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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. EA-2026-0183

DIRECT TESTIMONY

OF

MATT MICHELS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

**St. Louis, Missouri
May 2026**

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DIRECT TESTIMONY

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FILE NO. EA-2026-0183

I. INTRODUCTION

1

Q. Please state your name and business address.

2

3 A. Matt Michels, Union Electric Company d/b/a Ameren Missouri ("Ameren
4 Missouri" or "Company"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri
5 63103.

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Q. What is your position with Ameren Missouri?

6

7 A. I am the Director of Corporate Analysis.

7

**Q. Please describe your educational background and employment
9 experience.**

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9

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

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1 planning process, including plans that include significant new load additions, such as data
2 centers.

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

12 II. PURPOSE OF TESTIMONY AND KEY CONCLUSIONS

13 Q. What is the purpose of your Direct Testimony?

14 A. The purpose of my Direct Testimony is to support the Company's
15 application for certificates of convenience and necessity ("CCNs") for the construction of
16 Battery Energy Storage System projects ("BESS Projects") at the following sites, as
17 described in the Direct Testimony of Company witness Scott Wibbenmeyer: 95 megawatt
18 ("MW") at the Castle Bluff BESS Project ("Castle Bluff"), 250 MW at the Millcreek BESS
19 Project ("Millcreek"), and 200 MW at the Huck Finn BESS Project ("Huck Finn"). My
20 Direct Testimony also supports CCNs for construction of two new solar facilities, a 175
21 MW solar generation facility, to be known as the Tom Sawyer Solar Project ("Tom
22 Sawyer"), in Audrain County, Missouri; and a 225 MW solar generation facility, to be
23 known as the Ringer Solar Project ("Ringer"), in Stoddard County, Missouri (Tom Sawyer

1 and Ringer collectively referred to as the "Solar Projects" and the BESS and Solar Projects
2 collectively referred to as the "Projects").

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

4 A. The key conclusions of my Direct Testimony are:

5 • The Projects are needed to meet the capacity and energy
6 needs of existing and new customers, including new Large Load Customers
7 ("LLC"), reflecting a significant need for capacity in the near term and
8 increasing throughout the planning horizon, consistent with the Company's
9 2025 preferred resource plan ("PRP");

10 • The Solar Projects will provide renewable energy credits
11 ("RECs") that are needed to meet the Company's Missouri Renewable
12 Energy Standard ("RES") obligations;¹ and

13 • The Projects provide several other important benefits
14 because they can be implemented in the near-term, including avoiding the
15 risk of unforeseen delays and higher underlying materials and construction
16 costs if the Company were to wait to add additional capacity and energy
17 resources, allowing the Company to take advantage of valuable federal tax
18 credits that are available for the Projects now, and providing an important
19 hedge against fuel costs and critical risk mitigation against existing or future
20 environmental regulations that could negatively impact the production of
21 energy from the Company's fossil-fueled resources.

¹ Alternatively, part or all of the Solar Projects could be used to support customers through the Company's Renewable Solutions – LLC Program, as described in the testimony of Company witness Steve Wills.

1 **III. AMEREN MISSOURI'S PREFERRED RESOURCE PLAN**

2 **Q. Did Ameren Missouri change its PRP from the one included in the**
3 **Company's 2023 triennial IRP filing?**

4 A. Yes. Ameren Missouri filed a Notice of Change in PRP with the Missouri
5 Public Service Commission ("Commission") on February 28, 2025.² The Company's
6 formal Notice of Change in PRP is attached to my testimony as **Schedule MM-D1**.

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

8 A. There were two primary reasons. First, at that time, the Company had
9 experienced a surge in interest from LLCs locating in Ameren Missouri's service territory
10 and had signed construction agreements relating to over two gigawatts of new load. Peak
11 demand for individual LLCs can range from 75 MW to over a gigawatt ("GW"). As I
12 discuss later in my Direct Testimony, the Company indicated in its Notice of Change in
13 PRP filing that it expected as much as approximately 2 GW of such loads to begin ramping
14 up on the system as early as 2026 and to be fully ramped-up within three to five years.
15 Given the Company's obligation to serve, a change in the PRP was necessary to accelerate
16 the resources needed to reliably provide service to all customers. Second, while
17 significantly less impactful from an overall portfolio perspective, the reductions in
18 anticipated demand and energy savings based on the conclusion of the case involving its
19 most recent application for demand-side program approval under the Missouri Energy
20 Efficiency Investment Act ("MEEIA") required that the Company reassess its long-term
21 capacity and energy positions.

² On February 13, 2025, Ameren Missouri filed a brief notice of its intent to file a formal Notice of Change in PRP. The formal notice was filed in accordance with 20 CSR 4240-22.080(12).

- 1 • Retirement of two units at Labadie Energy Center at the end of 2036 and
2 the remaining two units at the end of 2042. This remains unchanged from
3 the Company's 2023 IRP preferred plan.
- 4 • Retirement of Venice Energy Center, a natural gas simple cycle ("NGSC")
5 facility located in Illinois, at the end of 2029. The retirement of Venice is
6 required to comply with the Illinois' Climate and Equitable Jobs Act
7 ("CEJA"), enacted in 2021, and remains unchanged from the Company's
8 2023 IRP preferred plan.
- 9 • Retirement of the Company's remaining Illinois NGSC facilities at the end
10 of 2039, also to comply with CEJA and unchanged from the Company's
11 2023 IRP preferred plan.
- 12 • Addition of 800 MW of NGSC capacity in late 2027 – the Castle Bluff
13 facility for which the Commission approved a CCN in October 2024 –
14 remains unchanged from the Company's 2023 IRP preferred plan.⁴
- 15 • Addition of another 800 MW of NGSC capacity in late 2028 at the former
16 site of the Company's coal-fired Rush Island Energy Center, which was
17 retired in October 2024 – the Big Hollow Energy Center ("BHEC"), for
18 which the Commission approved a CCN in February 2026.⁵
- 19 • Addition of 1,000 MW of wind generation by 2030 and another 1,000 MW
20 by 2035, unchanged from the Company's 2023 IRP preferred plan.

⁴ File No. EA-2024-0237.

⁵ File No. EA-2025-0238.

- 1 • Addition of 2,200 MW of solar generation by 2030 (including 900 MW now
2 in service or expected to be in service in 2026,⁶ another 250 MW for the
3 Reform Solar project, for which the Company was granted a CCN in May
4 2026,⁷ and another 1,050 MW, including the 175 MW Tom Sawyer Project
5 and the 225 MW Ringer Project (for which the Company is seeking CCNs
6 in this case) and another 500 MW by 2035. This represents an acceleration
7 of solar generation additions from that planned in the Company's 2023 IRP
8 preferred plan, which included 1,800 MW of solar resources by 2030.⁸
9 Renewable resource additions are a particularly important consideration in
10 attracting new LLCs, such as data centers.
- 11 • Addition of 1,000 MW of BESS by 2030 (including 400 MW which has
12 been approved for construction at the Company's Big Hollow Energy
13 Center⁹ and another 545 MW for which the Company is seeking CCNs in
14 this case), another 400 MW by 2036, and another 400 MW by 2042, for a
15 total of 1,800 MW.¹⁰ This also represents an acceleration as compared to
16 the 2023 PRP, as well as an increase relative to the 800 MW of BESS
17 additions included in the Company's 2023 PRP.

⁶ Ameren Missouri's Huck Finn, Cass County, Boomtown, Spit Rail, Vandalia, and Bowling Green solar energy centers.

⁷ See File No. EA-2025-0239.

⁸ The addition of Tom Sawyer and Ringer would bring the Company's total in-service and approved solar generation to approximately 1,550 MW, including 900 MW currently in service or expected to be in service in 2026, 250 MW for the Reform project, 175 MW for the Tom Sawyer project, and 225 MW for the Ringer project.

⁹ File No. EA-2025-0238.

¹⁰ All BESS included in the PRP is assumed to be 4-hour lithium-ion battery storage for modeling purposes. Additions beyond 2030 may deploy technologies currently under development.

- 1 • Addition of 2,100 MW of natural gas combined cycle ("NGCC") capacity
2 by the end of 2031 and another 1,200 MW of NGCC capacity by the end of
3 2036. This represents an acceleration of a portion of the "clean
4 dispatchable" resources included in the Company's 2023 IRP preferred plan,
5 shown in 2040 and 2043.
- 6 • Addition of a further 600 MW of NGSC capacity at the beginning of 2038
7 and another 600 MW of NGSC capacity at the beginning of 2043, both
8 representing new additions relative to the Company's 2023 IRP preferred
9 plan.
- 10 • Addition of 1,500 MW of nuclear generation at the beginning of 2040. This
11 represents the addition of further clean dispatchable generation, with the
12 selection of specific technology to be made at a later date.¹¹

13 **Q. How did Ameren Missouri arrive at its PRP?**

14 A. In short, Ameren Missouri evaluated a range of potential outcomes, or
15 cases, for what its system load would be if new large loads were added, determined for
16 each case the need for acceleration and addition of resources relative to its 2023 PRP to
17 meet load and Midcontinent Independent System Operator ("MISO") planning reserve
18 margin ("PRM") requirements, and selected the plan that 1) best represents expectations of
19 future large load additions at the time the 2025 PRP was adopted, 2) provides some
20 flexibility in the near-term regarding further large load additions, and 3) ensures the
21 Company maintains both short-term and long-term resource flexibility to address various
22 risks to its portfolio.

¹¹ For modeling purposes, the Company's assumptions for modular nuclear generation were used.

1 **Q. Please describe the LLC cases that were evaluated.**

2 A. Ameren Missouri evaluated seven different load cases, as shown in Table 1
3 below. The seven cases reflect three different levels of large load additions in the near term
4 – 500 MW, 1,500 MW, and 2,000 MW by 2032. Cases 1-3 reflect no further growth in
5 large loads after 2032. Cases 4 and 5 reflect continued growth from 1,500 MW and 2,000
6 MW loads achieved by 2032, respectively, to 2,500 MW and 3,500 MW, respectively, by
7 2040. Cases 6 and 7 reflect no further growth in large loads after 2032 (1,500 MW and
8 2,000 MW in place by 2032, respectively), then a reduction in large loads to 500 MW in
9 2039. Cases 6 and 7 are used as the basis for evaluating the cost of resource acceleration
10 to meet near-term LLC demand.

11 **Table 1. Large Load Cases – Annual Peak Demand (MW) at Meter¹²**

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

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

14 A. A load factor of 85% was used. This results in additional annual energy
15 sales of approximately four million megawatt-hours (“MWh”) for each 500 MW of large
16 load demand.

¹² Large load demand is assumed to begin at the levels shown on January 1st of each calendar year.

1 **Q. What resources did the 2025 PRP show were needed to meet customer**
2 **demand and energy needs in each of the seven load cases you just described?**

3 A. The resource additions called for by the 2025 PRP for each case are
4 summarized in the attached **Schedule MM-D2**. Note that 2,200 MW of solar was shown
5 to be needed by 2030 even if the Company realized only a small part of the new LLC
6 demand we had been planning for – just 500 MW. The additions of Tom Sawyer and
7 Ringer Projects would bring the Company's total solar generation to approximately 1,550
8 MW.

9 **Q. Which case did the Company choose for inclusion in its current PRP?**

10 A. Ameren Missouri chose Case 4 for inclusion in its PRP and therefore as the
11 basis for determining resource needs. Based on discussions with potential customers at that
12 time, the Company was also actively planning for Case 5 as an alternative scenario, as I
13 discuss later in my Direct Testimony, with the potential for even further additional demand.

14 **Q. Was it possible that large load demand could exceed the amounts**
15 **included in the PRP?**

16 A. Yes. Ameren Missouri included Case 5 as an alternative plan in the Notice
17 of Change in PRP filed with the Commission on February 28, 2025.¹³ It should be noted
18 that resource additions through 2032 for Case 5 are identical to those included for Case 4.
19 This provides flexibility in the near term as the Company continues to evaluate requests
20 for connection and service from prospective LLCs. Because discussions with potential
21 customers were ongoing, we recognized that demand could exceed even the high case.¹⁴

¹³ Schedule MM-D1, page 6, Table 1.1.

¹⁴ The Company announced in February 2026 that it had signed Energy Services Agreements ("ESAs") with LLCs with an expected aggregate demand of 2.2 GW once fully ramped-up. The Company further

1 **Q. Has the Company signed LLCs to ESAs for service under the**
2 **Company's Large Load Tariff approved in File No. ET-2025-0184?**

3 A. Yes. Ameren Missouri has signed ESAs for several LLC customers with
4 expected total peak demand of approximately 2.8 GW as of the time of the filing this case.
5 Company witness Rob Dixon describes the Company's economic development efforts in
6 his Direct Testimony.

7 **Q. What steps has Ameren Missouri taken to ensure that it has the**
8 **generation needed to ensure reliability and to meet its obligation to serve existing and**
9 **new customers that elect to take service under its approved tariffs?**

10 A. In the short term, we will utilize the interim capacity provisions of the large
11 load tariff to secure capacity from the capacity market or bilaterally, as well as increasing
12 the Company's own system capacity through recently completed projects and projects
13 expected to be completed in the next year or two that the Commission has already approved
14 – i.e., the Castle Bluff and Big Hollow NGSCs, the Big Hollow BESS, and the Huck Finn,
15 Boomtown, Vandalia, Split Rail, Cass County, Bowling Green and Reform solar facilities.
16 We have also completed adding oil backup capabilities to the Peno Creek Combustion
17 Turbine Generator ("CTG") facility to provide additional winter capacity and are in the
18 process of doing the same at the Audrain CTG facility. With respect to longer-term
19 resource planning, given the expected large load additions and the reduction in our
20 demand-side programs (and the lower level of MW savings from those programs) approved
21 in our last MEEIA docket, our February 2025 PRP contemplates acceleration of other
22 resources in the intermediate term, additional baseload gas generation as I discussed earlier

announced in May 2026 that it had signed an additional ESA, bringing the total signed to 2.8 GW.
Discussions are continuing with other prospective customers.

1 by 2031, as well as other generation through the 20-year planning horizon. As can be seen
2 from the charts in Figures 2 and 3, based on the generation projects for which Ameren
3 Missouri has received CCNs and which it is actively constructing, Ameren Missouri is
4 short of system capacity required to serve expected demand, including expected new LLCs,
5 starting in 2027 and continuing into the future unless the Projects and other generation
6 additions in the Company's 2025 PRP are constructed.¹⁵ The Company therefore has a need
7 to build new generation resources to meet its capacity needs to fulfill its obligations to
8 provide reliable electric service to all customers.

9 **Q. What are the Company's goals to ensure reliability for all its customers**
10 **– existing and new?**

11 A. To ensure reliability for all its customers, the Company has two main goals.
12 First, to continue to conduct robust integrated resource planning analysis to ensure that the
13 Company has sufficient dispatchable system capacity over the planning horizon with
14 enough reserve margin to meet its peak retail load demand needs even in extreme weather
15 and adverse system reliability conditions. And second, to ensure a balanced mix of
16 dispatchable and renewable generation resources to provide cost-effective energy during
17 all hours of every day for all customers in a reliable manner.

18 **Q. How is the Company ensuring it has adequate reserve margin to serve**
19 **all customers even under extreme weather conditions?**

20 A. The Company is implementing its PRP to ensure reliability for all customers. Later
21 in my Direct Testimony, I present various charts that show the Company's short capacity

¹⁵ The charts in Figures 2 and 3 are based on the Case 5 load assumptions included in the Company's February 2025 PRP filing. Given that the signed ESAs reflect loads that are materially higher (800 MW) than the Case 5 load assumptions, the need for the Projects is even greater than shown by those Figures.

1 positions and energy positions as well as charts that demonstrate that the implementation
2 of the Company's PRP, together with utilization of interim capacity over the next five years,
3 provides sufficient reserve margin to serve all customers and significantly mitigate
4 reliability risks arising from extreme weather conditions. The resources included in this
5 CCN filing are required to ensure that the Company has sufficient system capacity and the
6 capability to generate enough energy to meet its expected customer needs. In addition, as
7 Company witness Wibbenmeyer explains in his Direct Testimony, the Projects can be
8 constructed quickly and cost-effectively because the developments are mature, generator
9 interconnections are in place, investment tax benefits are timely, and significant
10 engineering and equipment contracting work has already been completed. This
11 combination of cost-effectiveness and speed to market supports the Company's obligation
12 to meet customers' capacity and energy requirements.

13 **IV. AMEREN MISSOURI'S NEED FOR CAPACITY**

14 **Q. How does Ameren Missouri evaluate capacity needs?**

15 A. This is done by evaluating the Company's capacity position, the difference
16 between the total generating capacity of its portfolio of resources and the peak demand and
17 MISO PRM. Ameren Missouri also analyzes all four seasons as part of its IRP planning.
18 However, the winter season currently drives resource needs, in part due to lower winter
19 accreditations for gas-only resources that experience fuel supply constraints during cold
20 weather.

21 **Q. What is the basis for the load and generating capacity assumptions**
22 **reflected in the capacity positions included in your Direct Testimony?**

1 A. The peak demand and unit accreditation values are the same as those used
2 in the Company's 2023 IRP analysis, with the modification to include additional winter
3 capability at Audrain described below.¹⁶

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

5 A. The 2023 IRP relied on the unit accreditations provided by MISO for its
6 2023-2024 Planning Resource Auction ("PRA"), often referred to as MISO's capacity
7 auction. A few modifications were made to normalize accreditations for certain resources,
8 which had experienced significant outages during the prior three years, to better represent
9 going-forward performance expectations for reliability purposes. The primary adjustments
10 were for Callaway and the Taum Sauk pumped hydro storage facility arising from past
11 outage events that are not expected to recur.

12 **Q. Why did you use values from MISO's 2023-2024 PRA instead of more**
13 **recent values from its 2026-2027 PRA?**

14 A. The primary reason is for continuity and consistency. MISO's approach to
15 unit accreditations changed when it adopted a seasonal Resource Adequacy ("RA")
16 construct. Company witness Andrew Meyer discusses the evolution of MISO's RA
17 construct in more detail in his Direct Testimony. Part of MISO's current approach includes
18 making an adjustment to unit accreditations based on actual performance during critical
19 hours – roughly 60 hours in each season, or less than 300 hours per year. MISO has been
20 phasing this adjustment into its accreditation process over three years, with 40% of the
21 adjustment included for planning year 2023-2024, 60% for planning year 2024-2025, and
22 80% starting in planning year 2025-2026. It is important to recognize that under this

¹⁶ 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.

1 construct, it is not possible to identify when such critical hours will occur in the future or
2 how units will perform during such hours. Another important aspect of the current
3 construct is that changes like the addition of oil backup at Audrain are not fully recognized
4 in winter unit accreditations because MISO phases such changes in over three years, even
5 though the units' improved ability to operate during winter occurs immediately. Because
6 of the uncertain and after-the-fact nature of these adjustments and the forward-looking
7 nature of resource planning, it makes more sense to use the 2023-2024 PRA accreditation
8 values as the basis for the capacity positions presented here. It is also important to note
9 that there have been no significant underlying changes in rated output for Ameren
10 Missouri's existing generating units.

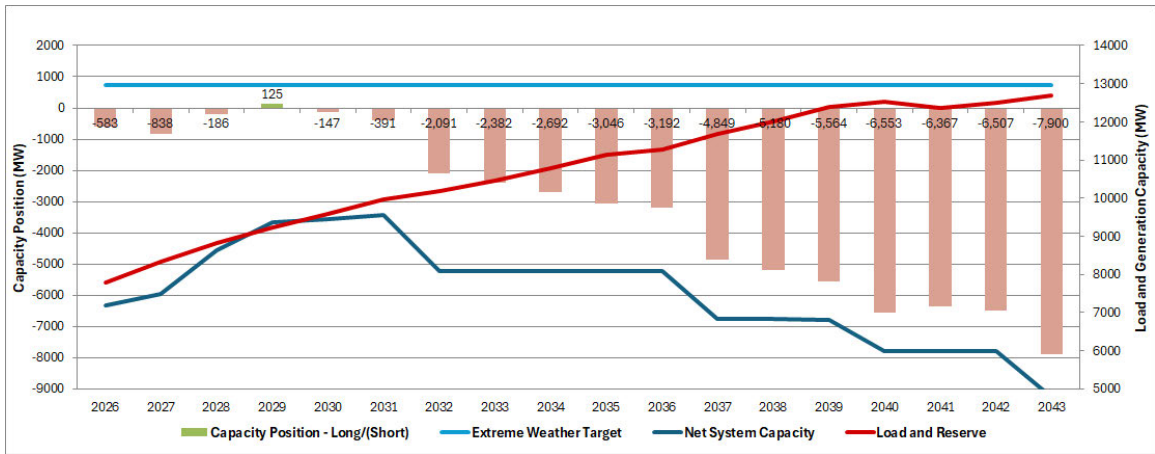
11 **Q. Have you prepared a capacity position for Case 5 loads with only**
12 **existing and approved resources?**

13 A. Yes. Figure 2 below shows the winter capacity position for Case 5 with
14 only existing and approved resources, and Figure 3 shows the summer capacity position
15 with only existing and approved resources, both under normal weather conditions.¹⁷ For
16 purposes of these charts, approved resources include all resources for which the
17 Commission has granted the Company a CCN but which have not yet been placed in
18 service.¹⁸ Note the light blue lines in each chart, which represent the Company's targeted
19 capacity position to mitigate risks of extreme weather. The Company's expected winter
20 capacity position falls well short of this target in every year, and the expected summer
21 capacity position falls well short beginning in 2030.

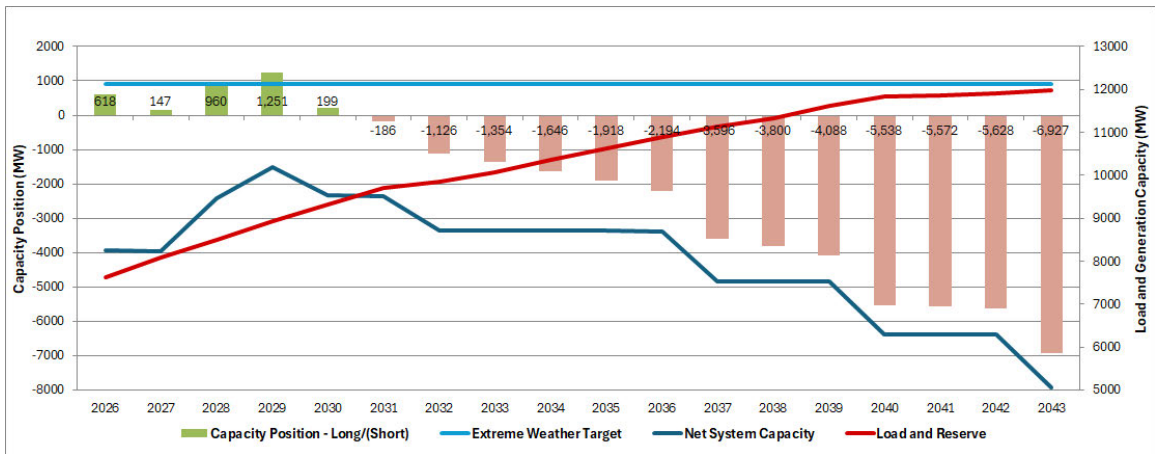
¹⁷ Note that especially in the winter (and some years in the summer), existing and planned resources do not provide enough capacity to cover load in extreme weather, which is happening far more frequently than it did several years ago,

¹⁸ Includes recent approval of CCNs for Big Hollow NGSC and BESS and Reform Solar.

1 **Figure 2. Winter Capacity Position with Only Existing and Approved Resources –**
2 **Load Case 5**



3 **Figure 3. Summer Capacity Position with Only Existing and Approved Resources –**
4 **Load Case 5**



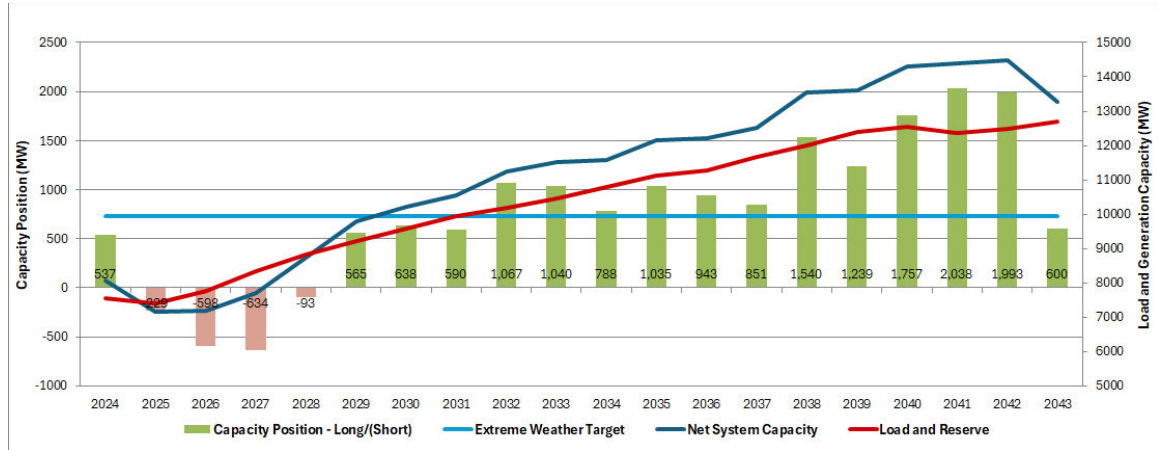
5 **Q. Have you also prepared capacity positions for Case 5 loads with all**
6 **planned resources?**

7 **A. Yes.** Figure 4 below shows the winter capacity position for Case 5, and
8 Figure 5 shows the summer capacity position, both under normal weather conditions. As
9 the capacity positions in Figures 4 and 5 show, in its alternative plan, Ameren Missouri
10 plans to have sufficient capacity to meet its load and reserve margin obligations starting in

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1 winter 2028-2029, with a potential minimal (less than a 100 MW) shortfall in winter 2027-
2 2028, and in summer in all years of the planning horizon. As discussed later in my Direct
3 Testimony, Ameren Missouri is taking steps to address winter capacity shortfalls during
4 the coming three years.

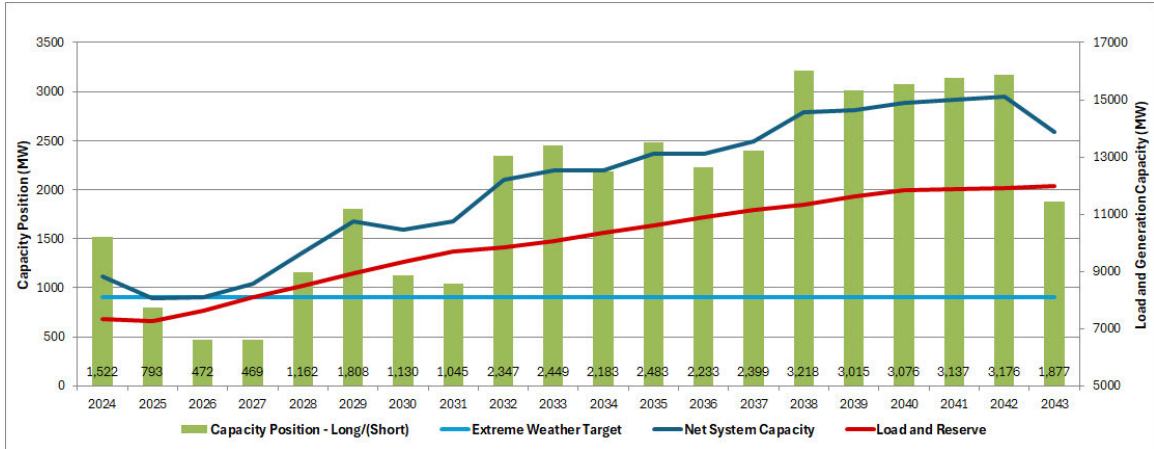
5 **Figure 4. Winter Capacity Position – Load Case 5¹⁹**



¹⁹ All winter capacity position charts shown reflect January and February of the calendar year and December of the prior year.

1

Figure 5. Summer Capacity Position – Load Case 5



2

3

Q. You mentioned NGSC and BESS as resources that can be used to meet peak demand, even though BESS produces no energy itself and NGSC units typically operate at relatively low capacity factors. Please explain the rationale for the Company's inclusion of both in its PRP.

7

A. Both NGSC and BESS currently provide significant capacity benefits in MISO. Ameren Missouri currently assumes accredited values equal to 95 percent of rated output for BESS and 91 percent of rated output for NGSC, both for the winter season, which is a key driver of resource needs for Ameren Missouri. Over time, and as BESS resources are added to the grid, the capacity value of BESS may decline as the incremental capacity benefit of further BESS additions diminishes.²⁰ Ameren Missouri has relied on analysis by Astrape' Consulting,²¹ a reliability modeling consulting firm that provides analytical support to utilities and regional grid operators, including to MISO, to determine the possibility of declining capacity value of battery storage. Figure 6 below shows that BESS provides capacity value at essentially its full rated output up to 500 MW on Ameren

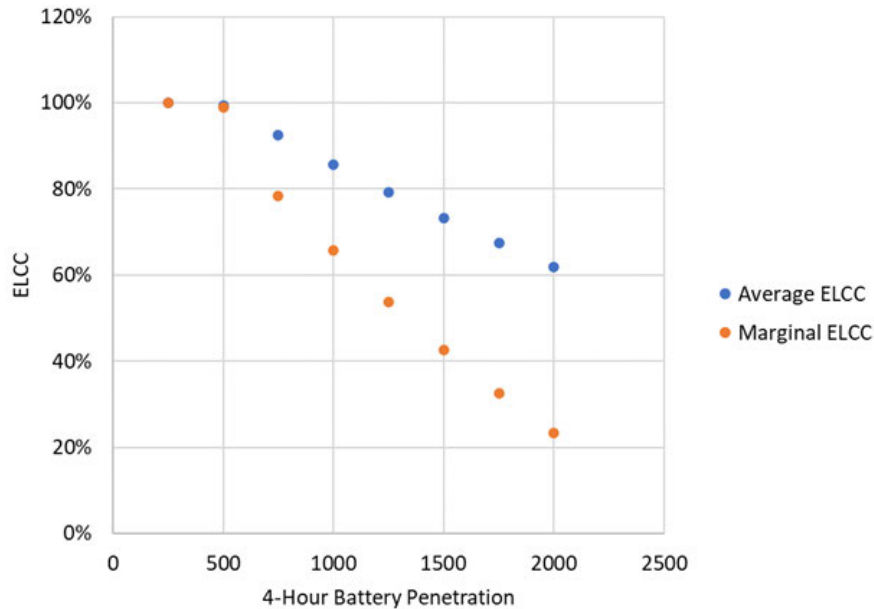
16

²⁰ In simple terms, the incremental capacity benefit of further BESS is expected to diminish as the opportunity to reduce peak net load by shifting load to different times of the day is reduced.

²¹ Astrape' was acquired by PowerGEM in 2024.

- 1 Missouri's system. As more BESS resources are added, the incremental capacity benefit,
2 expressed as effective load carrying capability ("ELCC") declines.

3 **Figure 6. Battery ELCC by Cumulative Capacity Deployed**



- 4 However, while longer term the marginal ELCC for BESS declines as additional
5 BESS resources are added to the grid, in the near- to intermediate-term, the economics of
6 BESS relative to new NGSC today are advantageous. As a result, there is a cross-over
7 point at which further BESS additions are less economical than additional new NGSC.
8 Ameren Missouri combined its evaluation of BESS and NGSC economics and the insight
9 from Figure 6 above to identify that likely cross-over point. Table 2 below shows a
10 comparison of the economics, as measured by the net present value of revenue
11 requirements ("NPVRR"), of increasing amounts of BESS relative to NGSC on a capacity
12 equivalent basis, using the Company's current accreditation value for NGSC and the ELCC
13 curve shown in Figure 6. As Table 2 shows, BESS is more economic than additional NGSC
14 (i.e., beyond that already included in the PRP) on a capacity equivalent basis beyond, and

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1 likely well beyond, 2,000 MW of BESS additions for Ameren Missouri (the negative
2 numbers in the last row of Table 2 reflect a reduction in net present value of revenue
3 requirement over the planning horizon resulting from deployment of BESS relative to a
4 capacity equivalent amount of NGSC).

5 **Table 2. Capacity Equivalent Economics w/ ITC – BESS vs. NGSC (Current**
6 **Accreditation)**

Current Accred. CTG vs. ELCC Battery	Initial BESS Additions	Incremental Storage Equivalent Cost at Marginal ELCC					
Incremental Battery Accredited Capacity (MW)	500	250	500	750	1000	1250	1500
Total Battery Accredited Capacity (MW)	500	750	1000	1250	1500	1750	2000
Marginal ELCC	100%	87%	74%	62%	49%	36%	23%
Average ELCC	100%	94%	87%	81%	74%	68%	62%
Battery Equiv. Maximum Capacity (MW)	500	267	574	929	1,345	1,840	2,439
Battery PVRR \$MM	502	268	576	932	1,350	1,847	2,448
CTG Equiv. Maximum Capacity (MW)	550	275	550	825	1,100	1,376	1,651
CTG PVRR \$MM	1,065	533	1,065	1,598	2,130	2,663	3,195
Difference (Battery - CTG) \$MM	(563)	(264)	(489)	(665)	(780)	(815)	(747)

7 Alternatively, I have also made a capacity equivalent comparison of BESS and
8 NGSC using indicative accreditation values for NGSC with dual fuel (as new NGSC are
9 being designed by Ameren Missouri to include) under MISO's proposed Direct-Loss-of-
10 Load ("DLOL") accreditation framework. Table 3 below shows a comparison of BESS
11 and NGSC on a capacity equivalent basis using MISO's most recent indicative DLOL
12 accreditation value for NGSC. Table 3 shows that BESS is more economic than additional
13 NGSC beyond, and again likely well beyond, 2,000 MW. Based on the results shown in
14 Table 2 and Table 3, BESS up to at least 2,000 MW is more economic relative to additional
15 NGSC above that included in the 2025 PRP. The Company's planned addition of 1,800
16 MW of BESS is clearly within the economic range.

1 **Table 3. Capacity Equivalent Economics w/ ITC – BESS vs. NGSC (MISO DL0L)**

DL0L Accred. CTG vs. ELCC Battery	Initial BESS Additions						
	500	250	500	750	1000	1250	1500
Incremental Battery Accredited Capacity (MW)	500	250	500	750	1000	1250	1500
Total Battery Accredited Capacity (MW)	500	750	1000	1250	1500	1750	2000
Marginal ELCC	100%	87%	74%	62%	49%	36%	23%
Average ELCC	100%	94%	87%	81%	74%	68%	62%
Battery Equiv. Maximum Capacity (MW)	500	267	574	929	1,345	1,840	2,439
Battery PVRR \$MM	502	268	576	932	1,350	1,847	2,448
CTG Equiv. Maximum Capacity (MW)	746	373	746	1,119	1,493	1,866	2,239
CTG PVRR \$MM	1,445	722	1,445	2,167	2,889	3,612	4,334
Difference (Battery - CTG) \$MM	(943)	(454)	(869)	(1,235)	(1,539)	(1,764)	(1,886)

2 **Q. Have you evaluated the comparative economics of NGSC and BESS if**
3 **federal tax credits are no longer available for BESS?**

4 A. Yes. Table 4 below shows a comparison of the economics of increasing
5 amounts of BESS relative to additional NGSC assuming the currently used accreditation
6 values for NGSC, and Table 5 shows a comparison using MISO's indicative accreditation
7 amount for NGSC, both without the inclusion of investment tax credits ("ITC") for BESS.

8 **Table 4. Capacity Equiv. Economics w/o ITC – BESS vs. NGSC (Current**
9 **Accreditation)**

Current Accred. CTG vs. ELCC Battery	Initial BESS Additions						
	500	250	500	750	1000	1250	1500
Incremental Battery Accredited Capacity (MW)	500	250	500	750	1000	1250	1500
Total Battery Accredited Capacity (MW)	500	750	1000	1250	1500	1750	2000
Marginal ELCC	100%	87%	74%	62%	49%	36%	23%
Average ELCC	100%	94%	87%	81%	74%	68%	62%
Battery Equiv. Maximum Capacity (MW)	500	267	574	929	1,345	1,840	2,439
Battery PVRR \$MM	870	465	998	1,617	2,342	3,204	4,246
CTG Equiv. Maximum Capacity (MW)	550	275	550	825	1,100	1,376	1,651
CTG PVRR \$MM	1,065	533	1,065	1,598	2,130	2,663	3,195
Difference (Battery - CTG) \$MM	(195)	(68)	(67)	19	212	541	1,050

1 **Table 5. Capacity Equivalent. Economics w/o ITC – BESS vs. NGSC (DL0L)**

DL0L Accred. CTG vs. ELCC Battery	Initial BESS	Incremental Storage Equivalent Cost at Marginal ELCC					
	Additions						
Incremental Battery Accredited Capacity (MW)	500	250	500	750	1000	1250	1500
Total Battery Accredited Capacity (MW)	500	750	1000	1250	1500	1750	2000
Marginal ELCC	100%	87%	74%	62%	49%	36%	23%
Average ELCC	100%	94%	87%	81%	74%	68%	62%
Battery Equiv. Maximum Capacity (MW)	500	267	574	929	1,345	1,840	2,439
Battery PVRr \$MM	870	465	998	1,617	2,342	3,204	4,246
CTG Equiv. Maximum Capacity (MW)	746	373	746	1,119	1,493	1,866	2,239
CTG PVRr \$MM	1,445	722	1,445	2,167	2,889	3,612	4,334
Difference (Battery - CTG) \$MM	(574)	(257)	(446)	(550)	(548)	(408)	(88)

2 As Table 4 shows, even without the benefit of ITC, BESS maintains an economic
3 advantage relative to additional NGSC up to 1,250 MW. Likewise, Table 5 shows an
4 advantage for BESS up to 2,000 MW. The BESS project additions for which the Company
5 is seeking CCNs in this case would bring the Company's total BESS installed capacity to
6 945 MW, well below the lowest level of installed capacity for which BESS economics
7 would be favorable compared to NGSC.²²

8 **Q. What if something changes the relative economics of BESS and NGSC**
9 **or other factors that may affect their implementation?**

10 A. In that case, the Company could adjust its plans for any uncommitted
11 resources at that time. Ameren Missouri's 2025 PRP reflects 1,000 MW of BESS by the
12 end of 2030 and another 400 MW by 2035. If the economics of further BESS become
13 disadvantageous, the Company would reassess further resource additions. Reassessing
14 further resource additions would also need to account for any advances in both BESS and
15 NGSC technology, such as the potential for longer duration BESS technologies, which
16 would improve the ELCC for BESS relative to the four-hour BESS technology currently

²² The economic break-even point of 1,250 MW of BESS only applies if tax credits are not available. Because tax credits are available under current law through 2036, the most appropriate view of the relative economics of BESS and NGSC is that reflecting tax credits for BESS.

1 planned and analyzed. It would also need to include consideration of any practical
2 limitations on the Company's ability to implement resources in a timely manner, such as
3 permitting, fuel constraints, or supply chain issues. Such changed conditions are a large
4 reason why utilities prepare IRPs every few years and conduct continuous planning in
5 between.

6 **Q. Do BESS project additions have any other advantages in the near**
7 **term?**

8 A. Yes. BESS projects can be deployed faster than gas-fired resources because
9 they do not require fuel and face fewer permitting challenges from emissions. As further
10 discussed by Company witness Wibbenmeyer, they also require little land and pair well
11 with solar and wind projects, allowing Ameren Missouri to develop them cost-effectively
12 on land it already owns near existing facilities and to use surplus interconnections or
13 MISO's expedited resource addition study ("ERAS") process to secure transmission
14 interconnection rights quickly and at low cost.

15 **Q. With the addition of solar generation for energy production and BESS**
16 **and NGSC for meeting peak demand, why is there a need for NGCC resources?**

17 A. While the combination of both renewable and peaking resources is
18 necessary for implementing a balanced energy transition, baseload resources are also
19 needed to ensure that customer needs are met around-the-clock and throughout the year.
20 This is especially true when considering the replacement of retiring baseload or coal
21 generation, such as Sioux, as well as the addition of large load customer demand with
22 essentially around-the-clock operations. This is why Ameren Missouri looks at the totality
23 of its customers' needs for both capacity and energy. It allows us to consider the entirety

1 of customer needs in the context of existing and potential market and regulatory conditions
2 over the entire planning horizon. Baseload gas resources provide both capacity and
3 around-the-clock energy; peaking gas resources provide capacity and energy during times
4 when they are needed most; renewable resources provide RECs for RES compliance and
5 for programs that help customer (including LLCs) meet their energy and sustainability
6 goals, carbon-free energy that helps to mitigate future regulatory risks, and zero-fuel-cost
7 energy that helps to mitigate market volatility, while also providing some capacity benefit;
8 BESS resources provide capacity and flexibility necessary to integrate renewable resource
9 on the grid. Together, these resources, along with the Company's existing coal, gas,
10 nuclear, and renewable resources, form a balanced portfolio to meet customer needs at a
11 reasonable cost and risk.

12 **V. AMEREN MISSOURI'S NEED FOR ENERGY AND RECS**

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

15 A. As the Company has previously described in its 2023 IRP and in several
16 CCN application cases in recent years, it is important to replace the Company's fleet as
17 aging coal-fired energy centers retire, ensuring reliability, maintaining affordability, and
18 addressing risks regarding the over-reliance on fossil fuels, including exposure to future
19 environmental regulations. The Company's replacement plans target a balanced portfolio
20 mix of both dispatchable generation and renewable energy resources that have no
21 emissions and no on-going fuel costs associated with the production of energy. Solar
22 resources, along with efficient natural gas, wind, storage resources, and nuclear generation,
23 play a key role in that transition. The addition of increased demand from LLCs, who also
24 place a high value on the role of lower emitting resources, means more energy generation

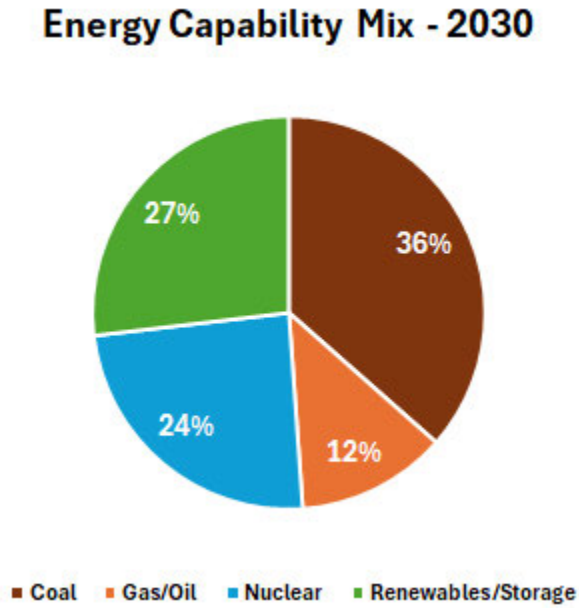
1 is needed sooner to serve rising customer energy needs in addition to meeting their needs
2 during times of peak demand, which can be met with peaking resources like BESS and
3 natural gas-fired generators. While potential wind projects are also attractive for providing
4 additional energy generation, solar projects have proven to pose fewer implementation
5 challenges relative to wind projects and provide energy generation during summer peak
6 times. As the Company has explained in its application for a tariff to provide service to
7 LLCs,²³ making sure renewable resources are timely available to address prospective
8 customers' energy needs and their desire to meet their carbon free energy goals is important
9 to attracting the customers in the first place.

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

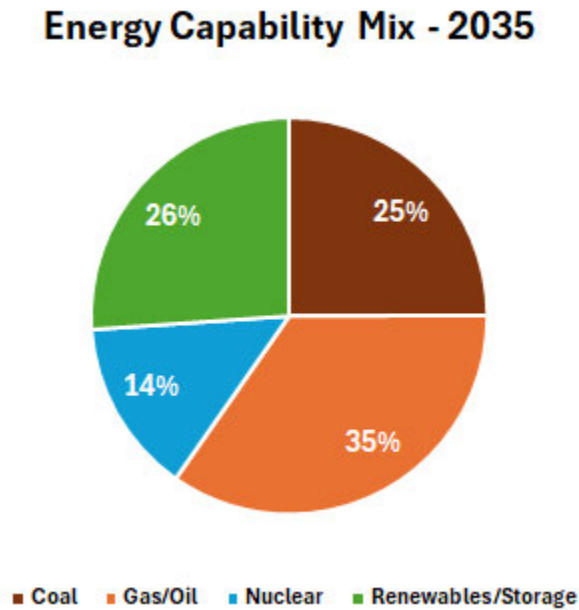
12 A. While actual energy production from the Company's fleet depends on a
13 number of factors, including fuel and energy prices and weather conditions, renewables are
14 expected to provide just under 30% of the Company's energy production capability. The
15 charts in Figures 7 and 8 below show the Company's expected mix of energy production
16 capability for the years 2030 and 2035, respectively.

²³ File No. ET-2025-0184.

1 **Figure 7. Energy Production Capability Mix – Load Case 5 - 2030**



2 **Figure 8. Energy Production Capability Mix – Load Case 5 - 2035**



3 **Q. You mentioned earlier that one of the Company's planning goals is to**
4 **have a balanced portfolio. Please explain.**

1 A. The Company's goal is to ensure that at least 70% of the energy required to
2 serve all customers in all hours of every year is obtained from dispatchable resources to
3 maintain reliability. This dispatchable portfolio consists of a mix of baseload and peaking
4 generation comprised of nuclear, coal, natural gas, hydro, and battery storage resources.
5 We plan to obtain the remaining up to 30% of required energy from zero fuel cost
6 renewable energy resources. The Tom Sawyer and Ringer projects are a key part of
7 meeting that up-to-30% goal, and the BESS projects provide both capacity and flexibility
8 to manage the variability in solar and wind resources.

9 **Q. Has the Company determined that providing up to 30% of the energy**
10 **its customers need from renewable energy resources is an appropriate level to ensure**
11 **reliability and cost-effective energy?**

12 A. Yes, we have. Renewable energy projects allow the Company to serve its
13 customers with zero-fuel-cost and carbon-free energy. In addition, renewable projects that
14 are completed in a timely manner can also benefit the Company's existing customers with
15 significant federal tax credits to reduce the cost impact of these generation resources.
16 Moreover, MISO studies indicate that around 30% renewable generation can be reliably
17 integrated into the MISO system, and we have evidence that about 30% renewable
18 generation has been reliably integrated by other Independent System Operators.
19 Considering these facts, the Company determined that maintaining renewable energy at up
20 to 30% strikes an appropriate balance between utilization of zero fuel cost and carbon free
21 renewables and dispatchable resources, including natural gas-fired and nuclear resources.
22 This balance will ensure reliability, take advantage of federal tax credits, and benefit all

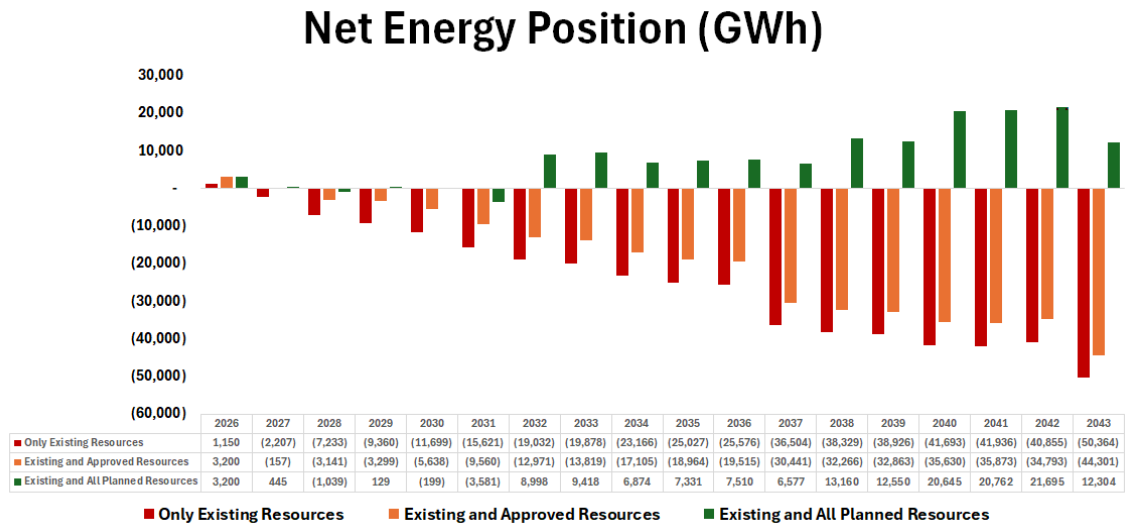
1 customers while also helping our existing commercial and industrial customers and new
2 large load customers to achieve their sustainability goals.

3 **Q. One of your key conclusions is that the Tom Sawyer and Ringer**
4 **Projects are necessary to meet the energy needs of new and existing customers. How**
5 **did you determine this?**

6 A. In short, by looking at the Company's expected energy position without new
7 resources. Figure 9 below shows the Company's energy position based on Load Case 5 in
8 Table 1 and reflects the full expected energy production capability of generation resources.
9 This is in contrast to forecasted energy positions based on expected economic dispatch of
10 generating units, which may or may not require the full utilization of generators during the
11 year based on market conditions and which I discuss economic energy later in my Direct
12 Testimony. Instead, we consider the levels of production of each unit if it were operated
13 at its full capability in every hour in which it is available. For example, the Company's
14 existing CTGs are subject to permit constraints on the number of hours they can be operated
15 during the year, so their energy production capability is based on operating for that limited
16 number of hours. All thermal units are subject to both planned and potential forced
17 outages, and intermittent renewable resources like wind and solar are subject to weather
18 conditions, so we make reasonable assumptions for capacity factors based on the
19 characteristics of each resource. Because we use the full energy production capability of
20 resources, I refer to the resultant energy position as an "energy capability position." A
21 summary of the assumptions used for determining generating capability used to develop
22 energy capability positions is shown in Schedule MM-D3.

1

**Figure 9. Energy Capability Position With and Without
New Resources – Case 5 Load, Normal Weather²⁴**



2

Q. What does the energy capability position in Figure 9 show?

3

A. It shows that without new resources, the Company expects its system

4

capacity to be short energy capability starting in 2027 and continuing through the planning

5

horizon at steadily increasing levels. If approved resources are included, the shortfall is

6

reduced but still persists from 2027 through the end of the planning horizon.²⁵ If all

7

planned resources, including the Projects, are included, the energy capability of the

8

Company's portfolio is sufficient to cover expected load in all but three years – 2028

9

(approximately one million MWh short), 2030 (approximately 200 thousand MWh short),

10

and 2031 (approximately 3.6 million MWh short). For those years and based on the

11

modeled assumptions, the Company would be a net purchaser of energy in the MISO

²⁴ Approved resources includes all resources for which the Commission has approved CCNs but which have not been completed and placed in service. It includes recent approval of CCNs for Big Hollow NGSC and BESS and Reform Solar.

²⁵ "Approved resources" include the Castle Bluff and Big Hollow NGSCs, the Big Hollow BESS, and the 250 MW Reform solar project.

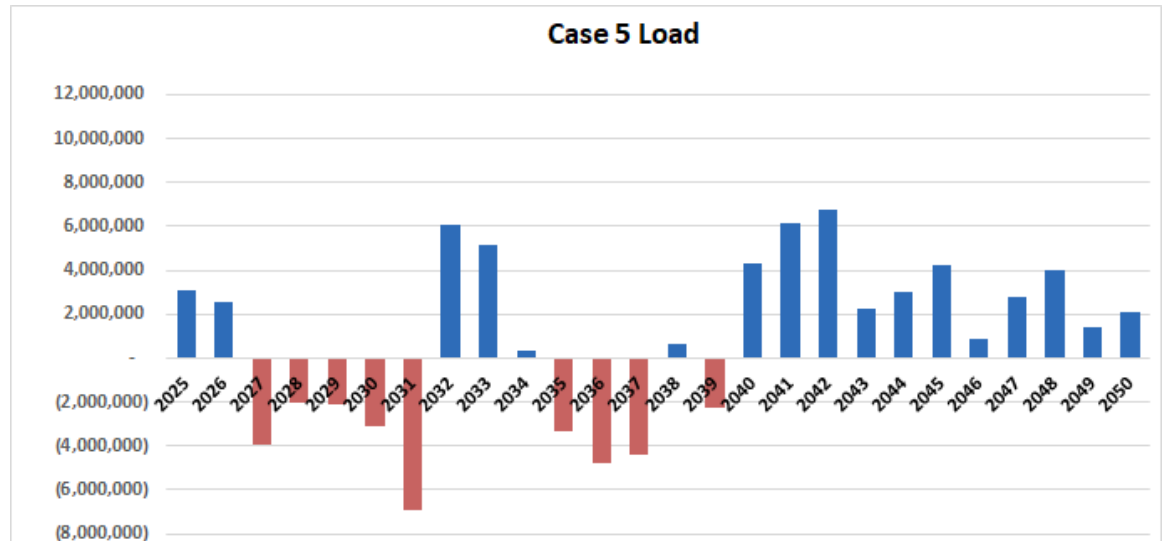
1 market. With 2.8 GW of LLC demand now expected in the near-term, the need for energy
2 capability is expected to be significantly greater.

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

6 A. No. As I mentioned previously, the charts above reflect energy production
7 *capability* rather than *expected generation* based on future market conditions. To see
8 energy positions reflecting the expected economic dispatch of the Company's fleet, we
9 need to look at a different set of charts that reflect those expectations. Figure 10 below
10 shows the expected economic energy position representing forecast energy production
11 based on modeled economic dispatch and shows that the Company would expect to be a
12 net purchaser of energy based on economic dispatch in MISO in a number of years until
13 2032 – four million MWh or less in all but 2032 (about seven million MWh) – and in some
14 years between 2035 and 2039 (five million MWh or less) based on Case 5 loads. In years
15 where the Company would be a net seller, the sales are, in general, significantly less than
16 the Company's historical (over the past decade or two) net energy sales and which for many
17 years created a substantial offset to net energy costs in the Company's fuel adjustment
18 clause. With 2.8 GW of LLC demand, this would further reduce the Company's net
19 economic energy position.

1

**Figure 10. Economic Energy Position (MWh) –
Case 5 Load, Normal Weather**



2

Q. What is the basis for the forecasted dispatch of the Company's fleet represented in Figure 10?

3

4

A. The dispatch represented in Figure 10 reflects a power price scenario assuming a middle level of large load growth across the Eastern Interconnect and the resultant impact on power prices. This scenario is based on modeling performed by Charles River Associates and described in the Company's February 2025 Notice of Change in PRP report.²⁶

5

6

7

8

9

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

10

11

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

12

13

14

²⁶ Schedule MM-D1, pp. 19-20.

1 **Q. Besides the overall need for energy resources in the Company's**
2 **portfolio described above, is there another specific need for renewable resources?**

3 A. Yes. While the Tom Sawyer and Ringer Projects and other planned
4 renewable resource additions to the Company's overall portfolio transition provide needed
5 energy without incurring any fuel costs, the Company's increased loads, including from
6 new LLCs, results in a need for additional renewable resources to satisfy the Company's
7 obligations under Missouri's RES.

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

10 A. Yes. In analysis supporting the Company's 2026-2028 RES Compliance
11 Plan, filed with the Commission in April of 2026,²⁷ the Company showed an incremental
12 need for 1.66 million RECs in 2029, which would steadily increase in the absence of
13 additional REC production capability, and determined that it would need to add 425 MW
14 of additional solar generation by 2029, another 400 MW by 2030, and another 300 MW by
15 2034 in addition to projects already in operation or in development subject to a
16 Commission-approved CCN to help ensure compliance over the next ten years.²⁸ The
17 Company's 2026-2028 RES Compliance Plan is attached to my Direct Testimony as
18 **Schedule MM-D4** and reflects the customer demand included in Case 4 loads shown in
19 Table 1. The Company's RES Compliance Plan model that supports its RES Compliance
20 Plan filed with the Commission, as described on page 10 of the RES Compliance Plan, has
21 been provided to Staff and included in response to a data request in that docket. Table 6

²⁷ File No. EO-2025-0281.

²⁸ The recently approved Reform Solar Project could meet a portion of the identified need if not used to support customer subscriptions under the Company's Renewable Solutions Program, but the Tom Sawyer and Ringer Projects would still be needed, along with additional renewable generation not yet acquired.

1 below shows an excerpt from the model indicating the need for 425 MW by 2029 and
2 another 400MW by 2030, as well as a need for a further 300 MW by 2034. The absence of
3 both the Tom Sawyer and Ringer Solar projects would significantly increase the
4 Company's need to purchase RECs in order to meet RES compliance over the planning
5 horizon.

6 **Table 6. RES Compliance Plan Additions (MW)**

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
MW of Management Wind Build	0	0	0	0	0	0	0	0	0	0
MW of Management Solar Build	0.0	0.0	0.0	425.0	400.0	0.0	0.0	0.0	300.0	0.0

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

11 A. Yes. There are several, as the Commission itself has previously recognized,
12 including in its Report and Order approving the Boomtown facility.²⁹ First, they fulfill
13 energy needs for customers in both the near term and the long term, as I have described
14 earlier in my Direct Testimony. Waiting to deploy renewable resources could result in
15 falling short of meeting energy needs, particularly if viable projects are limited or
16 transmission constraints cause delays or higher costs.

17 Second, the Solar Projects are expected to benefit from lucrative tax credits made
18 available by federal law in the near term. Failure to take advantage of those tax credits
19 now would likely mean adding needed solar generation at a later time that is very likely to
20 cost customers substantially more. This is because under the One Big Beautiful Bill Act
21 ("OBBBA"), which was signed into law in 2025, in order to qualify for the tax credits,

²⁹ File No. EA-2022-0245.

1 solar projects beginning construction after July 4, 2026, must be in service by the end of
2 2027.³⁰ Company witness Scott Wibbenmeyer discusses these tax benefits in his Direct
3 Testimony.

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

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

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

18 **Q. Please provide an example of how solar generation can help to mitigate**
19 **price volatility risk.**

20 A. Table 7 below shows the peak days for each summer and winter month from
21 2019 through 2021. For each peak day, it shows what the net energy position (generation
22 minus load) would have been had the now-retired Meramec and Rush Island coal units not

³⁰ The Tom Sawyer and Ringer Projects are subject to existing safe harbor provisions and must be completed by December 31, 2029, to qualify for tax credits under OBBBA.

1 been available to generate. Note that in every instance, net energy would have been
2 negative. That is, Ameren Missouri would have had to purchase more energy than it
3 generated to serve native load.

4 Also shown for each peak day is the actual measured solar irradiance, or Global
5 Horizontal Irradiance ("GHI"), in watts per meter squared ("w/m²"), along with its ratio
6 compared to the highest daily GHI for that month and that year. Note that for 13 of the 18
7 months shown, solar irradiance is at or above 80% of its daily maximum for the month,
8 and in four of the nine winter months shown, solar irradiance is at or above 30% of its daily
9 maximum for the year.

10 Table 7 also shows the on-peak and average Locational Marginal Power Prices
11 ("LMP") for each peak day and the approximate cost to purchase to cover the energy
12 shortfall at the average LMP. This shows that five of the 18 peak days would have been
13 expected to result in added costs of over a million dollars, with the peak day in February
14 2021 (during Winter Storm Uri) seeing a cost of over \$9 million on that day alone. Such
15 events may, and often do, last for multiple days.

16 Finally, Table 7 shows the estimated amount of electric energy the Tom Sawyer
17 Project would have produced had it been available on these days and the savings it would
18 have produced at the on-peak LMP. It shows that the Tom Sawyer Project would have
19 been expected to produce tens of thousands of dollars in benefits on most of the peak days
20 and over seventy-five thousand dollars *per day* on six of the 18 monthly peak days.³¹

³¹ The Tom Sawyer Project proposed in this case is also expected to provide benefits during periods of high prices and/or loads. The Ringer Project would be capable of providing similar benefits proportional to its size.

1

Table 7. Winter Peak Period Solar Benefits Example

Peak Day Net Energy, Solar Irradiance and LMP											
Date	Net Energy (excl. Mer/Rl) (MWh)	Global Horizontal Irradiance (W/m ²)		Month High	% Of Month High		On-Peak LMP (\$/MWh)	Average LMP (\$/MWh)	Estimated Cost (\$000)	Approx. Tom Sawyer (MWh)	Estimated Tom Sawyer Savings (\$000)
		NDX			GHI	GHI					
01/30/19	(19,597)	2942	2019-1	3039	97%	33%	62.32	54.29	1,064	737	46
02/08/19	(14,616)	2999	2019-2	5037	60%	34%	28.17	26.19	383	752	21
06/05/19	(1,688)	7838	2019-6	8909	88%	88%	26.90	24.16	41	1,964	53
07/19/19	(19,655)	8103	2019-7	8343	97%	91%	40.76	33.87	666	2,031	83
08/12/19	(17,938)	6201	2019-8	7904	78%	70%	31.00	26.62	478	1,554	48
12/16/19	(13,826)	1256	2019-12	2927	43%	14%	25.00	23.24	321	315	8
01/20/20	(19,331)	1225	2020-1	3275	37%	14%	28.00	26.15	505	307	9
02/14/20	(12,193)	4678	2020-2	5137	91%	53%	24.25	23.02	281	1,172	28
06/26/20	(33,860)	8026	2020-6	8769	92%	92%	25.61	21.55	730	2,011	52
07/09/20	(16,160)	7575	2020-7	8401	90%	86%	40.41	32.79	530	1,898	77
08/10/20	(13,392)	4127	2020-8	7509	55%	47%	38.28	31.38	420	1,034	40
12/25/20	(28,948)	2793	2020-12	3114	90%	32%	32.55	29.18	845	700	23
01/28/21	(36,177)	3460	2021-1	3652	95%	40%	26.73	25.41	919	867	23
02/15/21	(67,905)	2692	2021-2	4844	56%	31%	167.83	142.44	9,672	675	113
06/18/21	(52,823)	7809	2021-6	8704	90%	90%	44.72	37.49	1,980	1,957	88
07/29/21	(50,880)	6627	2021-7	8227	81%	76%	50.92	43.75	2,226	1,661	85
08/25/21	(27,348)	5900	2021-8	7682	77%	68%	69.21	57.04	1,560	1,479	102
12/07/21	(10,843)	635	2021-12	2856	22%	7%	61.21	52.95	574	159	10

2

Q. Are you suggesting that such benefits should be a primary basis for

3

deploying renewable resources?

4

A. No. Not at all. As I described previously, the main drivers of the need for

5

the Solar Projects and other renewable resources are to meet customer energy needs and at

6

times, as is the case for the Solar Projects, the Company's RES compliance needs. The

7

analysis shown above simply provides an indication of the kind of benefits solar projects

8

can deliver during peak demand or extreme conditions. And even though a solar facility

9

obviously will deliver more energy in the summer, solar energy generation in the winter

10

can provide substantial benefits as well.

11

Q. You mentioned risks that may affect the timing and magnitude of the

12

need for new energy resources. Can you describe some of these risks?

13

A. The most significant risk may be the inability to serve the kinds of LLCs

14

that are seeking to locate in the Company's service territory. As I mentioned earlier in my

15

Direct Testimony and as Mr. Dixon discusses in his testimony, the Company is seeing

16

significant interest from data centers and hyper-scalers beyond those for which 3.4 GW of

17

construction agreements and 2.8 GW of ESAs have been executed. The Solar Projects,

18

along with other planned energy resource additions, will continue to position the Company

1 and the state of Missouri favorably with respect to attracting and serving LLCs and
2 realizing significant economic development benefits that result.

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

1 Ameren Missouri did use the analytical services of Charles River Associates ("CRA") to
2 evaluate price sensitivity to large additions of large loads across MISO and the broader
3 market, as described in **Schedule MM-D1**, pages 19-22. In general, power prices increased
4 with the inclusion of additional large loads in MISO, with the high-case large load yielding
5 the greatest increase in power prices. These additional power price scenarios were used to
6 test the performance of the various alternative plans, including those with varying large
7 loads (i.e., Cases 1-7).

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

10 A. Unsurprisingly, the results show that the higher the load, the higher the
11 revenue requirement. That conclusion is not, in and of itself, useful. However, it does
12 provide a basis for evaluating the balance between costs and the new revenue contributions
13 from the additional demand and energy charges from new LLCs whose demand increases
14 result in the need to accelerate resource additions, as described in the Company's
15 application for a tariff to serve LLCs.³⁴

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

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

³⁴ File No. ET-2025-0184.

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

3 A. Yes. Specifically, I have evaluated the Company's PRP with updated costs
4 for the Projects that are the subject of this case, and I have evaluated alternative plans that
5 exclude the Projects. I have evaluated plans with both the base project costs and the risk
6 adjusted project costs described in the Direct Testimony of Company witness Scott
7 Wibbenmeyer. While the Company fully expects the Projects to qualify for investment tax
8 credits, as discussed by Mr. Wibbenmeyer in his Direct Testimony, I have also evaluated
9 the impact of the exclusion of ITC for the Projects to examine their impact on the Projects
10 in light of the statutory phase out of the credits and the benefits of capturing those tax
11 credits now. To provide a bounded range of results, I have included ITC with the analysis
12 of projects using base costs estimates and have excluded ITC with the analysis of projects
13 using risk-adjusted project cost estimates.

14 **Q. What were the results of the analysis?**

15 A. Table 8 below shows the results of the analysis of the PRP with and without
16 each of the Projects. As the table shows, NPVRR under probability-weighted average
17 ("PWA") CO₂ prices decreases when each Project is removed, regardless of assumptions
18 for ITC and project capital costs. These cost differentials represent a maximum change of
19 approximately 0.41 percent of total costs to customers as measured by total NPVRR.
20 NPVRR results for the different levels of CO₂ price assumption are similar for each
21 combination of assumptions for ITC and project capital costs for each of the Projects.

1 **Table 8. NPVRR Results – PRP With and Without each Project and for Reasonable**
2 **Substitution Resources³⁵**

NPVRR Results (\$MM)	Low CO2 Price	Base CO2 Price	High CO2 Price	PWA CO2 Price
a Modified PRP with Base Project Specific Costs and ITC	109,079	107,823	108,151	108,344
b Modified PRP with Risk-Adjusted Project Specific Costs and No ITC	109,774	108,518	108,846	109,039
c Modified PRP with Base Project Specific Costs and ITC - Without Castle Bluff BESS	108,994	107,736	108,067	108,259
d Modified PRP with Risk-Adjusted Project Specific Costs and No ITC - Without Castle Bluff BESS	109,610	108,352	108,683	108,875
e Modified PRP with Base Project Specific Costs and ITC - Without Mill Creek BESS	108,819	107,557	107,893	108,083
f Modified PRP with Risk-Adjusted Project Specific Costs and No ITC - Without Mill Creek BESS	109,327	108,065	108,401	108,592
g Modified PRP with Base Project Specific Costs and ITC - Without Huck Finn BESS	108,878	107,617	107,951	108,142
h Modified PRP with Risk-Adjusted Project Specific Costs and No ITC - Without Huck Finn BESS	109,438	108,177	108,511	108,702
i Castle Bluff BESS Replaced with Capacity Equivalent Simple Cycle Gas	109,180	107,921	108,249	108,443
j Mill Creek BESS Replaced with Capacity Equivalent Simple Cycle Gas	109,308	108,044	108,372	108,567
k Huck Finn BESS Replaced with Capacity Equivalent Simple Cycle Gas	109,269	108,006	108,334	108,529
l Modified PRP with Base Project Specific Costs and ITC - Without Tom Sawyer	108,963	107,698	108,030	108,223
m Modified PRP with Risk-Adjusted Project Specific Costs and No ITC - Without Tom Sawyer	109,535	108,270	108,602	108,796
n Tom Sawyer Replaced with Energy Equivalent Wind	108,953	107,703	108,032	108,223
o Modified PRP with Base Project Specific Costs and ITC - Without Ringer	108,957	107,690	108,022	108,216
p Modified PRP with Risk-Adjusted Project Specific Costs and No ITC - Without Ringer	109,482	108,215	108,547	108,741
q Ringer Replaced with Energy Equivalent Wind	108,942	107,693	108,022	108,212
Plan a - Plan c - Cost of Castle Bluff BESS with Base Project Costs and ITC	85	87	84	85
Plan b - Plan d - Cost of Castle Bluff BESS with Risk-Adjusted Costs and No ITC	164	166	163	164
Plan a - Plan e - Cost of Mill Creek BESS with Base Project Costs and ITC	259	266	258	260
Plan b - Plan f - Cost of Mill Creek BESS with Risk-Adjusted Costs and No ITC	447	453	445	448
Plan a - Plan g - Cost of Huck Finn BESS with Base Project Costs and ITC	201	206	199	202
Plan b - Plan h - Cost of Huck Finn BESS with Risk-Adjusted Costs and No ITC	336	342	335	337
Plan i - Plan a - Cost of Capacity Equivalent NGSC vs. Castle Bluff BESS	101	98	98	99
Plan j - Plan a - Cost of Capacity Equivalent NGSC vs. Mill Creek BESS	229	221	221	224
Plan k - Plan a - Cost of Capacity Equivalent NGSC vs. Huck Finn BESS	190	183	184	186
Plan a - Plan l - Cost of Tom Sawyer with Base Project Costs and ITC	115	125	121	120
Plan b - Plan m - Cost of Tom Sawyer with Risk-Adjusted Costs and No ITC	239	248	244	244
Plan n - Plan a - Cost of Energy Equivalent Wind vs. Tom Sawyer Solar	-125	-120	-119	-121
Plan a - Plan o - Cost of Ringer with Base Project Costs and ITC	121	133	128	128
Plan b - Plan p - Cost of Ringer with Risk-Adjusted Costs and No ITC	292	304	299	298
Plan q - Plan a - Cost of Energy Equivalent Wind vs. Ringer Solar	-136	-130	-129	-131

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

4 **A.** The analysis simply shows that these Projects, which are necessary to serve
5 expected customer capacity and energy needs and for the Solar Projects, to comply with
6 the requirements of the Missouri RES, result in costs that must be recovered through
7 customer rates. It is worth noting that the Company's 2023 PRP already included the

³⁵ Plan a in Table 8 reflects a plan with base project specific costs and ITC for each of the Projects. Plan b reflects a plan with risk-adjusted project specific costs and no ITC for each of the Projects. Plans c-j reflect removal of each of the Projects using a combination of base project costs with ITC or risk-adjusted project costs without ITC. Plan k reflects removal of the Tom Sawyer project and replacement with an energy equivalent amount of wind. Plans l-n reflect removal of each of the BESS projects and replacement with a capacity equivalent amount of NGSC.

1 implementation of 1,800 MW of solar generation additions by 2030, including 900 MW of
2 solar projects already placed in service or expected to be placed in service in 2026 and
3 another 250 MW for which the Company has recently been granted a CCN.

4 **Q. Table 8 includes four other plans (Plans l-n), which you have not**
5 **addressed. Please explain what those plans represent.**

6 A. Plans n and q represent replacement of the Tom Sawyer Project and the
7 Ringer Project, respectively, with an energy equivalent amount of wind – approximately
8 105 MW for Tom Sawyer and 135 MW for Ringer – operating at a 42% capacity factor.
9 Plans i-k represent replacement of each of the respective BESS Projects with an
10 equivalent amount of installed NGSC capacity.

11 **Q. What do the results of those plans show?**

12 A. For the BESS projects, it shows that replacing them with an equal amount
13 of installed NGSC capacity would result in an increase in net costs to customers as
14 measured by NPVRR by roughly \$100-225 million. For Tom Sawyer, it shows that
15 replacement with an energy equivalent amount of wind would reduce NPVRR by
16 approximately \$120 million, and for Ringer it shows that replacement with an energy
17 equivalent amount of wind would reduce NPVRR by approximately \$130 million. Note
18 that this assumes that the wind project would be eligible for production tax credits
19 ("PTCs"), and finding additional wind projects, especially projects that may be eligible
20 for PTCs, could be a significant challenge.

21 **Q. Does this conclude your Direct Testimony?**

22 A. Yes, it does.

