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MISSOURI PUBLIC SERVICE COMMISSION

File No. EA-2024-0237

DIRECT TESTIMONY

OF

MATT MICHELS

ON

BEHALF OF

UNION ELECTRIC COMPANY,

d/b/a Ameren Missouri

St. Louis, Missouri
June 2024

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TABLE OF CONTENTS

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 my current position as Director of Corporate Analysis. My 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 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 demonstrate the need for the project for which Ameren Missouri seeks a Certificate of Convenience and Necessity ("CCN") – the Castle Bluff simple cycle gas turbine generator ("SCGT") facility (the "Project"), which is expected to produce approximately 800 MW at full capacity. The primary purpose of the facility is to ensure sufficient generating capacity to serve Ameren Missouri customers during extreme weather conditions, primarily extreme winter weather conditions such as those seen during winter storms that affected large portions of the United States (e.g., winter storms Uri and Elliott). In addition, the Project will help to mitigate other key risks such as the recent surge in potential large load additions (e.g., data centers, manufacturing) and impacts on the Company's remaining fleet of coal-fired generators, including reduced utilization and the potential for accelerated retirements. Because the Project will be located in Missouri, it also provides a secondary benefit of increasing the

Company's accredited capacity throughout the year in the Midcontinent Independent System Operator ("MISO") market's Zone 5 and mitigate the risk of capacity shortfalls in all seasons. I will demonstrate that the addition of the Project, along with other mitigation steps the Company is taking, represents the best path for ensuring reliability and helping to integrate increasing levels of renewable generation throughout the planning horizon.

III. NEED FOR THE PROJECT

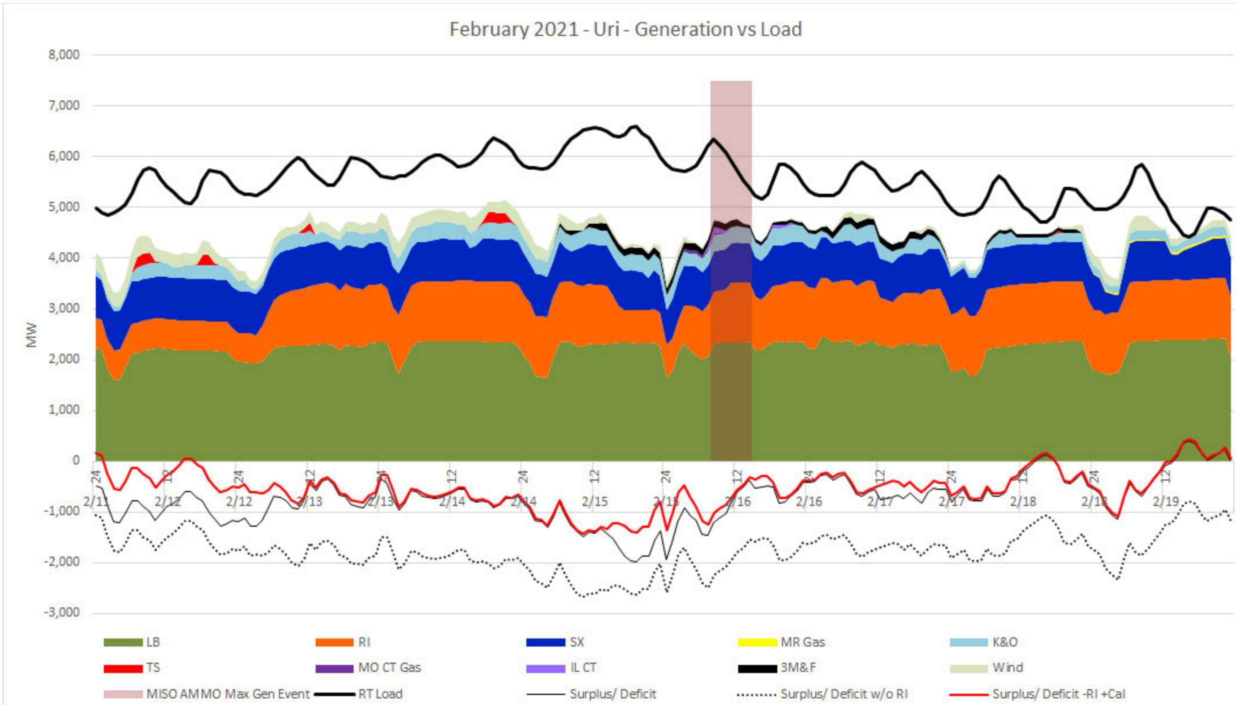
Q. What is the primary driver of need for the Project?

A. The primary driver is the need for resources to meet customer needs during widespread extreme weather events, when reliable electric service is most critical and when surplus capacity from neighboring utilities and regional transmission organizations ("RTO") is minimal or non-existent. A prime example of such conditions is winter storm Uri, which brought extreme cold weather to much of the country and resulted in an estimated 246 deaths in Texas in February 2021. Winter storm Uri also caused significant challenges across the grid outside of Texas, with significant transfers of power between multiple RTOs, including MISO. Figure 1 below shows Ameren Missouri's load and generation during winter storm Uri. Note that the chart in Figure 1 includes generation from the Company's coal-fired Rush Island Energy Center ("RIEC") and that the Company's Callaway nuclear facility was not in operation at the time. To account for the retirement of RIEC later in 2024 and to account for the expectation that Callaway would operate during such periods, net load and generation are shown without RIEC (the dotted line) and separately without RIEC but with Callaway included (the red line).[1] The red line indicates a maximum shortfall of 1,440 MW on the morning of February 15, 2021. This occurred during a period of 15 consecutive hours with an implied deficit of over 1,000 MW. The vertical,

[1] The thin black line below the x-axis indicates the Company's actual net resource surplus/deficit with no adjustments.

red highlighted portion in the middle of the chart denotes the duration of a MISO maximum generation event, which lasted for seven hours.

Figure 1 – Ameren Missouri Load and Generation During Winter Storm Uri

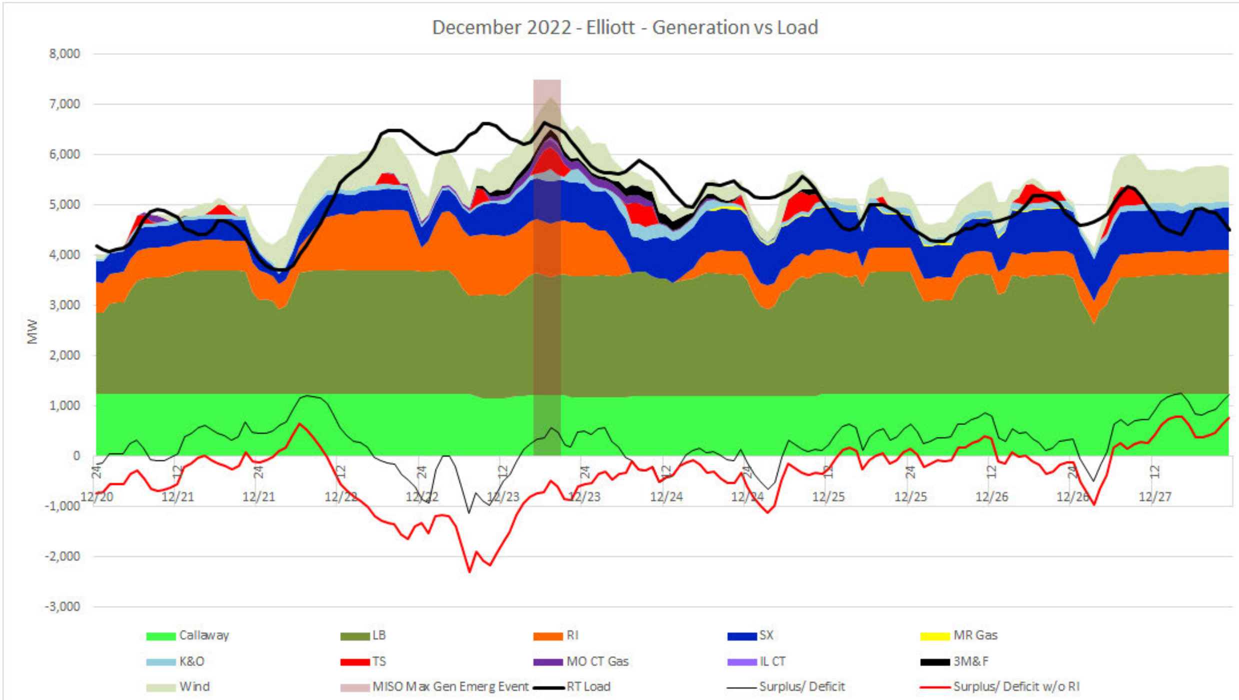


Winter storm Elliott, in December 2022, brought similar grid challenges. Figure 2 below shows Ameren Missouri's load and generation during that winter storm. Note that Callaway was operating during that storm, so the generation deficit is shown as it occurred as well as with RIEC removed (the red line). The implied deficit[2] without RIEC reached a maximum of 2,311 MW on the morning of December 23rd, and during a period of 23 consecutive hours, there was an implied deficit of over 1,000 MW.

Aside from the implied deficits without RIEC, it is also worth noting the difference in wind generation during the two winter storms, with significantly more wind generation during winter storm Elliot than during winter storm Uri.

[2] I.e., the resource deficit with RIEC generation removed.

Figure 2 – Ameren Missouri Load and Generation During Winter Storm Elliot



Q. Should the actual and/or implied resource deficits shown in Figures 1 and 2 be used as a basis for long-term resource planning?

A. No, but they do provide a strong indication of the need to consider such circumstances when evaluating resource needs, which requires a change in the Company's approach to resource planning.

Q. How have these winter storms affected Ameren Missouri's approach to resource planning?

A. Ameren Missouri has taken seriously the effects of these winter storms and the increase in the frequency of such events and has adjusted its approach to resource planning as recommended by the North American Electric Reliability Corporation ("NERC"). As NERC noted in its 2023 Long-term Reliability Assessment:

> Resource and system planners must have robust tools and capabilities for assessing energy needs, extreme weather scenarios, and grid stability. Planning Reserve Margins can fail to

> identify energy risks that stem from low [variable energy resource] output or generator fuel supply issues, making them unsuitable as a sole basis of resource adequacy. Resource planners and wholesale markets must use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments.[3]

The Company seeks to ensure reliability during all hours and under all weather conditions, especially during extreme weather conditions when the lack of electric energy could have dire consequences.

Q. What do you use to analyze needs under such circumstances?

A. The Company uses both analysis of Ameren Missouri's peak-hour resource balance under extreme weather conditions and hourly probabilistic analysis that considers actual historical weather, including extreme conditions. I will discuss the hourly probabilistic analysis later in my direct testimony. The Company examines the Company's load and resource balance (its capacity position) under the types of extreme weather conditions described above. Figure 3 below shows Ameren Missouri's winter capacity position under its current preferred resource plan ("PRP") with extreme winter weather and without the Project. The peak demand under such conditions is over 6,600 MW, or about 600 MW greater than normal peak demand. With a winter Planning Reserve Margin ("PRM") requirement in MISO of roughly 25%, this results in an increase in resource need of approximately 750 MW beyond what would be needed under normal weather conditions.

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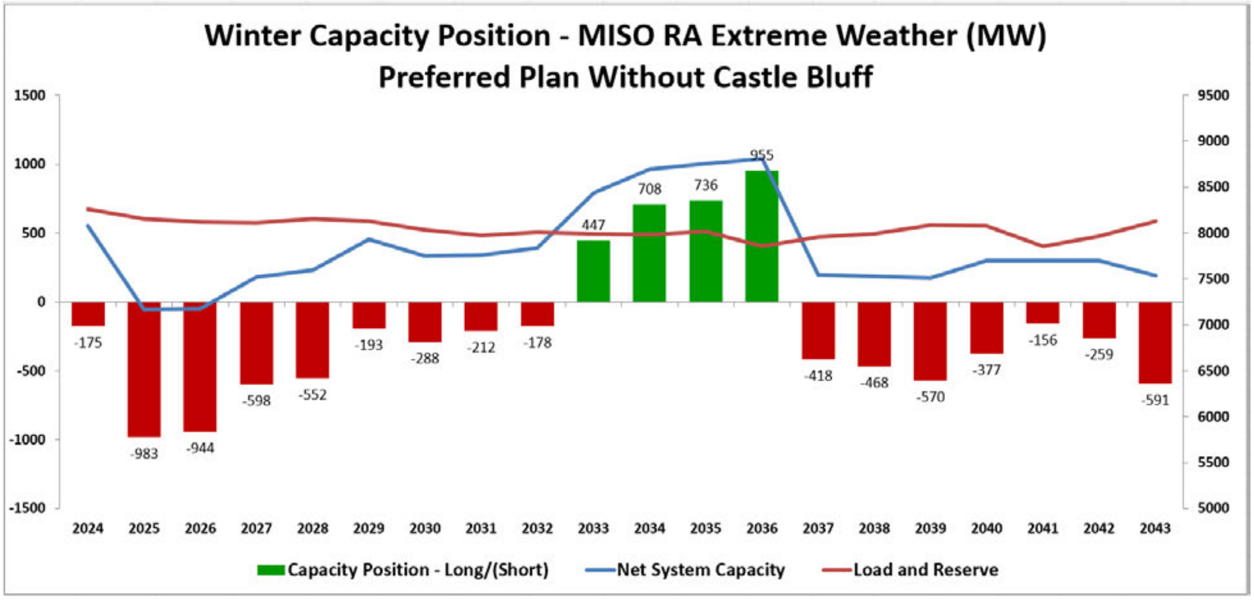
[3] Schedule MM-D2 – NERC 2023 Long-term Reliability Assessment, p. 11.

Figure 3 – Ameren Missouri Capacity Position – Extreme Weather, w/o the Project[4]



Q. You noted previously the difference in the level of actual wind generation during winter storms Uri and Elliot. Does the winter capacity position in Figure 3 include the capacity value of wind?

A. Yes. It reflects a capacity credit for wind of about 40% to start, declining to 30% in the long term.

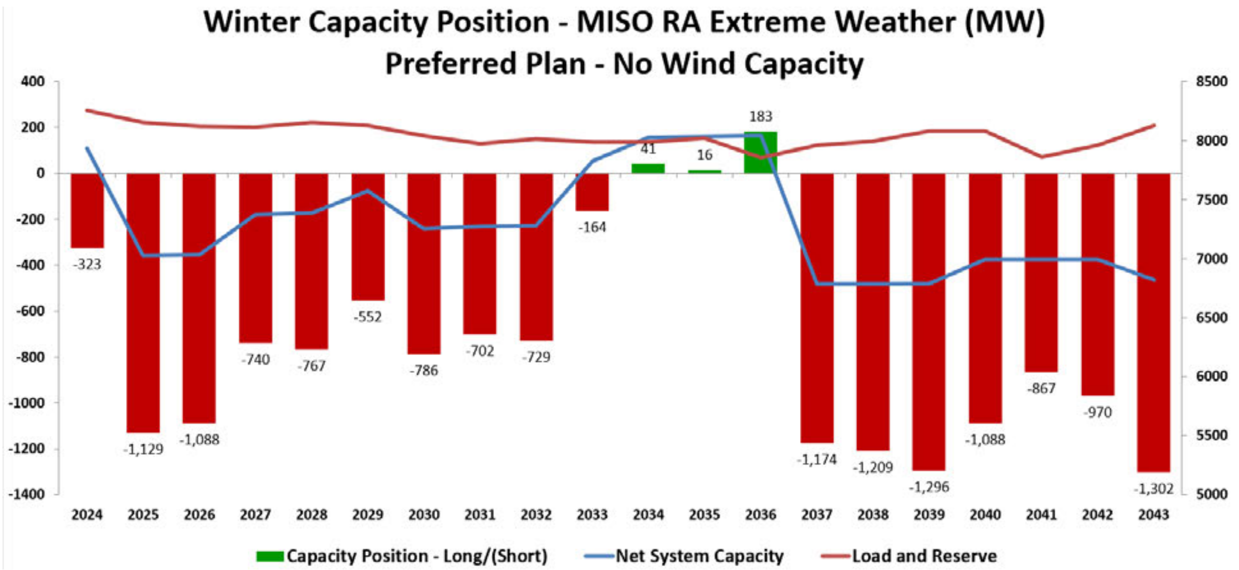
Q. What would the Company's capacity position show under extreme weather conditions with no wind production?

A. To examine the Company's capacity position without the benefit of the wind capacity, which would reflect conditions similar to those experienced during winter storm Uri, I have prepared a capacity position with extreme weather and without the benefit of the wind capacity, as shown in Figure 4 below. Figure 4 shows that during extreme weather conditions with no wind generation, the Company's capacity position consistently approaches or exceeds 750 MW

[4] "RA," as used within Figure 3, refers to resource adequacy.

until 2033, when 1,200 MW of natural gas-fired combined cycle ("NGCC") generation is added following the retirement of the Company's coal-fired units at its Sioux Energy Center, and again after the retirement of two units at the Labadie Energy Center at the end of 2036.

Figure 4 –Capacity Position – Extreme Weather, No Wind Capacity, w/o the Project



Q. Has the Company already taken steps to mitigate risks of extreme winter weather?

A. Yes. Ameren Missouri has restored oil-fired backup capabilities at its Peno Creek and Kinmundy Energy Centers to ensure those units can operate under extreme weather conditions when supplies of natural gas may be constrained, adding an estimated 47 MW and 40 MW, respectively, to the Company's winter accredited capacity. The Company is also in the process of adding oil-firing capability at its Audrain Energy Center, adding an estimated 312 MW of winter accredited capacity, with an expected completion of late 2026.[5] The increased capacity

[5] Note that the capacity values represent incremental accredited capability beyond that already recognized by MISO and not the full rated output of the facilities.

contribution of oil-fired capabilities for these units is reflected in the capacity positions shown in Figures 3 and 4 and elsewhere in my direct testimony.

Q. What is the basis for the load and generating capacity assumptions reflected in the capacity positions in Figures 3 and 4?

A. The peak demand and unit accreditation values are the same as those used in the Company's 2023 IRP analysis, with the modification to include additional winter capability at Audrain described above.[6]

Q. What was the basis for unit accreditations in the Company's 2023 IRP?

A. The 2023 IRP relied on the unit accreditations provided by MISO for its 2023-2024 Planning Resource Auction ("PRA"), often referred to as MISO's capacity auction. A few modifications were made to normalize accreditations, which had experienced significant outages during the prior three years, to better represent going-forward performance expectations for reliability purposes. The primary adjustments that were made were for Callaway and the Taum Sauk pumped hydro storage facility arising from past outage events that are not expected to recur.

Q. Why did you use values from MISO's 2023-2024 PRA instead of more recent values from its 2024-2025 PRA?

A. The primary reason is for continuity and consistency. MISO's approach to unit accreditations changed when it adopted a seasonal resource adequacy ("RA") construct. Company witness Andrew Meyer discusses the evolution of MISO's RA construct in more detail in his direct testimony. Part of MISO's new approach includes making an adjustment to unit accreditations based on actual performance during critical hours. MISO is phasing this adjustment into its accreditation process over three years, with 40% of the adjustment included for planning year

[6] An additional correction was made to the capacity for the Venice SCGT units, reducing total generating capacity by 123 MW and resulting in no material differences in plan performance.

2023-2024, 60% for planning year 2024-2025, and 80% starting in planning year 2025-2026. It is important to recognize that under this new construct, it is not possible to identify when such critical hours will occur in the future or how units will perform during such hours. Because of the uncertain and after-the-fact nature of these adjustments and the forward-looking nature of resource planning, it makes more sense to use the 2023-2024 PRA accreditation values as the basis for the capacity positions presented here. It is also important to note that there have been no significant underlying changes in rated output for Ameren Missouri's existing generating units.

Q. You've shown winter capacity positions for extreme weather with and without capacity from wind resources in Figures 3 and 4. Are there other risks to Ameren Missouri's capacity position?

A. Yes, there are two. First, Ameren Missouri and much of the United States have seen a rapid increase in interest from prospective customers who are searching for sites for new large data centers, with peak demands in the hundreds of megawatts each. Second, US EPA has continued to promulgate rules affecting fossil fueled resources, especially coal-fired generators. These regulations include the recently finalized rule on greenhouse gas ("GHG") emissions from existing coal-fired generators and new gas generators under Section 111(d) of the Clean Air Act and more stringent limits on emissions of nitrogen oxides (NO_x) under the Cross-State Air Pollution Rule ("CSAPR") during the summer ozone season (May through September), often referred to as the Good Neighbor Rule ("GNR"). Together, these regulations are expected to result in reduced generation and/or accelerated retirement of coal-fired units.

Q. Can you elaborate on the prospective customers you referenced?

A. Yes. The first is **______**, which plans to build a **___** MW data center in **_____________**, MO. **______** and Ameren have executed a construction agreement to

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the facility to the grid, with construction to begin July 2025 and in service in December 2025. **______** is working on incentives with the Missouri Department of Economic Development. The second is **__________________**, which plans to build a **___** MW data center in **______**, MO. A draft interconnection construction agreement was delivered to them on May 17, 2024. Details of the agreement are still being finalized.

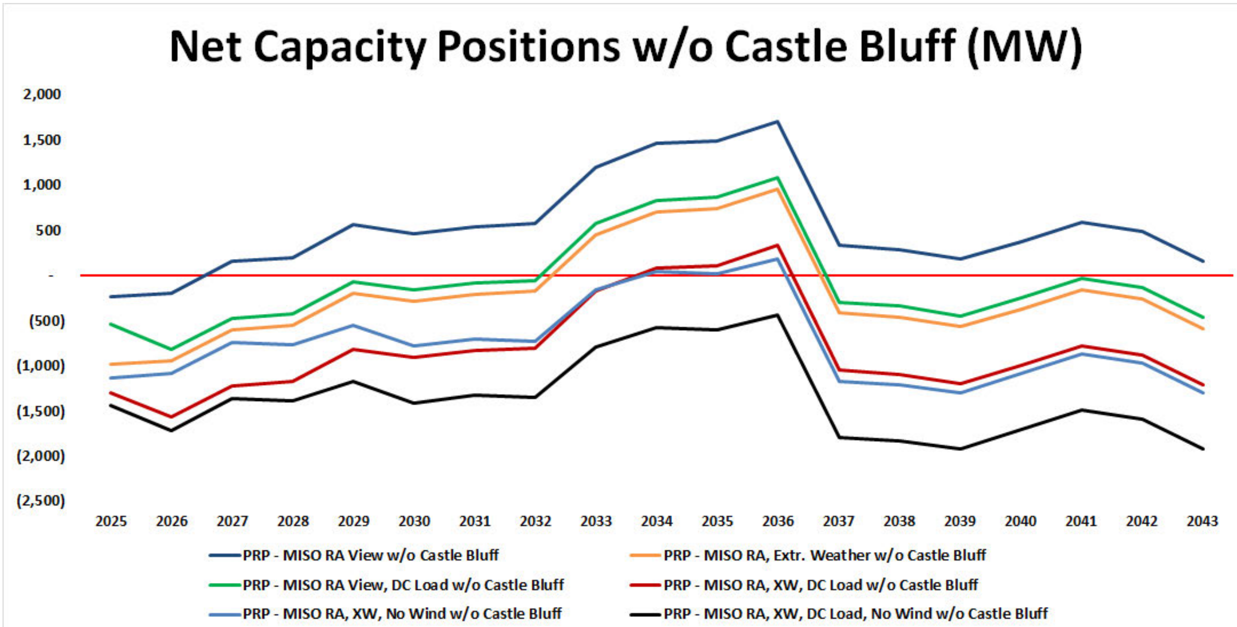
Q. Have you analyzed the impacts of these risks to Ameren Missouri's capacity position?

A. Yes. I have quantified the effects on the Company's capacity position of an additional **___** MW of peak demand (all seasons) to reflect the expectation that these loads will be added in the near-term. While new EPA regulations may have some effect on the Company's long-term resource needs, Ameren Missouri is still in the process of evaluating the potential impacts of the GHG rule. Therefore, I will discuss potential impacts of the regulations qualitatively. Figure 5 below shows capacity positions without Castle Bluff reflecting the following assumptions:

- A standard MISO RA view with normal weather (dark blue line);
- Extreme weather, with wind capacity (orange line) – this mirrors the chart in Figure 3;
- Normal weather with **_________** of new data center load (green line);
- Extreme weather with **__________** of new data center load (dark red line) (modified Figure 3 with data center load);
- Extreme weather with no wind capacity (light blue line) – this mirrors the chart in Figure 4; and

- Extreme weather with no wind capacity and with **______** of new data center load (black line) (modified Figure 4 with data center load).

Figure 5 –Capacity Positions Without the Project[7]



The capacity positions in Figure 5 indicate a capacity shortfall in 2030 of between roughly 300 MW to 1,400 MW under extreme weather conditions, with central values of roughly 800-900 MW. While the capacity deficit eases between 2033 and 2036 (due to a combined cycle unit addition planned for the end of 2032), it returns in 2037 following the retirement of two units at Labadie with even greater shortfalls, with the largest deficits approaching 2,000 MW.

Q. You mentioned the potential impact on resource needs from EPA regulations. Please elaborate.

A. For the Company's 2023 IRP, Ameren Missouri evaluated plans with and without selective catalytic reduction ("SCR") retrofits for Labadie driven by the GNR. The new GHG rule introduces additional potential impacts on the continued operation of the Company's coal-fired

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[7] "DC" = data center, "XW" = extreme weather

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units, creating greater risk of further reductions in generation and/or earlier retirements. Specifically, the rule requires coal-fired units to remove 90 percent of CO_2 emissions starting in 2032, based on carbon capture and sequestration ("CCS") technology, for units retiring after December 31, 2038, and co-firing with natural gas at a 40 percent gas blend (by heat input) with coal starting in 2030 for units retiring after December 31, 2031, and before January 1, 2039. The Company's PRP reflects two units at Labadie retiring in 2042, making them subject to the 90 percent removal requirement. The Company's PRP also reflects the other two units at Labadie retiring in 2036 and the two units at Sioux retiring in 2032, making those four units subject to the gas co-firing requirement. Because the GHG rule is expected to face legal challenges, there remains some uncertainty regarding the impact of these regulations. That said, the risks associated with the new regulation, considered together with other regulations including the GNR, may affect the Company's future resource needs, either as a result of reduced generation or earlier unit retirements or both. This is particularly important with respect to the Labadie units currently planned for retirement in 2036. Should the generation from those units be significantly reduced from currently expected levels or should earlier retirement be warranted, the easing of a capacity need between 2033 and 2036 may not materialize. Castle Bluff would provide a hedge against that risk. The Company continues to assess the requirements of the GHG rule and potential outcomes of legal challenges and consider what changes, if any, might be warranted to the Company's PRP.

IV. ADDITIONAL RELIABILITY ANALYSIS

Q. Have you analyzed the reliability contribution of the Project in addition to the capacity position analysis you've presented?

A. Yes. It continues to be important to evaluate reliability needs on a more granular basis. In addition to the analysis of the Company's capacity position, I have also analyzed reliability on a more granular and probabilistic basis.

Q. Please describe that probabilistic analysis.

A. The Company uses Astrapé Consulting's Strategic Energy and Risk Valuation Model ("SERVM") to evaluate reliability metrics on a probabilistic basis using a sequential Monte Carlo simulation with random draws for unit outages and weather patterns based on over 40 years of actual weather data. This kind of analysis is important in evaluating the potential for events that have a low probability but a high impact, such as the extreme winter conditions we've seen over the last few years. For the SERVM analysis, we used data and assumptions used for the Company's 2023 IRP analysis, including hourly load data and unit operating characteristics such as heat rates, ramp rates, and forced outage rates. The model simulates the dispatch of Ameren Missouri's fleet to meet customer load and minimize loss of load. The loss-of-load expectation ("LOLE") is a measure of the extent of loss-of-load events when sufficient generation is not available to meet load. Such events can be driven by high load due to extreme weather, generation shortages due to unit outages or other constraints, or some combination thereof. The utility industry's benchmark is to use an LOLE of 0.1 as a target level of reliability, which means an expectation of one loss of load event occurring in a ten-year period. We have assessed the reliability in terms of LOLE for the Company's PRP and a plan without the Project in years 2030 and 2037. Those years were selected because they immediately follow the retirement of existing generation, with Venice retiring at the end of 2029 (due to CEJA[8] limits) and two Labadie units retiring at the end of 2036.

Q. Did you analyze any other plans or portfolios?

A. Yes. In addition to the two plans I just described, we also evaluated two other plans jointly suggested by Missouri Public Service Commission ("MPSC") Staff and Office of Public Counsel ("OPC") pursuant to a stipulation and agreement in the Company's most recent solar CCN case.[9] Those additional plans are based on the Company's PRP, modified by the following:[10]

- Staff/OPC Scenario 2
    - Without SCGT in 2028 (i.e., the Project)
    - Without new renewable capacity other than capacity representing the Cass County, Bowling Green, Vandalia, Split Rail, and (anticipated) Callaway solar projects
    - Without batteries
    - With NGCC moved from 2033 to 2028
    - With NGCC moved from 2040 to 2037
- Staff/OPC Scenario 3
    - Without new renewable capacity other than capacity representing the Cass County, Bowling Green, Vandalia, Split Rail, and (anticipated) Callaway solar projects
    - Without batteries

[8] Illinois' Clean Energy and Jobs Act, adopted by the Illinois legislature in 2021.
[9] File No. EA-2023-0286.
[10] Note that Staff and OPC also provided a Scenario 1, which is the Company's PRP without the Project and is duplicative of the plan without the Project previously described.

- Build in 2028: 600 MW SCGT with ability to add a heat recovery steam generator ("HRSG")
- In 2029: add 600 MW SCGT with an ability to add HRSG
- In 2030: add 2 into 1 HRSG sized to accommodate the two SC above[11]

Q. What does your analysis of the Company's PRP with and without the Project and the two additional Staff/OPC scenarios show?

A. In short, the analysis shows that reliability as measured by LOLE is significantly lower and thus better with the Project than without it. Table 1 below shows the results for all four alternative plans for 2030, and Table 2 shows the results for 2037. It shows that LOLE for the PRP (indicated as "Base") is 0.24 in 2030 compared to 2.08 without the Project (Scenario 1) and 0.10 in 2037 compared to 1.26 without the Project. Staff/OPC Scenario 2 shows a lower LOLE than Scenario 1, but higher than the PRP in 2030, but higher than both Scenario 1 and the PRP in 2037. Staff/OPC Scenario 3 yields the lowest LOLE in both 2030 and 2037.

Table 1 – SERVM Results for 2030

Case	Base	1	2	3
Battery Storage	400	400	-	-
Castle Bluff	800	-	-	800
CCGT	-	-	1,200	1,800
CT Gas Existing	2,058	2,058	2,058	2,058
Labadie	2,372	2,372	2,372	2,372
Sioux	974	974	974	974
Solar	1,400	1,400	1,180	1,180
Wind	1,700	1,700	700	700
LOLE	0.24	2.08	0.45	0.01
Long/(Short) MW	(284)	(1,027)	(607)	667

[11] The addition of the HRSG in 2030 is assumed to add 600 MW of generating capacity based on a typical NGCC build.

Table 2 – SERVM Results for 2037

Case	Base	1	2	3
Battery Storage	800	800	-	-
Castle Bluff	800	-	-	800
CCGT	1,200	1,200	2,400	3,000
CT Gas Existing	1,918	1,918	1,918	1,918
Labadie	1,186	1,186	1,186	1,186
Sioux	-	-	-	-
Solar	2,700	2,700	1,180	1,180
Wind	2,700	2,700	700	700
LOLE	0.10	1.26	1.52	0.02
Long/(Short) MW	22	(782)	(893)	363

Q. Staff/OPC Scenario 3 appears to provide superior reliability to the Company's PRP. Why not adopt such a plan?

A. Primarily the cost, which I will discuss later in my direct testimony, but also the substantial risks such a plan would bring. Staff/OPC Scenario 3 increases risk to the Company and its customers by relying much more heavily on fossil-fueled resources than the PRP, including a new gas-fired resource that are subject to EPA's recently finalized GHG rule.[12]

Q. You previously mentioned the role that the Project plays in integrating increasing levels of renewable resources. Is that reflected in the analysis results shown in Tables 1 and 2?

A. Yes. Dispatchable resources, particularly those with the flexibility to start quickly and quickly change their level of output, like the Project, will become increasingly more important as more renewable resources are added to the grid. When wind output fluctuates significantly, or when solar output rapidly rises during morning hours and rapidly drops during evening hours, it is

[12] Other future regulations of fossil-fueled resources could also increase the cost and/or reduce the potential production from gas-fired resources.

important to have resources than can quickly respond and fill in the gaps in production from these intermittent resources. The Project is exactly the kind of resource that can fill this role.

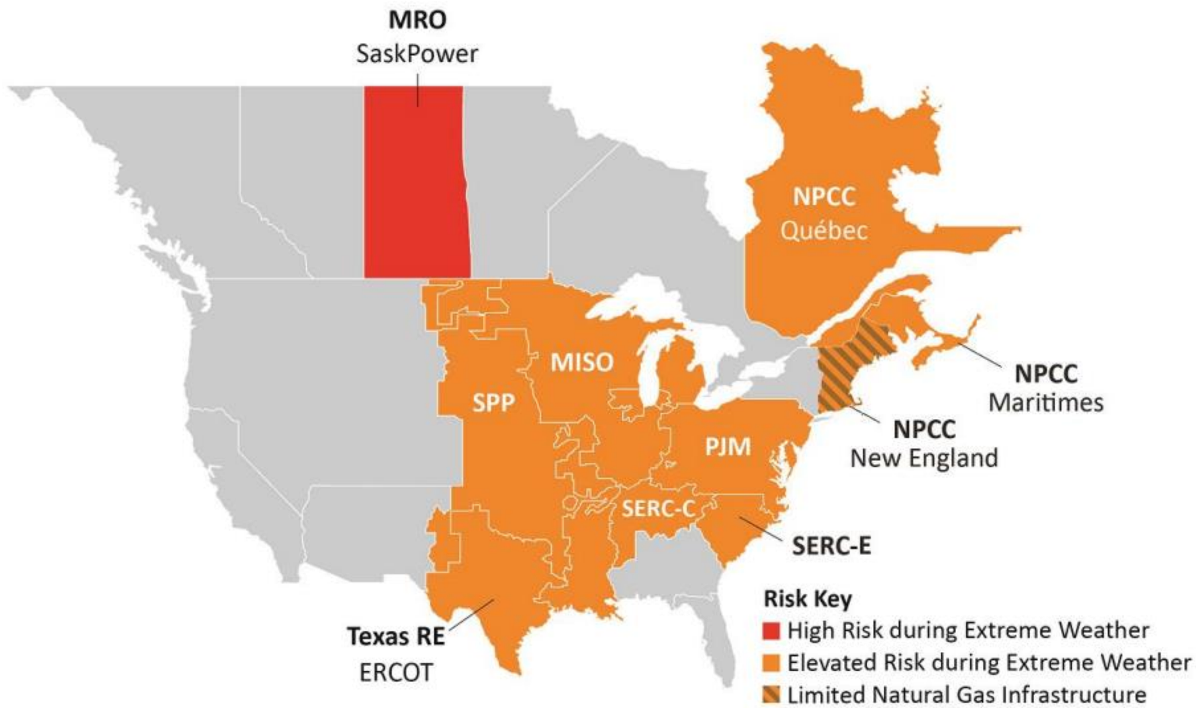
Q. Does the analysis that produced the results in Tables 1 and 2 include some level of reliance on the external market?

A. No. There is no guarantee that other resources will be available when needed, especially during widespread extreme weather events like winter storms Uri and Elliott. If we plan for our own reliability needs, Ameren Missouri's customers' needs are ensured. If there are cheaper resources available on the grid in any given hour, then we can take advantage of the market efficiency MISO provides. Under widespread extreme weather conditions, like those experienced during winter storms Uri and Elliot, the availability of external resources is far less likely, possibly non-existent.

Q. Has NERC expressed concern regarding resource adequacy in MISO?

A. Yes. In its 2023-2024 Winter Reliability Assessment, NERC indicated particular concerns regarding resource adequacy in MISO, designating MISO and neighboring regions as having "Elevated Risk" during extreme weather conditions, as shown in Figure 5 below.

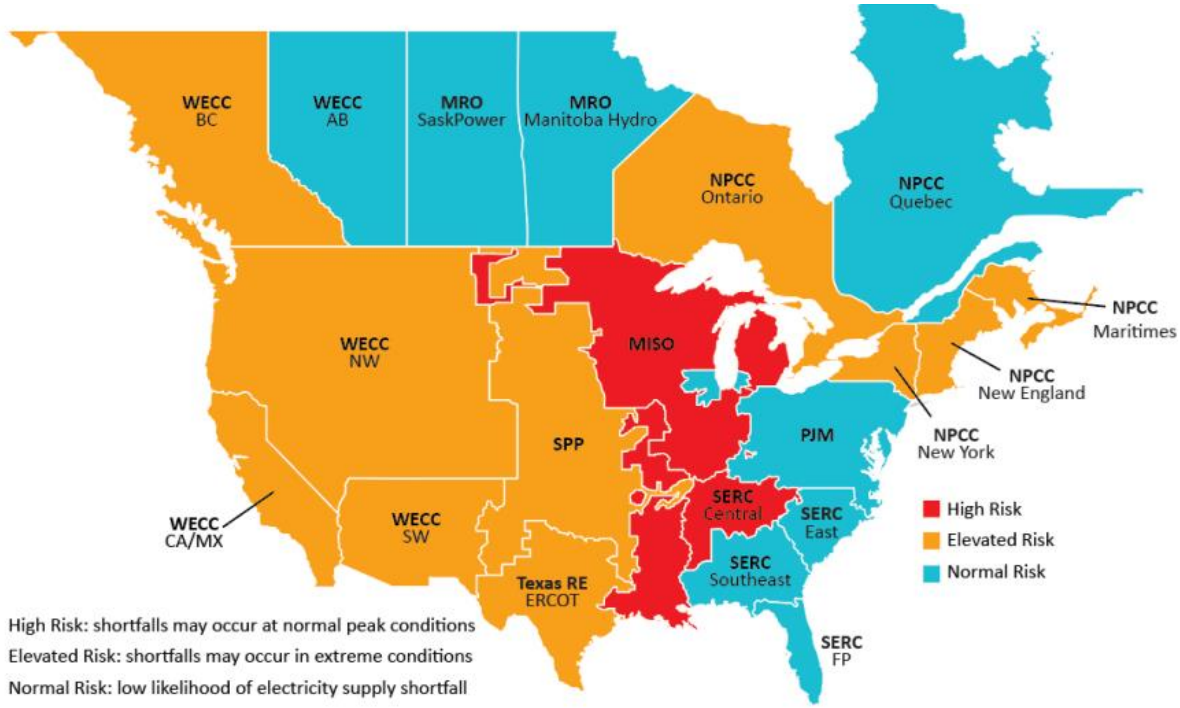
Figure 5 – NERC 2023-2024 Winter Reliability Map[13]



NERC has also indicated that MISO exhibits "High Risk" in its 2023 Long-Term Reliability assessment, as indicated in Figure 6 below. Note that "High Risk" in Figure 6 is based on normal conditions. Both Figures 5 and 6 indicate risks for both MISO and neighboring regions, including elevated risks during extreme winter weather.

[13] NERC 2023-2024 Winter Reliability Assessment, p. 5.

Figure 6 – NERC 2023-2024 Long-Term Reliability Map[14]



I have attached NERC's 2023-2024 Winter Reliability Assessment as Schedule MM-D1 and NERC's 2023 Long-Term Reliability Assessment as Schedule MM-D2.

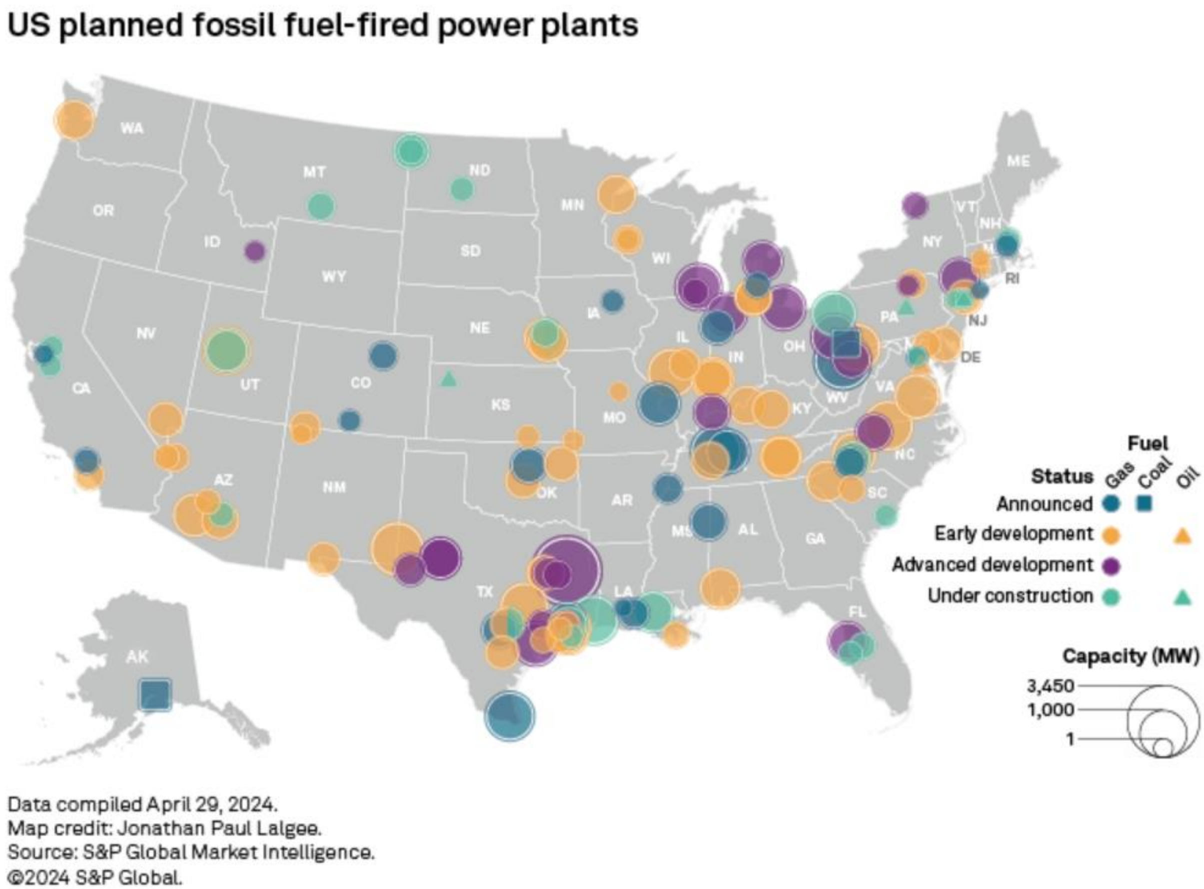
Q. Are there other factors that present potential reliability issues?

A. Yes. Growing load due to high interest in siting data centers, with peak demands in the hundreds of megawatts or more, represents a challenge to resource adequacy. The industry is increasingly turning to gas-fired generation to meet rising demand as it also transitions away from coal and toward more renewable resources for energy. In an article published by S&P Global, an evaluation of planned resource additions indicates that there are 133 gas-fired generator projects in the works as of April 2024, driven in part by rapidly rising demand. Figure 7 below shows the planned location of new fossil-fired generators. While the number of such projects that actually

[14] NERC 2023 Long-Term Reliability Assessment, p. 6.

come to fruition is uncertain, this trend strongly indicates the need for dispatchable generation, a preference for gas-fired generation, and a risk for resource additions keeping pace with demand.

Figure 7 – S&P Global Map of Planned Fossil Generation Additions[15]



[15] https://www.capitaliq.spglobal.com/apisv3/spg-webplatform-core/news/article?id=81469493&KeyProductLinkType=58&utm_source=MIAlerts&utm_medium=realtime-minewsresearch-newsfeature-energy%20and%20utilities-the%20daily%20dose&utm_campaign=Alert_Email

V. ALTERNATIVES CONSIDERED

Q. You've mentioned projects to restore or add oil-fired backup at several of the Company's gas-fired energy centers. Could additional oil-fired backup be pursued instead of the Project?

A. No. Once the oil backup project is completed at Audrain, all of the Company's SCGTs in Missouri will have oil-fired capability. The Company's remaining SCGTs are in Illinois and are subject to the limits of the Climate and Equitable Jobs Act ("CEJA"), which was passed by the Illinois legislature in 2021. Oil-fired backup was restored at the Kinmundy Energy Center at relatively low cost because it had previously been capable of oil-fired operation. The remaining Illinois SCGTs were not designed with that capability, and adding oil-fired capability to these Illinois SCGTs would be too costly and provide little or no benefit given the emission restrictions of CEJA. Many of the units are limited to less than 72 hours of operation during any 12-month period based on burning natural gas. Burning oil (which has higher emissions than gas) would further reduce their operable hours under the CEJA emission restrictions. A table of the Company's gas SCGT operating hour limits is attached as Schedule MM-D3.

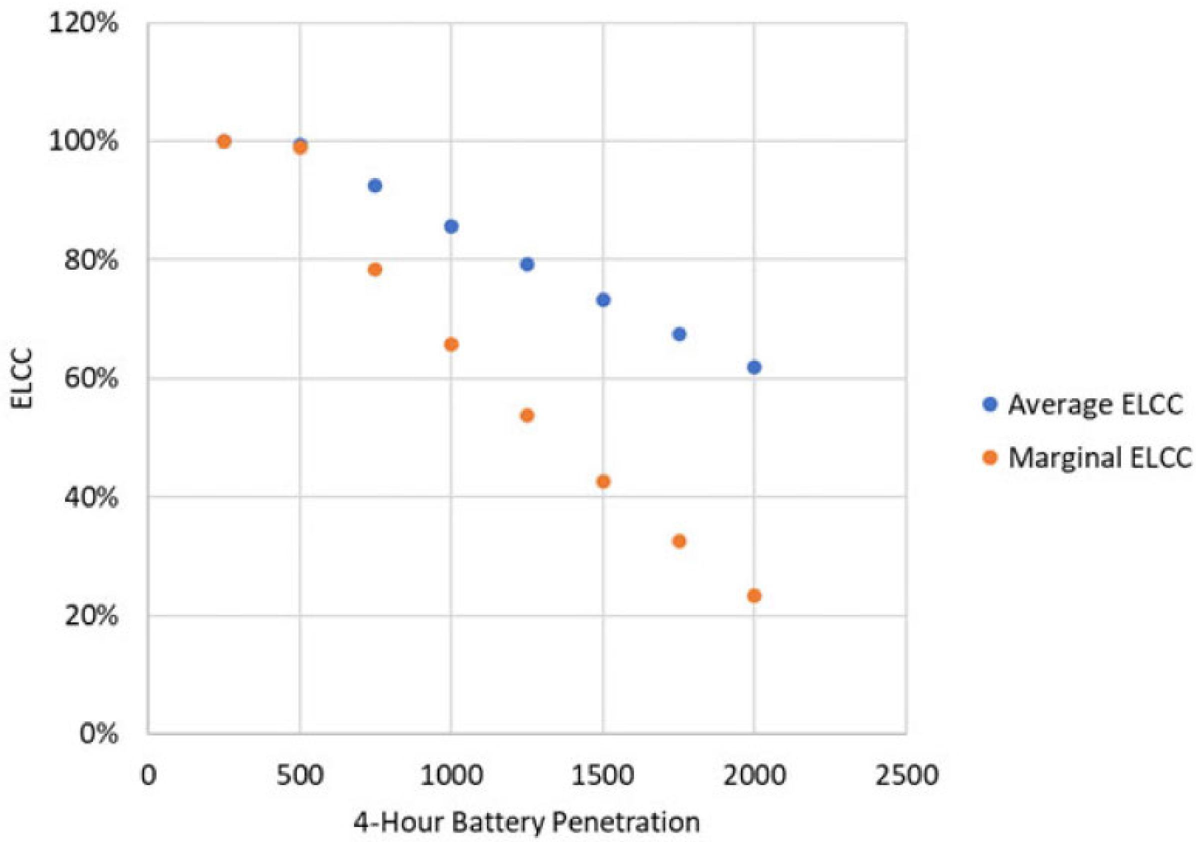
Q. What about building a natural gas combined cycle unit ("NGCC") instead of the Project?

A. While NGCC has a role to play in the Company's fleet in the long term, it comes with its own costs and risks. The chief risk is represented by environmental regulations, especially the EPA's recently finalized GHG rule. Under the rule, gas-fired turbine generators with a capacity factor greater than 40% must utilize CCS technology to capture at least 90 percent of CO_2 emissions. While the GHG rule is likely to be challenged in court, it is currently final and in effect, and pursuing additional NGCC capacity would be risky.

Q. What about additional battery storage resources?

A. Batteries can provide important services, including capacity, ramping capability, and frequency control. However, the incremental benefit of additional batteries declines as more battery resources are added to the system. The Company has already included 800 MW of battery storage in its PRP, and the incremental benefits of additional battery storage beyond that already included in the PRP would not be sufficient to justify their costs at this time. Figure 8 below shows the average and marginal capacity benefit of increasing penetrations of battery storage. As Figure 8 shows, marginal capacity benefits begin to decline when penetration reaches about 500 MW and drops to just over 40 percent at a penetration of 1,500 MW. If battery storage with a nominal capability equal to the Project, or about 800 MW, was added to the PRP, the average capacity contribution from all battery storage would drop from roughly 90 percent to roughly 70 percent, and the marginal contribution of the last 100 MW of battery storage would be less than 40 percent.

Figure 8 – Capacity Benefits of Increasing Battery Storage



Perhaps more importantly, battery storage resources may be of limited use during the kinds of extended extreme winter weather conditions we experienced during winter storms Uri and Elliot. During such events, there may be no opportunity to recharge battery resources if sufficient resources are not available. The batteries may be a "one-and-done" option during such events.

VI. ECONOMIC ANALYSIS

Q. Have you analyzed the costs to customers of implementing the Project?

A. Yes. I have analyzed the cost to customers on a Net Present Value of Revenue Requirements ("NPVRR") basis for the Company's PRP with and without the project. For the analysis, I have updated the Project costs to reflect the specific expected cost of approximately $811 million.[16]

Q. Did you also evaluate the economics of Staff/OPC's Scenarios 2 and 3?

A. Yes.

Q. What are the results of your analysis?

A. Table 5 below shows the NPVRR results for each plan for each of the three levels of assumed CO_2 price as well as the probability-weighted-average ("PWA") results. As Table 5 shows, removing the Project (Scenario 1) would reduce NPVRR by approximately $800 million. Removing the Project and replacing longer-term renewable and battery resources, as represented by Staff/OPC Scenario 2, would decrease NPVRR by approximately $500 million for the PWA results but would also introduce significant risk depending on future carbon policy during the planning horizon. Scenario 3, with long-term renewables and batteries removed and a significant increase in gas-fired resources in the near-term, results in an NPVRR that is more than $3 billion greater than that for the PRP.[17]

Table 5 – Difference in NPVRR vs. PRP ($MM)

Difference from Preferred Plan	Low	Base	High	PWA
Staff/OPC Scenario 1 (PRP w/o the Project)	(832)	(768)	(837)	(795)
Staff/OPC Scenario 2	(1,096)	(601)	(8)	(527)
Staff/OPC Scenario 3	3,004	3,143	3,388	3,183

[16] Excludes allowance for funds used during construction ("AFUDC").

[17] The stipulation in File No. EA-2023-0286 required that the Company provide these alternative plans to Staff along with the workpapers underlying them, which the Company did on June 6, 2024. Schedule MM-D4 attached hereto, which is one of the documents provided to Staff, contains an overview of the plans and results.

Q. An NPVRR for the PRP that is approximately $800 million greater than if the Project were removed seems like a significant cost to customers. Will this cause a large increase in customer rates?

A. No. In addition to analyzing PVRR differences, we also evaluate differences in levelized rates.[18] Table 6 below summarizes the levelized rates (PWA results), the percentage difference in levelized rates compared to the PRP, and the absolute difference in levelized rates compared to the PRP. As Table 6 shows, the inclusion of the Project results in rates that are approximately one percent higher than if the Project were not included. This provides important context when considering the benefits of increased reliability, particularly during extreme winter weather events. In essence, the project provides insurance against such risks. Also note that, as with the NPVRR results, levelized rates for Scenario 2 are less than those for the PRP but more than those for Scenario 1. This means that the renewable and battery storage investments in the PRP are cost beneficial relative to the alternative resources included in Scenario 2. Finally, and again, as with the NPVRR results, the levelized rates for Scenario 3 are substantially higher, nearly four percent greater than those for the PRP. As I mentioned previously, while Scenario 3 may result in greater reliability than other options, it comes at a significant cost to customers, arguably a case of over-insuring at a high cost, and it comes with greater exposure to changes in environmental and climate policy that could leave the Company ill-suited to meet customers' needs at all, or could result in even higher levels of expense associated with the need to broadly deploy carbon capture technology to comply with GHG rule requirements.

[18] Levelized rates represent a constant average rate to customers, expressed in cents per kwh, throughout the planning horizon that results in the same net present value cost to customers calculated using the year-by-year average annual rates that result from modeling a given alternative resource plan.

Table 6 – Levelized Rates and Differences vs. PRP

Levelized Rates	cents/kwh	% vs. PRP	Abs. vs. PRP
PRP	20.9	N/A	N/A
Scenario 1	20.7	-1.0%	(0.2)
Scenario 2	20.8	-0.6%	(0.1)
Scenario 3	21.7	3.9%	0.8

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 Permission and Approval and Certificate of Public Convenience and Necessity Authorizing it to Construct a Renewable Generation Facility	)))))	File No.: EA-2024-0237

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 6th day of June 2024.