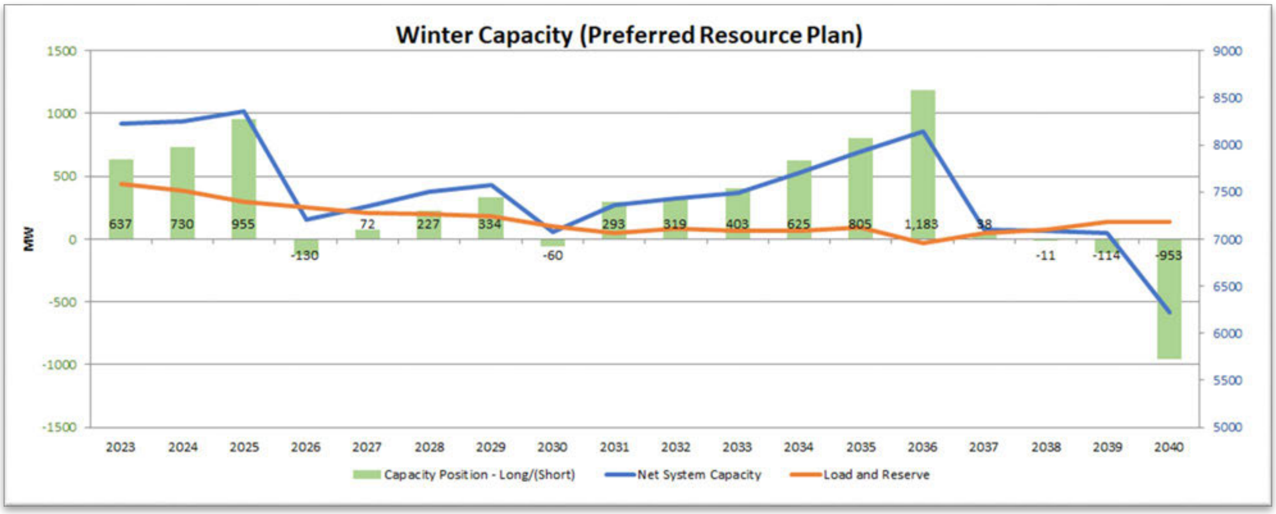
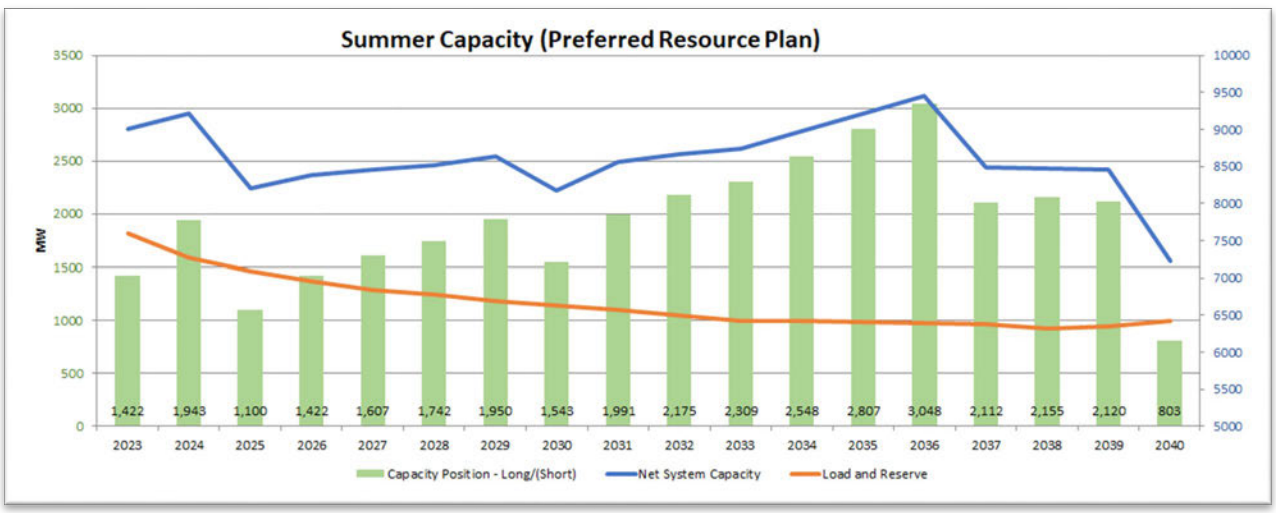


Figure 23



Q. What do capacity positions show without the Company's planned transition?

A. Capacity positions for winter and summer with no new resources beyond RES compliance are shown below (Figures 24 and 25). The winter capacity position shows a need for capacity beginning in 2026. Note that this could be sooner depending on the final retirement date

[25] For all capacity position charts, the lefthand scale shows the long or short position depicted by the green bars, and the righthand scale shows the total load or generation depicted by the red and blue lines.

of the Rush Island Energy Center. The summer capacity position shows a long-term need for nearly 2,400 MW of capacity, with the first shortfall in 2031.

Figure 24

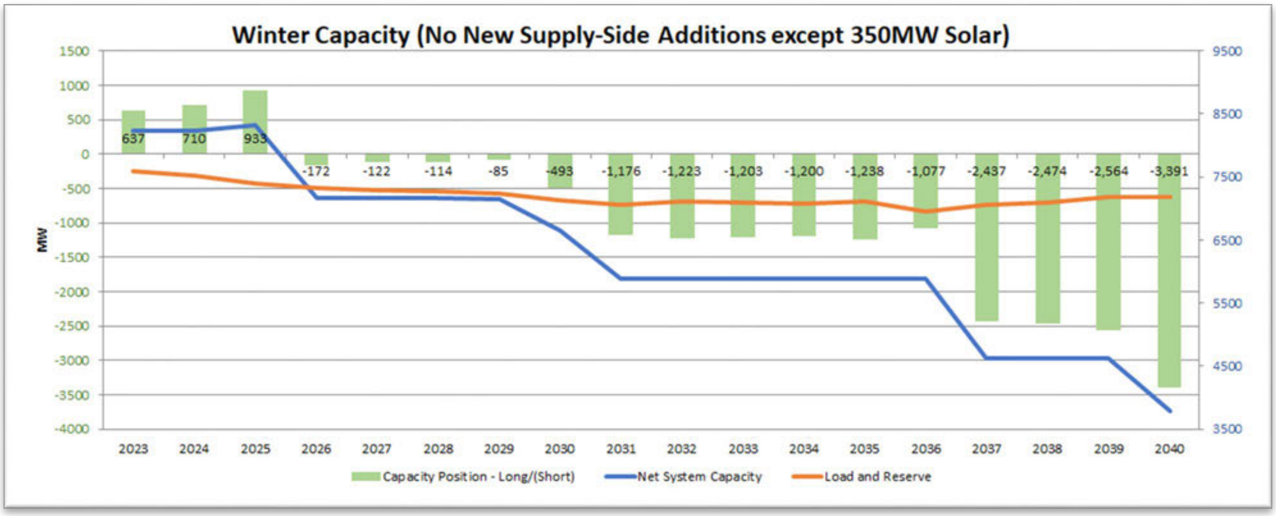
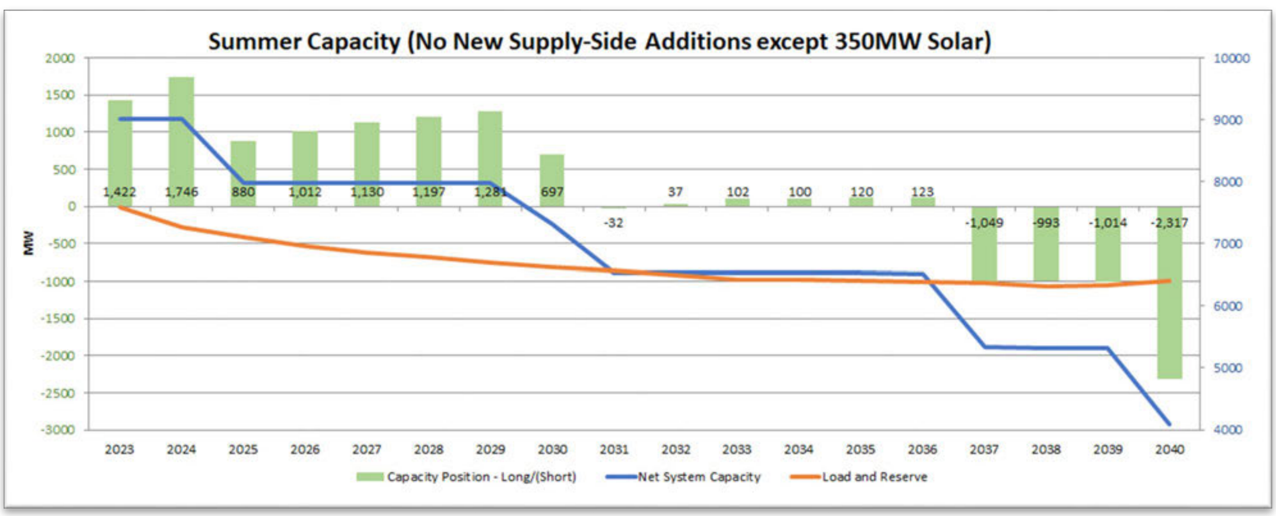


Figure 25



Q. Do the capacity positions shown above reflect any updates from those you provided in the Boomtown CCN case?

A. Yes. These capacity positions reflect Ameren Missouri's updated load forecast developed for its 2023 IRP. They also reflect updated capacity benefits from energy efficiency and demand response programs as determined by the Company's latest DSM market potential study, which will also be used in the Company's 2023 IRP analysis. Further, they reflect updated capacity accreditation multipliers for wind and solar. Finally, they include the restoration of oil backup for the Peno Creek and Kinmundy Energy Centers starting in 2025.[26]

Q. How were the capacity accreditation multipliers for wind and solar determined?

A. Values for the 2023-2024 planning year for MISO resource adequacy purposes are those used by MISO for the 2023-2024 PRA. Capacity multipliers typically decline as renewable penetration increases. To determine long-term multipliers for wind and solar, the Company requested analysis by Astrape' Consulting using its SERVM model for the year 2040 to separately determine the incremental capacity benefit of wind and solar added to the system based on the expansion of renewable resources in the Company's PRP. Results of the analysis both with and without external market support are shown in the charts in Figure 26 below.[27]

[26] The addition of oil-fired backup at Audrain Energy Center is not included but is being evaluated as part of the Company's 2023 IRP analysis.
[27] ELCC = Effective Load Carrying Capability.

Figure 26


Summer Average
(w/ Market Support)
Summer Average
(w/o Market Support)
Winter Average
(w/ Market Support)
Winter Average
(w/o Market Support)
ELCC
MW
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
1000
2000
3000
Solar
Wind

Because the Astrape' results yield higher values for summer wind and winter solar in 2040 than is used by MISO for planning year 2023-2024, the MISO values for 2023-2024 are used throughout the planning horizon for summer wind (18.1%) and winter solar (5%). The seasonal values for 2023-2024 and 2040, based on the average of the results shown above, are shown in the table below, with multipliers for intervening years based on a straight-line interpolation.

Table 1

Wind and Solar Capacity Accreditation Multipliers				
	2023-2024		2040	
	Summer	Winter	Summer	Winter
Wind	18.10%	40.30%	18.10%	30%
Solar	50%	5%	40%	5%

Q. The summer capacity position shows that the PRP adds more capacity than is needed to meet load and reserve margin requirement. Why is that?

A. Ameren Missouri plans to add the amount of new capacity resources necessary to meet its capacity requirement in all seasons. So, while it is true that the summer capacity position shows generating capacity above and beyond the need to meet load and reserve margin requirement in all years, those resource additions are necessary to ensure reliability in the winter season as demonstrated by the winter capacity position. Ameren Missouri can sell excess capacity into the MISO market and use that revenue to reduce costs to customers. The Company's IRP modeling reflects the sale of surplus capacity and the purchase of needed capacity to meet reserve margin requirements.

Q. Does it make sense to carry a greater level of capacity than is required by MISO?

A. It does when various risks and realities are considered. First, it must be recognized that the PRM is a minimum requirement. It should not in any way be viewed as a cap.

Second, capacity additions are "lumpy" by nature. It would be virtually impossible to try to exactly match capacity resources to capacity needs, and as the capacity position charts for summer and winter in Figures 8-11 above show, resource needs will be different in different seasons.

Third, even if resources could be exactly matched to need, waiting until the exact moment it is needed to add the resource or resources carries inherent risk that things may not go as planned. As mentioned previously, among other factors demand could change rapidly, resources could be retired or constrained sooner than planned, or loads could be higher than expected, including if the planned savings from demand-side programs fall short.

Fourth, and perhaps most relevant to this case, resources may be added to satisfy an energy need. As I mentioned before, renewable resources are primarily energy resources. They provide low-cost, carbon-free energy that is not subject to fuel price variability, because the "fuel" is free.

Q. Has Ameren Missouri previously added resources to address long-term needs?

A. Yes. Ameren Missouri has implemented MEEIA programs for a decade, during which time the Company and its customers have enjoyed the benefits of surplus capacity and energy. The deployment of demand-side resources pursuant to MEEIA recognizes real world considerations. Most notably, demand side resources are best implemented over a long time and before a resource need (from a pure, just-in-time capacity position planning standpoint) is imminent. Doing so over the last decade has put Ameren Missouri and its customers in a far better position from a reliability standpoint than if the Company had waited and tried to align the timing of deployment of demand-side resources more precisely with an imminent and strictly PRM-based capacity need.

Q. Is the deployment of renewable resources similar to the deployment of demand side resources?

A. Yes, in several ways. Renewable energy resource projects are typically on the order of hundreds of megawatts rather than a thousand megawatts or more. You can see that based on the 200 MW Huck Finn project and the 150 MW Boomtown project, both of which received CCN approval from the Commission, and based on Ameren Missouri's other recently added utility-scale renewable energy resources, which range in nominal capacity from 300 to 400 MW. One such project by itself does not necessarily "solve" a specific need; it is the *portfolio* of projects taken together that does so.

Demand side programs under MEEIA typically provide annual incremental demand savings on the order of 100-200 MW as well. Another similarity is the consideration of lost opportunities. Demand side programs are often designed to incentivize customers to make more energy efficient choices for appliances and applications that may have a life of ten years or more. If a less energy efficient choice is made, that opportunity is lost for a significant time. Similarly, the opportunity to build or acquire a renewable project at a favorable location may not be available later. This is important from at least a couple of perspectives, including locating resources where the wind or solar conditions are favorable, where transmission interconnection costs are minimized, and locating resources across a broad region to obtain a measure of geographical diversity can be leveraged since the sun does not shine and the wind does not blow at the same time or with the same intensity in all places at once. This is not to say that renewable resources and demand side resources are exactly the same or involve exactly the same considerations. Rather, it is simply important to recognize the specific characteristics and constraints of resource implementation for each resource type.

Q. Does the addition of solar generation in the near-term help to fulfill a need for capacity?

A. Yes, it does. Both Ameren Missouri and MISO are traditionally summer peaking. On hot summer afternoons, high demand can strain grid operations. Conveniently, this is usually the time when solar resources are generating at their highest output. The Solar Projects will provide capacity value on peak summer days, contributing energy and capacity to the grid when its reliability is potentially most at risk. Annual peak demand is also when MISO will have to dispatch its most expensive resources; the marginal zero-cost energy of solar resources can provide low-cost energy to the grid during times of peak demand and high costs, that is, every MWh produced by these facilities at those times will be a MWh the Company need not buy at what would likely be high market prices.

Further, based on our analysis of winter capacity position, Ameren Missouri does have a need for winter capacity in 2026 that can be met in part with new solar resources, which are assumed to provide reliable capacity of about 5% of rated output during the winter season. Solar resources are included in both the Renewable Transition Plan and the Renewables for Capacity Need Plan. The reliability analyses performed by Astrape' and discussed in Schedule MM-D2 and later in my testimony below also indicate a reliability benefit from the addition of solar generation over the next few years.

Q. Does adding a gas combined cycle unit in 2031 obviate the need for other resources?

A. No. Renewable resources are needed to meet the Company's energy needs, but they also provide capacity benefits as discussed. The winter capacity position for 2031 reflects total capacity benefits from wind and solar resources of 584 MW, including 100 MW of capacity credit for solar resources. Both renewable resources and dispatchable resources are needed to meet customers' energy and reliability needs in an affordable and sustainable manner over the planning horizon.

Q. Can you provide an example of a situation in which the Company's capacity length has benefited customers?

A. Yes. In MISO's 2015 planning resource auction, capacity prices in Zone 4 experienced significant separation from the rest of MISO, clearing at $150/MW-day compared to $3.48/MW-day in Zone 5 (which encompasses MISO's area in Missouri). Ameren Missouri was able to purchase capacity resources to meet its shortfall in Zone 5 at the lower price while selling the same amount of generation in Illinois at the higher Zone 4 price, resulting in net cost savings to customers of $27 million. Capacity prices in MISO went to CONE in the 2022-2023 auction. While many of Ameren's Illinois regulated utility customers were exposed to those high prices, Ameren Missouri's customers were shielded from the impacts of those high prices by the Company's portfolio of capacity resources and actually benefited economically as a result of Ameren Missouri's capacity length.

5. <u>Risk Mitigation Provided by Renewables</u>

Q. What are the risk mitigation benefits of adding renewable energy resources steadily over time as set forth in the Company's PRP?

A. There are several, as also discussed in detail in Company witness Arora's Direct Testimony. First, they fulfill a long-term energy need for customers, as I have described earlier in my Direct Testimony. Waiting to deploy renewable resources could result in falling short of meeting energy needs or requiring the rapid deployment of less beneficial resources, particularly if viable projects are limited, transmission constraints cause delays or higher costs, or financing rates are higher due to delaying transition from fossil fuels.

Second, renewable projects are expected to benefit from lucrative tax credits made available by federal law. The IRA expanded and extended tax credits for renewable projects, including making production tax credits ("PTC") available to solar projects.

Third, adding renewable resources provides a hedge against various market risks. This includes risks associated with power prices, carbon prices and fuel prices. The Company's IRP analysis demonstrates the benefits to customers of deploying renewable resources steadily over time.[28] Table 2 below shows that the substantial benefits to customers of steady renewable energy resource deployment would further increase under a high carbon price regime.[29] Likewise, higher prices for natural gas (and coal to the extent it is still in use) drive power prices higher and provide greater revenue and risk mitigation benefits for renewable resources.

Table 2

PVRR and PVRR Differences ($MM)	50%	50% <<<Probabilities	
	Low CO_2 Price	High CO_2 Price	Prob. Wtd.
Renewable Transition	78,194	80,010	79,102
Renewables for Capacity Need	79,170	81,479	80,325
Difference (Transitions vs. Capacity Need)	(977)	(1,469)	(1,223)

Q. Can you elaborate on the benefits of renewable resources as a hedge against fuel price risks?

A. Yes. Renewable resources are characterized by moderate capital costs, modest non-fuel operating and maintenance costs, and zero fuel costs. Once built or acquired, the costs of the

[28] E.g., in the probability weighted average case, the NPVRR of implementing the PRP and continuing the transition discussed in my testimony is approximately $1.2 billion lower than not doing so.
[29] Assumption changes since the Company's 2022 Notice of Change in Preferred Plan filing are listed in Schedule MM-D16.

resource are known and relatively stable. In fact, the fixed asset costs of renewables decline over time as the assets depreciate. Adding the benefits of federal tax credits significantly mitigates or offsets those costs. With no fuel costs, any production from renewable resources results in revenues from the market. In periods of high fuel costs (e.g., gas or coal), market prices will tend to increase as well while the "fuel" for renewable resources remains free.

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

A. Yes. Table 3 below shows the peak days for each summer and winter month from 2019 through 2021. For each peak day, it shows what the net energy position (generation minus load) would have been had the Meramec and Rush Island coal units not been available to generate, thus simulating a future state in which those units have been retired, which will in fact be a reality as early as next year. Note that in every instance, net energy would have been negative. That is, Ameren Missouri would have had to purchase more energy than it generated to serve native load.

Also shown for each peak day is the actual measured solar irradiance, or global horizontal irradiance ("GHI"), in watts per meter squared (w/m^2), along with its ratio compared to the highest daily GHI for that month and that year. Note that for 11 of the 18 months shown, solar irradiance is at or above 80% of its daily maximum for the month, and in four of the nine winter months shown, solar irradiance is at or above 40% of its daily maximum for the year.

Table 3 also shows the on-peak and average power prices ("LMP") for each peak day and the approximate cost to purchase to cover the energy shortfall at the average LMP. This shows that four of the 18 peak days would have been expected to result in added costs of over a million dollars, with the peak day in February 2021 (during winter storm Uri) seeing a cost of over $9 million on that day alone. Such events may, and often do, last for multiple days

Finally, the table shows the estimated amount of electric energy the recently approved Boomtown project would have produced had it been available on these days and the savings it would have produced at the on-peak LMP. It shows that the Boomtown Project would have been expected to produce tens of thousands of dollars in benefits on most of the peak days and over a hundred thousand dollars on the peak day in August 2021.[30]

Table 3

Peak Day Net Energy, Solar Irradiance and LMP

e	Net Energy (excl. Mer/RI) (MWh)	Global Horizontal Irradiance (W/m^2)	% Of Month High GHI	% Of Year High GHI	On-Peak LMP ($/MWh)	Average LMP ($/MWh)	Estimated Cost ($000)	Approx. Boomtown Gen. (MWh)	Estimated Boomtown Savings ($000)
30/19	(19,597)	3939	100%	47%	62.32	54.29	1,064	870	54
08/19	(14,616)	4325	92%	51%	28.17	26.19	383	955	27
05/19	(1,688)	7840	96%	93%	26.90	24.16	41	1,731	47
19/19	(19,655)	8002	95%	95%	40.76	33.87	666	1,766	72
12/19	(17,938)	3613	45%	43%	31.00	26.62	478	798	25
16/19	(13,826)	281	9%	3%	25.00	23.24	321	62	2
20/20	(19,331)	1445	46%	16%	28.00	26.15	505	319	9
14/20	(12,193)	4702	87%	53%	24.25	23.02	281	1,038	25
26/20	(33,860)	7842	88%	88%	25.61	21.55	730	1,731	44
09/20	(16,160)	7910	94%	89%	40.41	32.79	530	1,746	71
10/20	(13,392)	7121	91%	80%	38.28	31.38	420	1,572	60
25/20	(28,948)	1548	47%	17%	32.55	29.18	845	342	11
28/21	(36,177)	3893	100%	44%	26.73	25.41	919	859	23
15/21	(67,905)	2461	50%	28%	167.83	142.44	9,672	543	91
18/21	(52,823)	7982	91%	90%	44.72	37.49	1,980	1,762	79
29/21	(50,880)	5720	68%	65%	50.92	43.75	2,226	1,263	64
25/21	(27,348)	6859	87%	78%	69.21	57.04	1,560	1,514	105

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

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

[30] The Solar Projects proposed in this case are also expected to provide benefits during periods of high prices and/or loads.

Q. Has Ameren Missouri described in detail its consideration of the risk mitigation value of renewable resources?

A. Yes. The Company has done this first in its 2020 IRP, then in its June 2022 PRP change filing, and finally in the Direct Testimony of Company witness Arora in this case. The discussion in the two IRP documents I mentioned is included in Schedules MM-D4 and MM-D2, respectively.

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

A. Some of the most significant risks are those that may affect the ongoing operation and economic viability of Ameren Missouri's coal-fired fleet, including significant changes in energy policy. Regarding changes in energy policy, a number of legislative proposals have been considered by the U.S. Congress during the last two years, including various forms of Clean Energy Standards ("CES"). The U.S. EPA recently finalized rules for ozone season NOx emissions (the "Good Neighbor Rule") and announced proposed rules regulating the emissions of CO_2 from fossil-fueled power plants. These are indicative of the kinds of significant changes in energy policy that could drive the need for an imminent and significant expansion of renewable energy resources within an uncomfortably short timeframe. Regarding existing unit operations and economics, our coal-fired fleet has faced and continues to face actual changes and further potential changes in regulation as well as market dynamics that may affect coal energy center economics, which could in turn result in a need for new energy resources. The aforementioned Good Neighbor rule is expected to result in significant reductions in output during May through September each year from units without additional NOx controls. The proposed CO_2 emission rule would require further mitigation and/or reductions in the operation of existing coal and gas units as well as new gas units.

Such requirements could further restrict the energy production of new gas-fired generation, putting such units even more firmly in the role of providing electric generation to fill in the gaps otherwise left by intermittent wind and solar production. This is consistent with the Company's characterization of the "new fleet" in which renewable resources, along with nuclear and hydro, provide the bulk of the energy customers need while still relying on dispatchable resources like gas, storage, and demand response to ensure reliability in all hours.

Q. Why not transition to a new fleet by adding only renewables and storage with no reliance on new gas generation?

A. Ameren Missouri will need dispatchable resources that can produce at any hour. 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 Astrape' 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 4 below) represents 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 Witness Arora has demonstrated in his Direct Testimony, 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, key years in the Company's portfolio transition over the next ten years, which each follow the retirement of significant coal-fired generation – Rush Island by 2025 and Sioux by 2030. 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.

Table 4 – Astrape' 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

Q. What do the results for Cases 4-7 show?

A. For 2026, the addition of 550 MW of solar resources, which is the total combined capacity of the Solar Projects, 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.

Q. Are there other reliability issues that the Solar Projects could help address?

A. Yes. Solar reduces the reliability risks posed by water shortages. Water is essential for cooling steam-fired generators, including coal plants and nuclear generators, which can cause problems during droughts and other extreme weather. The Missouri River Basin and Mississippi

River Basin experienced a drought in 2022, and the Missouri River also experienced an ice blockage that impeded water flow during Winter Storm Elliot. The Labadie Energy Center is located on the Missouri, while the Rush Island and Sioux Energy Centers are located on the Mississippi; all require water for cooling. In fact, NERC cited the ongoing Missouri River Basin drought as a reliability risk for thermal generators located along the river, and the Southwest Power Pool noted that ice on the Missouri River threatened thousands of MWs of generation during Winter Storm Elliot.[31]

Should the duration and/or frequency of these extreme weather events intensify, they could pose serious reliability issues to the Company. This is not just a hypothetical threat to coal-fired generators – Southwest Public Service Company in New Mexico has accelerated the retirement date of the Tolk Generating Station for the second time in five years due to water shortages. Solar does not rely on water for cooling and therefore is not vulnerable to this risk.[32]

Q. In choosing its 2022 Preferred Resource Plan, did Ameren Missouri evaluate the potential effects of climate policy on the performance of alternative resource plans?

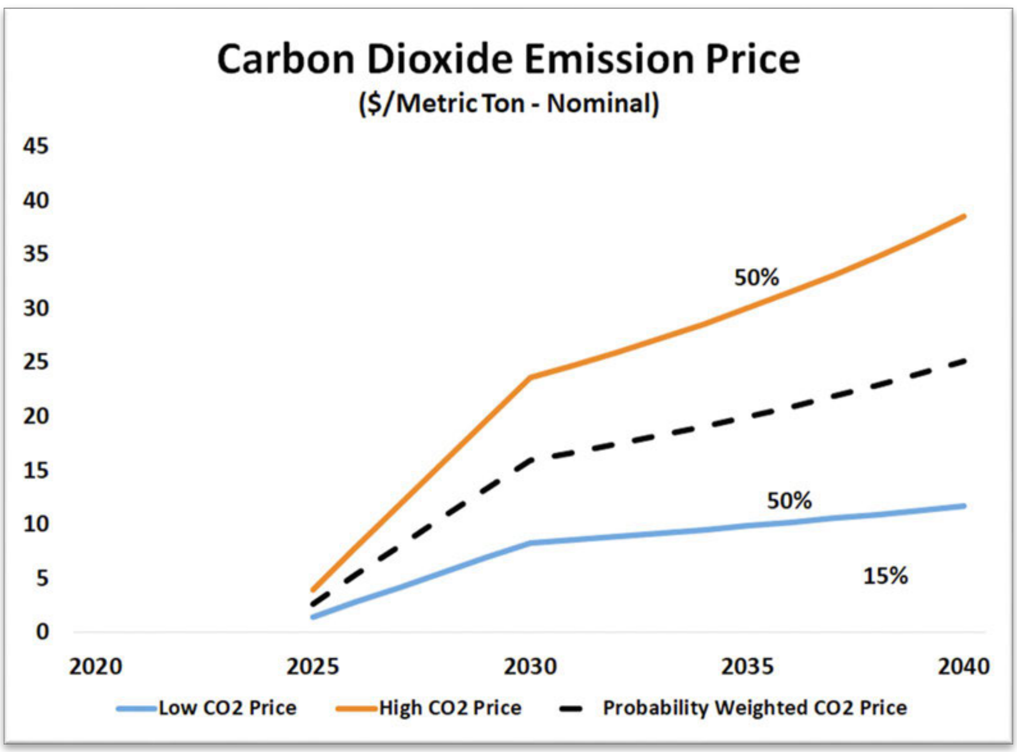
A. Yes. Ameren Missouri considered the potential impacts of climate policy as part of its consideration of the price scenarios I mentioned previously. While climate policy can take various forms, the end result is to provide an incentive to transition away from fossil fuels and

[31] *Drought Status Update for the Missouri River Basin*, National Integrated Drought Information System, (July 26, 2022),https://www.drought.gov/droughtstatus-updates/drought-status-update-missouri-river-basin-7-26-22; Rosenberg, J, "Drought conditions continue to pose shipping challenges on Mississippi River, officials hopeful for winter relief." Investigate Midwest, (December 1, 2022), https://investigatemidwest.org/2022/12/01/drought-conditions-continue-topose-shipping-challenges-on-mississippi-river-officials-hopeful-for-winter-relief/; Brown, C.J., "December 2022 Winter Storm Elliott," p. 7. Southwest Power Pool.

[32] Such risks appear to be persisting in Missouri as well. In addition to the discussion cited in the prior footnote from 2022, an examination of U.S. Geological Service Missouri River water levels as of June 7, 2023 indicate that Missouri River levels continue to be quite low, e.g., water levels at Washington, Missouri are at only the 2% percentile level (much below normal) and at Labadie the 12% percentile level (below normal). www.waterwatch.usgs.gov/?m=real&r=mo.

toward cleaner energy sources. One common way to represent this incentive is through the use of a price on CO_2 emissions. Ameren Missouri used a range of CO_2 prices to define its price scenarios, along with a range of assumed natural gas prices. The CO_2 price assumptions used for the analysis supporting our recently filed change in Preferred Resource Plan are shown in the chart in Figure 27 below and include the probabilities assigned to each price trajectory. The probability weighted average prices are also shown.

<u>Figure 27</u>



Q. Has the Company updated its CO_2 price assumptions for its 2023 IRP?

A. Yes. However, the Company has not yet completed its plan analysis for its 2023 IRP, so results reflecting these updated assumptions are not yet available.

Q. How would you expect the updated assumptions for CO_2 prices to affect the economics of renewable energy resources shown in Table 2?

A. I would expect the economics of renewable energy resources to improve using the 2023 IRP assumptions for CO_2 prices because the probability weighted average CO_2 price for the 2023 IRP will be higher than that used in the analysis that supported the Company's 2022 change in PRP.

Q. How did Ameren Missouri use these CO_2 price assumptions to assess the risks of alternative resource plans in the analyses that led to the adoption of the 2022 Preferred Resource Plan?

A. As mentioned previously, these CO_2 price assumptions were included in price scenarios that were used when modeling the operation and costs of the various alternative resource plans. This modeling analysis yielded estimates of the PVRR – the total cost to customers expressed in today's dollars – for each alternative resource plan. By evaluating the range of results for PVRR under the different scenarios for CO_2 prices, we are able to assess the sensitivity and risk to customer costs of these different levels of CO_2 pricing. Table 2, presented previously, shows the PVRR results for two alternative resource plans under the three levels of CO_2 prices.

As mentioned previously, the Renewables for Capacity Need Plan includes the addition of renewable resources to meet capacity needs or to meet the requirements of the RES (along with non-renewable resources to meet capacity needs). The Renewable Transition Plan, which was selected as the Company's PRP, reflects the addition of renewable resources starting in the near term and deployed somewhat evenly over the next twenty years. As noted earlier, Table 2 shows that the addition of significant renewable resources in the Renewable Transition Plan results in roughly a billion dollars or more in lower PVRR regardless of the CO_2 price assumed, and the net benefit of the Renewable Transition Plan relative to the Renewables for Capacity Need Plan is greater as the assumed price on CO_2 emissions is increased.

Q. Do the analysis results shown in Table 2 reflect any changes compared to those shown in the Boomtown CCN case?

A. Yes. First, the value of tax credits under the IRA have been included in the updated analysis. Project costs for wind and solar resources have also been updated to reflect the assumptions being used in the development of the Company's 2023 IRP. It is worth noting that the updated project cost assumptions align more closely with the risk scenario assessed by Roland Berger and included in the Company's 2022 Change in Preferred Plan filing (Schedule MM-D2). The analysis does not include other risks that were assessed by Roland Berger. Namely, it does not include assessment of financing cost risks or land availability for wind.

Q. Are the financing cost and land availability risks no longer of concern?

A. Not at all. The previous assessment of financing cost risk, which was quantified to be nearly $300 million, was based on the reasonable expectation of higher financing costs for utilities that do not make a concerted effort to transition their portfolios due to higher perceived risks. Specifically, Roland Berger estimated that portfolios reflecting a slower transition would face a borrowing cost premium of 200 basis points by 2030 and applied this to new resources added in the Capacity Need Plan. This premium could also be reasonably applied to any Company investments, which would yield a far greater impact on customer costs absent the Company's planned transition.

Regarding the land availability risk, this remains an important risk that the Company's planned transition mitigates by adding attractive projects over time as they are identified rather than waiting and settling for less attractive projects.

Q. How should the PVRR results shown in Table 2 be considered in the context of the Company's approach to mitigating transition risk with its planned expansion of renewable resources?

A. In simple terms, the change in PVRR associated with spreading out our renewable expansion over 20 years can be thought of as the "cost" of mitigating the risks. Our IRP analysis results indicate that costs to customers are reduced by spreading out the renewable expansion. This means that the risk mitigation realized by our current Preferred Resource Plan, which reflects the Renewable Transition Plan, will also be accompanied by significant expected savings for customers rather than an additional cost.

Q. You mentioned the possibility of more specific changes in energy policy that focus on the transition to clean energy, like a Clean Energy Standard ("CES"). How does the renewable buildout in Ameren Missouri's PRP address the potential for such a policy?

A. While the Preferred Resource Plan cannot anticipate the specific requirements of such a policy, it does provide a solid starting point for its consideration. By spreading the buildout of wind and solar resources over twenty years, the preferred plan is consistent with a sustained transition effort of the kind that is likely to be prescribed in such a policy. A sustained transition provides flexibility for making adjustments as conditions change and recognizes the implementation risks associated with a rapid large buildout of new resources. Sustained transitions are also typical of renewable portfolio standards, like the Missouri RES, which called for stair step increases in renewable energy from 2% to 5% to 10% to 15% over the course of ten years.

Q. You mentioned the Missouri RES. Could changes in state-level energy policies also drive the need for additional renewable energy sources?

A. They most definitely could, as evidenced by neighboring Illinois' CEJA. This is part of a larger trend toward cleaner energy sources, including greater expansion of wind and solar generation, that is taking place across the United States and other countries. Even if a particular policy proposal is not enacted in the near term, public support for policies that encourage the transition to cleaner energy sources appears to be increasing.

Q. Questions have been raised in other cases with respect to whether the addition of renewable resources result in reduced emissions of CO_2. Can you address this?

A. The addition of renewable resources necessarily displaces production from other resources on the grid. The production displaced is by and large from dispatchable resources that use fossil fuels, primarily coal and gas in MISO. While Ameren Missouri and other MISO market participants sell generation into the market and then buy from the market to serve load, the total production is matched to total load. All other things being equal, an increase in renewable production will result in a decrease in production from units that are on the margin (i.e., the last resources dispatched to meet load). In MISO's Central Region, which includes Ameren Missouri, the marginal unit is either coal or gas at least 80 percent of the time in most months.[33]

Q. There have also been questions regarding potential system issues at high levels of renewable penetration. How is Ameren Missouri considering this?

A. Because Ameren Missouri is a member of MISO, studies by MISO regarding renewable penetration and integration are particularly relevant. In February 2021, MISO released a report on Renewable Integration Impact Assessment ("RIIA"). Among the key findings in the

[33] Based on actual MISO data for calendar year 2022.

RIIA, MISO's analysis determined that renewable penetration up to 30 percent of total generation is not expected to cause integration challenges, indicating that, "integration complexity increases sharply after 30% renewable penetration." [34] As Company witness Arora has indicated in his Direct Testimony, the Company expects to add about 7.5 million MWh of annual renewable energy generation through 2030. Added to the Company's existing renewable portfolio, this will bring total expected wind and solar energy production to about 10 million MWh per year. With the 15-20 percent energy buffer for retail sales discussed by Company witness Arora, this would be about 27 percent of total generation, which remains under the threshold MISO has identified as increasing the challenge of integrating renewables.

Q. Ameren Missouri's PRP includes the continued operation of coal-fired generation beyond 2040. Why not retire that coal generation sooner to support the need for new renewable resources?

A. There are two primary reasons – affordability and reliability. Our IRP analysis showed that continued operation of certain coal-fired energy centers beyond this decade is expected to result in lower costs for customers than if we retired them much sooner. The Labadie Energy Center is among the most efficient and most cost-effective coal-fired facilities in MISO, and it continues to provide benefits to our customers through sales made into the MISO market.

In addition to their benefits to affordability, they also provide significant benefits to reliability by ensuring we continue to have dispatchable generation that is needed to fill in the gaps inherent in the operation of intermittent wind and solar resources. Continuing to operate these resources helps to make the necessary expansion of renewable resources outlined in our Preferred Plan possible.

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[34] Schedule MM-D17, p. 4

Q. You previously mentioned the risk mitigation value of renewable resources in the context of potential prices for CO_2 emissions. Does the continued operation of coal-fired resources erode that risk mitigation value?

A. No. While CO_2 prices have different implications for coal-fired resources than for renewable resources, that does not mean that coal-fired resources have no risk mitigation value or erode the risk mitigation value of renewables. The risk mitigation value of coal-fired resources is simply driven by the potential for lower values for CO_2 price rather than by the potential for higher values, as is the case for renewable resources. Together, these resources comprise a more diverse and balanced portfolio that provides reliable and affordable energy at a reasonable cost under a wide range of market conditions. This is not unlike a diverse investment portfolio that includes a mix of securities that perform well in different types of markets.

IV. PROJECT ECONOMICS

1. Modeling and Assumptions

Q. Have you analyzed the economics of the Solar Projects?

A. Yes. I have analyzed the economics of each of the four Solar Projects at issue in this case.

Q. What kind of analysis have you performed?

A. I have evaluated the expected incremental net present value of revenue requirement ("NPVRR") resulting from each Project. I have done so using a spreadsheet model to account for all the costs and benefits of the Solar Projects that would be reflected in the Company's jurisdictional electric retail revenue requirement for ratemaking, including the impact of available federal tax incentives.

Q. Please describe the basic operation of the spreadsheet model.

A. I utilized Ameren Missouri's corporate project finance model to assess the incremental net revenue requirement impact of each Project. The revenue requirement results can be understood as the sum of three basic components: 1) fixed asset costs; 2) operating costs; and 3) market revenues.

Fixed Asset Costs: The fixed asset costs are determined by calculating the return on net rate base in each year, the annual depreciation expense, and the net tax expense. Each Project base case is modeled at the estimated costs listed in Table 5 below, but due to uncertainty in the solar supply chain the exact cost of each Project is not fixed.[35]

***<u>**Table 5. Base Case Estimated Costs by Project**</u>

[redacted] ***

To account for the remaining uncertainty in Project cost, each Project is also modeled at a risk-adjusted estimated cost to incorporate additional contingencies. It is possible that the final cost of each Project will be above the risk-adjusted level, or below the base case level, but the Project cost range captured between these two cases represents the Company's current best estimate of the expected cost for each Project. The base case estimate includes internal development costs expected to be spent by Ameren Missouri to bring each Project online, land purchase costs for the sub-transmission Solar Projects (Vandalia and Bowling Green Solar), and upfront transmission

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[35] Company witness Scott Wibbenmeyer provides additional details on current supply chain challenges in the solar industry and the pricing structure of the various contracts used to acquire and construct the Solar Projects.

interconnection costs determined through the MISO generator interconnection process for the transmission-level Solar Projects (Split Rail and Cass County Solar).

Operating Costs: The model includes estimates for ongoing operating costs for each Project. Specifically modeled are operations and maintenance costs, real estate costs to cover ongoing land lease payments for the Split Rail and Cass County Solar Projects, transmission interconnection costs (paid over the first 20 years of the Project life) for the Split Rail and Cass County Solar Projects, and ongoing property taxes payments or anticipated Chapter 100 Payment In Lieu Of Taxes ("PILOT") estimates based on each Solar Project's location.

Market Revenues: Market revenues include both energy revenues and capacity revenues. Energy revenues are determined by applying a range of power market price estimates to the expected energy production of each Project. The range of power market price estimates were developed in the last several months by consultant Charles River Associates ("CRA") to be utilized in the Company's upcoming 2023 Integrated Resource Plan filing. Three scenarios from CRA were utilized in modeling the economics of the Solar Projects: 1) the base power price scenario of the eleven core scenarios analyzed by CRA, which reflects base assumptions for load, carbon and natural gas prices; 2) the lowest price scenario from among the eleven scenarios analyzed by CRA, which reflects base assumptions for load and low assumptions for carbon and natural gas prices; and 3) the highest price scenario analyzed by CRA, which reflects base assumptions for load and high assumptions for carbon and natural gas prices. The prices applied to the solar generation have been adjusted for basis differences, to reflect the location of each Solar Project, and for a solar profile, to reflect the variability of the solar generation. Capacity revenues also reflect price estimates developed in the last several months by CRA to be utilized in the Company's 2023 Integrated Resource Plan. The capacity prices utilized are seasonal and reflect the most recent seasonal capacity accreditation values for solar provided by MISO. These values are assumed to decline slightly over time.

Highly Confidential Schedule MM-D14 provides a summary of the base assumptions used for modeling each Project.

2. Analysis Results

Q. Of the available tax incentives for solar, which tax credits does the modeling assume for each Project?

A. For each Project, the Company analyzed the relative economics of the Project under both the Investment Tax Credit ("ITC") and Production Tax Credit ("PTC"). To assess the ITC, the project modeling assumes the ITC value is transferred to an unaffiliated third party for cash at 92% of its total value, and the cash received is not subject to normalization.[36] The Cass County Solar and Bowling Green Solar Projects are expected to qualify for an additional bonus due to their location in energy communities as defined by the IRS. Therefore, both Cass County Solar and Bowling Green Solar are modeled to reflect the additional 10% energy community tax credit boost. Workpapers are being provided to the parties for each tax option for each Project, and the base case NPVRR results for both ITC and PTC for each Solar Project are shown below in Table 6.

Table 6. Base Case NPVRR Results - ITC and PTC

Project	ITC NPVRR ($MM)	PTC NPVRR ($MM)
Split Rail Solar	163.3	182.8
Cass County Solar	62.8	89.7
Vandalia Solar	23.0	24.4
Bowling Green Solar	14.0	21.3

[36] Pending guidance from the IRS.

These preliminary results indicate that for all four of the Solar Projects, utilizing the ITC results in reduced costs for customers as compared to the PTC. For the additional scenario results presented below, all four Solar Projects are assumed to utilize the ITC across all scenarios. However, the Company believes that it is premature to formally select a tax strategy for the Solar Projects. Transferability guidelines have yet to be released from the IRS, and Project assumptions are still being refined. The Company will continue to diligence guidance released by the IRS and will continue to update the Project models until the timing is appropriate to select the optimal tax credit option for each Project.

Q. Please describe the scenarios assessed for each Project.

A. Although many modeling assumptions impact the overall economics, the following three assumptions have a meaningful impact on incremental net revenue requirement: power market prices, capacity factor, and total Project cost. Highly Confidential Schedule MM-D15 provides details on the twelve scenarios constructed to capture uncertainties in those key variables.

Q. Please summarize the results of your analysis for each Project.

A. Tables 7-10 below shows a summary of the analysis results for each of the four Solar Projects. It includes the present value revenue requirement for four cases under the three power price scenarios described above.

	Table 7 SPLIT RAIL SOLAR PROJECT			
NPVRR Impact of Project ($MM)	Base Cost and Capacity Factor	High Cost; Base Capacity Factor	Base Cost; Low Capacity Factor	High Cost; Low Capacity Factor
Low Price Scenario	215.8	267.4	240.5	292.1
Base Price Scenario	163.3	214.8	194.1	245.6
High Price Scenario	93.1	144.7	132.1	183.6

	Table 8 CASS COUNTY SOLAR PROJECT			
NPVRR Impact of Project ($MM)	Base Cost and Capacity Factor	High Cost; Base Capacity Factor	Base Cost; Low Capacity Factor	High Cost; Low Capacity Factor
Low Price Scenario	93.3	100.0	108.2	114.9
Base Price Scenario	62.8	69.5	81.2	87.9
High Price Scenario	25.9	32.6	48.6	55.3

	Table 9 VANDALIA SOLAR PROJECT			
NPVRR Impact of Project ($MM)	Base Cost and Capacity Factor	High Cost; Base Capacity Factor	Base Cost; Low Capacity Factor	High Cost; Low Capacity Factor
Low Price Scenario	33.3	41.3	38.2	46.3
Base Price Scenario	23.0	31.1	29.2	37.3
High Price Scenario	9.7	17.8	17.4	25.5

	Table 10 BOWLING GREEN SOLAR PROJECT			
NPVRR Impact of Project ($MM)	Base Cost and Capacity Factor	High Cost; Base Capacity Factor	Base Cost; Low Capacity Factor	High Cost; Low Capacity Factor
Low Price Scenario	24.2	31.3	29.2	36.3
Base Price Scenario	14.0	21.1	20.1	27.2
High Price Scenario	0.6	7.6	8.3	15.4

V. CONCLUSION

Q. What are your key conclusions about the Solar Projects?

A. The Solar Projects are an integral part of the Company’s Preferred Resource Plan, which facilitates Ameren Missouri’s transition to its new fleet which will consist of significantly more carbon-free, renewable resources. As I have described throughout my testimony, the

Company has evaluated the various scenarios and approaches that it could have taken in achieving this transition and has chosen the PRP as the most effective option.

There are myriad risks that could present themselves as the Company moves to implement its transition, perhaps most significantly, risks related to reliability if we are unable to execute the transition in the Company's PRP. The market is changing, and Ameren Missouri's historical approach to filling capacity needs is no longer sufficient. As its coal-fired resources move toward retirement, replacements for that output are necessary. The Solar Projects help to fulfill that need. And they are needed now because of the various risks and uncertainties I have discussed throughout my testimony that could affect Ameren Missouri's ability to provide reliable service to its customers.

Q. Does this conclude your testimony?

A. Yes.

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 a Certificate of Convenience and Necessity for Solar Facilities	)))	EA-2023-0286

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 *Direct Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

/s/ Matt Michels
Matt Michels

Sworn to me this 16th day of June, 2023.