Exhibit No. 15

Ameren – Exhibit 15
Michels
Surrebuttal
File No. EF-2024-0021

Exhibit No.:	
Issue(s):	Resource Planning
Witness:	Matt Michels
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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. EF-2024-0021

SURREBUTTAL TESTIMONY

OF

MATT MICHELS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
March 2024

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SURREBUTTAL TESTIMONY

OF

MATT MICHELS

FILE NO. EF-2024-0021

I. INTRODUCTION

Q. Please state your name and business address.

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

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

A. I work in Ameren Services Company's Corporate Strategy and Enterprise Risk Management Department as Director of Corporate Analysis. The Corporate Strategy and Enterprise Risk Management Department provides various corporate support services to Ameren Corporation and its subsidiaries, including Ameren Missouri.

Q. Are you the same Matt Michels who submitted direct testimony in this case?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

Q. To what testimony or issues are you responding?

A. I am responding to certain positions and issues raised in the rebuttal testimonies of Staff witnesses Claire Eubanks and Brad Fortson and Office of Public Counsel ("OPC") witness Jordan Seaver regarding Ameren Missouri's decision to retire the Rush Island Energy Center ("RIEC") and the alleged potential harm to customers resulting from the Company's decisions regarding RIEC.

Q. Please summarize the key points in your surrebuttal testimony.

A. In responding to the afore-mentioned witnesses, I will demonstrate the following:

1. The Company's decisions regarding RIEC since the time the Company received a Notice of Violation ("NOV") from the U.S. Environmental Protection Agency ("EPA") in 2010 would not have changed if the Company had performed the additional planning analysis Staff suggests the Company should have performed.[1] I present updated analysis of the Company's decision to retire RIEC to further confirm this, assuming the benefit of hindsight.

2. The Company's decisions regarding RIEC, including those cited in the NOV and through the Company's decision in December 2021 to retire RIEC, have not resulted in higher costs to customers than if the Company had pursued New Source Review ("NSR") permits and added flue gas desulfurization ("FGD") equipment at RIEC. I present a thorough analysis that compares the cost of these two series of decisions or previous potential decisions in support of this point.

In addition to the above, I will also address some logical flaws and errors in the rebuttal testimonies of the afore-mentioned witnesses. These include flawed logic regarding the transmission projects necessitated by the retirement of RIEC,[2] failure to consider the impact of sudden and significant changes in the planning environment,[3] errors in the calculation of costs for potential capacity shortfalls,[2] omission of key facts in consideration of such capacity shortfalls, erroneous assumptions regarding the Company's analysis of

[1] File No. EF-2024-0021, Claire Eubanks Rebuttal Testimony, p. 24 ll.13 to p. 25, l. 3; Brad Fortson Rebuttal Testimony p. 2, ll. 17 through p. 6, l.16.
[2] File No. EF-2024-0021, Claire Eubanks Rebuttal Testimony, p. 23
[3] File No. EF-2024-0021, Brad Fortson Rebuttal Testimony, p. 6; Claire Eubanks Rebuttal Testimony, p. 24

RIEC retirement,[4] errors in the assessment of FGD cost assumptions,[5] and using inappropriate comparisons of FGD costs to the cost of new solar projects as a basis for calculating a proposed disallowance.[6]

III. PERFORMING THE ANALYSIS STAFF SAYS THE COMPANY FAILED TO PERFORM WOULD NOT HAVE CHANGED THE COMPANY'S DECISIONS REGARDING RIEC

Q. Please explain Staff's criticism of the Company's planning analysis with respect to RIEC.

A. Mr. Fortson alleges several deficiencies in the Company's resource planning analysis going back to the Company's 2014 Integrated Resource Plan ("IRP"). Specifically, Mr. Fortson asserts that:

1. The Company did not, but should have, analyzed plans in its IRP process that included "near-term" retirement of RIEC due to potential outcomes of the NSR litigation prior to the Company's 2020 IRP.[7]
2. The Company should have been planning for potential NSR litigation outcomes since the time the Company received the NOV in 2010.[8]
3. Sierra Club alleged that the Company's 2017 IRP was deficient because it did not include analysis of potential outcomes of the NSR litigation.[9]

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[4] File No EF-2024-0021, Jordan Seaver Rebuttal Testimony, p. 6
[5] File No EF-2024-0021, Jordan Seaver Rebuttal Testimony, pp. 7-8
[6] File No EF-2024-0021, Jordan Seaver Rebuttal Testimony, p. 7
[7] File No. EF-2024-0021, Brad Fortson Rebuttal Testimony, pp. 2-3; Mr. Forston does not clearly define "near-term" retirement.
[8] File No. EF-2024-0021, Brad Fortson Rebuttal Testimony, pp. 3-4
[9] File No. EF-2024-0021, Brad Fortson Rebuttal Testimony, p. 4

4. The Company did not select one of its contingency plans from its 2020 IRP following the opinion of the 8th Circuit Court of Appeals, which upheld in part the ruling of the U.S. District Court as it pertained to RIEC.[10]

Q. Please provide a summary of your assessment of each of these assertions before getting into the details of each one.

A. My assessment is as follows:

1. Consideration of "near-term" retirement of RIEC would not have resulted in a near-term[11] need for new resources, because the Company's planning under the resource adequacy ("RA") construct used by the Mid-continent Independent System Operator ("MISO") during that time (an annual construct focused on summer peak) showed significant capacity length capable of covering the Company's resource needs in the event of retirement of RIEC. This was made clear in the Company's consideration, in both its 2014 and 2017 IRPs, of alternative resource plans that assumed retirement of RIEC in 2024. While the reason for selecting 2024 for the retirement date in those two IRPs was not explicitly connected to potential outcomes of the NSR, the fact is the Company did consistently evaluate the implications of early retirement in 2024 and that is in fact the date the plant will retire. The Company's significant capacity length rendered any potential decisions regarding RIEC a straightforward question of the ongoing economics of the plant in the MISO market without regard to a need for replacement resources. The result of such an economic analysis would simply

[10] File No. EF-2024-0021, Brad Fortson Rebuttal Testimony, p. 6

[11] As I used the phrase "near-term," it means within the first 10 years of an IRP planning horizon. As discussed below, based on the 2014 IRP there would have been a need during the first ten years of the planning horizon had Noranda remained on Ameren Missouri's system.

reflect the comparison of the cost of installing and operating FGD equipment and the benefits (and risks) of continued operation of the plant. Staff is clearly engaging in revisionist history based on hindsight, given that planning in the Company's 2014 and 2017 IRPs did not show a near-term need (i.e., within the first ten years of the 20-year planning horizon) to replace Rush Island had it retired in 2024. It is worth noting that Staff made absolutely no claims in its extensive comments on both of those IRPs that the Company's planning was either deficient or that the Staff had concerns with respect to planning related to RIEC.[12]

2. Setting aside the reality of the protracted NSR litigation schedule and the great uncertainty regarding potential outcomes of the NSR litigation, planning with respect to potential outcomes of the NSR litigation would have satisfied nothing more than academic curiosity. As mentioned in item 1 above, the Company's resource planning decisions set forth in its 2014 and 2017 IRPs would not have changed even had we explicitly cited "NSR litigation" as a reason to model alternative plans with an early RIEC retirement date, simply because the Company's capacity length in MISO did not indicate a near-term need for new resources if RIEC were retired.[13]

3. Sierra Club's allegation of a deficiency regarding the Company's 2017 IRP apparently did not affect the Missouri Public Service Commission's ("MPSC") finding that the Company's 2017 IRP complied with its IRP rules.

[12] See Staff's reports on the Company's 2014 and 2017 IRPs, attached as Schedules MM-S1 and MM-S2, respectively. Note that some schedules include confidential markings as such information was confidential at the time those documents were filed. Information so marked is no longer considered confidential unless indicated in my testimony.

[13] As discussed below, the 2014 IRP would have called for adding supply-side resources in 2025 if RIEC retired in 2024 but only because or the then-presence of Noranda's nearly 500 MW of load (plus required reserves), which has long since left the system.

Notably, once again, Staff did not allege such a deficiency or express a concern in this regard, nor did any other party to the Company's IRP other than Sierra Club, which was a party to the NSR case.

4. The Company did not select a contingency plan from its 2020 IRP because of two significant changes to the planning environment, which could not have been contemplated at the time the 2020 IRP was prepared, rendering such a selection inappropriate. Specifically, the Illinois Climate and Equitable Jobs Act ("CEJA") was signed into Illinois law by its governor on September 15, 2021, and MISO's application was submitted to the Federal Energy Regulatory Commission ("FERC") for approval of a new seasonal RA construct in November 2021, both long after the Company filed its 2020 IRP in September 2020. Staff is and was aware of these changes and supported the Company's request for an extension of the time[14] for the Company to file a notice of change in preferred resource plan ("PRP") with the MPSC.

Q. Please describe the Company's consideration of early retirement of RIEC in its IRP planning since the NOV.

A. In its 2014 IRP, Ameren Missouri evaluated a plan (Plan P) with retirement of RIEC at the end of 2024.[15] Ameren Missouri's 2014 IRP preferred plan was Plan I, which included in the addition of 600 megawatts ("MW") of supply-side resources in 2034, the last year of the planning horizon for the 2014 IRP.[16] In comparison, Plan P included

[14] Staff Recommendation, File No. EE-2022-0192, EFIS Item No. 3 (See Schedule MM-S11, *infra*.).
[15] Schedule MM-S3 - Ameren Missouri 2014 IRP Chapter 9 – Integrated Resource Plan and Risk Analysis, Table 9.6, page 16.
[16] *Id.*, p. 15. Plan I is identified as the Company's PRP in its 2014 IRP in 2014 IRP Chapter 10 – Strategy Selection, p. 13, attached hereto as Schedule MM-S4.

the addition of 769 MW of supply-side resources in 2025, the eleventh year of the 20-year planning horizon.[17]

In its 2017 IRP, Ameren Missouri evaluated a plan (Plan M) also with retirement of RIEC at the end of 2024.[18] Ameren Missouri's 2017 IRP preferred plan was Plan R, which included no non-renewable supply-side additions and slightly more renewable resources than needed for compliance with the Missouri Renewable Energy Standard.[19] In comparison, the only supply-side resources change in Plan M relative to Plan R was the inclusion of 600 MW of supply-side resources in 2037, the last year of the planning horizon for the 2017 IRP.[20]

In its 2020 IRP, Ameren Missouri again evaluated a plan (Plan R) with retirement of RIEC at the end of 2024.[21] Ameren Missouri's 2020 IRP preferred plan was Plan V, which included no non-renewable supply-side additions during the planning horizon (2021-2040).[22] Plan R also included no non-renewable supply-side additions during the planning horizon. As part of the Company's modeling beyond the planning horizon, both Plan R and Plan V included the addition of 800 MW of supply-side resources in 2043. As a result, the only difference between the two plans was the early retirement of RIEC in Plan R.[23]

[17] Schedule MM-S3 - Ameren Missouri 2014 IRP Chapter 9 – Appendix A, pages 3 and 5.
[18] Schedule MM-S5 - Ameren Missouri 2017 IRP Chapter 9 – Integrated Resource Plan and Risk Analysis, Table 9.4, page 10.
[19] *Id.*, Table 9.4, page 10. Plan R is identified as the Company's PRP in its 2017 IRP in 2017 IRP Chapter 10 – Strategy Selection, p. 11, attached hereto as Schedule MM-S6.
[20] Schedule MM-S5 - Ameren Missouri 2017 IRP Chapter 9 – Appendix A, page 3.
[21] Schedule MM-S7 - Ameren Missouri 2020 IRP Chapter 9 – Integrated Resource Plan and Risk Analysis, Table 9.4, page 12.
[22] Schedule MM-S8 - Ameren Missouri 2020 IRP Chapter 10 – Strategy Selection, Table 10.2, pages 5, 23.
[23] Schedule MM-S7 - Ameren Missouri 2020 IRP Chapter 9 – Appendix A, page 3.

Q. Why did the timing of new resource additions for early retirement of RIEC change between the 2014 IRP, which reflected a need for new resources immediately after the retirement of RIEC, and the 2017 IRP, which reflected no need for new resources until the end of the planning horizon?

A. The primary difference was the inclusion of the load in 2014 for the aluminum smelter in New Madrid, Missouri, owned and operated at that time by Noranda. The peak demand assumed for the smelter for the 2014 IRP was 495 MW.[24] Adding the 2025 planning reserve margin requirement of 17.3% assumed in the 2014 IRP, the total resource need implicated by the inclusion of the smelter's load was 580 MW. Absent that demand, Ameren Missouri's need for new resources in 2025, according to the 2014 IRP, would have been less than 200 MW, which is below the build threshold.[25] The 2014 IRP included discussion of the potential loss of the smelter load since the smelter received electric service from Ameren Missouri at that time under a contract that was set to expire in 2020, and the facility was facing challenges due to global competition for aluminum production.[26]

Q. Was Ameren Missouri planning for a potential need for new supply side resources in its 2014, 2017, and 2020 IRPs?

A. Yes. This is clear from the contingency planning discussion in Chapter 10 of each of those IRP filings. In the 2014 IRP, the Company acknowledged the potential for accelerating the need for new resources, stating the following:

[24] Schedule MM-S4 - Ameren Missouri 2014 IRP Chapter 10 – Strategy Selection, page 15.
[25] As Staff was well aware at the time of the 2014, 2017, and 2020 IRP filings, the Company's resource planning did not call for the addition of supply-side resources unless and until it was predicted to be short capacity by 300 MW or more. Staff has never expressed any concern about this build threshold.
[26] Schedule MM-S4 - Ameren Missouri 2014 IRP Chapter 10 – Strategy Selection, pages 15-16.

> Our analysis has shown that renewables, gas-fired combined cycle, and nuclear generation continue to be attractive options for meeting our customers' future energy needs. It is therefore important to ensure that we can exercise these options when needed and in response to changing circumstances. This includes continuing to evaluate opportunities for developing additional renewable energy resources, evaluating potential sites for new gas-fired generation, and taking actions to maintain an option for future nuclear generation and the associated economic development benefits that would be realized for the state of Missouri.[27]

The Company included very similar discussion in its 2017 IRP.[28] Ameren Missouri's 2020 IRP included explicit consideration of potential outcomes of the NSR litigation. With respect to the NSR litigation, the contingency planning discussion in the Company's 2020 IRP explicitly stated that, "The ultimate disposition of the current litigation will require careful consideration based on the specific details of the Appellate Court's judgment."[29] It is important to recognize that details of the eventual outcome of the litigation could not have been known at the time the Company filed its 2020 IRP.

Q. Mr. Fortson asserts that the Company was not planning for retirement of RIEC in 2024 due to potential outcomes of the NSR litigation until its 2020 IRP.[30] How do you respond?

A. Practically speaking, his statement is not true. The Company consistently evaluated retirement of RIEC at the end of 2024 in its 2014, 2017, and 2020 IRPs as I just described. The stated rationale for evaluating 2024 retirement of RIEC is of secondary importance, and indeed, is irrelevant. The Company was planning for a potential retirement of the facility and consistently concluded that replacement capacity resources would not

[27] Schedule MM-S4 - Ameren Missouri 2014 IRP Chapter 10 – Strategy Selection, page 19.
[28] Schedule MM-S6 – Ameren Missouri 2017 IRP Chapter 10 – Strategy Selection, page 13.
[29] Schedule MM-S8 - Ameren Missouri 2020 IRP Chapter 10 – Strategy Selection, page 25.
[30] File No. EF-2024-0021, Brad Forston Rebuttal Testimony, pp. 2-3 (please note all pages after page 1 are numbered as "6").

be needed for at least ten years into the planning horizon, even when assuming early retirement of RIEC in 2024, which, as it turns out, is precisely the year in which RIEC will retire.[31] Even so, the Company consistently accounted for the potential nearer term need for new generating capacity as part of its contingency planning. To say that the Company was not properly planning for potential early retirement of RIEC is to ignore what the Company actually analyzed and reported in its IRP filings for the last decade, with which Staff took no issue whatsoever.

Q. Mr. Fortson also mentions that Sierra Club alleged that the Company's 2017 IRP was deficient because it did not include explicit consideration of potential outcomes of the NSR litigation. Does that have any relevance to this case?

A. No, for two reasons. First, the Company did analyze a retirement of Rush Island in 2024, as discussed above. Second, the Commission found the Company's 2017 IRP to be in compliance, effectively dismissing Sierra Club's allegation.[32] The Commission did order the Company to analyze such outcomes in its 2020 IRP, following the District Court's decision in the remedy phase of the NSR litigation when potential outcomes became somewhat clearer. The Company performed and presented this analysis in its 2020 IRP.[33] As noted earlier, the analysis indicated that the Company had no need for additional supply-side resources until 2043, beyond the 2021-2040 planning horizon. Staff took no issue with that conclusion, raising neither a claimed deficiency nor concern about it.

[31] The need for resources assuming retirement of RIEC in 2024 would be further delayed and/or reduced assuming the absence of the New Madrid smelter load in the 2014 IRP.
[32] Commission order in File No. EO-2018-0038.
[33] The analysis was produced under a protective order issued by the Commission at the Company's request and was marked highly confidential. The protective order was requested because Sierra Club was a party to both the Company's IRP proceedings and the NSR litigation. The Commission's order is attached as Schedule MM-S9.

Q. Mr. Fortson notes that the Company did not choose one of its contingency plans following the appellate court decision in the NSR case, which upheld in part the district court decision. Was this the result of poor planning on the part of the Company?

A. No. While Mr. Fortson appears to disparage the Company for not selecting a contingency plan from its 2020 IRP, he ignores two very significant changes in the planning environment, facts of which Staff was well aware then and since. First, FERC approved MISO's proposed seasonal capacity construct in August 2022, which recognized the emerging importance of considering capacity needs beyond the summer peak that had been the focus of MISO's RA construct from the inception of MISO's resource adequacy processes and up to that point. Second, the Illinois CEJA statute was signed into law by Governor Pritzker in September 2021 and effectively required retirement of Ameren Missouri's natural gas-fired Venice Energy Center by the end of 2029 and all other Ameren Missouri gas-fired generators in Illinois by the end of 2039. The Company requested a variance to extend the time for filing a notice of change in PRP with the Commission, Staff supported the variance, and the Commission approved it.[34]

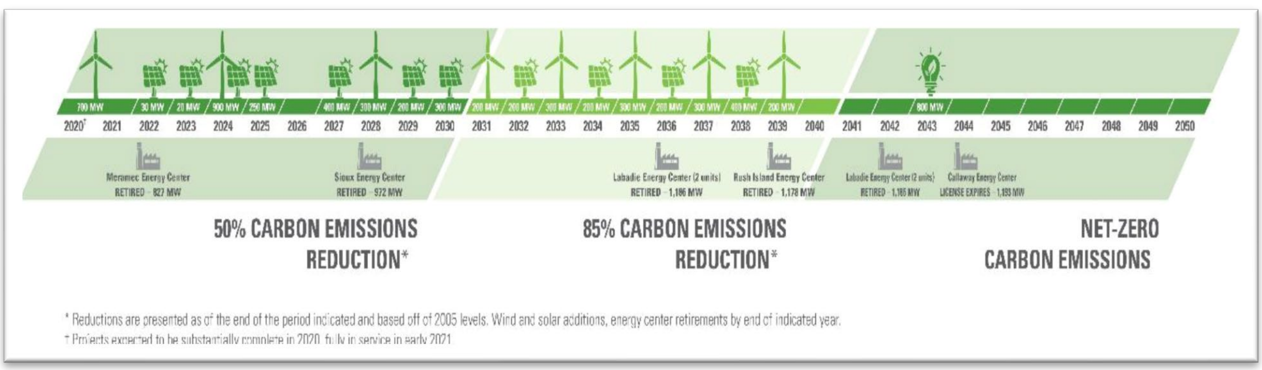
Q. How did the Company's consideration of these changes in the planning environment alter the Company's preferred plan, which it submitted in June 2022?

A. In addition to the early retirements of the Company's Illinois gas units resulting from the passage of CEJA and the early retirement of Rush Island, the Company delayed the retirement of Sioux Energy Center from 2028 to 2030, added 1,200 MW of natural gas-fired combined cycle ("NGCC") generation to its planned portfolio in 2031

[34] The Company's request for variance, Staff's recommendation, and the Commission's order are attached as Schedules MM-S10, MM-S11, and MM-S12, respectively.

800 MW of battery energy storage in 2033-2038, and 400 MW of additional clean dispatchable generation (technology unspecified) in 2043.[35] The 2022 preferred plan also reflected modest acceleration of renewable resource additions, primarily to better address transition risks identified by the Company and analyzed with the assistance of Roland Berger, an energy consulting firm, with a sustained implementation of the transition (e.g., maintaining a steady pipeline of projects and managing through various stages of project implementation).[36] As of that time, the planning analyses did not support the need for additional supply-side additions (apart from renewables) prior to 2031. Figure 1 shows the Company's preferred resource plan from its 2020 IRP, and Figure 2 shows the Company's revised preferred plan, filed with the Commission in June 2022.

Figure 1 – 2020 Preferred Plan Timeline[37]



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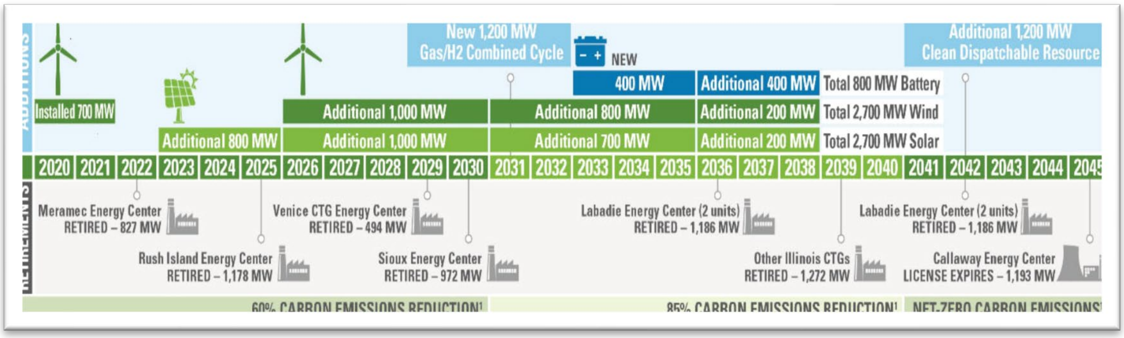
[35] Note that the clean dispatchable generation additions in 2043 in both the 2020 IRP and the 2022 change in PRP were beyond the 20-year planning horizon (2021-2040) but were included to capture the effects of retiring the Company's entire coal-fired fleet, including the retirement of the remaining two Labadie units in 2042.

[36] Schedule MM-S13 – Ameren Missouri 2022 Change in Preferred Plan Report, page 29

[37] See Schedule MM-S8 – Ameren Missouri 2020 IRP Chapter 10 – Strategy Selection, Figure 10.8, p. 24.

Figure 2 – 2022 Preferred Plan Timeline[38]

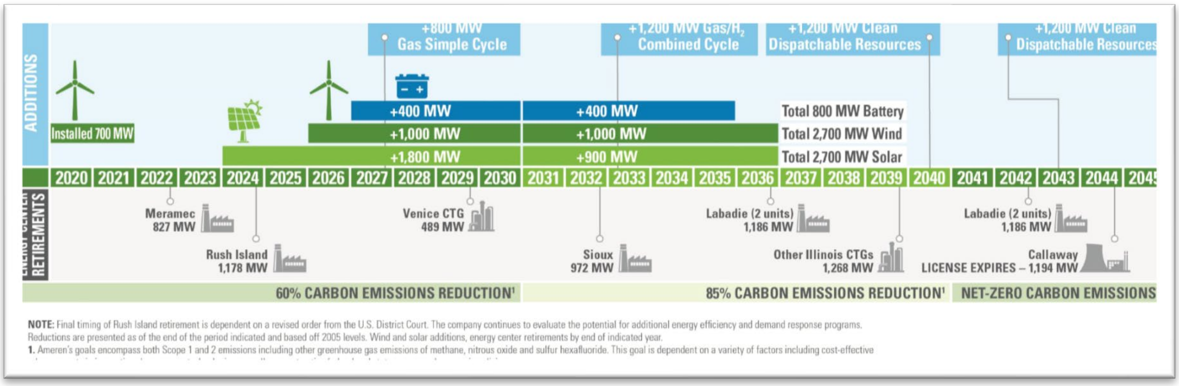


Q. Were there further resource changes reflected in the Company's 2023 IRP preferred plan?

A. Yes. In the Company's 2023 IRP preferred plan, Ameren Missouri further delayed the retirement of Sioux and the addition of the 1,200 MW NGCC to the end of 2032 (since the NGCC plant would, effectively, be the replacement for Sioux), accelerated the addition of battery storage (still 800 MW total) and post-2030 wind and solar additions to better address transition risks and capture the value of tax credits, and added another 1,200 MW of clean dispatchable generation (technology unspecified) in 2040. Figure 3 shows the Company's 2023 IRP preferred plan. The Company also added 800 MW of simple cycle gas generation in 2028 to ensure reliability during extreme weather conditions, the frequency of which had recently increased at that time.

[38] See Schedule MM-S13 – Ameren Missouri 2022 Change in Preferred Plan Report, Figure 1, p. 2.

Figure 3 – 2023 IRP Preferred Plan Timeline[39]



Q. Ameren Missouri's preferred plan has changed significantly with respect to dispatchable generation additions since the Company's 2020 IRP. Why?

A. There are three key factors that have resulted in greater levels of dispatchable generation in the Company's preferred plan. I have already mentioned two of them – 1) passage of CEJA, and 2) MISO's transition (approved in 2022 and effective staring June 1, 2023) to a seasonal RA construct. The retirement of gas units in Illinois reduces the Company's available capacity, but that is not the only aspect of CEJA that is affecting future reliability needs. CEJA also severely limits the operation of these units until they are retired by imposing strict emission limits based on the level of operation experienced during 2018-2020. Some units are limited to less than 30 hours of operation during any 12-month period.[40] While these units still receive capacity accreditation from MISO for seasonal resource requirements, longer periods of extreme weather (particularly in the summer) and/or constraints on the Company's existing fleet (such as those imposed

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[39] See Schedule MM-S14 – Ameren Missouri 2023 IRP Chapter 10 – Strategy Selection, Figure 10.22, p. 45.

[40] See Schedule MM-S15 – CTG Operating Hour Limits

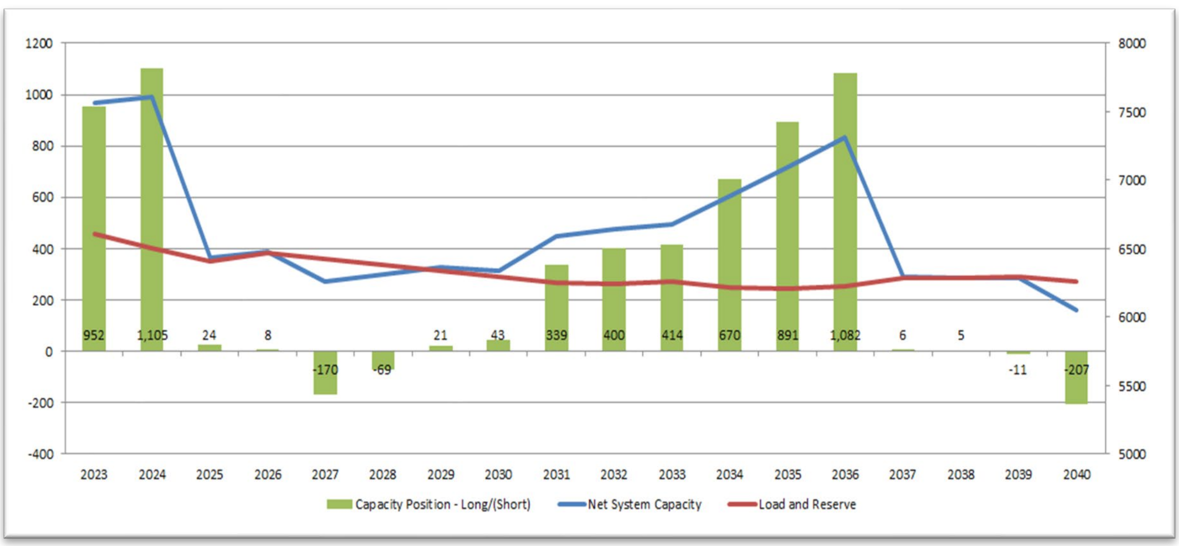
by EPA's Good Neighbor Rule) may require additional resources to meet customer demand.

MISO's transition to a seasonal RA construct is still evolving, and MISO is preparing to seek FERC approval for further changes to its RA construct. When MISO first applied to FERC for approval of the seasonal RA construct in November 2021, there was limited data and guidance available for the Company to use to assess its capacity position by season. This is apparent in reviewing MISO's Loss of Load Expectation ("LOLE") Study Report for planning year 2022-2023, published in November 2021, in which the focus remained the then-existing annual RA construct and no seasonal data were provided.[41] Ameren Missouri used available data to estimate seasonal unit accreditation values and incorporate them into its consideration of capacity needs when it revised its PRP in 2022, as shown in Figure 2. It is important to note that developing seasonal accreditation values and modifying the Company's IRP model to use them for seasonal capacity position analysis required a substantial effort over the course of several months and was therefore not available at the time the Company made the decision to retire RIEC. It is also important to recognize that the newly developed winter capacity position, based on the best available data and used for the analysis supporting the Company's 2022 Notice of Change in Preferred Plan, showed that the Company would not be short capacity immediately following the retirement of RIEC, as shown in Figure 4 below. Note also that the capacity shortfalls in 2027 and 2028 would not have been expected but for the assumed retirement of 275 MW of oil-fired units in Missouri at the end of 2026 – Fairgrounds,

[41] Schedule MM-S16 – MISO 2022-2023 Loss of Load Expectation Study Report.

Mexico, Moberly, and Morreau.[42] The retirement of those units was moved to the end of 2029 in the Company's 2023 IRP.[43] It should also be noted that none of the capacity shortfalls reflected in Figure 4 exceed the build threshold (short 300 MW or more) used by the Company for adding resources in its alternative resource plans. In summary, even after accounting for MISO's then-upcoming move to a seasonal construct in its 2022 change of preferred resource plan, using the data that was available (MISO had not actually published the data that would underlie the 2023-2024 planning year), the Company's resource planning did not indicate a need for additional dispatchable resources until the 2030s.

Figure 4 – 2022 Preferred Plan Winter Capacity Position



Several months after the Company filed its 2022 Notice of Change in Preferred Plan, MISO published a full LOLE analysis, the analysis MISO uses to establish planning reserve margin ("PRM") requirements for load-serving entities ("LSE"), that reflects the

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[42] See Schedule MM-S17 – Ameren Missouri 2020 IRP Chapter 4 – Existing Supply-Side Resources, Table 4.3, p. 12. Note that the total accredited value for the four oil-fired units (275 MW) is greater than the listed capacity due to differences in assumed accreditation for winter vs. the summer rated output (217 MW).

[43] See Schedule MM-S18 – Ameren Missouri 2023 IRP Chapter 4 – Existing Supply-Side Resources CONF, Table 4.4, p. 15.

seasonal construct in late 2022. The PRM requirements, along with newly established seasonal unit accreditations, were used by LSEs to prepare bids for MISO's 2023-2024 planning resource auction ("PRA"), sometimes referred to as its "capacity auction." Changes in PRM requirements and unit accreditations from the preliminary data used by Ameren Missouri for its 2022 change in PRP, along with refinements to the Company's determination of winter peak demand, resulted in the need for an additional 1,200 MW of capacity, but not until late in the planning horizon (i.e., in 2040). Table 1 shows the drivers of change in long-term capacity need from the 2022 change in PRP to the 2023 IRP under normal weather conditions.

Table 1 – Changes in Capacity Need: 2022 PRP to 2023 IRP[44]

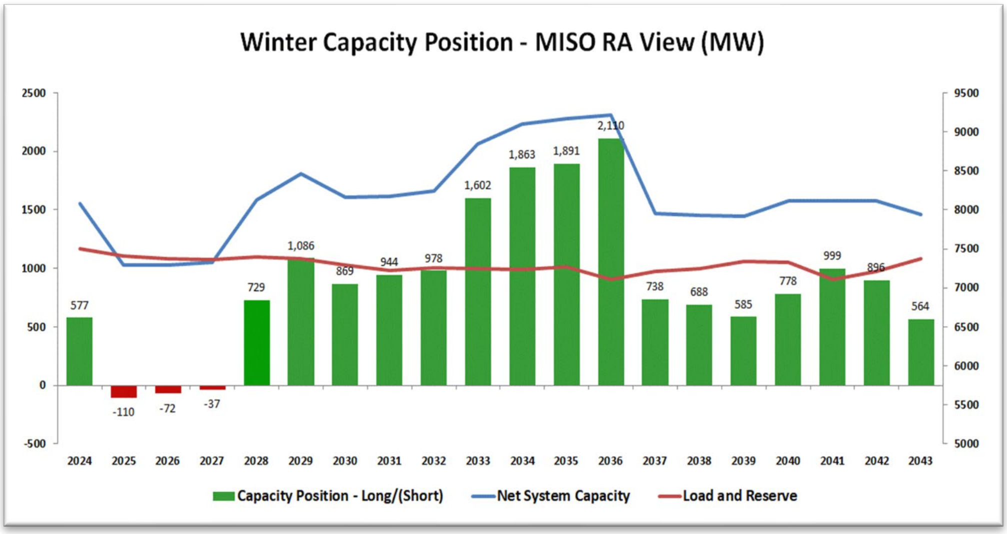
Changes Affecting Resource Need	MW	Notes
Refinements to winter peak forecasting	350	
Increase in winter PRM	750	From 15.9% to 25.5%
Higher winter capacity credit for wind	(400)	From 13% to 30% long term
Lower winter capacity credit for solar	150	From 11% to 5%
Reduction in existing unit accreditation	100	
CC accreditation reduction (vs. ICAP)	200	
Net Change in Resource Need	**1,150**	

As Table 1 shows, the Company's need for resources in the long term increased by nearly 1,200 MW between the 2022 PRP and the 2023 IRP. This resulted in the addition of 1,200 MW of dispatchable generation in 2040 in the Company's 2023 IRP preferred plan, as shown in Figure 3. The capacity position for the Company's 2023 IRP preferred plan, under normal weather conditions, is shown in Figure 5. As Figure 5 shows, the Company expects to be in a net short position during the years 2025-2027. But note that

[44] Line items other than the refinements to winter peak forecasting were based on data received from MISO in late 2022 for the MISO 2023-2024 PRA.

these shortfalls are still less than the 300 MW build threshold used by Ameren Missouri to determine when resources are added to alternative resource plans.

Figure 5 – 2023 IRP Preferred Plan Winter Capacity Position



Q. You discussed the Company's use of limited data to create a winter capacity position for Ameren Missouri for use in the analysis supporting the Company's 2022 Notice of Change in Preferred Plan. Did you review such information at the time the Company was considering retirement of RIEC in late 2021?

A. Yes. Based on a review of indicative data from MISO on unit accreditations and assumptions, the Company determined in late 2021 that it would have sufficient capacity to meet its load and planning reserve margin requirements after the retirement of RIEC. Table 2 shows the adjusted 2021-2022 planning year capacity and requirements reflecting MISO's then-proposed seasonal construct.[45]

[45] MISO provided indicative values in late 2021 to demonstrate how capacity requirements would have changed had MISO used the seasonal construct, as it was proposed at that time, was applied to the 2021-2022 planning year (as noted, the final seasonal construct did not get applied until the 2023-2024 planning year). The RA construct actually in effect for the 2021-2022 planning year was the annual construct.

Table 2 – Capacity Position (2021 MISO Indicative Values)

Capacity (MW)	Summer	Fall	Winter	Spring
Sum of Seasonal Accredited Capacity (SAC)	9,063	8,020	7,148	7,915
SAC w/o Meramec and Rush Island	7,386	6,485	5,754	6,430
SAC w/o Mer/Rush, Callaway Restored	7,386	6,485	6,150	6,764
Load and Planning Reserver Margin Requirment	6,906	6,063	6,042	5,591
Position w/o Mer/Rush, Callaway Restored	**480**	**422**	**108**	**1,173**

What this tells us is that at the time we made the decision not to retrofit RIEC with scrubbers but to retire it instead, even under MISO's proposed seasonal construct, we did not need additional dispatchable resources.

Q. What is the third key factor affecting the Company's increased need for dispatchable resources?

A. The third key factor is the increase in frequency of extreme winter weather events. In February 2021, Winter Storm Uri brought extreme cold weather that challenged grid reliability across a large portion of the United States, including Texas, where utility customers suffered through harsh winter weather conditions without power for days and weeks. That event in isolation was not, however, indicative of a trend. But in late December 2022, Winter Storm Elliott again brought extreme cold weather to a large portion of the country, straining grid reliability. The second such extreme winter weather event is as many years did suggest a trend, that grid reliability risks had indeed changed. Recognizing this new trend, Ameren Missouri reevaluated its reliability needs, with a focus on ensuring sufficient resources to meet customer demand in such extreme circumstances even if it otherwise would meet its planning reserve margin under normal weather conditions, which is what the MISO planning criteria require. Ameren Missouri was not alone in this line of thinking. The North American Electric Reliability Corporation ("NERC") was actively voicing its concern about winter reliability, including by making recommendations for more robust planning for extreme winter weather events in utility resource planning processes.[46]

Q. How did Ameren Missouri assess resource needs under such extreme weather conditions?

A. Ameren Missouri evaluated its capacity position under extreme weather for both summer and winter, reflecting the following assumptions:[47]

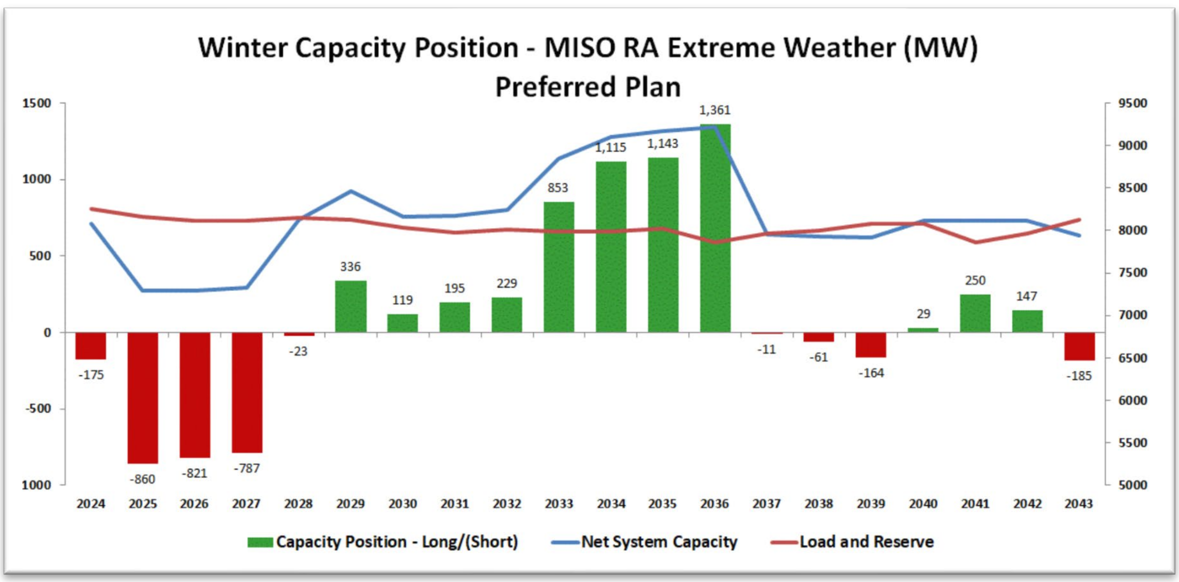
- All units reflected at MISO seasonal accredited capacity ("SAC") values;
- Planning reserve margins set to MISO seasonal values;
- Assessment with extreme weather assumes limited use units (i.e., Illinois combustion turbine generators ("CTGs")) are available for emergencies only; and
- Extreme weather reflects incremental peak demand of 600 MW in winter and 800 MW in summer based on recent extreme weather events.[48]

Figure 6 shows Ameren Missouri's capacity position for the winter season under extreme weather for its 2023 IRP preferred plan. As the figure shows, Ameren Missouri's resources fall short of demand and PRM requirements under extreme weather based on recent winter weather events in 2025-2027 by an average of roughly 800 MW until the addition of 800 MW of simple cycle gas generation in 2028. After 2029, the winter

[46] See NERC Winter Reliability Assessments for 2022-2023 and 2023-2024, attached as Schedules MM-S19 and MM-S20, respectively.
[47] See Schedule MM-S14 – Ameren Missouri 2023 IRP Chapter 10 – Strategy Selection, pp. 28-30.
[48] Summer peak load addition of 800 MW based on approximate midpoint of values calculated and presented in the extreme weather sensitivity analysis in Ameren Missouri 2023 IRP Chapter 3. Winter peak load addition of 600 MW based on approximate increase in peak demand above normal peak experienced during winter storm Elliott in December 2022.

capacity position under extreme winter weather is less than 300 MW long or short, except for the four years between the addition of the NGCC in 2033 and the retirement of the first two Labadie coal-fired units at the end of 2036. This long position serves to guard against potential risks to continued operation of the Labadie units until their current planned retirement dates.

Figure 6 – 2023 IRP Preferred Plan Winter Capacity Position – Extreme Weather



Q. Please summarize the evolution of dispatchable generation additions in the Company's preferred resource plans since its 2020 IRP.

A. MISO's shift to a seasonal RA (or capacity) construct, which took effect for the 2023-2024 MISO planning reserve auction (for the period June 1, 2023 to May 31, 2024) along with the emerging trend in observed extreme winter weather events and subsequent guidance from NERC, has resulted in a need to focus on winter resource needs. The evolution of MISO's seasonal construct has resulted in significant changes in the Company's assessment of resource needs. At the same time, constraints on the Company's fleet of gas-fired units in Illinois, as a result of CEJA, and the need to address a much higher frequency of extreme weather events, most notably in winter, has led to a further increase in the need for resources. Ameren Missouri has addressed these changes in resource need through its 2023 IRP, as illustrated in Figure 3. The additional dispatchable resources – 800 MW of simple cycle gas generation in 2028 and 1,200 MW of clean dispatchable generation in 2040 – directly address these increased resource needs.

Q. It appears that the Company's need for resources would be less if RIEC continued to operate through its previous retirement data of 2039. Please comment on that.

A. While it is true that continuing to operate RIEC as it has operated in the past would lessen the need for additional resources for a while, the cost to do so would have been significant and doing so would expose the Company and its customers to several ongoing risks. As I demonstrated with the analysis presented in my direct testimony, the Company found that adding FGD controls to RIEC and continuing to operate the plant through 2039 would be significantly more costly for customers than retiring the units at the time the decision was made.

Q. Is it reasonable or appropriate to judge the Company's decision in late 2021, to retire RIEC rather than add pollution controls, with the benefit of knowing what has transpired since?

A. No, it is neither reasonable nor appropriate to do so because doing so would necessarily depend on the application of hindsight. The Company made its decision with the best information available at the time. The analysis the Company relied on in making its decision, as presented in my direct testimony, considered a wide range of key uncertainties – carbon prices, natural gas prices, FGD costs, transmission upgrade costs –

just as we do in our regular IRP analyses. We also considered four different potential operating modes that RIEC may realize under a then-prospective agreement with MISO as a system support resource ("SSR"). In total, 48 different outcomes of the decision were evaluated, and 45 of those indicated that customers would be better off if RIEC were retired. To judge the decision with the benefit of hindsight is simply not reasonable or appropriate.

Q. Even if the Company had been able to foresee the events that transpired subsequent to its decision to retire RIEC, would it have made any difference?

A. No. The costs and risks of continuing to operate RIEC are still greater than the cost to serve customers with RIEC retired. That is, using hindsight demonstrates we made the correct decision.

Q. Have you performed any analysis to support that view?

A. Yes. I have prepared analysis that revisits the decision with the knowledge of the significant changes I've already mentioned – MISO seasonal RA construct, CEJA, and extreme winter weather events – as well as others that have emerged since December 2021, when the original decision to retire RIEC was made. I have done this by once again comparing two alternatives – 1) retrofit RIEC with FGD pollution controls and operate through 2039, or 2) retire RIEC by the end of 2024. To do the analysis, I have used the assumptions prepared for and used in the Company's 2023 IRP analysis. This includes the most up-to-date assumptions for natural gas prices, coal prices, carbon prices, power prices, capacity prices, new resource costs, transmission infrastructure needs, demand-side resources (energy efficiency and demand response), customer demand, MISO seasonal PRM requirements and unit accreditations, and others. It also includes assumptions for environmental compliance used in the Company's 2023 IRP analysis, including compliance with EPA's Good Neighbor Rule, for the fleet in the absence of RIEC. In addition to that base analysis, I have also considered costs and risks in the event that RIEC were to continue to operate through 2039 related to compliance with the Good Neighbor Rule and EPA's proposed greenhouse gas ("GHG") rule as sensitivities.

Q. Please provide an overview of the specific assumptions you have used relevant to the two alternatives.

A. For the retrofit alternative, I have evaluated three estimates – base, high and low – for the cost of installing FGD equipment – $716 million, $954 million, and $1,059 million.[49] Note that these are overnight costs, are expressed in 2025 dollars to match the in-service year assumed for the FGD, and do not include allowance for funds used during construction ("AFUDC"), which adds $75 million or more to the total capital cost. For the retirement alternative, I have updated the cost of transmission upgrades to reflect the estimate that resulted from the Attachment Y analysis by MISO – **__________**.[50]

Q. Does your analysis reflect any changes in resource needs as a result of continued operation of RIEC in the retrofit alternative?

A. Yes. The NGCC that is added in 2033 in the Company's 2023 IRP preferred plan is delayed to 2037, following the retirement of the first two units at Labadie. The natural gas simple cycle unit that is added in 2028 in the Company's 2023 IRP preferred plan is delayed to 2033, following the retirement of the Sioux Energy Center. The analysis

[49] The low estimate of $716 million is based on a 2009 study by Advatech with estimated costs in 2015 of $540 million and 30% cumulative inflation from 2015 to 2025. The base estimate of $954 million is based on an estimate from Shaw with estimated costs in 2016 of $725 million and 29% cumulative inflation from 2016 to 2025. The high estimate of $1,059 million is based on an estimate from Black & Veatch with estimated costs in 2015 of $799 million and 30% cumulative inflation from 2015 to 2025.
[50] The Company's latest forecast for these projects, three of which are complete or nearing completion, is that their total cost will be close to this **__________** value.

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reflects the change in costs to customers resulting from these resource deferrals, including differences in energy and capacity revenues for the resource portfolio.

Q. Does your analysis include the effect of reduced margins for RIEC while it operates under the SSR agreement with MISO?

A. Yes. To do so, I have reflected the revenue requirement effects of the difference between actual/forecast margins for RIEC under the SSR agreement with MISO and the estimated margins that likely would have been realized had RIEC continued to operate in a manner similar to its operations prior to the SSR agreement (i.e., operating at a high capacity factor based on its economics within MISO).[51]

Q. What were the results of the base analysis using the middle (base) FGD costs?

A. The base analysis shows that retirement of RIEC in 2024 results in net present value of revenue requirements ("NPVRR") costs to customers that are $1.452 billion lower than if the Company added FGD controls at RIEC and continued to operate it through 2039, assuming expected carbon prices. If carbon prices are at the low end of the range modeled, that advantage drops to $1.280 billion.

Q. What were the results of the sensitivities you referenced earlier?

A. Assuming the inclusion of selective catalytic reduction ("SCR") controls at RIEC in addition to FGD would be needed for RIEC to comply with EPA's Good Neighbor Rule,[52] the early retirement of RIEC results in NPVRR costs to customers that are $1.855

[51] The estimated margins for 2022-2024 for RIEC absent the SSR agreement reflect half the actual margins realized by Labadie Energy Center based on its similarities to RIEC in design and operation and adjusting for the difference in the number of units at the two facilities – two units at RIEC and four units at Labadie. Because the 2023 IRP modeling discounts revenue requirements to 2024, the discount rate was applied to 2022 and 2023 to reflect 2024 dollars (i.e., the dollar values for those years were increased for inclusion in the NPVRR results).
[52] And continuing to use the middle (base) FGD costs.

billion lower than if the Company added FGD controls at RIEC (using the middle FGD cost estimate) and continued to operate it through 2039, assuming expected carbon prices. If carbon prices are at the low end of the range modeled, that advantage drops to $1.697 billion.

Assuming the low FGD capital cost (and no SCR) reduces the NPVRR advantage for early retirement to $1.147 billion assuming expected carbon prices and $975 million assuming low carbon prices. Table 3 shows the results for various levels of carbon price, base, low and high FGD costs, and inclusion or exclusion of SCR controls.

Table 3 – NPVRR results for RIEC FGD Retrofit vs. Early Retirement ($MM)

	Carbon Prices			
Difference from Preferred Plan - Base FGD	**Low**	**Base**	**High**	**PWA**
Rush Island 2039-FGD	1,280	1,399	1,681	1,452
Rush Island 2039-FGD&SCR	1,697	1,807	2,066	1,855
	Carbon Prices			
Difference from Preferred Plan - Low FGD	**Low**	**Base**	**High**	**PWA**
Rush Island 2039-FGD	975	1,094	1,376	1,147
Rush Island 2039-FGD&SCR	1,392	1,502	1,761	1,550
	Carbon Prices			
Difference from Preferred Plan - High FGD	**Low**	**Base**	**High**	**PWA**
Rush Island 2039-FGD	1,416	1,535	1,816	1,587
Rush Island 2039-FGD&SCR	1.832	1.943	2.201	1.991

Q. What do you conclude from the analysis and results you just described regarding the Company's decision to retire rather than retrofit RIEC?

A. Using hindsight serves to confirm – even more strongly – the decision the Company made in December 2021 to retire RIEC instead of installing expensive pollution controls. That is, the costs to customers of retrofitting RIEC with FGD pollution controls and continuing to operate the plant through 2039 are much greater than the cost of retiring

RIEC by the end of 2024, by ***over a billion dollars*** in *all cases except one*, and the advantage for retirement for that one case is just under a billion dollars. Consideration of the significant ongoing risks to operating RIEC through 2039, primarily the cost implications of pending and potential future environmental regulation, further reinforces the appropriateness of the Company's decision to retire RIEC because any incremental spending required by such regulation, or negative impacts of such regulation on RIEC's generation had it remained in service, would only make the advantage for customers of retiring RIEC rather than retrofitting it even greater.

Q. Are there other costs or benefits you have not included in your analysis?

A. Yes. I have not included the costs of compliance with EPA's proposed GHG rule, which would likely require 40% gas cofiring at RIEC starting in 2030. A separate analysis, discussed later in my surrebuttal testimony, shows that adding gas cofiring increases NPVRR costs of keeping RIEC open by another $160 million.[53] I have also not included the benefits of securitization in the early retirement case, which is expected to further reduce costs to customers as a result of retiring RIEC. That estimated benefit is approximately $77-78 million.[54]

Q. Please summarize your conclusions regarding the Company's consideration of the decision to retire RIEC.

A. Ameren Missouri has been evaluating the potential impact of RIEC retirement in 2024 – the year in which it actually is retiring -- consistently since the NOV

[53] The $160 million cost increase due to inclusion of gas cofiring is discounted to 2012 since it is part of a separate analysis that includes consideration of hypothetical past investments, which I discuss later in my surrebuttal testimony. If discounted to 2023, the NPVRR impact would be roughly double that amount.
[54] See Schedules MJL-S4 and MJL-S8 to Company witness Mitch Lansford's surrebuttal testimony.

and took steps to prepare for emerging resource needs. The Company's IRP analysis through its 2020 IRP indicated that there is no near-term need for resources in the event of RIEC retirement.[55] Only the confluence of significant changes in the planning environment post-the 2014, 2017, and 2020 IRPs have resulted in a greater or more near-term need for resources – MISO's still evolving seasonal RA construct, CEJA's impact on the Company's Illinois gas-fired units, and the emergence of frequent extreme winter weather events. Even considering those significant changes with the benefit of hindsight, the Company's decision to retire RIEC rather than retrofit the plant with FGD equipment is still expected to result in far lower costs to customers and at the same time mitigate significant risks to customers in the future.

IV. THE COMPANY'S DECISIONS REGARDING RIEC HAVE NOT RESULTED IN HIGHER COSTS TO CUSTOMERS

Q. Please summarize the positions of Staff witnesses Eubanks and Fortson and OPC witness Seaver regarding alleged or implied potential harm to customers as a result of Ameren Missouri's decision to retire RIEC.

A. Ms. Eubanks notes the capacity shortfalls the Company expects in 2025-2027 and estimates this will cost customers $1-8 million to cover at the Company's 2023 IRP capacity price assumptions for those years and implies that such costs should not be borne by customers.[56] She also indicates that the currently expected costs for transmission upgrades resulting from the retirement of RIEC (**___________**) are higher than the costs assumed in the Company's RIEC retirement analysis performed in December 2021

[55] In fact, once Noranda retired post-the 2014 IRP but prior to the 2017 IRP, even with Rush Island retired by 2024 the IRP planning indicated no need for additional resources until sometime in the 2030s.
[56] File No. EF-2024-0021, Claire Eubanks Rebuttal Testimony, p. 23.

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($115 million) and used as the basis for the Company's decision to retire RIEC. In noting this change in estimated costs, she asserts that the Company had not planned for transmission upgrades needed in the event of retirement of RIEC.[57] While she does not recommend a disallowance of costs to be securitized, she indicates that the Company's recovery of transmission upgrade costs should be capped at the $115 million amount assumed by the Company in its 2021 retirement analysis and raises the potential for disallowance of costs incurred due to capacity shortfalls and future resource additions that may have been avoided had RIEC not been retired.

Mr. Fortson criticizes the Company's IRP planning for not explicitly addressing potential outcomes of the NSR case in its IRPs since 2011.[58] While Mr. Fortson does not explicitly say that future resource additions may be subject to disallowance, it is clear to me from reading his testimony that this is implied.

Mr. Seaver also focuses on the Company's need for resources, asserting that the Company did not account for the need for replacement resources in its RIEC retirement analysis and that the solar projects being implemented by Ameren Missouri would not have been implemented if RIEC did not retire. He then compares the capital costs of the solar projects (net of investment tax credits) to the capital cost of the FGD (using selected estimates) and concludes that the cost for the solar projects is $34 million higher, which he suggests should be disallowed from the costs to be securitized. The basis for seeking a disallowance is both his claim that the Company was imprudent for not obtaining NSR permits before completing the 2007 and 2010 RIEC outage work, and his claim that the Company made an imprudent decision when it decided to retire RIEC. He also notes that

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[57] File No. EF-2024-0021, Claire Eubanks Rebuttal Testimony, p. 23.
[58] File No. EF-2024-0021, Brad Fortson Rebuttal Testimony, p. 6.

future resource additions may have been avoided or deferred had the Company not decided to retire RIEC.

Q. Is Ms. Eubanks correct in her assessment and characterization of the Company's expected capacity shortfall?

A. No. The projected winter capacity shortfalls in 2025 (110 MW), 2026 (72 MW) and 2027 (37 MW) are less than the threshold shortfall of 300 MW that the Company has been using since its 2011 IRP as a basis for adding resources in alternative resource plans. Ameren Missouri has never planned to meet such small capacity shortfalls as part of its IRP planning as far back as its 2011 IRP. The 300 MW "build threshold" is based on an assessment of the degree to which the Company can rely on other resources within MISO to meet short-term capacity needs. This assessment was first performed for the Company's 2011 IRP and has been revisited during the preparation of each Ameren Missouri IRP since then. As noted earlier, Staff has never taken issue with this build threshold. For the 2023 IRP, the Company reduced its build threshold to 200 MW starting in 2029 to reflect longer-term expectations of capacity market tightness and uncertainty. As I previously noted, MISO's new seasonal RA construct was not approved by FERC until August 2022. MISO produced its first official seasonal PRM and capacity accreditation values in late 2022 for use in its first-ever PRA using the seasonal RA construct in 2023.[59]

[59] Ms. Eubanks' calculation of potential costs for the projected capacity shortfalls includes an error, which if corrected would reduce the estimate cost range to $0.7-5 million. The assumed capacity price for 2025 was applied to the capacity shortfalls in 2026 and 2027 rather than using the specific price assumptions for those years.

\Q. How do you respond to Ms. Eubanks' assertions regarding the Company's transmission planning and cost estimates?

A. Ms. Eubanks is not correct that the Company did not plan for potential transmission upgrades necessitated by the retirement of RIEC until late 2021. Ameren Missouri has included estimates for costs for transmission upgrades for each coal-fired energy center retirement analyzed in every IRP since 2011.[60] These cost estimates are based on the same kind of analysis used to assess MISO Attachment Y submittals, as was done for RIEC in 2021. That the Company had not submitted an Attachment Y request to MISO to evaluate the impact of RIEC retirement does not at all mean that the Company had not been considering such needs.

Changes in estimated transmission upgrade costs are not unusual, because the need for infrastructure is subject to numerous changes on the grid that are outside the control and influence of Ameren Missouri. These include changes in other generating resource retirements and additions, including the type, size and location of each retirement/addition. They also include changes in customer load and other changes in the broader transmission grid, which alters power flows. In short, the transmission system is extremely dynamic and what transmission upgrades forward-looking planning will indicate are needed in the event of the retirement of a given generator (here RIEC) almost certainly will vary each time the planning is done. It is for this very reason, that infrastructure needs are uncertain, that Ameren Missouri evaluated the break-even transmission cost for each of the 48 scenarios that were analyzed to support the RIEC decision in 2021, as presented in my direct

[60] See Schedule MM-S21 – 2014 IRP Chapter 7 – Transmission and Distribution, p. 9, Schedule MM-S22 – 2017 IRP Chapter 7 – Transmission and Distribution, p. 10, and Schedule MM-S23 – 2020 IRP Chapter 7 – Transmission and Distribution, p. 8.

testimony. That analysis showed that the break-even transmission cost for the scenario with the lowest FGD cost and the most restrictive SSR operating regime was expected to be $386 million, *far greater* than the eventual cost estimate of **__________**. In *only* five of the 48 scenarios analyzed were the break-even transmission upgrade costs found to be *less* than **__________**.[61] Consequently, Ms. Eubank's position that the breakeven analysis was based on a $115 million cost estimate is at best, incomplete, and at worst misleading, since more than 90% of the scenarios yielded break-even transmission cost estimates of **__________** or more.

Q. Ms. Eubanks attempts to support her assertion that the Company had not been properly planning for transmission upgrades needed in the event of RIEC retirement by citing the Company's response to Staff data request 0001 in File EO-2022-0215, in which the Company indicated that it had not previously evaluated RIEC retirement a year or five years ahead of retirement.[62] How do you respond?

A. This is also misleading. It does not mean the Company had not previously analyzed early retirement of RIEC. As I've previously discussed, the Company had done so for its IRP analysis after 2011. It merely means that the Company had not examined retirement of RIEC *in 2022* for its 2017 IRP or retirement *in 2019* for its 2014 IRP, for example. There was no compelling reason to do so. The Company focused on 2024 as a potential early retirement date in its planning after 2011, including as part of explicit analysis of a limited set of potential litigation outcomes in its 2020 IRP, and RIEC is now set for retirement by the end of 2024.

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[61] See Schedule MM-D1

[62] EO-2022-0215 Staff's Investigation of Matters Concerning the Rush Island Energy Center; a copy of the Company's response to Staff data request 0001 is attached as confidential Schedule MM-S24.

Q. Does Ms. Eubanks suggest that the Company should have retired RIEC *before* the end of 2024?

A. It is not clear to me that she is suggesting that, although the implication of suggesting that we should have examined nearer-term retirement of RIEC in past IRPs could be that we should have considered retirement of RIEC before 2024 It may also be that she believes that doing so would have saved customers the $49 million difference between the estimated costs of $115 million used in the Company's retirement analysis and the cost estimate of **__________** following MISO's Attachment Y study.

Q. Would customers have saved money if it were true that retiring RIEC sooner, say at the end of 2019, would have resulted in costs of only $115 million?

A. That is *extremely* unlikely. During the period 2020-2022, net margins for RIEC were approximately $360 million,[63] far more than the $49 million in transmission upgrade costs that ostensibly (really, only theoretically) could have been saved had it retired prior to 2020.[64] Such savings may not have even materialized to partially offset the loss of benefits of operating RIEC during that time. As I discussed previously, estimates for transmission upgrades are sensitive to numerous changes on the grid, which is why the Company's retirement analysis evaluated potential changes in such costs by examining the break-even transmission costs for each of the 48 scenarios included in the Company's 2021 RIEC retirement analysis.

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[63] Reflects settlements in MISO for energy as well as capacity revenues, fuel costs and fixed and variable O&M costs.

[64] Again, in most of the scenarios we ran, the break-even transmission costs were greater than **___________**.

Q. You previously discussed the Company's resource planning since 2011 and ongoing consideration of early retirement of Rush Island. Does that discussion sufficiently address what you believe to be the implications on potential recovery of future resource costs raised by Mr. Fortson?

A. Yes. As I stated previously, the Company's planning, up to and including its 2020 IRP, did not indicate a near-term need[65] for resources should Rush Island be retired in 2024, and the Company's decisions would have been no different had its planning gone any further in considering potential outcomes of the NSR litigation.

Q. How do you respond to Mr. Seaver's comparison of the costs of new solar resources to the cost of an FGD retrofit for RIEC?

A. It is an inapt comparison, and even if such a comparison was valid (it isn't), it reflects some significant misconceptions and errors of omission. First and foremost, the solar projects are not being pursued as a result of retiring RIEC earlier than its previously anticipated retirement date of 2039. As Figure 1 shows, the Company had planned to add 3,100 MW of wind and solar generation by the end of 2030 when the planned retirement date for RIEC was 2039. When the Company changed its PRP in 2022, which reflected early retirement of RIEC following the Company's December 2021 decision to do so, the total wind and solar additions increased only by about 13%, to 3,500 MW by the end of 2030, as shown in Figure 2. The primary driver for this change was the Company's more sustained plan for project implementation given its assessment of risks to the planned clean energy transition, which was performed with the assistance of Roland Berger, an energy consulting firm.[66] The driver was *not* the early retirement of RIEC.

[65] By the time of the 2017 and 2020 IRPs, no need until the 2030s.
[66] See Schedule MM-S13 – Ameren Missouri 2022 Change in Preferred Plan Report, p. 29.

Setting that aside for a moment, and assuming the comparison Mr. Seaver has made is appropriate (I want to emphasize again, it isn't), it reflects significant glaring errors of omission. The FGD cost estimates used by Mr. Seaver are expressed in 2015 and 2016 dollars rather than 2025 dollars to reflect the otherwise expected in-service date of the FGD system (had the Company decided to retrofit RIEC instead of retire it), thus omitting nine to ten years of inflation-driven increases that amount to a 29-30 percent increase in costs. The costs also do not include the costs of financing during construction, or AFUDC, which in the case of the FGD retrofit could be over $75 million. Mr. Seaver admits that (absent the Commission for some unspecified reason disallowing project costs, the cost of construction plus the AFUDC is the figure that would actually be reflected in customer rates.[67] Since the solar project costs he uses to compare to his average FGD costs did include AFUDC, Mr. Seaver is making an apples and oranges comparison.

Beyond that, the comparison fails because it includes only a portion of the costs and benefits. Mr. Seaver has included the benefits of tax credits, which is appropriate. However, he has not included the market energy benefits of the solar resources nor the ongoing costs associated with either the solar projects or the FGD units, and the ongoing costs for the FGD are particularly substantial given the need to purchase limestone and

[67] Deposition of Jordan Seaver, File No. EF-2024-0021, March 14, 2024, p. 138, ll. 8 – p. 139, l. 11 ("Q. And AFUDC are the financing costs that accrue on a capital project for a utility during the pendency of construction, right? A. Right. Q. So if it takes four years to build a scrubber, utility's spending money year one, year two, every month, every day going on, there's going to be an AFUDC rate, a financing rate applied to that, and that just going to keep adding costs to the project, Right? A. Basically, yes. Q. And at the end of the project, I mean, I'm just using round numbers. Let's say the project costs a hundred dollars and we accrued $20 of AFUDC, $120 of capital costs is going to go into rate base reflecting customer rates. Right? A. Well, those details would be worked out in a case, yeah. Q. Well, assuming it's prudent, assuming the Commission doesn't disallow some cost, the cost of the project's not a hundreds [sic] dollars in that example, the cost of the project is $120. Right? A. Yeah. Whatever the value of the AFUDC is yes, that's going to adjust that. Q. And assuming the Commission doesn't disallow some portion of that $120, it's $120 that gets reflected in rates, not the hundred dollars is my only point. Right? A. Assuming there's no disallowance, yes.").

operate and maintain the equipment (plus, FGD units required auxiliary power to operate, which reduces the generation that can be sold and thus the revenues of the plant). An appropriate comparison must include all the costs and benefits for the alternative being compared and must examine both based on the NPVRR to customers.

Even if an analysis like Mr. Seaver's were appropriate – again, it isn’t for the reasons just discussed – it makes absolutely no sense to use FGD estimates that do not including financing costs (AFUDC) and compare them to the solar costs that do include AFUDC. I noted earlier that AFUDC would add about $75 million or more to the estimates Mr. Seaver used. Mr. Seaver's estimate ($727 million for FGD) was calculated as follows: Add up the three FGD estimates from his Schedule JS-R-02 ($655 million, $582 million, and $646 million), plus the three estimates for FGD from my direct testimony ($681 million, $811 million, and $941 million), plus one additional estimate from his Schedule JS-R-03 ($776 million), the sum of which is $5.092 billion, resulting in an average of $727 million. He then compares that average to the solar projects' net cost, based upon estimates that as noted *do* reflect AFUDC. An apples-to-apples comparison would have been to add $75 million to each of the six estimates he used that did not account for AFUDC, which would bring the sum of his estimates to $5.617 billion, producing an average of $802 million – fully **________** *more* than the solar projects' total cost of **____________**. Thus, by Mr. Seaver's logic, retiring Rush Island instead of retrofitting it benefitted customers by **_________**. To be clear, this is a completely insufficient (and inaccurate) way to gauge the benefit (or detriment) resulting from the Company's decision to retire RIEC, but using Mr. Seaver's approach, this would be the result. Once again, a proper analysis must include *all* of the costs and benefits for two different and *comparable* alternatives.

Q. Can you describe what such a proper analysis must include?

A. Yes. It must include everything the Company considered in the retirement analysis it used to support its decision in December 2021 to retire RIEC rather than retrofit the facility with FGD pollution controls. That analysis included all of the costs and benefits of two comparable options – capital costs, operations and maintenance ("O&M") expense, fuel costs, emissions costs, changes in resource needs, energy revenues, and capacity revenues for *both* alternatives. These costs and benefits are always included in the Company's IRP analysis and any proper analysis of alternatives with resource implications.

Q. Mr. Seaver criticizes that analysis for not considering the need for or the cost of replacement resources. Is he correct?

A. No. As I've discussed previously in my surrebuttal testimony, the Company had determined that replacement resources would not be needed even if RIEC retired in 2024 based on its assessment of resource needs under the MISO RA construct in effect at the time. Only when MISO changed to a seasonal RA construct did the Company find that its future resource needs would be greater to meet winter capacity needs, and that seasonal construct had only been proposed in concept by MISO to FERC in November 2021 and was not approved by FERC until August 2022 for the 2023-24 PRA. Moreover, and as I've discussed previously in my surrebuttal testimony, MISO did not provide the data necessary to more accurately estimate resource needs under the seasonal RA construct until late 2022, after FERC had approved the seasonal RA construct. Ameren Missouri made its best efforts to estimate the impact of the seasonal construct when it made the decision to retire

RIEC in December 2021 and when it prepared its 2022 change in PRP, which was filed in June 2022, as I discussed previously in my surrebuttal testimony. Finally, the Company's winter capacity position for its 2022 PRP showed that the Company would have sufficient capacity to meet its winter load and PRM requirements immediately following the retirement of RIEC. Figure 4, presented earlier in my surrebuttal testimony, shows the winter capacity position for the Company's 2022 PRP based on estimated unit ratings and PRM requirements. Note once again that the capacity shortfalls in 2027 and 2028 would not have been expected but for the assumed retirement of 275 MW of oil-fired units in Missouri at the end of 2026 – Fairgrounds, Mexico, Moberly, and Morreau.[68] The retirement of those units was moved to the end of 2029 in the Company's 2023 IRP.[69] It should also be noted that none of the capacity shortfalls reflected in Figure 5 exceed the build threshold (short 300 MW or more) used by the Company for adding resources in its alternative resource plans, which I discussed previously in my surrebuttal testimony. In short, the Company reflected its best estimates of resource needs arising from the retirement of RIEC at each step in the analysis and decision-making process and based on the best information available at the time. As I stated previously in my surrebuttal testimony, it is neither reasonable nor appropriate to judge the decisions made by the Company regarding RIEC with the benefit of hindsight when Ameren Missouri made its best efforts to consider and properly evaluate all reasonably expected impacts of its decisions at the time those decisions were made.

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[68] See Schedule MM-S17 – Ameren Missouri 2020 IRP Chapter 4 – Existing Supply-Side Resources, Table 4.3, p. 12. Note that the total accredited value for the four oil-fired units (275 MW) is greater than the listed capacity due to differences in assumed accreditation for winter vs. the summer rated output (217 MW).

[69] See confidential Schedule MM-S18 – Ameren Missouri 2023 IRP Chapter 4 – Existing Supply-Side Resources, Table 4.4, p. 15.

Q. Does the updated retirement analysis you described previously address the concern raised by Mr. Seaver with respect to evaluating replacement resources?

A. Yes. Even had we had the foresight to predict the post-2021 changes, that analysis, which did examine the retirement of RIEC based on everything we know today and reflecting the assumptions used in the development of the Company's 2023 IRP, demonstrates that customers will incur costs that are about a ***billion dollars*** or more lower as a result of the Company's decision to retire RIEC rather than retrofit the facility with FGD pollution controls.

Q. As noted, Mr. Seaver recommends a disallowance based not just on his imprudence claims about the Company's 2021 retirement decision, but also based on what he claims were the Company's imprudent decisions back in 2007 and 2010 that gave rise to the NSR litigation, and that ultimately led to the early retirement of RIEC. Is it possible to perform an analysis that compares the decisions the Company has made regarding RIEC going back to its decisions to implement the projects that became the subject of the NSR litigation ("the Projects")?

A. Yes, and I have.

Q. Please describe the analysis you have performed.

A. I have evaluated two alternatives. In the first alternative, I have analyzed the results of the decisions that have actually been made by Ameren Missouri, namely that the Company did not seek NSR permits nor install FGD equipment around the time the Projects were implemented and chose to retire RIEC rather than install FGD controls once the NSR litigation had concluded – this is consistent with the Company's current IRP preferred plan as described in its 2023 IRP and is what actually happened. In the second alternative, I have assumed that the Company did seek NSR permits for the Projects, installed FGD controls in 2012 (reflecting a reasonable schedule for implementation), and continued to operate RIEC through 2039.

For the second alternative, I have also assumed that the 800 MW simple cycle gas-fired generators, shown going into service in 2028 in the Company's 2023 IRP, are delayed to 2033, following the retirement of Sioux Energy Center, since in this scenario RIEC would still provide capacity. I have also assumed that the 1,200 MW NGCC, shown going into service in 2033 in the Company's 2023 IRP, is delayed to 2037, following the retirement of two units at the Labadie Energy Center, again because in that scenario RIEC's capacity would still be on the system. For the base analysis, I have assumed a middle (base) FGD overnight capital cost of $954 million, as previously described in my surrebuttal testimony. For the base analysis, I have also assumed compliance with the EPA's Good Neighbor Rule via reduced generation. I have also performed sensitivity analysis to include 1) a low overnight capital cost for FGD installation of $716 million, 2) SCR technology for NOx (nitrogen oxide) control in service in 2027 for compliance with the Good Neighbor Rule, and 3) 40% natural gas cofiring starting in 2030 to comply with EPA's proposed GHG rule.

Q. What kind of model did you use to perform this analysis?

A. Because the Company's current IRP modeling begins with calendar year 2024 and is thus not capable of analyzing alternatives that must reflect the full cost of decisions made before then, I have prepared incremental revenue requirements analysis using the Company's Excel model used to evaluate the revenue requirement impact of specific projects. Each alternative is characterized by a series of models, each of which calculate the revenue requirement for specific investments and/or cost/benefit streams that are included in the characterization for that alternative. As noted, the Early Retirement alternative (what is happening) reflects the following:

- 800 MW Simple Cycle Gas – in service 1/1/2028 – includes capital expenditures, O&M expense, fuel costs, energy revenues and capacity revenues;
- NGCC – in service 1/1/2033 – includes capital expenditures, O&M expense, fuel costs, energy revenues and capacity revenues;
- Pre-retirement Operations for RIEC – capital expenditures, O&M expense, fuel costs, emissions costs and MISO energy and capacity revenues for 2022-2024; and
- Transmission Upgrades – capital expenditures of **__________** in service by 12/31/2024.

The 2012 FGD alternative (where NSR permits were obtained)) reflects the following:

- 800 MW Simple Cycle Gas – in service 1/1/2033 – includes capital expenditures, O&M expense, fuel costs, energy revenues and capacity revenues;
- NGCC – in service 1/1/2037 – includes capital expenditures, O&M expense, fuel costs, energy revenues and capacity revenues;
- FGD at RIEC – in service 1/1/2012 – includes capital expenditures and O&M expense for FGD operation for 2012-2039;

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- Reduced costs for other environmental projects that could have been avoided as a result of the FGD retrofit;
- Continued Operations for RIEC – capital expenditures, O&M expense, fuel costs, emissions costs, energy revenues and capacity revenues for 2022-2039 (excludes FGD costs capture separately); and
- Transmission Upgrades – capital expenditures of **____________** (2025 dollars) in service by 12/31/2039.[70]

Note that I have excluded certain economic effects that, if included, would benefit the Early Retirement alternative relative to the 2012 FGD alternative (i.e., my analysis is overly conservative). These include margin reductions resulting from 1) the higher dispatch cost for RIEC with FGD, 2) the reduction in net output resulting from the increase in station power requirements to operate the FGD equipment, and 3) outage time necessary to tie in the FGD facility to the existing emissions system.

Q. What are the results of your base analysis comparing the two alternatives – Early Retirement and 2012 FGD?

A. For the base analysis, using the base FGD capital cost, the NPVRR for the 2012 FGD alternative is greater than the Early Retirement alternative by **$770 million**. Assuming the low FGD capital costs, the NPVRR for the 2012 FGD alternative is greater than the Early Retirement alternative by **$531 million**.

Q. What conclusion do you draw from the results of your analysis?

A. The analysis indicates that customers will incur costs resulting from the Company's RIEC decisions (i.e., do not install FGD equipment and retire the units by then

[70] Annual inflation of 2% added from 2025 to 2039.

end of 2024) that are far less than those they would incur had the Company sought NSR permits, installed FGD equipment in 2012, and continued operating RIEC through 2039. That is, customers would be far worse off had NSR permits been obtained.

Q. What are the results of the sensitivity analysis including SCR controls for the 2012 FGD alternative?

A. The inclusion of SCR pollution controls for the 2012 FGD alternative increases the cost advantage for the Early Retirement alternative to $963 million assuming the base FGD capital cost and $724 million assuming the low FGD capital cost.

Q. Is it safe to say that also adding gas cofiring for potential GHG compliance to the 2012 FGD alternative further increases the advantage of the Early Retirement alternative?

A. Yes. Including gas cofiring increases the cost advantage for the Early Retirement alternative to $1.122 billion assuming the base FGD capital cost and $883 million assuming the low FGD capital cost.

Q. Reviewing the totality of the analysis and results you just described, what can you say regarding the effect of the Company's decisions regarding RIEC?

A. *Not* obtaining NSR permits and *not* adding FGD to RIEC more than a decade ago did not result in increased costs to customers relative to an alternative in which the Company had sought NSR permits and installed FGD equipment in 2012 and operated RIEC through 2039. In fact, not obtaining the NSR permits and not adding FGD is expected to result in hundreds of millions of dollars, possibly over a billion dollars, in savings to customers. This is true assuming that RIEC could continue to be operated through 2039 with no significant future risks, which we know is not the case. It's very safe to say that whatever the Commission's findings are on the prudence of the Company's decision-making related to the 2007 and 2010 projects at RIEC, customers were not economically harmed by those decisions, and in fact they economically benefited from them. As such, there is no basis for a disallowance.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Petition of Union	)	
Electric Company d/b/a Ameren Missouri	)	
for a Financing Order Authorizing the Issue	)	EF-2024-0021
of Securitized Utility Tariff Bonds for	)	
Energy Transition Costs related to Rush	)	
Island Energy Center.	)	

AFFIDAVIT OF MATT MICHELS

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

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

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

/s/ Matt Michels
Matt Michels

Sworn to me this 22nd day of March, 2024.