BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Staff's Investigation of Matters Concerning the Rush Island Energy Center Belonging to Union Electric Company d/b/a Ameren Missouri.	)))	File No. EO-2022-0215

AMEREN MISSOURI MONTHLY REPORT

COMES NOW Union Electric Company, d/b/a Ameren Missouri ("Ameren Missouri" or the "Company"), and provides its monthly report on the Rush Island Energy Center, as follows:

1. On February 15, 2022, the Missouri Public Service Commission ("MPSC") issued an order in this docket requiring Ameren Missouri to file monthly reports on the status of the proceedings at the federal court as well as the status of its planning for the retirement of the Rush Island Energy Center ("Rush Island"). These reports are due on the 15th of each month.

United States District Court for the Eastern District of Missouri Update

2. On June 8, 2022, Midcontinent Independent System Operator ("MISO") completed and posted its Attachment Y analysis (Attachment A to this Report). That analysis confirms that both units at Rush Island should be designated as System Support Resources ("SSR"). Per MISO's tariff, SSR designations last for 12 months but can be renewed provided that adequate justification exists. On June 8, 2022, MISO posted on OASIS its Draft Attachment Y analysis indicating Rush Island may be deemed as SSR and scheduled a stakeholder meeting for June 17, 2022, at which time it will take public feedback and alternatives from any interested stakeholder based on the results of the Attachment Y. Recommended and MISO verified mitigation measures will be discussed during the stakeholder meeting. Assuming no viable alternatives to SSR status are identified, then MISO will proceed to finalize its Attachment Y report and commence SSR Agreement discussions with Ameren Missouri. Any such agreement will be filed with FERC for

approval. Ameren Missouri does not believe there are viable alternatives to Rush Island being designated as an SSR.

3. The District Court has the ultimate authority to determine both the retirement date and operating regime for Rush Island and is not bound by either a MISO SSR determination or FERC's subsequent approval. Accordingly, on June 8, 2022, Ameren Missouri filed a supplemental brief and supporting witness declarations with the District Court describing the reliability issues identified by MISO and the need to first implement transmission upgrade (mitigation) projects prior to retirement (Attachment B to this Report). Ameren Missouri is seeking approval from the District Court to continue operating, on a reduced basis, until such time as the mitigation projects are completed. The Department of Justice, relying upon the District Court's "inherent equitable power", filed a motion seeking unspecified "mitigation" for what it deems "excess emission" from Rush Island (Attachment C to this Report). Ameren Missouri believes such request to be without merit considering the decision by the Court of Appeals for the Eight Circuit in this case, as well as prior appellate decisions.

4. On June 9, 2022, the District Court ordered responses to the latest pleadings to be submitted by June 21, 2022 and scheduled a status hearing for June 24, 2022 (Attachment D to this Report). The status hearing was subsequently moved to July 1, 2022.

Rush Island Energy Center Retirement Planning Update

5. Transmission Planning – As reported in the previous reports filed in this docket, Ameren Missouri has spent the last several months providing information to MISO as needed for the Attachment Y2 and Y analyses. Prior to the issuance of the Attachment Y Report, the Company started necessary pre-engineering work based on the MISO Y2 results, under the assumption that these transmission improvements will still be needed on the system after the Attachment Y study results are received. The Attachment Y report confirmed this and, based on the Attachment Y

Report, the pre-engineering work will continue on these projects. Ameren Missouri has also begun additional work based other projects identified within the Attachment Y Report and to otherwise meet transmission planning criteria. The projects that must be completed before Rush Island can be retired are as follows:

- Installation of a larger transformer at Ameren Missouri's Wildwood substation.
- Installation of a capacitor bank at Ameren Missouri's Overton Substation, and
- Installation of four Static Compensators (STATCOM) in and around the St. Louis region.

There are certain other projects to be completed to meet Ameren Missouri's local transmission planning criteria with the retirement of Rush Island, but the Rush Island retirement will be independent of these projects going into service:

- Reconductoring 50 miles of conductor on the 345 kV Coffeen to Roxford transmission line,
- Retap the breaker current transformers at the 138kV substation and install new line metering set on the transmission line to Spalding,
- Raising two structures on the 138kV Neoga-Effingham Northwest transmission line and installing new shunts on the entire line, and
- Constructing a new 138kV transmission line from Beehive to Dupo Ferry and expanding the capacity of the existing Ameren Illinois Dupo Ferry and to Beehive substations to accommodate the new line.

6. Operational Planning – The Company continues to work on multiple operational issues that will have to be addressed both during the transition and after retirement of the plant, including creating staffing plans, appropriately adjusting operations and maintenance expenditures and capital investment to reflect retirement of the plant, inspecting remaining inventory to see what is usable elsewhere, and making plans to leave equipment at the plant in safe condition (draining oil, water, etc.), to name a few. Ameren Missouri started with the shutdown plans it developed for the Meramec Energy Center and is modifying them for Rush Island. The Company has made progress on this work, but the final structure of these plans depends upon knowing the new Rush

Island retirement date and on how the facility will operate until retirement, which the Company cannot know until it receives a modified order from the District Court.

7. Mark Birk and other senior management personnel have met with Rush Island employees to update them on the status of the plant and to talk about other employment opportunities within the Company. The Company has created a Sharepoint site to assist current Rush Island employees in identifying electric distribution jobs that may be available and to understand how the individual's current job skills may translate into opportunities for those jobs.

Staff Specific Recommendations from its April 15th Report

8. Staff recommended Ameren Missouri update its existing tariffs which cover curtailment situations. The Company filed a new tariff, titled Emergency Energy Conservation Plan, with the Commission on June 10, 2022, as a replacement for its existing Coal Conservation Tariff. This tariff describes how the Company will comply with specified MISO and North America Electric Reliability Corporation ("NERC") procedures, as well as its own procedures and plans which it is required by NERC to maintain. Some of the actions are required by MISO or NERC and others will be taken when deemed necessary by the Company. The tariff also includes provisions for notification of Staff as specific events occur.

9. Staff also recommended that "Ameren Missouri begin developing specific plans to minimize risk to the St. Louis Metro area." As stated in its previous reports, the Company is and has been looking to identify specific steps to minimize reliability risk to all of its territory, but since the identified reliability risks are in the St. Louis metro area, the bulk of its work has focused on mitigation needs for the St. Louis metro. This is the focus of the MISO Y2 and Y processes and of the mitigation measures necessary to address the identified concerns. Ameren Missouri believes it has always focused on this aspect but if Staff has more specific concerns that it would like addressed, the Company welcomes a conversation with the appropriate personnel.

10. Staff also recommended the Company examine its demand response programs and other load management programs to mitigate reliability concerns. Ameren Missouri's transmission planning group looked at the specific locations which have reliability risk as identified in the MISO Attachment Y2 and Attachment Y Reports. As a result of that review, the Company does not believe that demand response or other load management is a viable, non-emergency solution to these specific problems. To avoid losing the substation in Wildwood, for example, the Company would have to have a program that removed all load from that substation. Which would have the same impact as the reliability event itself, meaning it is not a viable solution.

Actions from Commission's May 4, 2022, Order

11. The Commission's May 4, 2022, order requires Ameren Missouri to respond to the 2022/2023 MISO Planning Resource ("PRA") Auction results. On May 19, 2022, Ameren Missouri met in person with Staff and the Office of Public Counsel ("OPC") to discuss the MISO PRA and the implications of that auction on generation reliability for 2022 and 2023. Staff and OPC have the document from that presentation.

WHEREFORE, Ameren Missouri requests the Missouri Public Service Commission accept this filing as compliant with the order to file monthly status reports.

Respectfully submitted,

/s/ Wendy K. Tatro

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served on the Missouri Public Service Commission Staff and the Office of the Public Counsel via electronic mail (e-mail) or via regular mail on this 15th day of June, 2022.

/s/ Wendy K. Tatro
Wendy K. Tatro

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Attachment Y Study Report

Union Electric Company – Ameren Missouri
Rush Island 1 and 2: 1195 MW
Start Date: September 1, 2022

June 8, 2022

MISO

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EXECUTIVE SUMMARY

On February 28, 2022, Union Electric Company – Ameren Missouri submitted an Attachment Y notice to *MISO* for the suspension of Rush Island Units 1 and 2 effective September 1, 2022.

MISO performed a Transmission System reliability assessment of Rush Island 1 and 2 set forth in the MISO Business Practices Manuals and was discussed and reviewed with the impacted Transmission Owners (TOs): *Ameren Missouri, Ameren Illinois, South Illinois Power Cooperative, and Wabash Valley Power Alliance.*

After being reviewed for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), the analysis determined that there are reliability issues identified related to the suspension of *Rush Island* that may require the generators to be designated as a System Support Resources ("SSR") units following the stakeholder process.

There were both severe steady state and transient voltage recovery (TVR) violations that may require the generators to be designated SSR units. In the summer peak case, there were five stability violations that did not meet Ameren voltage recovery criteria and would result in over 1,000 MW of load loss, which, if allowed, would be considered a potential Interconnection Reliability Operating Limit (IROL) within the MISO footprint in accordance with BPM-020 Section L.3.6. All voltage violations seen can be mitigated with load shed per MISO SSR criteria and additionally per WVPA there already exists operating guides to mitigate the known issues.

Prior to this Attachment Y, MISO also studied an Attachment Y-2 submitted by Union Electric Company – Ameren Missouri. This study had an effective date of June 1, 2023, but there were no other changes to study assumptions or system topology between the time the Attachment Y was submitted and the final Y-2 report. Therefore, the results of the Attachment Y-2 study will also be used to determine SSR need. The Attachment Y-2 report is included as an Appendix to this Attachment Y report. Three thermal violations were identified in three different scenarios in 2023 that require mitigation based on Ameren's Local Planning Criteria and one steady state voltage violation was identified for the winter peak case in 2023 and several stability voltage violations were identified for the summer peak case in 2023 that may require *Rush Island* to be designated as System Support Resources ("SSR") units following the stakeholder process.

The transmission system was also evaluated for Ameren Local Planning Criteria with two different scenarios including non-coincident peak loads in Ameren territory and Winter Storm Uri. The results show thermal violations that would require mitigation, but these violations should not be utilized in designating Rush Island generation as an SSR.

In addition, MISO performed an analysis to determine if both units are required to mitigate the violations identified. That analysis determined that with one unit online, violations still exist that may require *Rush Island* to be designated as System Support Resources ("SSR") units.

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Table I-1: Overview of SSR Violations for Rush Island Attachment Y

Study	Year	Scenario	Steady State - Thermal Analysis	Steady State - Voltage Analysis	Stability Analysis
Attachment Y	2022	Summer Shoulder	No violations that met criteria	No violations that met criteria	No TVR violations met criteria
		Summer Peak	No violations that met criteria	Voltage violations can be mitigated per the MISO SSR Criteria	TVR violations that result in greater than 1,000 MW of load loss
		Summer low Load	No violations that met criteria	Voltage violations can be mitigated per the MISO SSR Criteria	No TVR violations met criteria
		Winter Peak	No violations that met criteria	Voltage violations can be mitigated per the MISO SSR Criteria	No TVR violations met criteria
Attachment Y-2	2023	Summer Shoulder	No violations that met criteria	Voltage violations can be mitigated per the MISO SSR Criteria	No TVR violations met criteria
		Summer Peak	Thermal violations can be mitigated per the MISO SSR Criteria, but need mitigation as per Ameren's LPC.	Voltage violations can be mitigated per the MISO SSR Criteria	TVR violations that result in greater than 1,000 MW of load loss
		Summer Low Load	Thermal violations can be mitigated per the MISO SSR Criteria, but need mitigation as per Ameren's LPC.	Voltage violations can be mitigated per the MISO SSR Criteria	No TVR violations met criteria
		Winter Peak	Thermal violations can be mitigated per the MISO SSR Criteria, but need mitigation as per Ameren's LPC.	P12 violation that cannot be mitigated per the MISO SSR Criteria	No TVR violations met criteria
	2031	Summer Peak	No violations that met criteria	No violations that met criteria	N/A

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TABLE OF CONTENTS

PUBLIC

1. INTRODUCTION

The Market Participant *Union Electric Company – Ameren Missouri* submitted an Attachment Y notice to *MISO* on February 28, 2022 for the suspension of *Rush Island 1 and 2* effective September 1, 2022.

The total capacity of *Rush Island* is 1195 MW based on its Generator Verification Test Capacity (GVTC) Value. It is connected to the 345 kV transmission systems, and is located in Festus, MO.

1-I Study Unit

Power Flow Area	Unit Description	kV Network[1]	Total MW[2]	Start Date
AMMO	Rush Island Unit 1	345	597.2	09/01/2022
AMMO	Rush Island Unit 2	345	597.8	09/01/2022
Total			**1,195**	

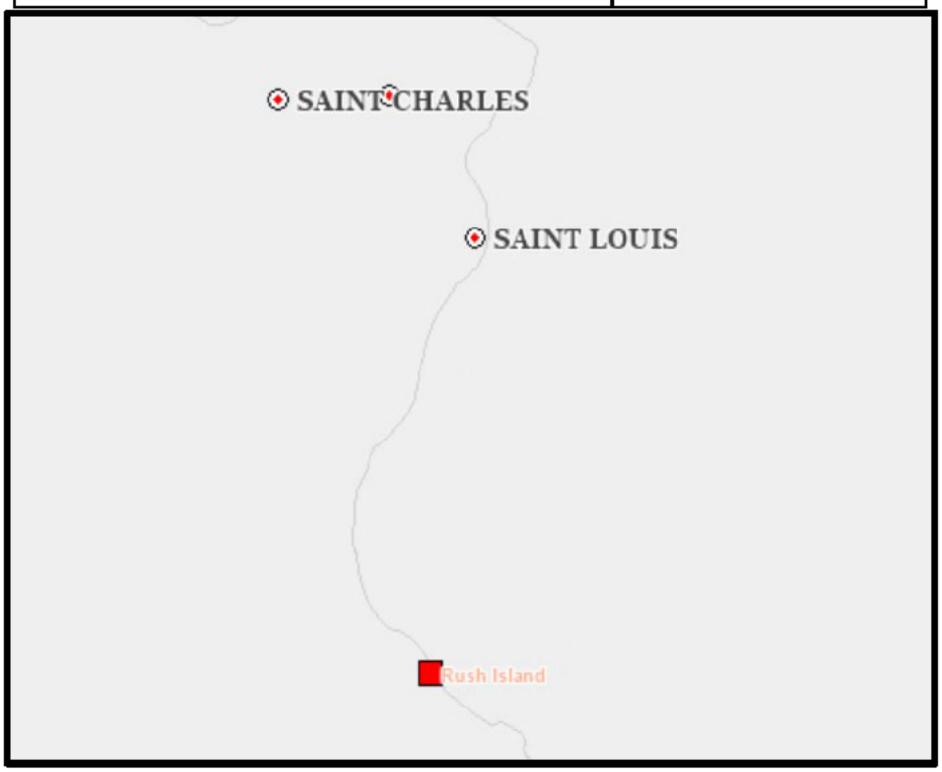

Figure 1: General Location Rush Island Generating Station

[1] In study models
[2] Generator Verification Test Capacity (GVTC) Value. Auxiliary Loads of Study Units will not be modelled. These values are the Net MW Output.

2. STUDY OBJECTIVE

Under Section 38.2.7 of MISO's Tariff, SSR procedures maintain system reliability by providing a mechanism for MISO to enter into agreements with Market Participants (MP) that own or operate Generation Resources or Synchronous Condenser Units (SCUs) that have requested to either Retire or Suspend, but are required to maintain system reliability.

The principal objective of an Attachment Y study is to determine if the unit(s) for which a change in status requested is necessary for system reliability based on the criteria set forth in the MISO Business Practices Manuals. The study work included monitoring and identifying the steady state branch/voltage violations on transmission facilities due to the unavailability of the Generation Resource or SCU. The relevant MISO Transmission Owner(s) and/or regional reliability criteria are used for monitoring such violations.

The purpose of this study is to assess the reliability impacts from the suspension of *Rush Island 1 and 2* located in Festus, MO effective September 1, 2022.

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3. STUDY ASSUMPTIONS & INPUTS

3.1 Study Models

Studies performed using the following power flow models:

- The near-term starting models will be from the MISO MTEP21 2022 case, changes will be made to the models to reflect system topology for the start date of the generation's change of status request:
  - 2022 Summer Shoulder (Source: MISO21_2022_SHAW_TA)
  - 2022 Summer Peak (Source: MISO21_2022_SUM_TA)
  - 2022 Summer Low Load (Source: MISO21_2022_SLL40_TA)
  - 2022 Winter Peak (Source: MISO21_2022_WIN_TA)

- Results from the out-term case in the recently complete Attachment Y-2 Study regarding Rush Island Units 1 and 2 were used to satisfy the Attachment Y out term model requirement. Please refer to Appendix 10.4 for model and assumptions information.

For each model, two scenarios were created which represent the "before" and "after" generator change of status.

3-I Study Models

Model Name	Loads	Topology	Study Unit(s)	Dispatch Type[3]	Contingencies Category
2022SH_RUSH_ISLAND_OFF	Summer Shoulder	2022	OFF	SCED	P1,P2,P4,P5,P7, Selected P3, P6
2022SH_RUSH_ISLAND_ON	Summer Shoulder	2022	ON	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6
2022SP_RUSH_ISLAND_OFF	Summer Peak	2022	OFF	SCED	P1,P2,P4,P5,P7, Selected P3, P6
2022SP_RUSH_ISLAND_ON	Summer Peak	2022	ON	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6
2022SL_RUSH_ISLAND_ON	Summer Low Load	2022	ON	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6
2022SL_RUSH_ISLAND_ON	Summer Low Load	2022	ON	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6

[3] Dispatching according to procedure explained in BPM-020. "SCED + Scale" in the online cases means that all generators in the vicinity of the generator under study will remain dispatched at their SCED values identified in the corresponding offline case, and the rest of MISO will be scaled down to balance the overall generation in MISO after turning on the study units.

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2022WP_RUSH_ISLAND_OFF	Winter Peak	2022	OFF	SCED	P1,P2,P4,P5,P7, Selected P3, P6
2022WP_RUSH_ISLAND_ON	Winter Peak	2022	ON	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6

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3.2 Study Assumptions

3.2.1 Generation

- All applicable approved Attachment Y (Retirement/Suspension) generators were modelled offline
- Only new generators with signed GIA were modelled.

3-II Generation Assumptions

Generation Type	Unit(s) Description	2022
Nearby Approved Attachment Y	[redacted]	[redacted]
	Dallman 31 and 32	Offline
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]

3.2.2 Transmission

A Future Projects included in 2022 study models

3-III Future Projects in Models

MOD Project Name	MOD ID	Project Type	Status	MOD Effective Date
AM_GrandTower-Retire-ATT-Y	120771	Generator	Planned	6/1/2019
AM_Shelbyville Retirement	120773	Generator	Planned	6/1/2019
AM_MB-20 Richwoods Renewable	129513	Generator	Planned	6/1/2020
AM_MB-21 Utica at Lathrop	129515	Generator	Planned	6/1/2020
AM_MB-22 Green City Renewable at Kirksville	129517	Generator	Planned	6/1/2020
AM_DG18004 Salem Solar 10.5 MW	129501	Generator	Planned	12/1/2020
AM-TP1229-16794-Cahokia-Meramec	134872	MTEP A	Planned	12/1/2020
TP-961-11973-Cane-Grand Island Switching Station	23479	MTEP C	Target MTEP A	12/31/2020
AM-TP1288-16549-Lincoln-Meister	134333	Non-MISO Network	Planned	12/31/2020
AM_DG_DG17004 Duupue Substation 20 MW solar	129497	Generator	Planned	3/31/2021
AM-TP131-3033-Beehive substation	24625	MTEP A	Planned	7/13/2021

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MOD Project Name	MOD ID	Project Type	Status	MOD Effective Date
AM-TP131-3033-Beehive substation	24625	MTEP A	Planned	7/13/2021
AM-TP131-3033-Beehive substation	24625	MTEP A	Planned	7/13/2021
AM-TP131-3033-Beehive substation	24625	MTEP A	Planned	7/13/2021
AM_TPSIRP005-11929 N Coult 230-345 conv	24775	MTEP A	Planned	10/2/2021
AM-TP1295-17324-J1055-GLACIER WF	129346	Generator	Planned	10/15/2021
AM-BASECASE-MACHINE DATA-UPDATES_ALSEY-G2-MOD32	148562	Generator	In Service	10/25/2021
AM-BASECASE-MACHINE DATA-UPDATES_G545	148564	Generator	In Service	10/25/2021
AM-TP1392-18311-J813	129475	Generator	Planned	10/31/2021
AM-TP1443-Upgrade Casey West-Sullivan 345 kV line	142114	Generator	Planned	10/31/2021
AM-TP1028-13795-Cahokia-Roxford	119150	MTEP A	Planned	11/1/2021
AM-J845-TP1400-18321-Ford WF	131740	Generator	Planned	11/1/2021
AM-TP970-12964-Boar Substation	23693	MTEP A	Planned	12/1/2021
AM-TPSIRP004-11928-Commodore 230-345kV conversion	24771	MTEP A	Planned	12/1/2021
AM-TP928-11966-Gateway Substation	25364	MTEP A	Planned	12/1/2021
AM-TP1024-15524-Sioux 345-138kV TX Replacement	118098	MTEP A	Planned	12/1/2021
AM-TP1121-16491-Sioux_Meppen-Sioux-Huster	120183	MTEP A	Planned	12/1/2021
AM-TP1129-16554-Maline	120206	MTEP A	Planned	12/1/2021
AM-TP1184-7862-Galena	120899	MTEP A	Planned	12/1/2021
AM-TP1133-17065-Tegler Breakers	123802	MTEP A	Planned	12/1/2021
AM-TP597-17224-Pershall substation	123814	MTEP A	Planned	12/1/2021
AM_DG_DG18003-Canton South	129499	Generator	Planned	12/1/2021
AM-TP1273-16709-Venice-ashely	130548	MTEP A	Planned	12/1/2021
AM-TP868-9733-Page Over stress breakers	130568	MTEP B	Target MTEP A	12/1/2021
AM-TP1291-11951-J800 BMTWN solar	134381	Generator	Planned	12/1/2021
AM-TP1047-17344-Berkeley sub repl brkers	140613	MTEP A	Planned	12/1/2021
AM-TP1257-15329-St Franc-Rivermines-2-Rebuild	140709	MTEP A	Planned	12/1/2021

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MOD Project Name	MOD ID	Project Type	Status	MOD Effective Date
AM-TP1020-17829 Loose Creek Reactor	130604	MTEP A	Planned	12/2/2021
AM_TP866_9732-Mason Breaker replacement	119545	MTEP A	Planned	12/8/2021
AM-TP1256-16227 Marblehead Terminal upgrade	119619	MTEP A	Planned	12/8/2021
AM-TP1442-J1102-20905-Mulligan Solar	143348	Generator	Planned	12/21/2021
AM-TP1158-16793-Montgomery B12 upgrade	144064	MTEP A	Planned	12/30/2021
AM-TP1305-17665-Barrett Station 2nd TX	129914	MTEP A	Planned	12/31/2021
AM-TP1395-18315-J844-Sandburg WF	130902	Generator	Planned	5/1/2022
AM-TP1394-18314-J826 McLean WF	131119	Generator	Planned	5/1/2022
AM-TP1401-18322-J848	134029	Generator	Planned	5/28/2022
AM-TP938-11947-Greenback Substation	24560	MTEP A	Planned	6/1/2022
AM-TP965-12173-Miller substation	24680	MTEP A	Planned	6/1/2022
AM-TP974-15528-Dirksen	108686	MTEP A	Planned	6/1/2022
AM-TP891-9830-Meramec-Jachim	125768	MTEP A	Planned	6/1/2022
AM-TP1269-16705-Pana-Shelbyville Rebuild	130545	MTEP A	Planned	6/1/2022
AM-MB23-9843_20365-Normal E 138/69kV TX	136900	MTEP A	Planned	6/1/2022
AM-TP1416-19085-Shelbyville ring bus	139300	MTEP A	Planned	6/1/2022
AM-TP1433-19968-J1025-Fabius Substation	140454	Generator	Planned	6/1/2022
AM-TP1283-16990-Kline Ring Bus	141043	MTEP A	Planned	6/1/2022
AM-TP1359-18085-Tazewell XFMR 1 Replacement	141208	MTEP A	Planned	6/1/2022
AM-TP1339-18034-Tazewell Bkr Replacements	141475	MTEP A	Planned	6/1/2022
AM-TP735-17644-Rt51 sub	141497	MTEP A	Planned	6/1/2022
AM-TP1351-18074-Jacksonville IP BKR 1302	142254	MTEP A	Planned	6/1/2022
AM-TP914-11906-Casey West-Kansas 345 kV Line	142257	MTEP A	Planned	6/1/2022
AM-TP1458-21325-Rossville-Vermilion-Rebuild	144695	MTEP B	Target MTEP A	6/1/2022
AM-TP1381-18250-Robinson STATCOM	130919	MTEP A	Planned	6/2/2022
AM-TP1145-15490-Rador Breaker Additions	141484	MTEP A	Planned	6/2/2022
AM_DG18005 - Pilot Grove Solar 25 MW hamilton	129503	Generator	Planned	6/30/2022
AM_DG18006 Blue Willow Solar 25 MW Blandsville	129505	Generator	Planned	6/30/2022

3.3 Monitoring and contingencies

3.3.1 Monitor

Monitor all 100 kV and above facilities in areas AECI, SIPC, AMMO, and AMIL.

3.3.2 Contingencies

NERC Category P1, P2, P4, P5, and P7 used in MTEP21 study of facilities within areas AECI, SIPC, AMMO, and AMIL.

Category P3 contingencies were created using all single generator contingencies (P1-1), extracted from the P1 contingencies provided above, combined with all P1 contingencies provided above. To limit the number of possible P3 combinations:

- Only Category P1 events of facilities 100 kV or above within 8 (eight) Buses from the Study Unit(s) were used in creating the required P3 combinations.
- Generator contingencies (Category P1-1) with aggregated generation above 50 MW were used in creating the required P3 contingencies.

Similarly, Category P6 contingencies were created using all non-generator contingencies (P1-2 to P1-5) of facilities 100 kV or above within 8 (eight) Buses from the Study Unit(s).

Per Ameren Local Planning Criteria additional system sensitivity analysis was also performed.

- Non-coincident peak load in the Summer Peak case
- Winter Storm Uri scenario from February 15, 2021, using the State Estimator Model
    - Additional contingencies run by Ameren Transmission were also added to this analysis

4. STUDY CRITERIA

4.1 Applicable Reliability Criteria

4.1.1 Steady State Thermal Reliability Criteria

Ameren Transmission Planning Criteria applied for thermal analysis:

- For System Intact (NERC Category P0), all thermal loadings within 95% of the normal rating.
- For NERC Category P1-P7 contingencies, all thermal loadings within 95% of the emergency rating.

Southern Illinois Power Cooperative Transmission Planning Criteria applied for thermal analysis:

- For System Intact (NERC Category P0), all thermal loadings within 100% of the normal rating.
- For NERC Category P1-P7 contingencies, all thermal loadings within 100% of the emergency rating.

4.1.2 Steady State Voltage Reliability Criteria

Ameren Transmission Planning Criteria applied for voltage analysis:

- For NERC Category P0 (System Intact) – Pre Contingent
- For NERC Category P1-P7 contingencies – Post Contingent

Rated Voltage	Pre Contingent		Post Contingent	
	Min PU	Max PU	Min PU	Max PU
345	0.95	1.05	0.95	1.075
230, 161, 138	0.95	1.05	0.93	1.075

Southern Illinois Power Cooperative Transmission Planning Criteria applied for voltage analysis:

- For NERC Category P0 (System Intact) – Pre Contingent
- For NERC Category P1-P7 contingencies – Post Contingent

Rated Voltage	Pre Contingent		Post Contingent	
	Min PU	Max PU	Min PU	Max PU
All	0.95	1.07	0.91	1.09

4.1.3 Stability Analysis Monitored Facilities and Performance Criteria

MISO will monitor all generators and buses within the AMMO and AMIL control area. Simulation results will be interpreted and compiled against MISO planning criteria.

The following criteria will be used to evaluate the simulation results:

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- All on-line generating units are stable
- No unexpected generator tripping
- Post-fault transient voltage limits: 1.2 per unit maximum, 0.7 per unit minimum
- Post-fault steady-state voltage limits: 1.1 per unit maximum, 0.9 per unit minimum
- All machine rotor angle oscillations must be positively damped with a minimum damping ratio of 0.81633% for disturbances with a fault or 1.6766% for line trips without a fault
- Ameren transient voltage recovery criteria:
  - Following the clearing of a fault resulting from single or multiple contingency events (Planning Events P1- P7), transmission voltages should return to 80% of nominal or greater within two seconds and 90 % of nominal or greater within ten seconds unless the system becomes radial following the outage of multiple contingencies.
  - Small signal analysis would show satisfactorily damped post-disturbance response with damping ratios of 3% or higher with modelled excitation system parameters based on field-tested data. Otherwise, damping ratios of 5% or greater would demonstrate satisfactory damping.
- Local Planning Criteria, if applicable as determined by the Transmission Owner

4.2 MISO Transmission Planning BPM SSR Criteria

In accordance with MISO BPM-020, System Support Resource (SSR) criteria for determining if an identified facility is impacted by the generator change of status are:

- Under NERC Category P0 conditions and category P1-P7 contingencies, branch thermal violations are only valid if the flow increase on the element in the “after” retirement scenario is equal to or greater than:
  - Five percent (5%) of the “to-be-retired” unit(s) MW amount (i.e. 5% PTDF) for a “base” violation compared with the “before” scenario, or
  - Three percent (3%) of the “to-be-retired” unit(s) MW amount (i.e. 3% OTDF) for a “contingency” violation compared with the “before” scenario.
- Under NERC category P0 conditions and category P1-P7 contingencies, high and low voltage violations are only valid if the change in voltage is greater than one percent (1%) as compared to the “before” scenario

Available mitigation may be applied for the valid NERC Category P1-P7 thermal and voltage violations describe above as allowed by NERC Standards.

- The need for the SSR is determined by the presence of unresolved violations of reliability criteria that can only be alleviated by the SSR generator and where no other mitigation is available.
- Evaluation of mitigation solutions will consider the use of operating procedures and practices such as equipment switching and post-contingent Load Shedding plans allowed in the operating horizon.

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Ameren LPC will also be accounted for when determining if the facility will be required as an SSR and when determining potential mitigations for identified violations.

5. STUDY METHODOLOGY

5.1 Steady-State Performance Analysis

PTI – PSS/E version 34 and PowerGEM – TARA version 2102.1 were used to perform AC contingency analysis and SCED. Cases were solved with automatic control of LTCs, phase shifters, DC taps, switched shunts enabled (regulating), and area interchange disabled. Contingency analysis was performed on before and after cases. The results were compared to find if there were any criteria violations due to the unit(s) change of status.

5.2 Stability Analysis

MISO's stability analysis examined the impact of the Retiring Generating Facility by evaluating local and regional stability performance on the MISO transmission system in the Bench and Study cases. The most recent dynamics data from Ameren was used to develop these cases. DSATools – TSAT and PowerGEM – TARA was used to perform transient thermal and voltage analyses respectively. Fault analysis was performed on bench and study cases for the fault lists as specified by Ameren. The results were compared to find if there are any criteria violations due to the unit(s) change of status.

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6. STABILTIY RESULTS

MISO's stability analysis identified violations that result in the loss of load due to Transient Voltage Recovery (TVR) issues with the suspension of *Rush Island 1 and 2*, including several scenarios that result in cascading voltage issues and loss of load. Detailed below are the contingencies with the most severe impact on the transmission system due to the suspension of *Rush Island 1 and 2*. Appendix 10.1 includes further information and the full results of MISO's stability study.

6.1.1 2022 Summer Shoulder TVR Issues

- No TVR violations met MISO or Ameren LPC criteria within the study area

6.1.2 2022 Summer Low Load TVR Issues

- No TVR violations met MISO or Ameren LPC criteria within the study area

6.1.3 2022 Winter Peak TVR Issues

- No TVR violations met MISO or Ameren LPC criteria within the study area

6.1.4 2022 Summer Peak TVR Issues

- The TVR violations reported in Table 7-I detail the most severe violations for the 2022 Summer Peak case.

6-I Top Voltage Violations 2022 Summer Peak Offline Case

Con Name	Monitored Bus	Vmin	Voltage Threshold	Duration	Time Threshold	Load At Risk
[redacted]	345156	0.7616	0.9000	5.517	3.000	1031 MW
[redacted]	345156	0.7612	0.9000	5.004	3.000	1017 MW
[redacted]	345156	0.7606	0.9000	3.4	3.000	1032 MW
[redacted]	345156	0.7613	0.9000	3.4	3.000	1023 MW
[redacted]	345148	0.7525	0.9000	3.284	3.000	1119 MW

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7. STEADY STATE RESULTS

Appendices 10.2 of this report includes all constrained elements impacted by the suspension of *Rush Island*.

7.1 2022 Summer Shoulder Analysis

Analysis of the 2022 Summer Shoulder case identified the following

7.1.1 2022 Summer Shoulder Post Contingent Thermal Overloads

- No thermal overloads met the MISO SSR criteria
  - ≥ 3% OTDF or ≥ 5% PTDF of the study unit

7.1.2 2022 Summer Shoulder Post Contingent Voltage Issues

- No voltage violations met the MISO SSR criteria
  - ≥ +/- 1% adverse impact of study unit

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7.2 2022 Summer Low Load Analysis

Analysis of the 2022 Summer Low Load case identified the following

7.2.1 2022 Summer Low Load Post Contingent Thermal Overloads

- No thermal overloads met the MISO SSR criteria
  - ≥ 3% OTDF or ≥ 5% PTDF of the study unit

7.2.2 2022 Summer Low Load Post Contingent Voltage Issues

- The top post contingent voltage issues reported in Table 6-IV met the MISO SSR criteria
  - +/- 1% adverse impact of study unit
- All post contingent voltage issues that met the MISO SSR Criteria can be mitigated
  - Details are provided in Appendix 10.2
- Pre-Existing and Non-SSR issues are provided for informational purposes

7-I Top Post Contingent Voltage Issues 2022 Summer Low Load Offline Case

Area Name	Monitored Bus	Voltage [ON]	Voltage [OFF]	Voltage [DIF] (>1%)
AMMO	345301	0.9368	0.9231	-0.0137
AMMO	345302	0.9368	0.9231	-0.0137
AMMO	345301	0.9368	0.9231	-0.0137
AMMO	345302	0.9368	0.9231	-0.0137
AMMO	345305	0.9368	0.9231	-0.0137
AMMO	345305	0.9368	0.9231	-0.0137

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7.3 2022 Summer Peak Analysis

Analysis of the 2022 Summer Peak case identified the following

7.3.1 2022 Summer Peak Post Contingent Thermal Overloads

- No thermal overloads met the MISO SSR criteria
  - ≥ 3% OTDF or ≥ 5% PTDF of the study unit

7.3.2 2022 Summer Peak Post Contingent Voltage Issues

- The top post contingent voltage issues reported in Table 6-VI met the MISO SSR criteria
  - +/- 1% adverse impact of study unit
- All post contingent voltage issues that met the MISO SSR Criteria can be mitigated
  - Details are provided in Appendix 10.2
- Pre-Existing and Non-SSR issues are provided for informational purposes

7-II Top Post Contingent Voltage Issues 2022 Summer Peak Offline Case

Area Name	Monitored Bus	Voltage [ON]	Voltage [OFF]	Voltage [DIF] (>1%)
AMMO	345310	0.9404	0.9263	-0.0141
AMMO	345310	0.9404	0.9266	-0.0138
AMMO	345485	0.9362	0.9233	-0.0129
AMMO	345486	0.9362	0.9233	-0.0129
AMMO	345489	0.9362	0.9233	-0.0129

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7.4 2022 Winter Peak Analysis

Analysis of the 2022 Summer Peak case identified the following

7.4.1 2022 Winter Peak Post Contingent Thermal Overloads

- No thermal overloads met the MISO SSR criteria
    - ≥ 3% OTDF or ≥ 5% PTDF of the study unit

7.4.2 2022 Winter Peak Post Contingent Voltage Issues

- The top post contingent voltage issues reported in Table 6-VI met the MISO SSR criteria
    - +/- 1% adverse impact of study unit
- All post contingent voltage issues that met the MISO SSR Criteria can be mitigated
    - Details are provided in Appendix 8.2
- Pre-Existing and Non-SSR issues are provided for informational purposes

7-III Top Post Contingent Voltage Issues 2022 Winter Peak Offline Case

Area Name	Monitored Bus	Voltage [ON]	Voltage [OFF]	Voltage [DIF] (>1%)
AMMO	344099	0.9354	0.9253	-0.0101
AMMO	344094	0.9354	0.9253	-0.0101
AMMO	345301	0.9315	0.9214	-0.0101
AMMO	345302	0.9315	0.9214	-0.0101
AMMO	345305	0.9315	0.9214	-0.0101
AMMO	345485	0.9397	0.927	-0.0127
AMMO	345485	0.9397	0.927	-0.0127
AMMO	345486	0.9397	0.9269	-0.0128
AMMO	345486	0.9397	0.9269	-0.0128
AMMO	345489	0.9397	0.9269	-0.0128
AMMO	345489	0.9397	0.9269	-0.0128

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8. LOCAL PLANNING CRITERIA ANALYSIS

Ameren Local Planning Criteria and NERC TPL standards require that the transmission system be evaluated under NERC Category P0 through P7 contingencies for core scenarios involving Summer Peak, Light Load, Winter Peak and Summer Shoulder Scenarios. MISO's Attachment Y and Y2 results indicate that there would be both thermal and Voltage violations for these core scenarios which may require Rush Island generation to be designated as SSR until those violations are mitigated. Here are the four violations in three different scenarios that require mitigation.

1. Winter Peak Scenario: Wildwood 345 /138 kV transformer would overload for the [redacted] with Rush Island generation offline. Ameren's LPC in section 2.2.2.1 requires that no interruption of firm transmission service will be permitted for P6 outages involving two 345 kV lines. Apart from thermal violation, under winter peak scenario there was a Voltage violation at Overton 345 kV substation for the [redacted] which will require a mitigation as per the NERC standards and Ameren LPC.
2. Summer Light Load Scenario: Rush Island 345 kV bus tie would overload for the [redacted] with Rush Island generation offline. This overload needs to be mitigated as per Ameren's LPC.
3. Summer Peak Scenario: Moro – Laclede North section of Wood River – North Staunton 138 kV line would overload for the [redacted] This violation needs to be mitigated as per Ameren's LPC and NERC TPL standard. After the Rush Island Y2 report has been published Ameren has aligned the In Service Dates of the Moro Project (MISO Project id# 11948) and Roxford Transformer addition (MISO Project Id#19988) which would mitigate the thermal violation on this 138 kV line.

Apart from core scenarios mentioned above, Ameren's Local Planning Criteria (LPC) and NERC Transmission Planning standards also require that assessments of the transmission system be made with wide ranging scenarios from system peak load to various weather sensitivities. For this Attachment Y study, Ameren Transmission team suggested to consider two specific scenarios on top of the core scenarios that were considered, these include Non-Coincident 1 day in 10 year peak load and Winter Storm Uri.

Ameren recognizes that the issues identified under the Ameren's Local Planning Criteria are sensitivity scenarios that needs mitigation but should not be utilized for the designation of the Rush Island as an SSR.

Ameren Transmission team working with MISO evaluated the impact of Rush Island generation retirement under these scenarios and the results are included in Appendix 10.3.

Non-Coincident peak load scenario:

In this scenario, non-coincident peak loads were utilized for the Ameren Missouri and Ameren Illinois control areas instead of MISO coincident peak load. The rationale for choosing this

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scenario was to test the impact of Rush Island retirement during summer peak conditions as the weather in the St. Louis Metropolitan area has historically shown hotter conditions compared to the rest of MISO. Ameren believes that this is a high likely scenario and recommended that this scenario be evaluated with Rush Island Generation offline. The results of this scenario indicate that there could be voltage issues in the St. Louis Metro East and Metro South regions under single contingency (N-1) conditions.

For the outage of [redacted] the voltage at Dupo Ferry, Valmeyer and Selma substations could drop below acceptable levels without Rush Island generation. These voltages are below acceptable values from Ameren's planning criteria and will require a mitigation.

Winter Storm Uri Scenario:

Ameren requested MISO team to consider impact of Rush Island generation offline during Winter Storm Uri as the second sensitivity scenario. MISO utilized state estimator model to evaluate this scenario, and when Rush Island generation was turned offline the power flow case became unstable. MISO had to dispatch Callaway generation even though this plant was offline during Winter Storm Uri. The instability in the power flow case indicates that there is a potential for a local area collapse if Rush Island generation would have been offline during this time. The local area collapse could exceed 1500 MW in the St. Louis metro area and could have affected significant number of customers in both Ameren Missouri and Ameren Illinois.

The results of the analysis showed multiple thermal issues for NERC Category P3 (N-1 + Generator) and significant number of thermal issues (more than 80 unique overloads) for category P6 (N-1-1) contingency events. Ameren recommends that the issues identified for NERC P1 (N-1) and P3 (N-1+ Generator) events be mitigated for this scenario.

There was a total of nine thermal issues identified under P1 and P3 events, out which five of them could be mitigated either with projects currently under construction or with projects that are in advanced stages of planning like MISO LRTP Tranche 1. There are four thermal violations that Ameren recommends be mitigated which include the overloads on

(1) Effingham NW – Neoga South 138 kV line
(2) Hannibal West – Palmyra 161 kV line
(3) Spalding – Hannibal West 161 kV line
(4) Coffeen North – Roxford 345 kV line.

9. CONCLUSION

After being reviewed for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), the analysis determined that there are reliability issues identified related to the suspension of *Rush Island* that may require the generators to be designated as System Support Resources ("SSR") units following the stakeholder process.

There were both severe steady state and transient voltage recovery (TVR) violations that would require the generators to be designated SSR units. In the summer peak case, there were five stability violations that did not meet Ameren voltage recovery criteria and would result in over 1,000 MW of load loss, which, if allowed, would be considered a potential Interconnection Reliability Operating Limit (IROL) within the MISO footprint in accordance with BPM-020 Section L.3.6. All voltage violations seen can be mitigated with load shed per MISO SSR criteria and additionally per WVPA there already exists operating guides to mitigate the known issues.

Prior to this Attachment Y, MISO also studied an Attachment Y-2 submitted by Union Electric Company – Ameren Missouri. This study had an effective date of June 1, 2023, but there were no other changes to study assumptions or system topology between the time the Attachment Y was submitted and the final Y-2 report. Therefore, the results of the Attachment Y-2 study will also be used to determine SSR need. The Attachment Y-2 report is included as an Appendix to this Attachment Y report. Three thermal violations were identified in three different scenarios in 2023 that require mitigation based on Ameren's Local Planning Criteria and one steady state voltage violation was identified for the winter peak case in 2023 and several stability voltage violations were identified for the summer peak case in 2023 that may require *Rush Island* to be designated as System Support Resources ("SSR") units following the stakeholder process.

In addition, MISO performed an analysis to determine if both units are required to mitigate the violations identified. That analysis determined that with one unit online, violations still exist that may require *Rush Island* to be designated as System Support Resources ("SSR") units.

10. APPENDICES

10.1 Stability Study Results

Appendix 10.1 is attached to this report.

10.2 Steady State Study Results

Appendix 10.2 is attached to this report

10.3 Sensitivity Study Results

Appendix 10.3 is attached to this report. For the Winter Storm Uri case, the files with the format “Winter_Storm_Uri_[Result Type]” were run by MISO and the file labelled with “Ameren” was run by Ameren. For the Non-Coincident Load case, the file labelled “2022SP_NC” is the transient voltage recovery analysis results and the files with the format “Non-Coincident_Load_[Result Type]” are the steady state analysis results.

10.4 Attachment Y-2 Report

Appendix 10.4 is attached to this report.

10.5 Possible SSR Mitigations Analysis

10.5.1 Overview

Additional mitigation analysis was also conducted for this study to determine whether both units are needed for grid reliability. The analysis determined that there are reliability issues identified related to the suspension of *Rush Island* that would require both generators to be designated as a System Support Resources ("SSR") units. There still exists one TVR violation that did not meet Ameren voltage recovery criteria and would result in over 1,000 MW load loss. Further details regarding this analysis are provided in Appendix 10.5.2.

10.5.2 SSR Mitigation Analysis Results

Appendix 10.5.2 is attached to this report.

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

UNITED STATES OF AMERICA, Plaintiff, SIERRA CLUB, Plaintiff-Intervenor, v. AMEREN MISSOURI, Defendant.	Civil Action No. 4:11-cv-00077-RWS

AMEREN'S SUPPLEMENTAL BRIEF IN SUPPORT OF ITS
MOTION TO MODIFY THE COURT'S REMEDY RULING

Ameren Missouri ("Ameren") submits this supplemental brief in support of its Motion to Modify Remedy Ruling (ECF #1196, the "Motion").

Ameren's Motion requests modification of the Court's Remedy Ruling to allow Ameren to retire the Rush Island Energy Center ("Rush Island") in lieu of installing wet flue gas desulfurization ("FGD") technology. Retiring Rush Island, rather than installing FGD and continuing operation for decades to come, will eliminate *all* emissions from the plant, including all emissions of sulfur dioxide (SO2), carbon dioxide (CO2), nitrogen oxides (NOx), particulate matter (PM), and mercury (Hg), resulting in substantial overall emissions reductions compared to continuing operation of the plant with the FGD that would occur under the Remedy Ruling. The resulting environmental benefits to the public will be enormous—elimination of over 100 million metric tonnes of CO2, tens of thousands of tons of NOx, hundreds of pounds of Hg, and thousands of tons of SO2 that would have been emitted if the FGD had been installed. There is no disagreement among the parties that modifying the Remedy Ruling to allow for Rush Island's retirement is in the public interest.[1]

There also is no disagreement that the Midcontinent Independent System Operator, Inc. ("MISO") must approve both Rush Island's retirement and the timing of its retirement, to ensure that the reliability of the transmission system will be maintained and will not be compromised as a result. This, too, is in the public interest. Congress has declared that "the transmission of electric energy . . . is necessary in the public interest," 16 U.S.C. § 824(a), and MISO therefore "evaluates the importance of the would-be retired facility and may require continued operation if necessary for the reliability of energy supply." *Verso Corp. v. Fed. Energy Reg. Comm'n*, 898 F.3d 1, 4 (D.C. Cir. 2018). The importance of ensuring the reliability of the transmission system under MISO's functional control recently came into even sharper focus. MISO's annual capacity auction, which serves as the marketplace to ensure sufficient generating capacity during peak demand periods, was held on April 14, 2022 and unexpectedly resulted in a "nearly fiftyfold jump" in clearing prices "surg[ing] to $236.66 per megawatt-day from $5 a year ago" for the Midwest subregion of MISO that includes Missouri.[2] Subsequently, "MISO raised an alarm on April 28 when it said that it projects 'insufficient firm resources' to cover the summer peak under typical demand and generation outages."[3] As the Wall Street Journal reported on May 8, "MISO . . . said

[1] Plaintiffs might continue to argue that Rush Island's past SO2 emissions need "mitigation"—despite the Eighth Circuit's reversal of the "mitigation" remedy—yet, it is an indisputable fact that Ameren's retirement of Rush Island, eliminating *all* future plant emissions, will result in greater environmental benefits to the public than the "mitigation" remedy Plaintiffs previously sought. That is why Plaintiffs do not oppose Ameren's request to allow retirement of Rush Island in lieu of FGD installation and continued operations.

[2] Jeffrey Tomich, "Soaring prices signal challenges ahead for Midwest grid," E&E News (April 18, 2022) (available at https://www.eenews.net/articles/soaring-prices-signal-challenges-ahead-for-midwest-grid/).

[3] Sonal Patel, "ERCOT, MISO Warn of Potential Power Supply Shortfalls," POWER Magazine (May 5, 2022) (available at https://www.powermag.com/ercot-miso-warn-of-potential-power-supply-shortfalls/) (discussing results April 14 capacity auction and summer forecast presented during MISO's April 28 Seasonal Readiness Workshop); *see also* MISO Seasonal Readiness Workshop Summer 2022 PowerPoint Presentations, at Slides 27-28 (available at

last month that capacity shortages may force it to take emergency measures to meet summer demand and flagged the risk of outages."[4] The North American Electric Reliability Corporation ("NERC"), in its recent 2022 Summer Reliability Assessment, similarly concluded that MISO "faces a capacity shortfall in its North and Central areas, resulting in high risk of energy emergencies during peak summer conditions."[5] NERC categorized MISO as "High Risk":

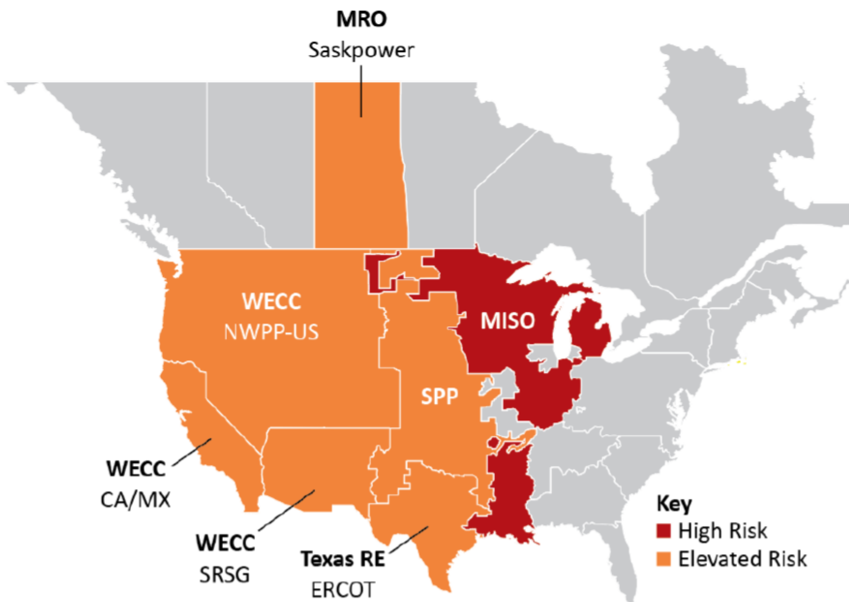


Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

Id. at Slide 5.

MISO's Director of Resource Utilization and former Reliability Coordinator has provided a declaration (the "MISO Declaration") explaining the significance of these developments:

https://cdn.misoenergy.org/20220428%20Summer%20Readiness%20Workshop624245.pdf) ("Under typical demand and generation outages, MISO is projecting insufficient firm resources to cover summer peak forecasts.").

[4] Katherine Blunt, "Electricity Shortage Warnings Grow Across U.S.," Wall Street Journal (May 8, 2022) (copy attached as Ex. F hereto).

[5] NERC, "2022 Summer Reliability Assessment" (May 2022), at Slide 4 ("Key Findings") (available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf).

"MISO faces increasing challenges to system reliability and the ability to commit sufficient resources to supply electricity to customers within the MISO region. . . . The results [of the recent auction] showed capacity shortfalls in both the north and central regions, even including the ongoing operation of Ameren Missouri's Rush Island plant, located in Zone 5, part of the central region." (June 7, 2022 Declaration of Andrew Witmeier (Ex. E hereto, "MISO Decl.") at ¶¶ 3-4.) The MISO Declaration notes that, in light of these developments, MISO's President and Chief Operating Officer observed that such shortfalls create "increased risk of temporary, controlled outages to maintain system reliability," and MISO's Executive Director – Market Operations added that the "north and central regions of MISO" are "at increased risk of temporary, controlled outages to preserve the integrity of the bulk electric system." (*Id.* at ¶¶ 6-7.)[6] As the MISO Declaration explains, "[g]iven the existing regional supply situation, resources need to remain online and available to provide capacity and transmission grid stability to meet the system's needs until sufficient replacement capacity is brought online," and specifically "Rush Island . . . has also been identified as necessary for the reliability of the grid surrounding the plant." (*Id.* at ¶ 8.)

Within this broader context, the retirement of Rush Island requires modeling and analysis of any downstream effects on the reliability of the transmission system, identification of any potential reliability issues, and careful planning and execution of steps needed to alleviate any such issues to ensure that system reliability will be maintained when Rush Island is retired and disconnected from the grid. MISO, through its Attachment Y and Y-2 processes, has identified multiple reliability issues associated with retiring Rush Island which require Ameren to perform

[6] *See also* Tomich, "Soaring prices signal challenges ahead for Midwest grid" (quoting MISO's President and Chief Operating Officer); MISO Apr. 28, 2022 Press Release, "MISO projects risk of insufficient firm generation resources to cover peak load in summer months" (quoting MISO's Executive Director – Market Operations) (available at https://www.misoenergy.org/about/media-center/miso-projects-risk-of-insufficient-firm-generation-resources-to-cover-peak-load-in-summer-months/).

certain transmission projects to ensure system reliability. The MISO Declaration recognizes that "MISO is responsible for studying all retirement requests for impacts to the grid from a transmission security standpoint," and states that "MISO has identified multiple reliability constraints that require the Rush Island plant to remain online as a System Support Resource until transmission upgrades are in place that would allow the plant to suspend operation." (*Id.* at ¶ 9.)

The specific reliability issues and transmission projects are described below, and in supporting declarations from Ameren employees Justin Davies and Tim Lafser submitted with this brief (attached as Exhibits B & C hereto, respectively). It is in the public interest to perform the projects necessary to alleviate the reliability issues that will result from Rush Island's retirement, to ensure the reliability of the transmission system. Ameren, working within MISO's process, has already begun taking steps to plan, obtain approval for, procure, and perform the necessary transmission projects, and will continue this work expeditiously.

Until those transmission projects are completed, some operation of the Rush Island units will be needed to ensure the reliability of the transmission system. MISO has indicated that unless alternative mitigation measures are identified—which is unlikely given the nature and severity of the risks identified—it will designate the units as System Support Resource ("SSR") units, meaning that they are necessary for system reliability. (MISO Decl. (Ex. E) at ¶ 9.) Ameren has been assessing what operations may be needed from the Rush Island units should MISO designate them as SSR units to ensure reliability during the interim period until the necessary transmission projects are completed. In conjunction with MISO's Attachment Y analysis (attached as Exhibit A hereto) Ameren has determined that, while the units are needed for reliability purposes during certain peak periods and always must be available to be called upon by MISO to operate in order to address any emergency events that may arise (which have become more common[7]), there will be significant periods when the units will not need to operate at full load, and when neither unit will need to operate, absent an emergency. These anticipated operational needs, limited to what is necessary to ensure reliability and address emergencies, and based on MISO's Attachment Y results, are explained in more detail below, and in the supporting declarations.

The reduced operations can be managed according to a cap on emissions of SO2—an approach that allows for the flexibility to operate in order to buttress system reliability when needed, to operate at lower levels or not operate when one or both units are not needed to ensure reliability, and to stand by to address emergency scenarios as identified by MISO. This cap approach is described more fully below. The trigger for MISO to invoke emergency operations is defined by recognized standards (*i.e.*, the MISO FERC Electric Tariff and the NERC Operating Manual) and/or extreme weather events that, by their nature, are unpredictable. This approach would maximize flexibility and minimize the administration of managing operations, while also striking a balance between the dual public interests of ensuring reliability and reducing emissions. It is also an approach that has been used previously by MISO and approved by the Federal Energy Regulatory Commission ("FERC").

The Court's Remedy Ruling, an injunction entered pursuant to the exercise of its equitable authority, weighs the various interests affecting the public and seeks to maximize the overall public interest. In this brief, Ameren lays out an approach and proposed plan for Rush Island's retirement, including the completion of necessary transmission projects to address reliability issues identified

[7] *See* MISO Seasonal Readiness Workshop Summer 2022 PowerPoint Presentations, at Slide 6 (available at https://cdn.misoenergy.org/20220428%20Summer%20Readiness%20Workshop624245.pdf) ("Max Gen Declarations" by MISO to address emergency events "have become more common over the last 6 years."); *see also* Blunt, "Electricity Shortage Warnings Grow Across U.S." (Ex. F hereto) (noting MISO "has more frequently resorted to emergency measures to shore up supplies in recent years").

by MISO, reduced operation of the Rush Island units in the interim until those projects are completed in accordance with MISO's SSR process, and ultimately the retirement of Rush Island and its disconnection from the grid upon the completion of the final transmission project, which Ameren currently anticipates will occur no later than Fall 2025, and perhaps earlier. This proposed plan maximizes benefits to the public of reducing and ultimately eliminating emissions while at the same time ensuring and maintaining system reliability. Ameren therefore respectfully requests that the Court modify the Remedy Ruling to allow Ameren to execute this plan, as set forth at the end of this brief.

I. MISO Must Approve Rush Island's Retirement to Ensure System Reliability.

As a condition of membership and participation in MISO, the owner of an electric generating facility (*i.e.*, a power plant) must forego the autonomy it would otherwise have to shut down that facility, if MISO determines that the absence of the facility would jeopardize the reliability of the transmission system in the MISO region. Generating facilities would normally retire if the economics or useful life of the plant do not support their continued operation. But the sudden absence of a particular generating facility can destabilize the interstate electric grid by removing a source of injected energy and changing the flows on the grid, which may cause overloads on the grid as currently configured, increasing the risk of cascading power outages. Consequently, when an owner seeks to retire a generating facility, it must submit an Attachment Y notice to MISO of the planned retirement no less than 26 weeks in advance.

Upon receipt of an Attachment Y notice, MISO's engineering staff conducts an analysis to model the transmission system without that generating facility in service. If MISO determines that the reliability of the system would be jeopardized, MISO may compel that generating facility to continue operating by designating it as a System Support Resource, or SSR, for such period of time as may be required until the reliability risk can be mitigated. Mitigating such reliability concerns usually takes the form of the construction or installation of new transmission facilities or equipment (*e.g.*, power lines, transformers). When MISO designates a retiring generating facility as an SSR, MISO's tariff provides that MISO must enter into an SSR Agreement with the facility owner. When the necessary transmission system mitigations are in place, MISO terminates the SSR Agreement, and the facility is permitted to retire.

MISO's SSR determination is made as part of its Attachment Y study of transmission system reliability issues. MISO seeks to identify violations of applicable standards that will be caused by the removal of the generating facility at issue and cannot be resolved without the operation of that facility. The SSR provisions of MISO's tariff on file with FERC require that "[t]he [SSR] evaluation will consider the performance of the transmission system to determine if thermal or voltage violations of applicable [NERC] Standards and Transmission Owner planning criteria occur when the unit is offline compared to conditions when the unit is online." MISO FERC Electric Tariff § 38.2.7(c). MISO's published Business Practice Manual on this topic requires that MISO identify any issues that require mitigation to meet [NERC] and local planning criteria. Moreover, the MISO Transmission Owners Agreement generally requires MISO to recognize those local criteria when operating the system.

An SSR Agreement typically covers a term of twelve (12) months, and is subject to periodic review and extension as needed based on reliability requirements. *See id.* § 38.2.7(b), (f).

II. <u>Transmission Projects Must Be Completed in Order to Ensure System Reliability.</u>

The retirement of Rush Island could compromise the reliability of the transmission system. Losses of electricity due to such effects on the transmission system could detrimentally impact the public, critical facilities and services, all of which depend on the constant reliable transmission and delivery of electricity. A primary goal of MISO's modeling and analysis is to identify potential problems and risks impacting system reliability caused by Rush Island's retirement, and to identify mitigation measures to address those problems and risks as part of the retirement planning, which can include construction projects necessary to buttress the transmission system to eliminate or at least alleviate the problems and risks. (MISO Decl. (Ex. E) at ¶ 9.)

MISO presented the results of its modeling and analysis in its Attachment Y Study Report, issued on June 2, 2022. (Ex. A (public version).) In that report, and as required by its tariff, MISO applied both Ameren's Criteria and Guidelines (a/k/a Local Planning Criteria ("LPC")) and national NERC TPL standards. MISO's analysis confirms that both Rush Island units should be designated as SSR units. MISO concluded:

> After being reviewed for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), the analysis determined that there are reliability issues identified related to the suspension of *Rush Island* that may require the generators to be designated as a System Support Resources ("SSR") units following the stakeholder process.
>
> There were both severe steady state and transient voltage recovery (TVR) violations that may require the generators to be designated SSR units. In the summer peak case, there were five stability violations that did not meet Ameren voltage recovery criteria and would result in over 1,000 MW of load loss, which, if allowed, would be considered a potential Interconnection Reliability Operating Limit (IROL) within the MISO footprint in accordance with BPM-020 Section L.3.6. All voltage violations seen can be mitigated with load shed per MISO SSR criteria and additionally per WVPA there already exists operating guides to mitigate the known issues.
>
> Prior to this Attachment Y, MISO also studied an Attachment Y-2 submitted by Union Electric Company – Ameren Missouri. This study had an effective date of June 1, 2023, but there were no other changes to study assumptions or system topology between the time the Attachment Y was submitted and the final Y-2 report. Therefore, the results of the Attachment Y-2 study will also be used to determine SSR need. The Attachment Y-2 report is included as an Appendix to this Attachment Y report. Three thermal violations were identified in three different scenarios in 2023 that require mitigation based on Ameren's Local Planning Criteria and one steady state voltage violation was identified for the winter peak case

> in 2023 and several stability voltage violations were identified for the summer peak case in 2023 that may require Rush Island to be designated as System Support Resources ("SSR") units following the stakeholder process.
>
> The transmission system was also evaluated for Ameren Local Planning Criteria with two different scenarios including non-coincident peak loads in Ameren territory and Winter Storm Uri. The results show thermal violations that would require mitigation, but these violations should not be utilized in designating Rush Island generation as an SSR.
>
> In addition, MISO performed an analysis to determine if both units are required to mitigate the violations identified. That analysis determined that with one unit online, violations still exist that would may require *Rush Island* to be designated as System Support Resources ("SSR") units.

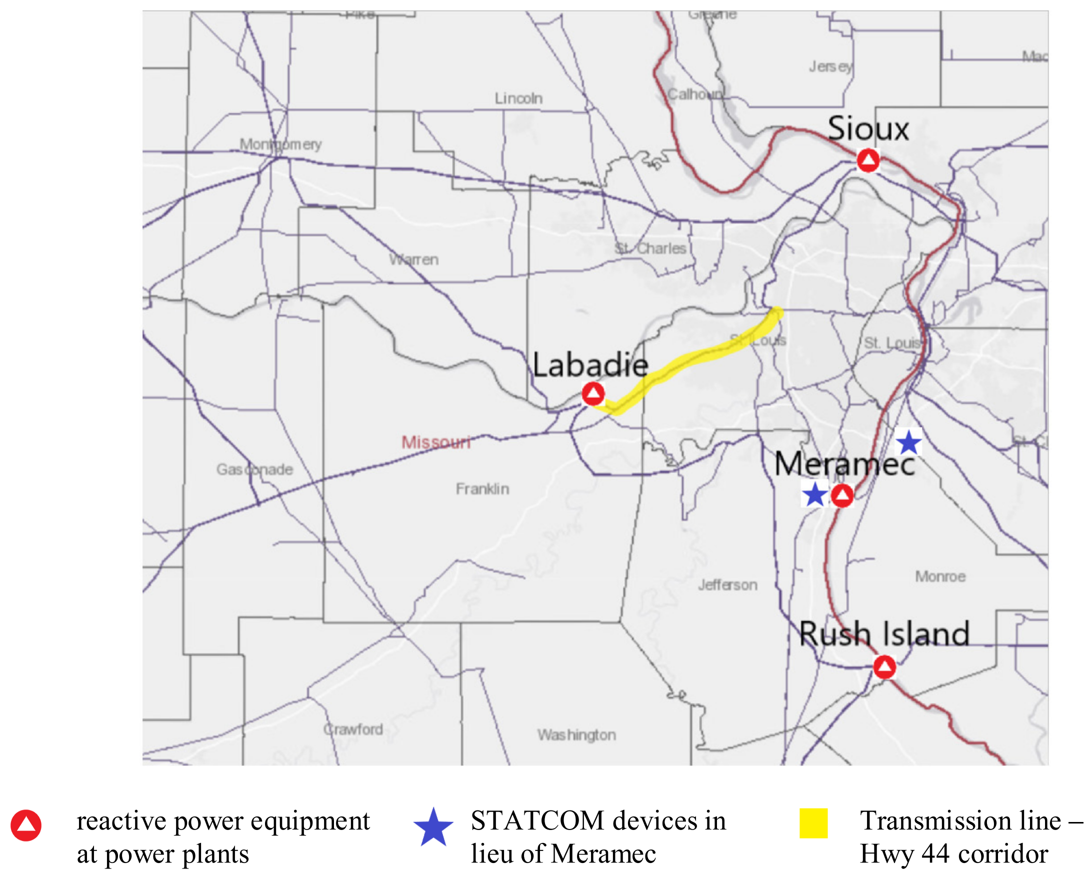
(MISO Attachment Y Report (Ex. A) at 2-3.)

Ameren's and MISO's planning teams have identified mitigation projects, described below, that must be completed before retirement can safely and reliably occur. (MISO Decl. (Ex. E) at ¶ 9.) Ameren Transmission, as the transmission owner and as contemplated by MISO's tariff, provided required input as to specific mitigation measures and locations. While the Attachment Y process is a confidential process, once a determination is made that a resource is needed for reliability, there is a public process that allows for the consideration of alternatives to the SSR determination. Ameren does not believe viable alternatives exist that would both address the reliability issues identified in the Attachment Y study and be consistent with Ameren's LPC. (Davies Decl. (Ex. B) at ¶ 6.)

As Mr. Davies explains in his declaration, reliability concerns arising from the retirement of Rush Island stem from three (3) primary conditions: thermal overload due to altered power flow; loss of power for customers (load) due to insufficient voltage support resources; and loss of power for customers due to insufficient transient voltage recovery resources. (*Id.* at ¶ 7.)

Thermal Overload Due to Altered Power Flow. Ameren's transmission system was constructed based upon a design flow of energy from large, baseload facilities into and around the St. Louis metropolitan area. As designed, the transmission network is supported, or "propped up," by Ameren's four coal plants (Rush Island, Sioux, Meramec, and Labadie). In addition to generating energy/megawatts (MW), the coal plants provide reactive power critical to balancing the voltage levels (MVars) that flow across lines that support the transmission system. The retirement of Rush Island will disrupt these energy flow patterns resulting in a disruption in the designed flow of energy. Below is a simplified schematic that depicts the location of these "props" relative to major transmission lines in the metropolitan area. (*Id.* at ¶ 8.)

AMEREN 345 kV TRANSMISSION LINES AND REACTIVE POWER SUPPORT



These shifts in energy flow patterns are analogous to the local transportation system. The retirement of Rush Island is akin to permanently shutting down Highway 55 between I-270 and downtown, thereby re-directing traffic onto Highways 44 and 64. In addition, retiring Rush Island also will create a weakness in the current system analogous to forcing three-lane traffic onto a two-lane bridge, where two lanes were sufficient before the retirement but not after. Bottlenecks and overload occur. Transmission reliability modeling indicates that without Rush Island in service, overloads at various locations could occur as the network (lines and substations) will no longer be in sync with original design criteria and flow assumptions. Addressing the re-directed and increased flow across part of the system will require installing a larger capacity transformer at a substation in the Wildwood, Missouri area. MISO has confirmed that the reliability risk associated with the transmission line overload requires designation of both Rush Island units as SSR units until such time as the Wildwood transformer has been replaced and is in service. In addition, upgrading a bus bar connection at the transmission substation located at Rush Island allows for a better synced energy flow and addresses the bottleneck issue (*i.e.*, the two-lane bridge example referenced above). (*Id.* at ¶¶ 9-10.)

Insufficient Voltage Support Resources. Modeling also reflects that with Rush Island retired, and not producing the significant amount of dynamic voltage support it otherwise would, there is a risk that during the winter peak period unacceptable low voltages may occur. Modeling further indicates that these voltage-based reliability concerns are not limited solely to Ameren's transmission network and retail customers. They could extend to customers of other utilities, including Citizen's Electric and Associated Electric Cooperative Inc. To address this issue, MISO has proposed the installation of a capacitor bank at the Overton Substation, near Columbia, Missouri. At this substation, multiple high power transmission lines (345/161 kV) come together and connect with 69kV distribution lines. The capacitor bank project will help regulate the appropriate voltage level across the Ameren network and various interconnections. MISO has confirmed that until the capacitor bank equipment can be placed in service to address this problem, the reliability risk caused by Rush Island's retirement (and concomitant reduced voltage support) requires designation of both Rush Island units as SSR units. (*Id.* at ¶ 11.)

Insufficient Transient Voltage Recovery Resources. In addition, without Rush Island online to contribute transient voltage recovery support, there is a risk of additional transmission system failures. Without adequate reactive power, the system cannot adequately recover from short-term events, such as a windstorm, lightning strike or transmission tower failure. When these events occur, the large providers of reactive power (like Rush Island) provide an immediate and short-term supply of dynamic voltage support in the milliseconds and seconds after a major disruption to the grid as described above. Without that immediate reactive voltage support, the grid voltage may collapse (resulting in power outages for customers). For example, a windstorm could cause a failure on the major 345 kV transmission line that runs from Labadie Energy center, along the Highway 44 corridor, into the metropolitan area. That failure, in turn, could cause an immediate, short-term voltage drop from which the system could not recover without a significant load reduction (customers losing power). Ameren estimates that type of event would place at risk approximately 1,000 megawatts of load, or roughly 200,000 customers. Both Ameren's LPC and national NERC TPL standards have design and operating requirements regarding such occurrences. To address similar voltage support issues caused by the retirement of the Meramec Energy Center (which is scheduled to be retired later this year), Meramec's reactive power capability will be replaced by two static var compensators ("STATCOM")—voltage regulation devices—installed at strategic locations in Missouri and Illinois. (Locations noted on map above.) These transmission network upgrade projects cost approximately $244 million. (*Id.* at ¶¶ 12-14.)

Transmission Projects to Ensure System Reliability. To address and alleviate the problems described above, Ameren has determined, and MISO concurs, that the following transmission projects are needed to ensure system reliability.[8]

Project	Estimated Completion Date
Installation of a Capacitor Bank at the Overton Substation to address voltage issues	Spring/Fall 2023
Replacement of a Transformer at the Wildwood Substation in St. Louis County to address overload concerns	Spring 2024
Upgrading of a bus bar tie position at a substation adjacent to Rush Island to address voltage issues	Spring/Fall 2023
Installation of four (4) STATCOMs in the St. Louis Metropolitan area to provide reactive power support; installations to occur as equipment becomes available 2024-2025	Final STATCOM Fall 2025, perhaps earlier

(*Id.* at ¶ 16.)

Ameren proposes to move forward contemporaneously with all of these projects on an expedited basis. MISO's approval is needed for each of these projects because they affect the transmission system, but MISO has already indicated to Ameren that it will fast-track its approval of these transmission projects. Ameren expects that MISO's approval will be granted by late summer 2022. Assuming that MISO approves these projects, then Ameren will immediately begin design and procurement work. (*Id.* at ¶¶ 18-19.)

[8] The recently completed Attachment Y analysis identified additional reliability issues associated with both the summer and winter peak periods and the potential for load loss. Working with MISO, Ameren is in the process of identifying any additional transmission projects needed to address those concerns. (Davies Decl. (Ex. B) at ¶ 17.)

III. Ameren Proposes to Cap Emissions Until the Transmission Projects Are Completed.

As illustrated in the chart above, the necessary transmission projects will be installed on a rolling basis as expeditiously as possible. Until those projects are completed, Ameren proposes to greatly reduce Rush Island's operations to reduce emissions while at the same time ensuring the Rush Island units are available to address reliability concerns on the transmission network as well as availability needs as may be required by MISO during peak periods and emergency conditions.

Demand for power generation within the MISO area is dynamic and fluctuates on an hourly, daily, and weekly basis depending upon myriad of factors including weather, forced outages, and load level. Recognizing the difficulty in accurately predicting a set operating requirement, Ameren proposes that the Court adopt an emission cap set at a level that addresses reliability concerns. Once the necessary transmission projects are completed and in service, Rush Island can be permanently retired. (Lafser Decl. (Ex. C) at ¶ 3.)

As discussed below and in Mr. Lafser's accompanying declaration, the Rush Island units' proposed reduced operations—those necessary to maintain both transmission system reliability and safe plant operations while ensuring plant availability when needed by MISO—will result in significantly lower generation and emissions levels.

Summer Peak Months (June, July, August, September) Through Summer 2025: Peak demand and electricity usage typically occurs during the summer air-conditioning season of June, July, August, and September. This summer peak period poses a reliability risk due to both voltage regulation issues and potential transmission line overloads. These risks will be mitigated by performing a bus upgrade at a substation adjacent to Rush Island (estimated completion date end of 2023), and installing four STATCOM devices on the transmission system. Based upon supply chain challenges, it is possible that the final STATCOM equipment set may not be placed into service until fall 2025, though installation could occur in late 2024 or spring 2025. The proposed emissions cap contemplates reduced operations of both Rush Island units. (*Id.* at ¶ 4.a.)

Winter Peak Months 2022-2023 (December, January, February): Through the date that the capacitor bank project is expected to be completed at the Overton Substation—currently estimated at February 2023— the proposed emissions cap contemplates that both Rush Island units must remain online during the winter months to hold voltage and provide stable operations. (*Id.* at ¶ 4.b.)

Winter Peak Months 2023-2024 (December, January, February): Replacement of the capacitor bank does not solve all overload issues, however, given a potential for overload at critical locations such as along the Highway 44 corridor where a transmission line delivers power into the St. Louis metropolitan area. Consequently, even after replacement of the capacitor bank, mitigating that overload risk requires installation of a larger capacity transformer at the Wildwood Substation near Wildwood, Missouri. Accordingly, during the winter peak months through February 2024, the proposed SO2 cap includes a single Rush Island unit that must remain fully operational to meet system needs until the Wildwood Substation transformer is in service. The proposed cap contemplates that until that transformer is in service, Ameren would also bring the second Rush unit online when ambient temperatures are forecasted to be below 20 degrees Fahrenheit. At those low temperatures, the second unit is necessary to ensure freeze protection of the Rush Island Energy Center, which could occur if the first Rush Island unit unexpectedly trips offline. (*Id.* at ¶ 4.c.)

Shoulder Months, Generally Offline Except for Emergencies: During the shoulder months of March, April, May, October, and November, the Rush Island units are generally expected to be offline and not generating, unless MISO calls upon such units on an emergency basis. (*Id.* at ¶ 4.d.)

Emergency Availability for Extreme Weather Conditions: MISO's reliability review is defined by its modelling criteria and does not include the potential for extreme weather events such as experienced in February 2021 during Winter Storm Uri, when Arctic weather drove high generation and transmission outages and led to unprecedented flows across the MISO system to support MISO and its neighbors. Prior to that storm, MISO issued a Cold Weather Alert, committed additional generation in advance of need, and extended start/stop times for generation resources to avoid start failures. For the Ameren system, all available generation was called upon, including the Rush Island units. Rush Island played a crucial role in preventing load shedding in Missouri and, due to its proximity to Illinois, also reduced the amount of load that needed to be shed in Illinois to mitigate additional overloads on Ameren's facilities. This example demonstrates the importance of Rush Island being available to respond to emergency events and requests by MISO, such as Cold Weather Alerts. Emergency events can happen at any time of year, and in the past, MISO has averaged seven such emergency events annually. Assuming half of these events occur in shoulder seasons when the Rush Island units would not normally be operating, there could be additional operation needed to address any such emergencies. MISO may commit the units a day in advance of any emergency event. As described above, for summer 2022, MISO projects it will have insufficient resources to cover peak forecasts and that emergency resources may be needed, and such emergency events could become more frequent until additional generation capacity and transmission resources are built. To address emergency events, MISO must be able to call upon one or both Rush Island units to operate temporarily during brief but extreme periods when the grid can experience stress and a shortage of generating resources.

Because these events are by their nature unpredictable, Ameren has not included them in the proposed emissions caps set forth above, but it is critical that Rush Island be available to MISO at critical moments to prevent or lessen the impact to the public due to a shortage of adequate generation resources. (*Id.* at ¶¶ 10-11.)

To express the limited operations described above in terms of SO2 emissions, Ameren has estimated Rush Island generation necessary to address the specific transmission concerns identified in the MISO Attachment Y study: voltage regulation support deficiencies; transmission line overloading problems; and having the ability to quickly meet MISO's demands (through supply of energy) as and when needed. These estimates are based on transmission system modeling performed in connection with the Attachment Y study, and such modeling scenarios do not always match the reality of dynamic electric grid operations. Moreover, large coal-fired boilers, such as the Rush Island units, cannot be turned on quickly. The Rush Island units need between 18 and 24 hours to reach full operational capacity from a cold start, which Ameren has accounted for in its estimates. To meet the goals of transmission system reliability including voltage regulation support, the availability of sufficient capacity to meet MISO's generating needs, and the ability to be online and ready to increase operations to meet both MISO's fluctuating day-to-day energy needs and declared emergencies, all while ensuring the operational flexibility necessary to address conditions that change on a daily basis, Ameren is proposing plant-wide SO2 emissions caps, as set forth in the table below. Due to the uncertainty regarding the installation date of the final STATCOM device (likely fall 2025, but perhaps as early as late 2024 or spring 2025), Ameren has proposed caps for 2025. The 2025 operations may be unnecessary if all STATCOMs are placed in service before those dates. (*Id.* at ¶¶ 6-7.)

In any event, the proposed plant-wide caps reflect significantly reduced operation of, and emissions from, the Rush Island units:

Cap Period	**Proposed Plant-wide SO2 Emissions Cap**
9/1/2022 – 12/31/2022	2,600 tons
1/1/2023 – 12/31/2023	9,500 tons
1/1/2024 – 12/31/2024	9,500 tons
1/1/2025 – 2/28/2025	1,700 tons (if final STATCOM is not yet installed)
3/1/2025 – 9/30/2025	2,500 tons (if final STATCOM is not yet installed)

(*Id.* at ¶ 7.)[9] This represents a significant reduction in emissions as compared to recent years:

Year	**Plant-wide SO2 Emissions**
2017	22,167 tons
2018	18,484 tons
2019	13,201 tons
2020	17,321 tons
2021	19,529 tons
Average	**18,140 tons**

[9] Ameren has estimated megawatt hours, and consequently SO2 tons, through September 2025. Should the Rush Island units go into outage in the fall of 2024 to support the STATCOM installations, such emission levels would be reduced. If, however, the outages were delayed due to supply chain delays or disruptions or some other issue, then the cap period and applicable tonnage amounts would need to be adjusted. As in other industries, supply chains for components necessary for the types of transmission projects that must be performed have been delayed and disrupted by the COVID-19 pandemic, labor shortages, increased demand, and the war in Ukraine, among other factors. *See generally* Declaration of Benjamin Ford (attached as Exhibit D hereto). Specifically, the estimated lead time to procure transformers and other electrical equipment has doubled or tripled, and core steel used in STATCOM equipment has become increasingly scarce due to the war. *Id.* Ameren has taken, and continues to take, steps to minimize, to the extent it can, the effects of supply chain delays and disruptions so that it may perform necessary projects as expeditiously as possible. *Id.* Nonetheless, ever-changing supply chain dynamics create increasing uncertainty in construction scheduling. Ameren will update the Court if any changes in procurement schedules or other supply chain effects impact the anticipated schedule laid out in this submission.

(*Id.* at ¶ 8.)

IV. <u>This Cap Would Reduce Emissions More Substantially Than the Remedy Ruling.</u>

The Court's Remedy Ruling ordered installation of FGD technology at Rush Island, which would require a multi-year construction period through mid-2024 during most of which the plant would continue operating. The emissions of SO2 during that multi-year period of FGD construction would have likely exceeded 36,000 tons (an average of 18,000 tons per year). By comparison, Ameren's proposed emissions cap totals just 25,800 tons through September 2025, and if all STATCOMs are installed earlier, SO2 emissions would be lower. Moreover, emissions of all other pollutants, including carbon, NOx, and mercury would be reduced dramatically as well. (*Id.* at ¶¶ 7-8.) Moreover, the foregoing reductions pertain only to the period when FGD construction would have otherwise occurred, and up until the final transmission project is completed. After that point in time, Rush Island's retirement will eliminate all emissions, resulting in substantially lower overall emissions than would have otherwise been released if FGD technology were installed and the units operated for additional decades in the future.

V. <u>A Cap Is Reasonably Administrable and Provides Needed Operational Flexibility.</u>

Ordering that SO2 emissions be capped at a certain amount will provide Ameren with the operational flexibility needed to respond to MISO and operate the Rush Island units on a day-to-day basis to ensure system reliability. Operating conditions vary every day. This includes natural variation of conditions on the transmission grid, variation in weather conditions, and unplanned unit outages at both Rush Island and other nearby generating units. With the increasing usage of renewable generation in MISO, daily weather changes (wind, sunshine) increasingly affect available generation and transmission. MISO will need the ability to dispatch Rush Island with flexibility. An emissions cap—as opposed to a defined regime for operation—provides such flexibility. (*Id.* at ¶ 5.)

At the same time, an SO2 emissions cap will provide the benefit to both the Court and the parties of making administration of the injunction considerably easier than under a defined operating regime. *See, e.g.*, *See Nat. Res. Def. Council, Inc. v. U.S. E.P.A.*, 966 F.2d 1292, 1300 (9th Cir. 1992) (declining to enjoin the EPA from extending Clean Water Act permit applications from municipal and industrial waste dischargers because this "[i]njunctive relief could involve extraordinary supervision by this court. Injunctive relief may be inappropriate where it requires constant supervision."); *Sw. Org. Project v. United States Dep't of the Air Force,* 526 F. Supp. 3d 1017, 1072 (D.N.M. 2021) (where plaintiffs sought injunctive relief to mitigate the Air Force's handling of petroleum-based fuels under the Resource Conservation and Recovery Act (RCRA), the court declined to issue such relief and determined that since "the Plaintiffs' requested injunctive relief requires scientific or technical expertise, the Court will defer to the [New Mexico] Environment Department's expertise here"). Furthermore, MISO has previously used an emission cap in SSR agreements to implement environmental restrictions. (Lafser Decl. (Ex. C) at ¶ 9.)

CONCLUSION

In conclusion, there is no disagreement among the parties that it is in the public interest to modify the Remedy Ruling to allow for Rush Island's retirement in lieu of installing FGD and continuing operations. There is also no disagreement that ensuring the reliability of the transmission system is in the public interest. MISO has identified reliability issues resulting from Rush Island's retirement, which must be addressed. The proposed plan outlined in this brief will strike a balance between ensuring reliability until necessary transmission projects can be completed, and in the interim reducing operations of the Rush Island units and lowering SO2 emissions until retirement. Ameren respectfully requests that the Court approve this plan and grant Ameren's Motion to Modify (ECF # 1196), as supplemented herein.

Specifically, the Court should order as follows:

1. In lieu of installing FGD at Rush Island, as previously ordered, Ameren shall instead retire Rush Island as soon as possible and, based upon the information presented in Ameren's supplemental brief, no later than September 30, 2025, subject to and consistent with MISO's input with respect to operations of the Rush Island units needed during this interim period to ensure system reliability and address emergency events until necessary transmission projects are completed that will alleviate the transmission issues identified by MISO in its Attachment Y analysis.

2. In the interim period while the necessary transmission projects are being performed, Ameren shall operate the Rush Island units, consistent with MISO's input, so that total emissions of SO2 from both units shall not exceed the following plant-wide limits, for the periods set forth below, except as otherwise provided in this Order:

Cap Period	Plant-wide SO2 Emissions Cap
9/1/2022 – 12/31/2022	2,600 tons
1/1/2023 – 12/31/2023	9,500 tons
1/1/2024 – 12/31/2024	9,500 tons
1/1/2025 – 2/28/2025	1,700 tons (if final STATCOM is not yet installed)
3/1/2025 – 9/30/2025	2,500 tons (if final STATCOM is not yet installed)

3. During such interim period, if MISO identifies an emergency as defined in MISO's tariff, NERC Operating manual, or an extreme weather event as determined by MISO (collectively "emergency condition") that requires it to call upon the Rush Island units, then Ameren shall operate the units at MISO's direction in order to address the emergency condition, and emissions

of SO2 resulting from operation of the Rush Island units in response to MISO's direction during any such emergency shall not count towards the emissions limits set forth above. Within ten (10) business days of the end of any such emergency condition, Ameren shall provide the Court, with a copy to Plaintiffs, a description and duration of the circumstances giving rise to the emergency condition and MISO's directions to address it.

4. Ameren shall work with MISO to ensure that the requirements of the Court's Order shall be incorporated into any SSR Agreement or extensions of such an agreement with MISO, to be filed with FERC in accordance with MISO's and FERC's procedures.

5. Commencing September 1, 2023, and continuing annually until retirement of Rush Island occurs, Ameren shall work with MISO to update MISO's reliability analysis and Ameren shall provide a report to the Court upon the completion of any such study or analysis.

6. Ameren shall provide quarterly status reports to the Court commencing on January 1, 2023 and continuing until retirement of Rush Island occurs. The quarterly status reports will include the status of implementation of the reliability projects approved by MISO and shall describe the emergency operations, if any, that occurred during that quarter.

7. The Court shall retain jurisdiction over this matter until units 1 and 2 of the Rush Island Energy Center cease operation and Ameren submits a request to the Missouri Department of Natural Resources (MDNR) to withdraw units 1 and 2 from the operating permit. Ameren shall provide the Court a copy of such withdrawal notification.

Finally, Ameren respectfully requests that the Court schedule a status conference on June 30, 2022 if that date is available and acceptable to the Court. Ameren's counsel have conferred with Plaintiffs' counsel and June 30 will work for all of the parties' counsel and provide sufficient time for any additional briefing on these issues. If that date is unavailable, counsel will promptly confer regarding the dates the Court has available.

Dated: June 8, 2022

Respectfully submitted,

/s/ *Matthew B. Mock*

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Counsel for Defendant Ameren Missouri

CERTIFICATE OF SERVICE

I hereby certify that on June 8, 2022, I caused the foregoing document to be electronically filed with the Clerk of Court using the CM/ECF system, which will cause an electronic copy to be served on all counsel of record.

/s/ *Matthew B. Mock*
Matthew B. Mock

EXHIBIT A

Public

Attachment Y Study Report

Union Electric Company – Ameren Missouri
Rush Island 1 and 2: 1195 MW
Start Date: September 1, 2022

June 8, 2022

MISO

P.O. Box 4202
Carmel, IN 46082-4202
Tel.: 317-249-5400 Fax: 317-249-5703
http://www misoenergy.org

EXECUTIVE SUMMARY

On February 28, 2022, Union Electric Company – Ameren Missouri submitted an Attachment Y notice to *MISO* for the suspension of Rush Island Units 1 and 2 effective September 1, 2022.

MISO performed a Transmission System reliability assessment of Rush Island 1 and 2 set forth in the MISO Business Practices Manuals and was discussed and reviewed with the impacted Transmission Owners (TOs): *Ameren Missouri, Ameren Illinois, South Illinois Power Cooperative, and Wabash Valley Power Alliance.*

After being reviewed for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), the analysis determined that there are reliability issues identified related to the suspension of *Rush Island* that may require the generators to be designated as a System Support Resources ("SSR") units following the stakeholder process.

There were both severe steady state and transient voltage recovery (TVR) violations that may require the generators to be designated SSR units. In the summer peak case, there were five stability violations that did not meet Ameren voltage recovery criteria and would result in over 1,000 MW of load loss, which, if allowed, would be considered a potential Interconnection Reliability Operating Limit (IROL) within the MISO footprint in accordance with BPM-020 Section L.3.6. All voltage violations seen can be mitigated with load shed per MISO SSR criteria and additionally per WVPA there already exists operating guides to mitigate the known issues.

Prior to this Attachment Y, MISO also studied an Attachment Y-2 submitted by Union Electric Company – Ameren Missouri. This study had an effective date of June 1, 2023, but there were no other changes to study assumptions or system topology between the time the Attachment Y was submitted and the final Y-2 report. Therefore, the results of the Attachment Y-2 study will also be used to determine SSR need. The Attachment Y-2 report is included as an Appendix to this Attachment Y report. Three thermal violations were identified in three different scenarios in 2023 that require mitigation based on Ameren's Local Planning Criteria and one steady state voltage violation was identified for the winter peak case in 2023 and several stability voltage violations were identified for the summer peak case in 2023 that may require *Rush Island* to be designated as System Support Resources ("SSR") units following the stakeholder process.

The transmission system was also evaluated for Ameren Local Planning Criteria with two different scenarios including non-coincident peak loads in Ameren territory and Winter Storm Uri. The results show thermal violations that would require mitigation, but these violations should not be utilized in designating Rush Island generation as an SSR.

In addition, MISO performed an analysis to determine if both units are required to mitigate the violations identified. That analysis determined that with one unit online, violations still exist that may require *Rush Island* to be designated as System Support Resources ("SSR") units.

Table I-1: Overview of SSR Violations for Rush Island Attachment Y

Study	Year	Scenario	Steady State - Thermal Analysis	Steady State - Voltage Analysis	Stability Analysis
Attachment Y	2022	Summer Shoulder	No violations that met criteria	No violations that met criteria	No TVR violations met criteria
		Summer Peak	No violations that met criteria	Voltage violations can be mitigated per the MISO SSR Criteria	TVR violations that result in greater than 1,000 MW of load loss
		Summer low Load	No violations that met criteria	Voltage violations can be mitigated per the MISO SSR Criteria	No TVR violations met criteria
		Winter Peak	No violations that met criteria	Voltage violations can be mitigated per the MISO SSR Criteria	No TVR violations met criteria
Attachment Y-2	2023	Summer Shoulder	No violations that met criteria	Voltage violations can be mitigated per the MISO SSR Criteria	No TVR violations met criteria
		Summer Peak	Thermal violations can be mitigated per the MISO SSR Criteria, but need mitigation as per Ameren's LPC.	Voltage violations can be mitigated per the MISO SSR Criteria	TVR violations that result in greater than 1,000 MW of load loss
		Summer Low Load	Thermal violations can be mitigated per the MISO SSR Criteria, but need mitigation as per Ameren's LPC.	Voltage violations can be mitigated per the MISO SSR Criteria	No TVR violations met criteria
		Winter Peak	Thermal violations can be mitigated per the MISO SSR Criteria, but need mitigation as per Ameren's LPC.	P12 violation that cannot be mitigated per the MISO SSR Criteria	No TVR violations met criteria
	2031	Summer Peak	No violations that met criteria	No violations that met criteria	N/A

TABLE OF CONTENTS

1. INTRODUCTION

The Market Participant *Union Electric Company – Ameren Missouri* submitted an Attachment Y notice to *MISO* on February 28, 2022 for the suspension of *Rush Island 1 and 2* effective September 1, 2022.

The total capacity of *Rush Island* is 1195 MW based on its Generator Verification Test Capacity (GVTC) Value. It is connected to the 345 kV transmission systems, and is located in Festus, MO.

1-I Study Unit

Power Flow Area	Unit Description	kV Network[1]	Total MW[2]	Start Date
AMMO	Rush Island Unit 1	345	597.2	09/01/2022
AMMO	Rush Island Unit 2	345	597.8	09/01/2022
Total			**1,195**	

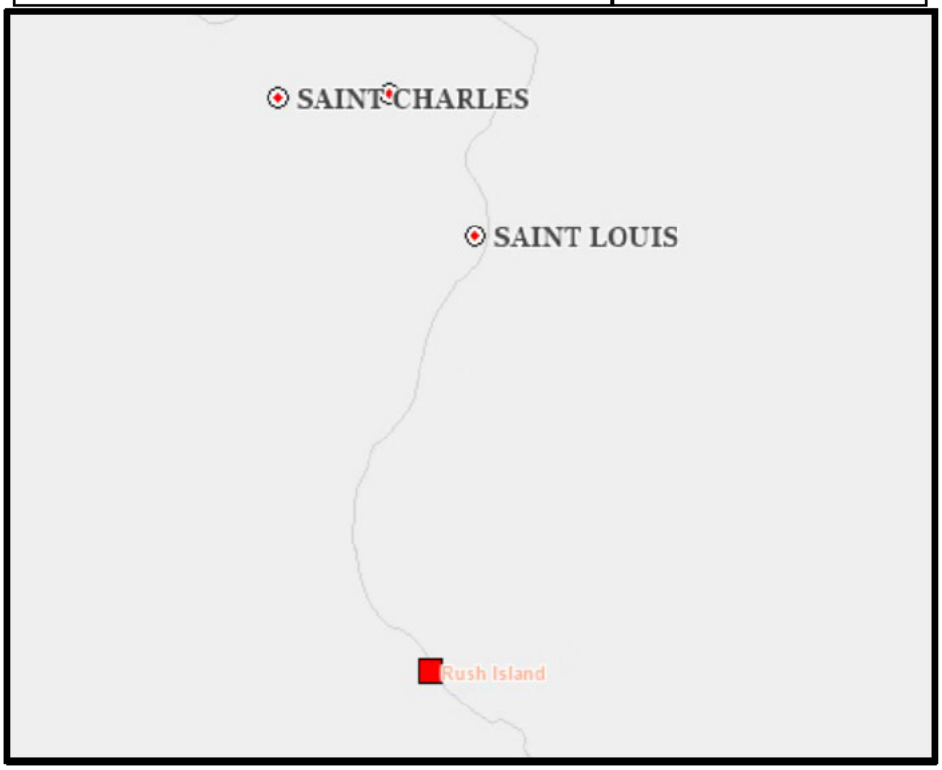

Figure 1: General Location Rush Island Generating Station

[1] In study models
[2] Generator Verification Test Capacity (GVTC) Value. Auxiliary Loads of Study Units will not be modelled. These values are the Net MW Output.

2. STUDY OBJECTIVE

Under Section 38.2.7 of MISO's Tariff, SSR procedures maintain system reliability by providing a mechanism for MISO to enter into agreements with Market Participants (MP) that own or operate Generation Resources or Synchronous Condenser Units (SCUs) that have requested to either Retire or Suspend, but are required to maintain system reliability.

The principal objective of an Attachment Y study is to determine if the unit(s) for which a change in status requested is necessary for system reliability based on the criteria set forth in the MISO Business Practices Manuals. The study work included monitoring and identifying the steady state branch/voltage violations on transmission facilities due to the unavailability of the Generation Resource or SCU. The relevant MISO Transmission Owner(s) and/or regional reliability criteria are used for monitoring such violations.

The purpose of this study is to assess the reliability impacts from the suspension of *Rush Island 1 and 2* located in Festus, MO effective September 1, 2022.

3. STUDY ASSUMPTIONS & INPUTS

3.1 Study Models

Studies performed using the following power flow models:

- The near-term starting models will be from the MISO MTEP21 2022 case, changes will be made to the models to reflect system topology for the start date of the generation's change of status request:
    - 2022 Summer Shoulder (Source: MISO21_2022_SHAW_TA)
    - 2022 Summer Peak (Source: MISO21_2022_SUM_TA)
    - 2022 Summer Low Load (Source: MISO21_2022_SLL40_TA)
    - 2022 Winter Peak (Source: MISO21_2022_WIN_TA)

- Results from the out-term case in the recently complete Attachment Y-2 Study regarding Rush Island Units 1 and 2 were used to satisfy the Attachment Y out term model requirement. Please refer to Appendix 10.4 for model and assumptions information.

For each model, two scenarios were created which represent the "before" and "after" generator change of status.

3-I Study Models

Model Name	Loads	Topology	Study Unit(s)	Dispatch Type[3]	Contingencies Category
2022SH_RUSH_ISLAND_OFF	Summer Shoulder	2022	OFF	SCED	P1,P2,P4,P5,P7, Selected P3, P6
2022SH_RUSH_ISLAND_ON	Summer Shoulder	2022	ON	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6
2022SP_RUSH_ISLAND_OFF	Summer Peak	2022	OFF	SCED	P1,P2,P4,P5,P7, Selected P3, P6
2022SP_RUSH_ISLAND_ON	Summer Peak	2022	ON	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6
2022SL_RUSH_ISLAND_ON	Summer Low Load	2022	ON	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6
2022SL_RUSH_ISLAND_ON	Summer Low Load	2022	ON	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6

[3] Dispatching according to procedure explained in BPM-020. "SCED + Scale" in the online cases means that all generators in the vicinity of the generator under study will remain dispatched at their SCED values identified in the corresponding offline case, and the rest of MISO will be scaled down to balance the overall generation in MISO after turning on the study units.

2022WP_RUSH_ISLAND_OFF	Winter Peak	2022	OFF	SCED	P1,P2,P4,P5,P7, Selected P3, P6
2022WP_RUSH_ISLAND_ON	Winter Peak	2022	ON	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6

3.2 Study Assumptions

3.2.1 Generation

- All applicable approved Attachment Y (Retirement/Suspension) generators were modelled offline
- Only new generators with signed GIA were modelled.

3-II Generation Assumptions

Generation Type	Unit(s) Description	2022
Nearby Approved Attachment Y	[redacted]	[redacted]
	Dallman 31 and 32	Offline
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]

3.2.2 Transmission

A Future Projects included in 2022 study models

3-III Future Projects in Models

MOD Project Name	MOD ID	Project Type	Status	MOD Effective Date
AM_GrandTower-Retire-ATT-Y	120771	Generator	Planned	6/1/2019
AM_Shelbyville Retirement	120773	Generator	Planned	6/1/2019
AM_MB-20 Richwoods Renewable	129513	Generator	Planned	6/1/2020
AM_MB-21 Utica at Lathrop	129515	Generator	Planned	6/1/2020
AM_MB-22 Green City Renewable at Kirksville	129517	Generator	Planned	6/1/2020
AM_DG18004 Salem Solar 10.5 MW	129501	Generator	Planned	12/1/2020
AM-TP1229-16794-Cahokia-Meramec	134872	MTEP A	Planned	12/1/2020
TP-961-11973-Cane-Grand Island Switching Station	23479	MTEP C	Target MTEP A	12/31/2020
AM-TP1288-16549-Lincoln-Meister	134333	Non-MISO Network	Planned	12/31/2020
AM_DG_DG17004 Duupue Substation 20 MW solar	129497	Generator	Planned	3/31/2021
AM-TP131-3033-Beehive substation	24625	MTEP A	Planned	7/13/2021

MOD Project Name	MOD ID	Project Type	Status	MOD Effective Date
AM-TP131-3033-Beehive substation	24625	MTEP A	Planned	7/13/2021
AM-TP131-3033-Beehive substation	24625	MTEP A	Planned	7/13/2021
AM-TP131-3033-Beehive substation	24625	MTEP A	Planned	7/13/2021
AM_TPSIRP005-11929 N Coult 230-345 conv	24775	MTEP A	Planned	10/2/2021
AM-TP1295-17324-J1055-GLACIER WF	129346	Generator	Planned	10/15/2021
AM-BASECASE-MACHINE DATA-UPDATES_ALSEY-G2-MOD32	148562	Generator	In Service	10/25/2021
AM-BASECASE-MACHINE DATA-UPDATES_G545	148564	Generator	In Service	10/25/2021
AM-TP1392-18311-J813	129475	Generator	Planned	10/31/2021
AM-TP1443-Upgrade Casey West-Sullivan 345 kV line	142114	Generator	Planned	10/31/2021
AM-TP1028-13795-Cahokia-Roxford	119150	MTEP A	Planned	11/1/2021
AM-J845-TP1400-18321-Ford WF	131740	Generator	Planned	11/1/2021
AM-TP970-12964-Boar Substation	23693	MTEP A	Planned	12/1/2021
AM-TPSIRP004-11928-Commodore 230-345kV conversion	24771	MTEP A	Planned	12/1/2021
AM-TP928-11966-Gateway Substation	25364	MTEP A	Planned	12/1/2021
AM-TP1024-15524-Sioux 345-138kV TX Replacement	118098	MTEP A	Planned	12/1/2021
AM-TP1121-16491-Sioux_Meppen-Sioux-Huster	120183	MTEP A	Planned	12/1/2021
AM-TP1129-16554-Maline	120206	MTEP A	Planned	12/1/2021
AM-TP1184-7862-Galena	120899	MTEP A	Planned	12/1/2021
AM-TP1133-17065-Tegler Breakers	123802	MTEP A	Planned	12/1/2021
AM-TP597-17224-Pershall substation	123814	MTEP A	Planned	12/1/2021
AM_DG_DG18003-Canton South	129499	Generator	Planned	12/1/2021
AM-TP1273-16709-Venice-ashely	130548	MTEP A	Planned	12/1/2021
AM-TP868-9733-Page Over stress breakers	130568	MTEP B	Target MTEP A	12/1/2021
AM-TP1291-11951-J800 BMTWN solar	134381	Generator	Planned	12/1/2021
AM-TP1047-17344-Berkeley sub repl brkers	140613	MTEP A	Planned	12/1/2021
AM-TP1257-15329-St Franc-Rivermines-2-Rebuild	140709	MTEP A	Planned	12/1/2021

MOD Project Name	MOD ID	Project Type	Status	MOD Effective Date
AM-TP1020-17829 Loose Creek Reactor	130604	MTEP A	Planned	12/2/2021
AM_TP866_9732-Mason Breaker replacement	119545	MTEP A	Planned	12/8/2021
AM-TP1256-16227 Marblehead Terminal upgrade	119619	MTEP A	Planned	12/8/2021
AM-TP1442-J1102-20905-Mulligan Solar	143348	Generator	Planned	12/21/2021
AM-TP1158-16793-Montgomery B12 upgrade	144064	MTEP A	Planned	12/30/2021
AM-TP1305-17665-Barrett Station 2nd TX	129914	MTEP A	Planned	12/31/2021
AM-TP1395-18315-J844-Sandburg WF	130902	Generator	Planned	5/1/2022
AM-TP1394-18314-J826 McLean WF	131119	Generator	Planned	5/1/2022
AM-TP1401-18322-J848	134029	Generator	Planned	5/28/2022
AM-TP938-11947-Greenback Substation	24560	MTEP A	Planned	6/1/2022
AM-TP965-12173-Miller substation	24680	MTEP A	Planned	6/1/2022
AM-TP974-15528-Dirksen	108686	MTEP A	Planned	6/1/2022
AM-TP891-9830-Meramec-Jachim	125768	MTEP A	Planned	6/1/2022
AM-TP1269-16705-Pana-Shelbyville Rebuild	130545	MTEP A	Planned	6/1/2022
AM-MB23-9843_20365-Normal E 138/69kV TX	136900	MTEP A	Planned	6/1/2022
AM-TP1416-19085-Shelbyville ring bus	139300	MTEP A	Planned	6/1/2022
AM-TP1433-19968-J1025-Fabius Substation	140454	Generator	Planned	6/1/2022
AM-TP1283-16990-Kline Ring Bus	141043	MTEP A	Planned	6/1/2022
AM-TP1359-18085-Tazewell XFMR 1 Replacement	141208	MTEP A	Planned	6/1/2022
AM-TP1339-18034-Tazewell Bkr Replacements	141475	MTEP A	Planned	6/1/2022
AM-TP735-17644-Rt51 sub	141497	MTEP A	Planned	6/1/2022
AM-TP1351-18074-Jacksonville IP BKR 1302	142254	MTEP A	Planned	6/1/2022
AM-TP914-11906-Casey West-Kansas 345 kV Line	142257	MTEP A	Planned	6/1/2022
AM-TP1458-21325-Rossville-Vermilion-Rebuild	144695	MTEP B	Target MTEP A	6/1/2022
AM-TP1381-18250-Robinson STATCOM	130919	MTEP A	Planned	6/2/2022
AM-TP1145-15490-Rador Breaker Additions	141484	MTEP A	Planned	6/2/2022
AM_DG18005 - Pilot Grove Solar 25 MW hamilton	129503	Generator	Planned	6/30/2022
AM_DG18006 Blue Willow Solar 25 MW Blandsville	129505	Generator	Planned	6/30/2022

3.3 Monitoring and contingencies

3.3.1 Monitor

Monitor all 100 kV and above facilities in areas AECI, SIPC, AMMO, and AMIL.

3.3.2 Contingencies

NERC Category P1, P2, P4, P5, and P7 used in MTEP21 study of facilities within areas AECI, SIPC, AMMO, and AMIL.

Category P3 contingencies were created using all single generator contingencies (P1-1), extracted from the P1 contingencies provided above, combined with all P1 contingencies provided above. To limit the number of possible P3 combinations:

- Only Category P1 events of facilities 100 kV or above within 8 (eight) Buses from the Study Unit(s) were used in creating the required P3 combinations.
- Generator contingencies (Category P1-1) with aggregated generation above 50 MW were used in creating the required P3 contingencies.

Similarly, Category P6 contingencies were created using all non-generator contingencies (P1-2 to P1-5) of facilities 100 kV or above within 8 (eight) Buses from the Study Unit(s).

Per Ameren Local Planning Criteria additional system sensitivity analysis was also performed.

- Non-coincident peak load in the Summer Peak case
- Winter Storm Uri scenario from February 15, 2021, using the State Estimator Model
    - Additional contingencies run by Ameren Transmission were also added to this analysis

4. STUDY CRITERIA

4.1 Applicable Reliability Criteria

4.1.1 Steady State Thermal Reliability Criteria

Ameren Transmission Planning Criteria applied for thermal analysis:

- For System Intact (NERC Category P0), all thermal loadings within 95% of the normal rating.
- For NERC Category P1-P7 contingencies, all thermal loadings within 95% of the emergency rating.

Southern Illinois Power Cooperative Transmission Planning Criteria applied for thermal analysis:

- For System Intact (NERC Category P0), all thermal loadings within 100% of the normal rating.
- For NERC Category P1-P7 contingencies, all thermal loadings within 100% of the emergency rating.

4.1.2 Steady State Voltage Reliability Criteria

Ameren Transmission Planning Criteria applied for voltage analysis:

- For NERC Category P0 (System Intact) – Pre Contingent
- For NERC Category P1-P7 contingencies – Post Contingent

Rated Voltage	Pre Contingent		Post Contingent	
	Min PU	Max PU	Min PU	Max PU
345	0.95	1.05	0.95	1.075
230, 161, 138	0.95	1.05	0.93	1.075

Southern Illinois Power Cooperative Transmission Planning Criteria applied for voltage analysis:

- For NERC Category P0 (System Intact) – Pre Contingent
- For NERC Category P1-P7 contingencies – Post Contingent

Rated Voltage	Pre Contingent		Post Contingent	
	Min PU	Max PU	Min PU	Max PU
All	0.95	1.07	0.91	1.09

4.1.3 Stability Analysis Monitored Facilities and Performance Criteria

MISO will monitor all generators and buses within the AMMO and AMIL control area. Simulation results will be interpreted and compiled against MISO planning criteria.

The following criteria will be used to evaluate the simulation results:

- All on-line generating units are stable
- No unexpected generator tripping
- Post-fault transient voltage limits: 1.2 per unit maximum, 0.7 per unit minimum
- Post-fault steady-state voltage limits: 1.1 per unit maximum, 0.9 per unit minimum
- All machine rotor angle oscillations must be positively damped with a minimum damping ratio of 0.81633% for disturbances with a fault or 1.6766% for line trips without a fault
- Ameren transient voltage recovery criteria:
  - Following the clearing of a fault resulting from single or multiple contingency events (Planning Events P1- P7), transmission voltages should return to 80% of nominal or greater within two seconds and 90 % of nominal or greater within ten seconds unless the system becomes radial following the outage of multiple contingencies.
  - Small signal analysis would show satisfactorily damped post-disturbance response with damping ratios of 3% or higher with modelled excitation system parameters based on field-tested data. Otherwise, damping ratios of 5% or greater would demonstrate satisfactory damping.
- Local Planning Criteria, if applicable as determined by the Transmission Owner

4.2 MISO Transmission Planning BPM SSR Criteria

In accordance with MISO BPM-020, System Support Resource (SSR) criteria for determining if an identified facility is impacted by the generator change of status are:

- Under NERC Category P0 conditions and category P1-P7 contingencies, branch thermal violations are only valid if the flow increase on the element in the "after" retirement scenario is equal to or greater than:
  - Five percent (5%) of the "to-be-retired" unit(s) MW amount (i.e. 5% PTDF) for a "base" violation compared with the "before" scenario, or
  - Three percent (3%) of the "to-be-retired" unit(s) MW amount (i.e. 3% OTDF) for a "contingency" violation compared with the "before" scenario.
- Under NERC category P0 conditions and category P1-P7 contingencies, high and low voltage violations are only valid if the change in voltage is greater than one percent (1%) as compared to the "before" scenario

Available mitigation may be applied for the valid NERC Category P1-P7 thermal and voltage violations describe above as allowed by NERC Standards.

- The need for the SSR is determined by the presence of unresolved violations of reliability criteria that can only be alleviated by the SSR generator and where no other mitigation is available.
- Evaluation of mitigation solutions will consider the use of operating procedures and practices such as equipment switching and post-contingent Load Shedding plans allowed in the operating horizon.

Ameren LPC will also be accounted for when determining if the facility will be required as an SSR and when determining potential mitigations for identified violations.

5. STUDY METHODOLOGY

5.1 Steady-State Performance Analysis

PTI – PSS/E version 34 and PowerGEM – TARA version 2102.1 were used to perform AC contingency analysis and SCED. Cases were solved with automatic control of LTCs, phase shifters, DC taps, switched shunts enabled (regulating), and area interchange disabled. Contingency analysis was performed on before and after cases. The results were compared to find if there were any criteria violations due to the unit(s) change of status.

5.2 Stability Analysis

MISO's stability analysis examined the impact of the Retiring Generating Facility by evaluating local and regional stability performance on the MISO transmission system in the Bench and Study cases. The most recent dynamics data from Ameren was used to develop these cases. DSATools – TSAT and PowerGEM – TARA was used to perform transient thermal and voltage analyses respectively. Fault analysis was performed on bench and study cases for the fault lists as specified by Ameren. The results were compared to find if there are any criteria violations due to the unit(s) change of status.

6. STABILTIY RESULTS

MISO's stability analysis identified violations that result in the loss of load due to Transient Voltage Recovery (TVR) issues with the suspension of *Rush Island 1 and 2*, including several scenarios that result in cascading voltage issues and loss of load. Detailed below are the contingencies with the most severe impact on the transmission system due to the suspension of *Rush Island 1 and 2*. Appendix 10.1 includes further information and the full results of MISO's stability study.

6.1.1 2022 Summer Shoulder TVR Issues

- No TVR violations met MISO or Ameren LPC criteria within the study area

6.1.2 2022 Summer Low Load TVR Issues

- No TVR violations met MISO or Ameren LPC criteria within the study area

6.1.3 2022 Winter Peak TVR Issues

- No TVR violations met MISO or Ameren LPC criteria within the study area

6.1.4 2022 Summer Peak TVR Issues

- The TVR violations reported in Table 7-I detail the most severe violations for the 2022 Summer Peak case.

6-I Top Voltage Violations 2022 Summer Peak Offline Case

Con Name	Monitored Bus	Vmin	Voltage Threshold	Duration	Time Threshold	Load At Risk
[redacted]	345156	0.7616	0.9000	5.517	3.000	1031 MW
[redacted]	345156	0.7612	0.9000	5.004	3.000	1017 MW
[redacted]	345156	0.7606	0.9000	3.4	3.000	1032 MW
[redacted]	345156	0.7613	0.9000	3.4	3.000	1023 MW
[redacted]	345148	0.7525	0.9000	3.284	3.000	1119 MW

7. STEADY STATE RESULTS

Appendices 10.2 of this report includes all constrained elements impacted by the suspension of *Rush Island*.

7.1 2022 Summer Shoulder Analysis

Analysis of the 2022 Summer Shoulder case identified the following

7.1.1 2022 Summer Shoulder Post Contingent Thermal Overloads

- No thermal overloads met the MISO SSR criteria
    - ≥ 3% OTDF or ≥ 5% PTDF of the study unit

7.1.2 2022 Summer Shoulder Post Contingent Voltage Issues

- No voltage violations met the MISO SSR criteria
    - ≥ +/- 1% adverse impact of study unit

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7.2 2022 Summer Low Load Analysis

Analysis of the 2022 Summer Low Load case identified the following

7.2.1 2022 Summer Low Load Post Contingent Thermal Overloads

- No thermal overloads met the MISO SSR criteria
  - ≥ 3% OTDF or ≥ 5% PTDF of the study unit

7.2.2 2022 Summer Low Load Post Contingent Voltage Issues

- The top post contingent voltage issues reported in Table 6-IV met the MISO SSR criteria
  - +/- 1% adverse impact of study unit
- All post contingent voltage issues that met the MISO SSR Criteria can be mitigated
  - Details are provided in Appendix 10.2
- Pre-Existing and Non-SSR issues are provided for informational purposes

7-I Top Post Contingent Voltage Issues 2022 Summer Low Load Offline Case

Area Name	Monitored Bus	Voltage [ON]	Voltage [OFF]	Voltage [DIF] (>1%)
AMMO	345301	0.9368	0.9231	-0.0137
AMMO	345302	0.9368	0.9231	-0.0137
AMMO	345301	0.9368	0.9231	-0.0137
AMMO	345302	0.9368	0.9231	-0.0137
AMMO	345305	0.9368	0.9231	-0.0137
AMMO	345305	0.9368	0.9231	-0.0137

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7.3 2022 Summer Peak Analysis

Analysis of the 2022 Summer Peak case identified the following

7.3.1 2022 Summer Peak Post Contingent Thermal Overloads

- No thermal overloads met the MISO SSR criteria
  - ≥ 3% OTDF or ≥ 5% PTDF of the study unit

7.3.2 2022 Summer Peak Post Contingent Voltage Issues

- The top post contingent voltage issues reported in Table 6-VI met the MISO SSR criteria
  - +/- 1% adverse impact of study unit
- All post contingent voltage issues that met the MISO SSR Criteria can be mitigated
  - Details are provided in Appendix 10.2
- Pre-Existing and Non-SSR issues are provided for informational purposes

7-II Top Post Contingent Voltage Issues 2022 Summer Peak Offline Case

Area Name	Monitored Bus	Voltage [ON]	Voltage [OFF]	Voltage [DIF] (>1%)
AMMO	345310	0.9404	0.9263	-0.0141
AMMO	345310	0.9404	0.9266	-0.0138
AMMO	345485	0.9362	0.9233	-0.0129
AMMO	345486	0.9362	0.9233	-0.0129
AMMO	345489	0.9362	0.9233	-0.0129

PUBLIC

7.4 2022 Winter Peak Analysis

Analysis of the 2022 Summer Peak case identified the following

7.4.1 2022 Winter Peak Post Contingent Thermal Overloads

- No thermal overloads met the MISO SSR criteria
  - ≥ 3% OTDF or ≥ 5% PTDF of the study unit

7.4.2 2022 Winter Peak Post Contingent Voltage Issues

- The top post contingent voltage issues reported in Table 6-VI met the MISO SSR criteria
  - +/- 1% adverse impact of study unit
- All post contingent voltage issues that met the MISO SSR Criteria can be mitigated
  - Details are provided in Appendix 8.2
- Pre-Existing and Non-SSR issues are provided for informational purposes

7-III Top Post Contingent Voltage Issues 2022 Winter Peak Offline Case

Area Name	Monitored Bus	Voltage [ON]	Voltage [OFF]	Voltage [DIF] (>1%)
AMMO	344099	0.9354	0.9253	-0.0101
AMMO	344094	0.9354	0.9253	-0.0101
AMMO	345301	0.9315	0.9214	-0.0101
AMMO	345302	0.9315	0.9214	-0.0101
AMMO	345305	0.9315	0.9214	-0.0101
AMMO	345485	0.9397	0.927	-0.0127
AMMO	345485	0.9397	0.927	-0.0127
AMMO	345486	0.9397	0.9269	-0.0128
AMMO	345486	0.9397	0.9269	-0.0128
AMMO	345489	0.9397	0.9269	-0.0128
AMMO	345489	0.9397	0.9269	-0.0128

8. LOCAL PLANNING CRITERIA ANALYSIS

Ameren Local Planning Criteria and NERC TPL standards require that the transmission system be evaluated under NERC Category P0 through P7 contingencies for core scenarios involving Summer Peak, Light Load, Winter Peak and Summer Shoulder Scenarios. MISO's Attachment Y and Y2 results indicate that there would be both thermal and Voltage violations for these core scenarios which may require Rush Island generation to be designated as SSR until those violations are mitigated. Here are the four violations in three different scenarios that require mitigation.

1. Winter Peak Scenario: Wildwood 345 /138 kV transformer would overload for the [redacted] with Rush Island generation offline. Ameren's LPC in section 2.2.2.1 requires that no interruption of firm transmission service will be permitted for P6 outages involving two 345 kV lines. Apart from thermal violation, under winter peak scenario there was a Voltage violation at Overton 345 kV substation for the [redacted] which will require a mitigation as per the NERC standards and Ameren LPC.
2. Summer Light Load Scenario: Rush Island 345 kV bus tie would overload for the [redacted] with Rush Island generation offline. This overload needs to be mitigated as per Ameren's LPC.
3. Summer Peak Scenario: Moro – Laclede North section of Wood River – North Staunton 138 kV line would overload for the [redacted] This violation needs to be mitigated as per Ameren's LPC and NERC TPL standard. After the Rush Island Y2 report has been published Ameren has aligned the In Service Dates of the Moro Project (MISO Project id# 11948) and Roxford Transformer addition (MISO Project Id#19988) which would mitigate the thermal violation on this 138 kV line.

Apart from core scenarios mentioned above, Ameren's Local Planning Criteria (LPC) and NERC Transmission Planning standards also require that assessments of the transmission system be made with wide ranging scenarios from system peak load to various weather sensitivities. For this Attachment Y study, Ameren Transmission team suggested to consider two specific scenarios on top of the core scenarios that were considered, these include Non-Coincident 1 day in 10 year peak load and Winter Storm Uri.

Ameren recognizes that the issues identified under the Ameren's Local Planning Criteria are sensitivity scenarios that needs mitigation but should not be utilized for the designation of the Rush Island as an SSR.

Ameren Transmission team working with MISO evaluated the impact of Rush Island generation retirement under these scenarios and the results are included in Appendix 10.3.

Non-Coincident peak load scenario:

In this scenario, non-coincident peak loads were utilized for the Ameren Missouri and Ameren Illinois control areas instead of MISO coincident peak load. The rationale for choosing this scenario was to test the impact of Rush Island retirement during summer peak conditions as the weather in the St. Louis Metropolitan area has historically shown hotter conditions compared to the rest of MISO. Ameren believes that this is a high likely scenario and recommended that this scenario be evaluated with Rush Island Generation offline. The results of this scenario indicate that there could be voltage issues in the St. Louis Metro East and Metro South regions under single contingency (N-1) conditions.

For the outage of [redacted] the voltage at Dupo Ferry, Valmeyer and Selma substations could drop below acceptable levels without Rush Island generation. These voltages are below acceptable values from Ameren's planning criteria and will require a mitigation.

Winter Storm Uri Scenario:

Ameren requested MISO team to consider impact of Rush Island generation offline during Winter Storm Uri as the second sensitivity scenario. MISO utilized state estimator model to evaluate this scenario, and when Rush Island generation was turned offline the power flow case became unstable. MISO had to dispatch Callaway generation even though this plant was offline during Winter Storm Uri. The instability in the power flow case indicates that there is a potential for a local area collapse if Rush Island generation would have been offline during this time. The local area collapse could exceed 1500 MW in the St. Louis metro area and could have affected significant number of customers in both Ameren Missouri and Ameren Illinois.

The results of the analysis showed multiple thermal issues for NERC Category P3 (N-1 + Generator) and significant number of thermal issues (more than 80 unique overloads) for category P6 (N-1-1) contingency events. Ameren recommends that the issues identified for NERC P1 (N-1) and P3 (N-1+ Generator) events be mitigated for this scenario.

There was a total of nine thermal issues identified under P1 and P3 events, out which five of them could be mitigated either with projects currently under construction or with projects that are in advanced stages of planning like MISO LRTP Tranche 1. There are four thermal violations that Ameren recommends be mitigated which include the overloads on

(1) Effingham NW – Neoga South 138 kV line
(2) Hannibal West – Palmyra 161 kV line
(3) Spalding – Hannibal West 161 kV line
(4) Coffeen North – Roxford 345 kV line.

9. CONCLUSION

After being reviewed for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), the analysis determined that there are reliability issues identified related to the suspension of *Rush Island* that may require the generators to be designated as System Support Resources ("SSR") units following the stakeholder process.

There were both severe steady state and transient voltage recovery (TVR) violations that would require the generators to be designated SSR units. In the summer peak case, there were five stability violations that did not meet Ameren voltage recovery criteria and would result in over 1,000 MW of load loss, which, if allowed, would be considered a potential Interconnection Reliability Operating Limit (IROL) within the MISO footprint in accordance with BPM-020 Section L.3.6. All voltage violations seen can be mitigated with load shed per MISO SSR criteria and additionally per WVPA there already exists operating guides to mitigate the known issues.

Prior to this Attachment Y, MISO also studied an Attachment Y-2 submitted by Union Electric Company – Ameren Missouri. This study had an effective date of June 1, 2023, but there were no other changes to study assumptions or system topology between the time the Attachment Y was submitted and the final Y-2 report. Therefore, the results of the Attachment Y-2 study will also be used to determine SSR need. The Attachment Y-2 report is included as an Appendix to this Attachment Y report. Three thermal violations were identified in three different scenarios in 2023 that require mitigation based on Ameren's Local Planning Criteria and one steady state voltage violation was identified for the winter peak case in 2023 and several stability voltage violations were identified for the summer peak case in 2023 that may require *Rush Island* to be designated as System Support Resources ("SSR") units following the stakeholder process.

In addition, MISO performed an analysis to determine if both units are required to mitigate the violations identified. That analysis determined that with one unit online, violations still exist that may require *Rush Island* to be designated as System Support Resources ("SSR") units.

10. APPENDICES

10.1 Stability Study Results

Appendix 10.1 is attached to this report.

10.2 Steady State Study Results

Appendix 10.2 is attached to this report

10.3 Sensitivity Study Results

Appendix 10.3 is attached to this report. For the Winter Storm Uri case, the files with the format "Winter_Storm_Uri_[Result Type]" were run by MISO and the file labelled with "Ameren" was run by Ameren. For the Non-Coincident Load case, the file labelled "2022SP_NC" is the transient voltage recovery analysis results and the files with the format "Non-Coincident_Load_[Result Type]" are the steady state analysis results.

10.4 Attachment Y-2 Report

Appendix 10.4 is attached to this report.

10.5 Possible SSR Mitigations Analysis

10.5.1 Overview

Additional mitigation analysis was also conducted for this study to determine whether both units are needed for grid reliability. The analysis determined that there are reliability issues identified related to the suspension of *Rush Island* that would require both generators to be designated as a System Support Resources ("SSR") units. There still exists one TVR violation that did not meet Ameren voltage recovery criteria and would result in over 1,000 MW load loss. Further details regarding this analysis are provided in Appendix 10.5.2.

10.5.2 SSR Mitigation Analysis Results

Appendix 10.5.2 is attached to this report.

EXHIBIT B

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

UNITED STATES OF AMERICA, Plaintiff, SIERRA CLUB, Plaintiff-Intervenor, v. AMEREN MISSOURI, Defendant.	Civil Action No. 4:11-cv-00077-RWS

DECLARATION OF JUSTIN DAVIES IN SUPPORT OF AMEREN'S SUPPLEMENTAL BRIEF IN SUPPORT OF ITS MOTION TO MODIFY THE COURT'S REMEDY RULING

I, Justin Davies, am over 18 years of age and make the following declaration pursuant to 18 U.S.C. § 1746:

1. This Declaration is based on my personal knowledge, and information available to me in my role at Ameren Missouri ("Ameren"). On December 13, 2021, I filed a previous declaration describing Ameren's preliminary reliability assessment and its January 2022 Y-2 Application to the Midcontinent Independent System Operator, Inc. ("MISO"). In this Declaration, I describe the grid stability risks that would be caused by Rush Island's retirement, as identified by MISO in both the Attachment Y-2 and the recently completed Attachment Y study. I also describe certain transmission grid projects necessary to address and mitigate those risks. Finally, I address the process for MISO's expedited approval of the mitigation projects and the timeline for their installation.

2. For the Court's convenience, I repeat certain aspects of my original Declaration. I have been employed by Ameren Services Company for approximately 20 years. Ameren Services provides business and administrative services to Ameren Corporation's family of companies including Ameren Missouri. I hold the position of Director of Transmission Planning. Among our responsibilities, Transmission Planning interacts with regional transmission organizations and implements reliability guidelines and standards. In performing our work, we use sophisticated models to evaluate system configurations and identify transmission risks, including risk of load loss, line or equipment overloads, voltage problems, and other circumstances where system collapse could occur.

3. Ameren is a member of MISO, a regional grid operator regulated by the Federal Energy Regulatory Commission ("FERC"). MISO manages the regional transmission grid and operates energy markets pursuant to a Tariff approved by FERC. In addition to owning generating assets, Ameren owns and operates a transmission network in Missouri including five Missouri and Illinois counties that comprise the St. Louis metropolitan area. Ameren's transmission network is interconnected with other networks, all of which form an integrated transmission system needed to ensure the reliable delivery of power to the region.

4. Ameren's Transmission Planning group and MISO are responsible for evaluating the potential impact on Ameren's transmission grid should Rush Island be removed from service, *i.e.*, retired. Specifically, my group has evaluated whether such retirement, without mitigation measures, could result in an adverse impact on local and/or regional grid stability.

5. **MISO's SSR Determination.** On February 28, 2022, Ameren submitted an Attachment Y application and requested that MISO evaluate the impact of Rush Island's pending retirement. After finalizing its Scoping Study and modelling runs, MISO completed its assessment

on June 7, 2022. MISO's Attachment Y analysis confirms that both Rush Island generating units must be designated as a System Support Resources (SSR) Units unless feasible alternatives are identified. MISO's Attachment Y analysis applied, as required by its Tariff, both Ameren's Criteria and Guidelines (also known as the Local Planning Criteria ("LPC")) and national NERC TPL-001-4 standards.[1]

6. Ameren's and MISO's transmission planning teams have identified transmission reliability risks that must be addressed before Rush Island's retirement can safely and reliably occur. Ameren Transmission, as the transmission owner and as contemplated by MISO's Tariff, provided required input as to specific mitigation measures and locations. While the Attachment Y process is confidential, once a determination is made that a resource (here, Rush Island) is needed for reliability and is designated by MISO as a likely System Support Resource, a public comment process begins and allows for the consideration of alternatives to MISO's SSR designation. MISO is in the process of scheduling a stakeholder meeting to take public comments on the SSR designation. Ameren does not believe viable alternatives exist with respect to MISO's SSR designation that both address the reliability issues identified in the Attachment Y study and are consistent with the LPC.

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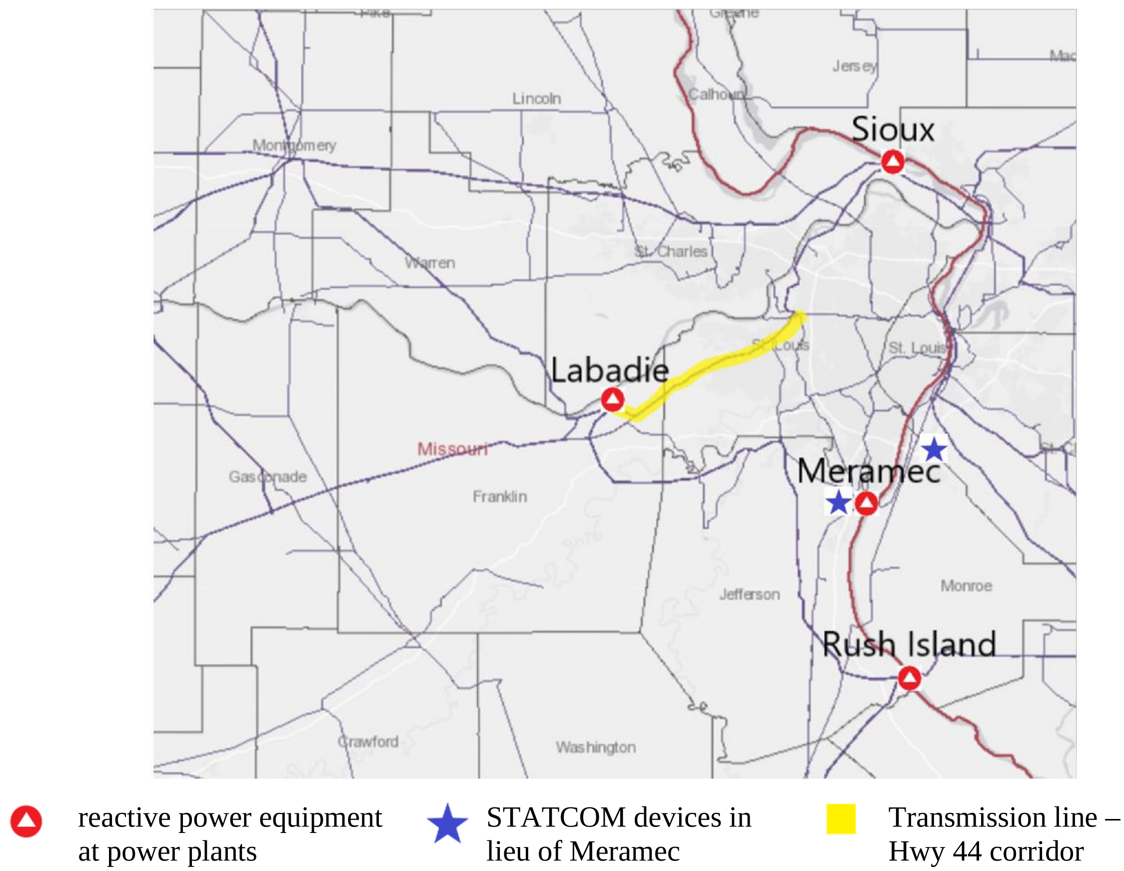
[1] In its Y-2 study (completed in early 2022), MISO did not consider Ameren's LPC for both the study scenarios and mitigation measures. The Attachment Y analysis included such local criteria and also included several extreme weather sensitivity scenarios such as a reoccurrence of Winter Storm Uri and a summer peak load, heat-wave event. Ameren Transmission also analyzed the high – load, extreme weather scenarios. Should there be a recurrence of Winter Storm Uri, and in the absence of mitigation measures, the modeling identified two significant concerns associated with transmission lines in Illinois and the potential for system collapse in Missouri. Removal of Rush Island (and Meramec) from the system results in a lack of generation in the metro area requiring MISO to direct power from Indiana across transmission lines in Illinois that would then be loaded above their current carrying capacity. If such lines were to trip because of overload, load drop (i.e., large-scale outages) could occur in the St. Louis metro area. In addition, should Ameren's Callaway Energy Center unexpectedly go offline during an extreme winter storm event AND a transmission related outage occurs on Ameren's system, then there exists a risk of system collapse in the St. Louis metropolitan area.

7. There are three primary risks associated with the retirement of Rush Island without mitigation: (a) thermal overload due to altered power flow; (b) loss of load (power for customers) due to insufficient voltage support resources; and (c) loss of load due to insufficient transient voltage recovery resources.

8. **Thermal Overload Due to Altered Power Flow.** Ameren's transmission system was constructed based upon a design flow of energy from large, baseload generation facilities into and around the metropolitan area. The retirement of Rush Island disrupts these energy flow patterns resulting in a disruption in the designed flow of energy. Below is a simplified schematic that depicts the location of these "props" relative to major transmission lines in the metropolitan area.

<u>AMEREN 345 kV TRANSMISSION LINES AND REACTIVE POWER SUPPORT</u>



9. These shifts in energy flow patterns can perhaps be illustrated via an analogy to the local transportation system. The retirement of Rush Island is akin to permanently shutting down Highway 55 between I-270 and downtown, thereby re-directing traffic onto Highways 44 and 64. Retiring Rush Island also creates a weakness in the current system best illustrated in our transportation example by forcing 3-lane traffic on a two-lane bridge, where 2 lanes were sufficient before the retirement. Bottlenecks and overload occur. (Attached as Exhibit 1, for the Court's convenience, is a map of the highway systems around the St. Louis metropolitan area.)

10. Transmission reliability modeling indicates that without Rush Island in service, overloads at various locations could occur as the network (lines and substations) will no longer be in sync with original design criteria and flow assumptions. Ameren proposes to address the re-directed and increased flow across part of the system by installing a larger capacity transformer at a substation in the Wildwood, Missouri area. MISO has confirmed that the reliability risk associated with the transformer overload renders Rush Island as a System Support Resource (SSR) until such time as the Wildwood transformer has been replaced and is in service. In addition, upgrading a bus bar connection at the transmission substation located at Rush Island allows for a better synched energy flow and addresses the bottleneck issue (*i.e.*, the two-lane bridge example referenced above).

11. **Insufficient Voltage Support Resources.** As designed, the transmission network is supported, or "propped up" by Ameren's four coal plants (Rush Island, Sioux, Meramec, and Labadie). In addition to generating energy/megawatts (MW), the coal plants provide reactive power critical to balancing the voltage levels (MVars) that flow across lines that support the transmission system. Modeling also reflects that with Rush Island retired, and not producing the significant amount of voltage support resources it otherwise would, there is a risk that during the

winter peak period unacceptable low voltages may occur. Modeling further indicates that these voltage-based reliability concerns are not limited solely to Ameren's transmission network and retail customers. They could extend to customers of other utilities, including Citizen's Electric and Associated Electric Cooperative Inc. To address this issue, MISO has proposed the installation of a capacitor bank at the Overton Substation, near Columbia, Missouri. At this substation, multiple high power transmission lines (345/161 kV) come together and connect with 69kV distribution lines. The capacitor bank project will help regulate the appropriate voltage level across the Ameren network and various interconnections. MISO has confirmed that until the capacitor bank equipment can be placed in service to address this problem, the reliability risk caused by Rush Island's retirement (and concomitant reduced voltage support) renders Rush Island a System Support Resource (SSR).

12. **Insufficient Transient Voltage Recovery Resources.** In addition to the above issues, without Rush Island online to contribute so-called transient voltage recovery support, there is a risk of additional system failures. Without adequate reactive power, the system cannot adequately recover from short-term events, such as a windstorm, lightning strike or transmission tower failure. When these events occur, the large providers of reactive power (like Rush Island) provide an immediate and short-term supply of voltage support in the milliseconds and seconds after a major disruption to the grid as described above. Without that provision of immediate reactive voltage support, the grid may lose load (and consequently service to customers).

13. For example, a windstorm could cause a failure on the major 345 kV transmission line that runs from Labadie Energy center, along the Highway 44 corridor, into the metropolitan area. That failure, in turn, could cause an immediate, short-term voltage drop from which the system could not recover without a significant load reduction (customers losing power). Ameren

estimates that type of event would place at risk approximately 1000 MW of load, or roughly 200,000 customers. Both Ameren's LPC and national NERC TPL standards have design and operating requirements regarding such occurrences.

14. To address similar voltage support issues caused by the retirement of the Meramec Energy Center (which is scheduled to be retired later this year), Meramec's reactive power capability will be replaced by two static var compensators ("STATCOM")—voltage regulation devices—installed at strategic locations in Missouri and Illinois. (Locations noted on map above, along with other transmission system upgrades.) These transmission network upgrade projects cost approximately $244 million.

15. As part of my job duties, I am responsible for reviewing and updating as appropriate Ameren Transmission's LPC and filing same with FERC on an annual basis. Copies of our most recently updated LPC, along with the prior versions, are attached as Exhibit 2 hereto. Absent mitigation, during the summer months and at times of heavy air conditioning load, with Rush Island offline the system does not meet Ameren's LPC criteria for approximately 900 different scenarios, with a maximum 1000 MW or 200,000 customers at risk. The attached Ameren LPC classifies load at risk in Section 2.8.3. In Section 2.2.2 of the Ameren LPC, Ameren denotes a load at risk limit to be 300MW.

16. **Mitigation Projects to Ensure Reliability**. Ameren has identified, and MISO concurs, the following transmission projects are necessary to address the reliability concerns identified in the February 2022 Attachment Y-2 report and also the June 2022 Attachment Y report:

Project	Estimated Completion Date
Installation of a Capacitor Bank at the Overton Substation to address voltage issues	Spring/Fall 2023
Replacement of a Transformer at the Wildwood Substation in St. Louis County to address overload concerns	Spring 2024
Upgrading of a bus bar tie position at a substation adjacent to Rush Island to address voltage issues	Spring/Fall 2023
Installation of four (4) STATCOMs in the St. Louis Metropolitan area to provide reactive power support; installations to occur as equipment becomes available 2024-2025	Final STATCOM Fall 2025, perhaps earlier

17. **Attachment Y Report**. The recently completed Attachment Y analysis identifies additional reliability issues associated with both the summer and winter peak periods and the potential for load loss. Working with MISO, Ameren is in the process of identifying those additional mitigation projects to address those concerns. At present, Ameren believes that the timeline for implementation of such additional projects falls within the above general timeframe. While such projects are required by MISO and Ameren's Local Planning Criteria, those projects do not result in the units being designated as SSRs.

18. **Expedited Approval by MISO.** To ensure rapid approval and deployment of the mitigation projects, Ameren has coordinated with MISO to identify and reach consensus on the necessary mitigation projects and has submitted the above projects to MISO as part of MISO's expedited project review ("EPR") process. MISO's stakeholder process approval could come during late summer 2022. By using the EPR, the approval timeline process is accelerated as compared to the standard, once-per-year MISO Transmission Expansion Plan ("MTEP") process. Under the annual MTEP process, new transmission projects would need to be proposed by September 2022 but would not be subject to approval until December 2023.

19. **Timing of Project Installations.** Based on current planning projections, and assuming project approval by MISO by late summer 2022, two of the four projects (Overton Capacitor Bank and Rush Island Bus Upgrade) can be completed in 2023, with the Wildwood Transformer in 2024. The STATCOM equipment set includes a specifically designed transformer in addition to the STATCOM device. My colleague, Ben Ford, describes the supply chain issues associated with core steel and transformers. We have met with vendors at recently as May 26, 2022, regarding indicative pricing, manufacturing specifications and timing. Based upon present knowledge, Ameren believes it could install the final STATCOM equipment set following the summer of 2025, and perhaps earlier. Construction projects on the transmission system require line and substation outages that must be coordinated and scheduled with MISO and are generally limited to the spring and fall months to avoid peak load periods. As my colleague Tim Lafser addresses in his Declaration, Rush Island could operate at a significantly reduced level during this interim period and generally would not operate during the spring and fall months.

Executed on: June 7, 2022

Justin Davies

Justin Davies

EXHIBIT 1

Exhibit 1

St. Louis Metropolitan Area Highway Systems

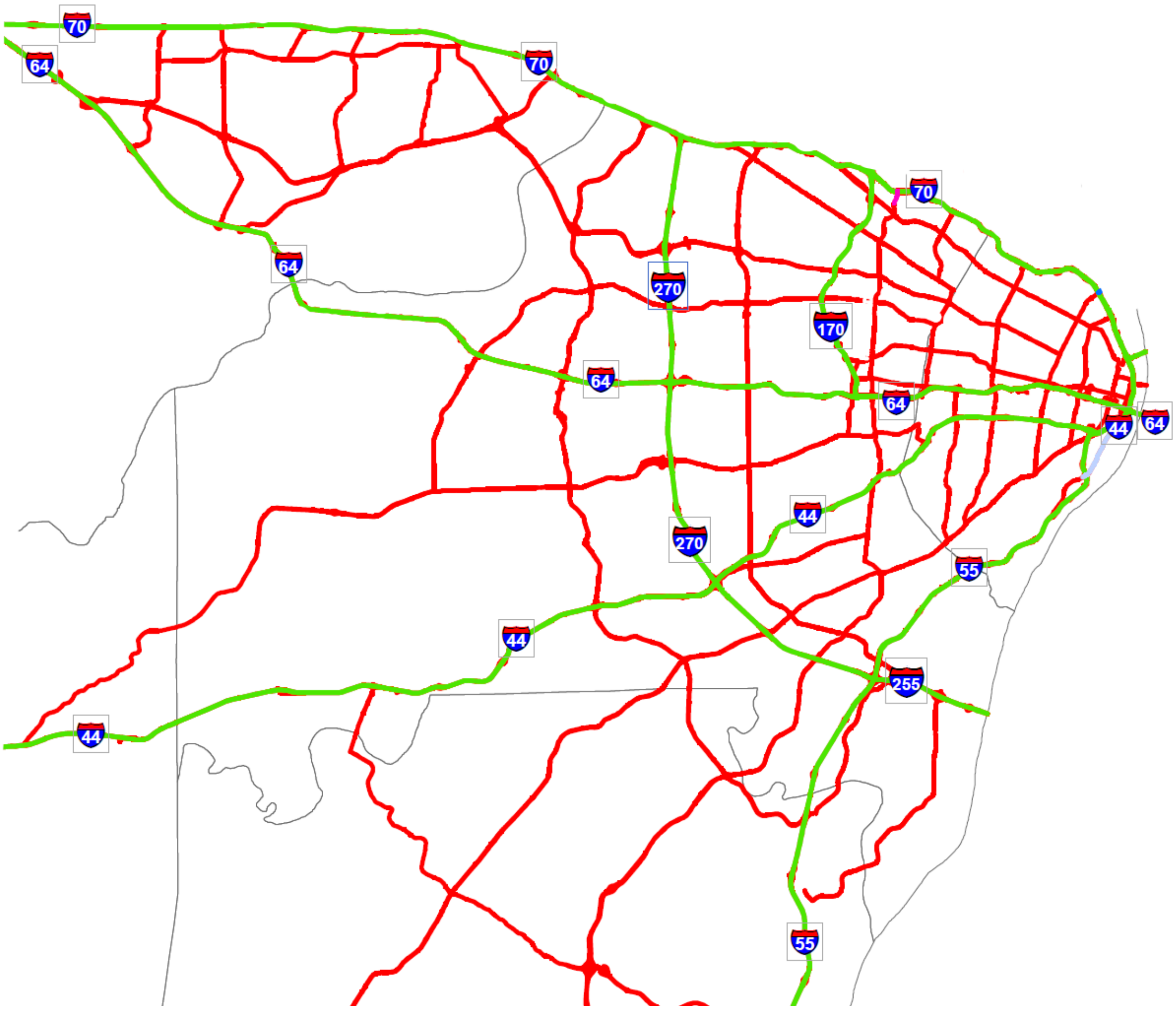


EXHIBIT 2

AMEREN's
(On Behalf of Its Transmission Owning Affiliates, Including Ameren Missouri, Ameren Illinois, and Ameren Transmission Company of Illinois)

TRANSMISSION PLANNING

CRITERIA AND GUIDELINES

Document Approvals			
Approved by	**Role**	**Signature**	**Date**
Justin Davies	Manager Transmission Planning	Signature via SharePoint	

Revision History		
Revision Number	**Revision Date**	**Revisions**
0	03/28/2003	First Issue
1	04/29/2003	Annual Update
2	03/29/2004	Annual Update
3	03/29/2005	Annual Update
4	03/29/2006	Annual Update
5	03/27/2007	Annual Update
6	03/31/2008	Annual Update
7	03/25/2009	Annual Update
8	03/31/2010	Annual Update
9	03/28/2011	Annual Update
10	03/30/2012	Annual Update
11	03/21/2013	Annual Update
12	03/14/2014	Annual Update
13	03/24/2015	Annual Update
14	10/22/2015	Annual Update
15	03/22/2016	Annual Update
16	03/15/2017	Annual Update
17	03/26/2018	Annual Update
18	03/1/2019	Annual Update
19	04/12/2020	Reorganized document and removed information that is duplicated in other documents. Clarified criteria for load shedding, import capability, Short circuit, voltage limits, transient voltage recovery, and interconnections.
20	03/05/2021	Clarified wording regarding HVDC voltage schedules and corrected typos.

Table of Contents

1.0 INTRODUCTION

This document contains the Ameren Transmission Planning criteria and guidelines. The Ameren Transmission Planning Department is responsible for planning the development of the Ameren bulk power system facilities, 100 kV and above, on behalf of its transmission owning affiliates, including Ameren Missouri, Ameren Illinois, and Ameren Transmission Company of Illinois. These criteria address customer expectations, and compliance with NERC reliability standards, SERC regional criteria, applicable state regulations, and public policy requirements.

There is a definite distinction between criteria and guidelines as used in this document. Criteria have had specific management approval and are unconditional, for they are the principles by which a reliable Ameren transmission system is planned. A guideline is of lesser importance and subject to engineering judgment. A guideline may reflect generally accepted practice, normal procedure, or a general philosophy to be applied depending on the particular circumstances in a specific case.

Deterministic tests of a limited number of system conditions require the application of engineering judgment to evaluate the complex multi-variable problems involved in planning analysis. Sensitivity analyses, reliability margins, and adequacy assessments are used in conjunction with the criteria and guidelines to plan a robust transmission system.
Though a project may be identified as a result of this document's application, project timing may be dependent on several factors including regulatory restrictions, management directives, contractual relations with others, and/or socio-environmental considerations.

These criteria and guidelines have evolved over a number of years, and reflect considerable planning and operating experience for the Ameren transmission system. Ameren Transmission Planning criteria are subject to change at any time at Ameren's discretion. Situations that could precipitate such a change could include, but are not limited to, new system conditions, operational issues, maintenance issues, customer requests, regulatory requirements and Regional Entity or NERC requirements.

While the following criteria and guidelines provide a framework for planning the Ameren transmission system, it must be recognized that the system that exists at any point in time will likely be different from planned system conditions due to variations in dispatch, facility outages, market activity, environmental factors, etc.

2.0 RELIABILITY CRITERIA AND GUIDELINES

The measure of successful transmission system planning is the attainment of a system that provides dependable service at a reasonable cost over a long period of years, and in the process of its growth and development, acquires no significant weakness that stands in the way of substantially greater growth or utilization. Each individual piece of system equipment must be selected so as to meet probable future demands; even more importantly, the basic system pattern must be such that it can grow without causing the obsolescence or the major rebuilding of facilities already installed.

2.1 NERC Reliability Standards and SERC Regional Criteria

Ameren intends to comply with all NERC Reliability Standards. Ameren's transmission planning criteria and guidelines, at a minimum, are intended to provide full compliance with the NERC Planning Standards, as they pertain to transmission system planning.

SERC regional criteria are detailed regional criteria and guidelines describing the process to be used at the regional level to be compliant with the NERC Reliability Standards.

2.2 Ameren Planning Criteria and NERC Reliability Standards

2.2.1 NERC Reliability Standard TPL Planning Events

Short-term emergency ratings may be required to cover post-contingency conditions until system adjustments can be made to mitigate any overloads or low system voltages, and particularly for planning events involving the outage of multiple facilities (P2, P3, P6, or P7). Such adjustments would include generation redispatch, transmission switching, shedding of load, or transfer of load at the subtransmission level. Transmission upgrades or other mitigation may need to be initiated or advanced if the expected short-term emergency ratings cannot cover the expected post-contingency loadings, or if the proposed mitigation cannot be accomplished within the time duration of the short-term emergency rating. Refer to Ameren's FAC-008 procedure document for short-term emergency rating information.

2.2.2 Specific Cases Where Ameren Transmission Planning Criteria Exceed Performance Requirements of NERC Reliability Standard TPL-001-4

In several instances, Ameren Transmission Planning Criteria exceed the performance requirements of NERC TPL Standards. These specific cases are listed below:

1. Following N-2 (or N-1-1) contingency events involving two 345 kV circuits (Planning Events P6-1-1 and P7), no interruption of Firm Transmission Service or loss of Non-Consequential Load will be permitted, except to those generators that have only two outlet lines that would be involved in the contingency event. In general, no system adjustments will be allowed between transmission circuit contingencies; however, when a contingency outages a line that terminates at a ring bus, either manual or SCADA controlled restoration of the ring bus following the first contingency (open line disconnects or open loops), would be allowed, and all facilities would be operated within applicable ratings.

2. For NERC Planning Events P2-2, P2-3, P2-4 and P4-P7, no NERC cascading shall occur and Total Load at Risk shall be limited to 300 MW. (Note exception for EHV facilities in item 1.) *The 300 MW level for loss of load for more than 15 minutes due to equipment failures represents the threshold of a NERC reportable event under NERC Standard EOP-004 and also the threshold for the DOE Energy Emergency Incident and Disturbance Reporting Requirement per Form EIA-417.* Load restoration via manual transfers (to reduce the magnitude of the load loss) shall *not* be considered when determining if the 300 MW threshold will be exceeded.

3. For NERC Planning Events P3-1 through P3-5, no System adjustments would be allowed except for increased generation to provide the replacement power for the outaged generators. The Ameren transmission system should be planned to handle a variety of generation dispatch scenarios and should not be dependent on a particular set of generation dispatch patterns to mitigate thermal overloads or low voltage conditions.

4. An entire peaking plant or intermittent plant should be considered as a single generator for NERC Planning Events P1-1, and P3-1 through P3-5. No System adjustments would be allowed except for increased generation to provide the replacement power for the outaged plants. The Ameren transmission system should be planned to handle a variety of generation dispatch scenarios and should not be dependent on peaking plants or intermittent resources to mitigate thermal overloads or low voltage conditions. Osage hydro generation should be considered as a peaking plant for the purposes of planning the Ameren transmission system, recognizing that the Osage units can provide some reactive support while operating as synchronous condensers.

5. Double-line-to-ground faults would be utilized instead of single-line-to-ground faults for NERC Planning Events P2-2, P2-3, P4-1, P4-2, P4-3, P4-5, P5-1, P5-2, P5-3 and P5-5.

6. For all NERC Planning Events relevant to Callaway Plant, three-phase

faults would be utilized per the Callaway NPIR.

2.2.3 Use of Remedial Action Schemes or Operating Guides/Procedures to Meet Reliability Standards

Remedial Action Schemes (RAS) or Operating Guides/Procedures may be used as an interim solution to alleviate steady state transmission constraints pending the completion of planned and committed network upgrades to meet national and regional standards and Ameren transmission planning criteria. RAS may be considered, on an interim basis, as generation plants can often be constructed and operational before the necessary transmission facilities can be upgraded to allow network resource (NR) status or resolution of injection-related transmission constraints to allow energy resource (ER) status. Remedial Action Schemes may be utilized on a long-term basis for maintaining transient stability of one or more generating units in response to a specified set of contingency events as detailed in in section 2.4.7.

2.3 Transmission Interconnection Planning

2.3.1 New AC Transmission Interconnections

Consistent with FAC-001 and FAC-002 requirements, all new Transmission Interconnections and Material modifications of existing Transmission facilities are addressed in the Ameren document "Transmission Facility Interconnection Procedures" posted on OASIS.

2.3.2 Incremental Import Capability Criteria and Guidelines

2.3.2.1 Criteria for Incremental Import Capability Related to Generation Reserve

Unless a level of import capability requirement for generation reserves is otherwise specified by RRO or RTO requirements, a minimum simultaneous (meaning from multiple cardinal directions at the same time) incremental import capability (First Contingency Incremental Transfer Capability = FCITC) of 2000 MW as limited by an Ameren transmission element would be used as a proxy to maintain transmission capability related to generation reserves in the Ameren Missouri or Ameren Illinois footprint. Note that valid limits to the transfers tested would consist of those facilities for which a PTDF (power transfer distribution factor) or OTDF (outage transfer distribution factor) of 3% or greater exists.

2.3.2.2 Guidelines for Voltage Constrained Maximum Simultaneous Incremental Import Capability for St. Louis Metro Area

Voltage constrained maximum simultaneous incremental import capability is an assessment of the adequacy of reactive resources in the St. Louis Metro area[1]. The basis of this assessment is the coincident outage of multiple generating units within roughly 100 miles of the St. Louis Metro area with all transmission facilities in service. Simultaneous incremental import capability simulation is performed so as to identify and prioritize locations for reactive compensation and/or system upgrades. Ameren's maximum simultaneous import capability shall be considered adequate if there are neither significant facility overloads, nor any metropolitan area subtransmission substation with 34.5 kV and 69 kV voltages below 95% of nominal.

For simulating this test, the coincident outage of any seven generating units within 100 miles of the St. Louis Metro area should be considered, with system loads based on the Ameren corporate load forecast.

Additional considerations for this test should include the coincident outage of a transmission facility and any five generating units within 100 miles of the St. Louis Metro area.

2.3.2.3 Guidelines for Nonsimultaneous Incremental Import Capability Testing

The Ameren transmission system is tested for nonsimultaneous transfer capability for imports (First Contingency Incremental Transfer Capability = FCITC) from all cardinal directions when sourcing from generally a single direction (north, south, east or west) at a time. An incremental import capability level of approximately 1200 MW, as limited by an Ameren transmission element, would be used as a proxy for each of the Ameren Illinois and Ameren Missouri systems. Valid limits are facilities for which a PTDF (power transfer distribution factor) or OTDF (outage transfer distribution factor) of 3% or greater exists. Powerflow simulations would be run to confirm that the area voltages would be acceptable to support the levels of transfer identified in the linear analysis.

Typically, values of nonsimultaneous incremental import capability into Ameren Illinois or Ameren Missouri from each cardinal direction in excess of 1200 MW would be considered as adequate. Values less than or equal to approximately 2/3 of the "Adequate" levels would be considered as less than adequate, and would require further review of the constraints for possible mitigation.

2.3.2.4 Guidelines for Nonsimultaneous Incremental Import Capability in Regional Studies

[1] St. Louis Metro area includes St. Louis City, St. Louis County, Jefferson, Franklin, and St. Charles Counties in Missouri, and Madison, St. Clair, and Monroe Counties in Illinois.

Ameren transfer capabilities are also determined in SERC and MISO regional studies, in which Ameren transmission planning engineers are participants. Linear analysis methods are used to calculate transfer capabilities, with AC power flow solutions used to confirm that the area voltages would be acceptable to support the transfer levels identified. Valid limits are facilities for which a PTDF (power transfer distribution factor) or OTDF (outage transfer distribution factor) of 3% or greater exists.

Ameren reviews the adequacy of the nonsimultaneous import FCITC due to the need to address variations in local and regional generation dispatch, net scheduled interchange, and uncertainties in the powerflow models associated with them. Less than adequate transfer capability may limit Ameren's options to import power from specific directions during both economic and emergency conditions. Economic considerations may require higher import capabilities than stated here for reliability purposes.

The above magnitudes of transfer capability reflect the requirements of the transmission system to supply the Ameren customer load with the desired reliability levels for a variety of system operating conditions considering:

1. The geographic location of the Ameren, Ameren Illinois, and Ameren Missouri systems and its electrical connections in the Eastern Interconnection,
2. The existing capability of the Ameren, Ameren Illinois, and Ameren Missouri systems and its interconnections to supply the Ameren customer load during first contingency conditions,
3. The response of the Ameren transmission system to system transfers, including those not involving Ameren,
4. The magnitude and economics of available generation in the Midwest,
5. The increased utilization of the transmission system for economic benefits, to maintain adequate generation reserve levels, to defer capacity additions, and/or to reduce fossil fuel emissions, and
6. The impact of simultaneous power transfers and other actions on day-to-day system operation.
7. Transmission service reservations impacting Ameren facilities.

Operating guides, procedures which may or may not involve operator intervention to alleviate the loading on a particular transmission facility, including generation redispatch and transmission switching may be used to enhance transfer capability between areas.

2.3.2.5 Subsystem Guidelines

To test the capabilities of the Ameren transmission system, different combinations of sink points should be selected for development of import subsystems. These import subsystems should, at a minimum, reflect generating units in close proximity and within the same relative geographic areas, such as Ameren Illinois, Ameren Missouri, or the St. Louis metropolitan area. The import subsystem participation file can also include the largest unit at each base-load plant in the Missouri and Illinois sides of the Ameren footprint. Other import subsystems can be developed based on fuel type, specific rail carrier or type of transportation, specific gas pipeline supply, system voltage, or other common concern. The status of generating units on interfaces should also be considered, including units in neighboring powerflow control areas electrically close to the Ameren system (e.g. Kincaid, Thomas Hill, New Madrid, Powerton, Gibson, etc.) to determine the impacts on import capability.

Source subsystem definitions should consider combinations of increased generation or decreased loads in powerflow control areas outside of the Ameren footprint. Control areas inside as well as outside of the MISO footprint should be considered for these exporting areas. System transfers from all cardinal directions should be considered.

2.4 Generation or HVDC Connection and Outlet Transmission Criteria

The planning of generation outlet transmission follows "General Transmission Planning Criteria", plus additional criteria for certain specific items such as stability considerations and high-speed reclosing of EHV circuits.

Consistent with FAC-001 and FAC-002 requirements, new Generator Interconnections and Material Modifications to existing generation facilities are addressed in the Ameren document "Generation Connection Procedures Requirements" posted on OASIS.

Material changes to existing generator interconnections shall trigger a review of system performance by Transmission Planning, as required by standard FAC-002. Such facility changes would include the following items:

1. Any change in nameplate MVA capability of generators or GSU transformers.
2. Any change in net MW or net Mvar capability of generators.
3. Any change to impedances of generator windings or GSU transformers.
4. Any change to generator, exciter, governor, or stabilizer model types or model parameters.
5. Any changes to generator/turbine inertia constants.
6. Any purchases of spare equipment, including GSU transformers, exciters, or other major electrical equipment planned to be installed on a short notice.

Studies would include a review of steady-state, short-circuit, and dynamics system performance under both normal and contingency conditions as necessary to ensure system reliability. Study assumptions, system performance, alternatives considered, and coordinated recommendations will be documented for review by the entities involved.

Requests for connecting generating equipment to the Ameren transmission system are handled by the Midcontinent Independent System Operator (MISO) via Attachment X to the MISO Tariff.

The MISO process includes application of a Transmission Owner's Local Planning Criteria. As this applies to Ameren transmission facilities, Ameren's Local Planning Criteria are stated in this document.

The new generator will be responsible to pay for system upgrades to mitigate overloads related to tests specified by the Ameren Planning Criteria when:

1) The overload was not identified for mitigation by the non-Ameren Planning Criteria tests performed as part of the generator connection request; and,
2) The new generator has a 3% TDF on the limiting element, or when the new generator increases the amount of the flow by more than 5% of the limiting facility's rating. (Appropriate seasonal normal rating used for non-outage condition, and Long Term Emergency rating used for a contingency.)

When applying the Ameren import capability criteria and guidelines found in sections 2.3, the new generator would be responsible for system improvements required to mitigate limitations to transfer capability for those facilities for which a PTDF (power transfer distribution factor) or OTDF (outage transfer distribution factor) of 3% or greater exists, and for which a 200 MW or greater reduction in transfer capability would result.

2.4.1 Generator and HVDC terminals Power Factor

As a minimum criterion, all synchronous generators are required to have minimum capability of 95% leading and lagging net power factor at the point of interconnection.

Newly interconnecting non-synchronous generators will be required to design their Generating Facilities to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation. At that point, the non-synchronous generator must provide dynamic reactive power within the power factor range of 0.95 leading to 0.95 lagging, unless the transmission provider has established a different power factor range that applies to all non-synchronous generators in the transmission provider's control area on a comparable basis.

Owners of HVDC transmission lines connected to the Ameren transmission system would be required to inject or absorb reactive power (+/- 95% power factor at AC high voltage connection at the converter station at all real power levels).

2.4.2 Plant Bus Configuration Criteria

For future generation connections to Ameren's transmission system with a voltage above 100 kV, the following minimum criteria apply as indicated in the table below. These criteria are consistent with past planning philosophy that provides the highest reliability configurations on the 345 kV system and highly reliable circuit arrangements at 230 kV, 161 kV and 138 kV. These configurations are consistent with Ameren design criteria and permit Ameren to maintain contiguous ownership of the transmission system. Note: Ameren is converting its 230 kV system to 345 kV, so plants should not connect at 230 kV unless they can convert to 345 kV as needed.

Connection Type	Configurations Allowed	Ownership
345 kV	Ring Bus Breaker-and-a-Half	Ameren owns all substation facilities at the connection point (network facilities). Ameren or IPP may own the lead line(s) connecting the IPP facility and Ameren substation (interconnection facilities).
161 kV or 138 kV	Ring Bus Breaker-and-a-Half Straight Bus	Same as above Note that a Straight Bus connection would only be permitted at an existing substation at Ameren's sole discretion.
230 kV	Ring Bus Breaker-and-a-Half	Ameren is converting its 230 kV system to 345 kV, so plants should not connect at 230 kV unless they can convert to 345 kV as needed.

Prior to 1980, AmerenMO had designed the plant connection at 345 kV at Labadie and Rush Island Plants via a straight bus arrangement. Because of the difficulties encountered (typically space requirements) in converting the straight bus style of connection, it is not intended to retroactively apply the current design configuration requirements to the existing plants, even for planned future generation connections at these facilities.

2.4.3 Plant Outlet Transmission Line Outage Criteria

Plant outlet transmission is considered adequate when, with the plant at full rated output, and with other generation in electrical proximity to the plant under study which contributes in an additive manner to the critical circuit loading dispatched so as to maximize facility loading such that the outage of any plant outlet circuit or other valid local single contingency does not result in the loading of any circuit above its emergency rating, and there are no transmission system voltages below values specified in section 3.1.

2.4.4 Steady-State Stability Criteria

Plant outlet transmission is considered adequate, from the standpoint of steady-state stability, when it will pass both of the following simulated tests:

1. With the plant at full real power output and lagging power factor (unit is providing Vars), with an outage of any one of the transmission outlet circuits, all generating units at the plant should remain stable in the steady-state.

2. With the plant at full real power output and lagging power factor (unit is providing Vars), with an outage of transmission outlet circuits on a common tower, all generating units at the plant should remain stable in the steady-state.

If the Test #2 listed above is not met, use of operating guides including reduced generation at the plant may be considered for a limited time until a committed reinforcement is implemented. Dynamic models representing winter peak load conditions should be used for the stability analysis, as the loads in these models provide less damping than the load in summer peak models and fewer generating units are available to provide synchronizing power.

Small signal analysis would show satisfactorily damped post-disturbance response with damping ratios of 3% or higher with modeled excitation system parameters based on field-tested data. Otherwise, damping ratios of 5% or greater would demonstrate satisfactory damping.

2.4.5 Guidelines for Determination of Generator Underexcitation Limits

A generator's underexcitation limit consists of operating points at which the generator is on the verge of losing synchronism with the remainder of the system. For a particular real power output, this occurs when the generator's excitation is gradually decreased so that the generator voltage behind the saturated synchronous reactance leads the Thevenin equivalent system voltage by 90°. Usually the generator is underexcited (absorbing reactive power) at this absolute underexcitation limit.

To allow for possible generator governor action in response to system disturbances, an appropriate margin is selected. Typically, these margins would be 3% of the generator capability with automatic voltage regulating equipment in-service, 5% for a non-continuous acting voltage regulator in-service, or 10% of the generator capability if automatic voltage regulating equipment is assumed to be out-of-service or is not present. Calculation of this minimum excitation limit for various real power output levels for a particular generator yields minimum excitation values which would result in the generator reaching its absolute minimum excitation limit should the generator governor call for an increase in generator real power output.

Typically, light load system conditions are used as a basis to determine minimum generator excitation limits, with the strongest source (outlet line) assumed out-of-service at the plant under study.

2.4.6 High-Speed Reclosing of the 345 kV Circuits Criteria

High-speed reclosing after the tripping of 345 kV circuits terminating at power plants is not allowed. The reason for this criterion is to reduce the probability of torsional oscillations causing damage to the shafts of the turbine-generators, in accordance with manufacturer's recommendations.

When required hot-bus dead-line reclosing of these EHV circuits is to be delayed by a minimum of ten seconds.

2.4.7 Transient Stability and Circuit Breaker Clearing Times Criteria

Plant outlet transmission is considered adequate, from the standpoint of transient stability, when

Contingency Test	Contingency Event Description and Outcome	Corresponding NERC Reliability Standard and Contingency Category
1.	With all lines in service, the plant and remainder of the system shall remain stable when a sustained three-phase fault on any outlet facility is cleared in primary clearing time.	TPL-001-4 Planning Event P1-2
2.	With all lines in service, the plant and the remainder of the system shall remain stable when sustained single-line-to-ground faults on any two circuits of a multiple circuit tower line is cleared in primary clearing time.	TPL-001-4 Planning Event P7
3.	With one outlet facility out of service, the plant and the remainder of the system shall remain stable when a sustained three-phase fault on any of the remaining facilities is cleared in primary clearing time.	TPL-001-4 Planning Event P6-1-1

4.	With all lines in service, the system and the remainder of the plant units shall remain stable when a sustained double-line-to- ground (2-L-G) fault* on any Ameren 345, 230, 161 or 138 kV plant bus section or outlet facility is cleared in breaker or relay-failure back-up clearing time including tripping of a transmission facility and generating unit(s), if any, on the bus associated with the "stuck breaker" (except Bus-tie breaker).	TPL-001-4 Planning Events P4-1, P4-2, P4-3, P4-5 P5-1, P5-2, P5-3 and P5-5 Also covers Planning Events P2-2 and P2-3 as a breaker failure for a line fault would result in the clearing of a straight bus or the adjacent facility in a ring bus or breaker and a half arrangement.

*: Callaway Plant shall meet the three-phase fault test as outlet for this plant was designed for three-phase faults. Note that Ameren's general use of 2-L-G fault conditions with delayed clearing (breaker-failure) conditions is more stringent than the consideration of single-line-to-ground (S-L-G) fault conditions as specified in NERC Reliability Standard TPL-001-4.

Simulations and Other Considerations

a) Consistent with Table 1 Planning Event P5, the impact of loss of system protection should be investigated for those locations where back-up protection systems on plant outlet lines are significantly slower than primary relaying schemes. Double-line-to-ground fault conditions should be tested assuming primary protection scheme failures that would result in breaker clearing times that are greater than the clearing time associated with the breaker failure protection scheme. This testing is generally required because of older system protection schemes associated with older power plants or substations. (See item 4 above.)

b) Dynamic models representing winter peak load conditions should be used for plant stability analysis, as the loads in these models provide less damping than the load in summer peak models and fewer generating units are available to provide synchronizing power. Winter peak output (MW and Mvar) of the generating unit(s) shall be considered. For power plants located in or near the St. Louis metro area or the Peoria area where there are high concentrations of residential air-conditioning load, the modeling of summer peak load conditions, with dynamic load behavior, should be considered for the stability analysis. Off-peak or minimum load system conditions with pumped-storage hydro units operating in pump mode should also be considered for the stability analysis.

c) Plant voltages will be modeled at the low end of their scheduled voltage range.

d) The transient stability Tests 2, 3, and 4 above are considered a double-contingency test. The "stuck breaker" is considered one of the contingencies in test 4.

e) Any of the Tests 1, 2, 3, or 4 for outlet of new generation shall not in any way degrade existing stability limits including critical clearing times of any of the nearby plants. All oscillations must exhibit acceptable damping.

f) The term "stable" in above Tests 1 through 4 means the generating unit(s) which remain connected to the system following fault clearing remain in synchronism. All oscillations must exhibit acceptable damping.

g) Plant outlet transmission configuration resulting in no outlet transmission for Test 3 or 4 or both shall require installation of out-of-step-protection on generators, and shall not in any way degrade existing stability limits including critical clearing times of any of the nearby plants or result in system instability.

h) In Test 4 for the "stuck breaker" simulation, a due consideration shall be given to down-grading of the initiating double-line-to ground fault (three phase fault for Callaway) to a single-line-to ground fault if the associated breakers are equipped with the independent pole operated (IPO) mechanism.

i) For the non-peaking units at plants connected to the 345 kV system, light load system conditions shall also be considered. Due consideration should be given to breakers equipped with independent pole operated (IPO) mechanisms.

j) For Test 3 above, a planned reduction in generation associated with the out-of-service outlet line may be considered to maintain plant stability.

k) Use of Remedial Action Schemes (RAS) shall not be allowed for Tests 1 or 2. If RAS is used to meet Test 3 or 4 above, it shall meet the requirements of the NERC Reliability Standards and/or SERC regional criteria. Remedial Action Schemes may be utilized on a long-term basis for maintaining transient stability of one or more generating units in response to a specified set of contingency events related to Tests 3 or 4 above.

l) The transient stability Tests 1, 2, 3, and 4 above are also applicable to inverter-based resource generating facilities.

m) Ameren reserves the right to evaluate the stability of any generating units connected to the Ameren transmission system, including those owned by retail customers. If it is determined that such generation would cause a material detriment to the transmission system or other nearby generation, then such generators would be required to make modifications such that it would be capable of meeting Ameren's criteria with respect to transient stability performance.

n) Ameren checks the damping with the Power System Stabilizer circuit out-of-service which may result in operating guides.

2.4.8 Transient Stability Fault Scenario Selection

As a guide to selection of fault conditions for development of a portfolio of transient stability simulations for assessment of the transmission system, the following should be considered:

a) The most severe fault for selected Planning Events P1 through P7 or Extreme Event contingencies should be simulated for each power plant on the Ameren system which has units on-line in the stability power flow model being used. Typically, the element that is selected for fault simulation has the longest clearing time, is the strongest source to the system, or results in the greatest number of facilities being removed from service. Close-in faults are usually the most severe from a generator perspective but slow-clearing remote faults should also be given consideration for study. Often the fault selection is based on the knowledge gained from performing a plant stability study which is updated when major changes at the plant or on the nearby system occur.

b) At a minimum, the most severe fault for selected Planning Event P1 through P7 or Extreme Event contingencies should be simulated at each substation or switchyard on the Ameren system with three or more 345 kV lines connected. Typically, the element that is faulted has the longest clearing time or results in the greatest number of facilities being removed from service.

c) At a minimum, the most severe fault for selected Planning Event P1 through P7 or Extreme Event contingencies should be simulated at each substation or switchyard on the Ameren system with 8 or more networked 161 or 138 kV lines. Typically, the element that is faulted has the longest clearing time or results in the greatest number of facilities being removed from service.

d) The most severe fault for selected Planning Event P1 through P7 or Extreme Event contingencies should be simulated for each substation on the Ameren system that serves more than 300 MW of customer load. Typically, the element that is faulted is a transformer or lead line serving the substation in order to determine the impact of losing the load on the stability of the transmission system.

e) Faults that historically have been known to present stability issues on the Ameren or nearby transmission systems should be simulated until upgrades are implemented to completely resolve these issues. These fault simulations are based on the historical events and circumstances that led to the stability concerns, and could include relay misoperations as part of the events.

f) All faults required to meet the Clinton and Callaway NPOA agreements should be simulated. These faults scenarios are prescribed in the NPOA agreements.

The portfolio of transient stability scenarios would be expanded over time to include progressively more than the most severe contingency events at any given location.

2.4.9 Synchronous Generator Out-of-Step Protection

To provide protection for generating equipment should synchronism be lost following a contingency event, new generators to be connected to the Ameren transmission system with capacity of 100 MW or more, would be required to have out-of-step protection installed.

2.4.10 Inverter Based Resources (Wind Farm, Solar Farm, Battery Storage Facility)

An inverter based resource (IBR), consisting of a wind farm, solar farm, or battery storage facility, shall meet all the requirements specified in FERC Order 661A. Also, Ameren will follow any MISO guidelines related to inverter based generation. Inverter based resources should also meet power quality requirements as specified in section 3.6 Harmonics. The general procedure for performing an assessment of an inverter based facility is covered in the Ameren document "Guide to Inverter Based Resource Interconnection Studies", dated February 5, 2019.

2.5 Short Circuit Criteria

The interrupting requirements of all Ameren circuit breakers must remain within circuit breaker interrupting capabilities considering the impacts of asymmetry, reclosing (where allowed), and actual system operating voltage for the appropriate type of circuit breaker in the field (breakers rated on a total current basis or symmetrical current basis). The maximum short circuit current to be interrupted for both new and existing circuit breakers is calculated.

Circuit breakers with fault duties in excess of interrupting capabilities are candidates for immediate replacement or other acceptable mitigation alternative that meets power flow, relay coordination, and system stability requirements. Such mitigation may include the opening of bus-tie circuit breakers.

2.5.1 Ultimate Fault Current determination:

Ameren considers the impact of possible future projects when determining ultimate fault levels. The following criteria is used to specify the required interrupting capability of breakers for facility additions or modifications.

Near future maximum fault current (assuming additional transformation and synchronous generation with GIA)	Ultimate fault (kA)
< 18 kA	25 kA
< 35 kA	40 kA
< 45 kA	50 kA
>= 45 kA	63 kA

2.5.2 Identification of a Weak System

Using the weighed short circuit formula as defined by IEEE standard P2800, a short circuit ratio less than 3 indicates potential problems for inverter-based resources. An inverter based resource that connects at that location would be required to have PSCAD analysis performed. The weighted short circuit is

$$WSCR_{MVA} = \frac{\sum_i^N SCMVA_i * P_{RMVA_i}}{(\sum_I^N P_{RMVA_i})^2}$$

$SCMVA_i$ is the short circuit MVA at bus i. P_{RMVA_i} is the MVA output of the non-synchronous generator(s) connected at bus i. N is the number of interacting units in the area.

2.6 Nuclear Plants and Transmission Operator Agreements

In accordance with NERC Standard NUC-001, All Nuclear Plants with a Nuclear Plant Interconnection Requirement (NPIR) with Ameren shall have an NPOA which includes rights and responsibilities of each party. This agreement includes rights and responsibilities of the Transmission Planning Department to evaluate the transmission system's ability to support plant needs from voltage levels, short circuit, and stability considerations. These needs are to be considered along with other criteria and guidelines contained in this document in developing overall transmission plans.

Ameren will enter into any appropriate agreements with the Transmission Provider and nuclear plant regarding study requirements.

2.7 System Conditions and Modeling Assumptions

System conditions that are assumed to be in effect when the criteria are tested can have a great influence on the results obtained. Detailed information on system conditions and modeling assumptions for developing power flow and stability models for testing Ameren's transmission system performance are found in the Ameren MOD-32 Procedures.

2.7.1 System Study Criteria

For transient stability study work, a progressively unbounded list of facilities which are reported with out-of-step conditions following clearing of a fault would be an indication of an unbounded cascading condition. In addition, generator frequency relay models are included, which would act to trip generators offline should a severe over- or underfrequency event occur.

2.7.2 Cascading Criteria

Total Load at Risk in excess of 1500 MW or loss of 4000 MW of generation would also be a proxy for cascading conditions. Note that load disconnected temporarily by customer-owned protection systems (e.g., residential air-conditioners with reciprocating compressors) should not be considered as an indication of cascading.

2.7.3 Total Load at Risk

Total Load at Risk is defined as the sum of the following four types of load loss, which are identified in steady-state analyses.

1) Consequential Load Loss (NERC definition) = "All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault."

2) Interruptible load (NERC definition) = "Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment."

3) Subsequent cascading load loss = Load that is outaged as a result of subsequent element-based outages during the remaining cascading tier analysis. This type of load loss is a result of either voltage sensitive load tripping when load buses are below 0.89 p.u. or load islanding due to lines/transformers tripping. The 0.89 p.u. load tripping threshold is used as a proxy to simulate the response of voltage sensitive load. The response of voltage sensitive load refers to the tripping of the load due to intrinsic voltage protection mechanisms that manufacturers build into their equipment.

4) Non-Consequential Load Loss (NERC definition) = "Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end user equipment."

Cascading (NERC Definition) = "The uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."

In the Ameren area, widespread transmission planning load loss is the potential loss of 1500 MW or more of Total Load at Risk.

2.8 Load Connection and Power Factor

Consistent with FAC-001 and FAC-002 requirements, Requirements for the Connection of Customer Load to the Ameren Transmission System are addressed in the Ameren document "End-User Connection Requirements to Ameren's Transmission System" posted on OASIS.

2.8.1 Material Modifications to End-User Facilities Require Study

Material changes to existing end-user interconnections shall trigger a review of system performance by Transmission Planning, as required by standard FAC-002. Such facility changes would include the following items:

1. Any change in nameplate MVA capability of transmission connected transformers.
2. Any change to impedances of transmission connected transformers.
3. Any line extension from the existing interconnection to supply system load or to connect a generator.
4. Any increase in load magnitude (MW, Mvar, or MVA) by 10% or more.

Studies would include a review of steady-state, short-circuit, and dynamics system performance under both normal and contingency conditions as necessary to ensure system reliability. Study assumptions, system performance, alternatives considered, and coordinated recommendations will be documented for review by the entities involved.

3.0 VOLTAGE CRITERIA

Voltage criteria are used to assess the transmission system reliability during assumed normal and contingency conditions. The transmission system response to various contingencies, whether steady state or transient conditions, must be assessed on the basis of these and other criteria. These criteria are presented below and are used by the transmission planning engineers to determine the level of reliability of the transmission system. Depending on the type of analysis being performed, steady state or transient, most or all of the following voltage criteria are used to determine the reliability of the transmission system through the use of computer simulations. The voltage limits and criteria used in planning the Ameren transmission system are presented below. These voltage limits are also used by transmission system operators to ensure that the transmission system is operated in a safe and reliable manner.

3.1 Transmission Voltage Levels and Limits

	Normal Condition (P0)		Post Contingency Condition Steady State (P1-P7)		
Nominal voltage	Minimum (p.u.)	Maximum (p.u.)	Minimum (p.u.)	Maximum(p.u.)	Deviation (%)
345 kV	0.95	1.05 see note 1	0.95 See note 2	1.075	8% of Nominal see note 3
230 kV, 161 kV, 138 kV	0.95	1.05 see note 1	0.93 See note 2	1.075	8% of Nominal see note 3

NOTES and EXCEPTIONS TO ABOVE CRITERIA

Note 1: Operation in the range 105% to 107.5% of nominal would be permitted on a case-by-case basis, as allowed by ANSI guides, Ameren standards, or manufacturer's exception.
Note 2: Under single (line, transformer, or generator) contingencies, voltages below 95 percent of nominal are used as a screening tool to flag the need for further analysis. Voltages below this threshold would initiate further analysis and/or discussion with the Distribution System Planning groups to ensure that adequate distribution voltages would be provided for these conditions. Minimum voltage limits would apply at the point of delivery. When performing GMD studies, minimum voltage will be as specified in section 3.8.

Note 3: Post-contingency scenarios where the transmission voltage change is greater than 8% of nominal, when compared to pre-contingency conditions, and the resulting transmission voltage is below the minimum allowed post-contingency voltage, will be investigated to determine what actions, if any, are required to avoid wide-spread outages.
For single customers supplied from the transmission system, the following minimum voltage limits would apply at the point of delivery: • Normal Conditions (all facilities in service): 92% • Single Contingency Conditions: 90%. These limits are in line with governing tariffs in both Missouri and Illinois.
Exceptions to the above voltage criteria would apply to the Callaway and Clinton 345 kV switchyards, as defined in the Nuclear Plant Interconnection Requirements (NPIR) document for these facilities. For Callaway, the required 345 kV bus voltage limits are 372.6 kV (108.0%) to 329.8 kV (95.6%), but the desired upper limit is 362.5 (105.0%). For Clinton, the required 345 kV bus voltage limits are 362.25 kV (105.0%) to 327.75 kV (95.0%). Bus voltages outside of these NPIR limits would require mitigation
Exceptions to the above voltage criteria would apply to the Clinton 138 kV ERAT bus, as defined in the Nuclear Plant Interconnection Requirements (NPIR) document for this facility. The Clinton 138 kV voltage limits are 144.9 kV (105.0%) to 129.72 kV (94.0%). Bus voltages outside of these NPIR limits would require mitigation.

3.2 Potential voltage collapse

In the course of study work, should post-contingency transmission voltages in a general area drop to 90% of nominal or below, closer examination is warranted to determine whether voltage collapse for such contingency conditions is likely. Distribution bus voltages less than or equal to 90% would indicate possible motor stalling (considering voltage drop of 5-7% on distribution feeders). Transmission voltages of 85% is the level at which a voltage collapse is essentially assured. Situations which show transmission voltages in the range of 86% -89% in a steady state analysis carry significant risk for voltage collapse. When performing a detailed study of an area that may be exposed to voltage collapse, distribution line capacitors should be modeled as a separate element from distribution reactive load. Transformer LTC’s should be locked at the pre-contingency position when evaluating exposure to voltage collapse, as the collapse would likely occur before the LTCs would begin to operate. When investigating potential voltage collapse in a load pocket, consideration should be given to using 90/10 forecast load or non-coincident local area load levels.

3.3 Transient Voltage Recovery

Following the clearing of a fault resulting from single or multiple contingency events (Planning Events P1- P7), transmission voltages should return to 80% of nominal or greater within two seconds and 90 % of nominal or greater within ten seconds unless the system becomes radial following the outage of multiple contingencies. This criterion would not be applicable to remote or isolated sections of the transmission system, or to portions of Ameren's transmission system that are supplied primarily via another company's facilities.

Means of addressing transient voltage recovery issues would include additional reactive supply provided by capacitor banks or static reactive sources (SVC or STATCOM), or additional transmission facilities connecting to the affected portion of the transmission system. The particular solution pursued would depend on the specific area and size of the affected portion of the transmission system, and whether static or dynamic reactive resources would be deemed necessary to address the particular deficit.

3.4 Application of Shunt Reactors

Shunt reactors would be considered for installation to maintain EHV steady-state transmission voltages at or below 107.5% of nominal, and particularly for the retirement of large power generators connected to the EHV transmission system.

Reactors will be installed on buses if possible. To avoid encountering damage to breakers due to trapped charge and the delayed voltage zero crossing phenomenon, the utilization of pre-insertion resistors or modification to the switching scheme will be considered. If installed on a line, the reactor will be tripped off prior to line reclosing.

3.5 Voltage Fluctuation due to Capacitor or Reactor Switching

Based on IEEE Standard 1453 and 519 and consistent with Good Utility Practice, when installing new shunt reactive devices steady state voltage fluctuation resulting from capacitor or reactor switching would be limited to a maximum of 3.3% of nominal on the transmission system under normal system conditions. The test for this criterion will be conducted via steady state load flow analysis with automatic controlling devices such as switched shunts, load tap changing transformers ("LTC") and phase shifting transformers ("PARS") locked. Dynamic VAR devices such as STATCOMs and SVCs should be allowed to control voltage during these simulations. Transient simulations may be required to ensure equipment will be sized to avoid harmonic resonance." Single contingency conditions will be evaluated for capacitor switching voltage fluctuation considering the outage of the strongest area source element or facility (largest contributor of short circuit current). Ameren has established a guideline for single contingency conditions, that steady state voltage fluctuation resulting from capacitor or reactor switching should be limited to a maximum of 5% of nominal on the transmission system.

3.6 Harmonics

All generation and load connections to the Ameren system should conform to IEEE Standard 519 with respect to voltage distortion. These limits restrict individual harmonic distortion limits to 1.5% between 69 kV and 161 kV, and 1.0% at 161 kV and above, with Total Harmonic Distortion limited to 2.5% between 69 kV and 161 kV, and 1.5% at 161 kV and above.

3.7 Voltage and Reactive Control

A generating plant or HVDC terminal should maintain either a specified voltage or reactive power schedule in accordance with NERC Reliability Standards VAR-001-5 and VAR-002-4.1.

3.8 Transmission Steady-State Voltage Criteria for Benchmark GMD Events

Acceptable Ameren transmission steady-state voltage criteria for NERC defined benchmark GMD events shall be when all Ameren transmission bus voltages are within the range 0.90 – 1.075 p.u. (NERC Standard TPL-007-1 R3). This voltage range would be used to gauge Ameren system performance in GMD Vulnerability Assessments of the Near-Term Transmission Planning Horizon considering both peak load and off-peak load conditions (NERC Standard TPL-007-1 R4).

3.9 Transmission Line and Substation Equipment Short-Term Overvoltage Capability

Typical and switching overvoltage capability for transmission lines are as shown in the table below. The steady-state maximum voltage limit would be 107.5% of nominal, with overvoltage capability due to switching of three times the maximum steady-state voltage.

Nominal System Line-to-Line Voltage	138 kV	161 kV	230 kV	345 kV
Maximum System Line-to-Ground Voltage (Nominal Voltage/1.732) x 1.075)	86 kV	100 kV	143 kV	214 kV
Switching Overvoltage Requirement (Maximum System Line-to-Ground x 3)	258 kV	300 kV	429 kV	642 kV

Transmission line insulator string flashover characteristics for porcelain suspension insulators are based on the number of insulators in a given string, and are as follows:

Number of Insulators	6	7	8	9	10	11	12	13	14	15	16	17	18
Low Frequency Flashover Wet (kV)	240	280	320	360	400	440	480	520	560	600	640	680	720

On a short-term basis (up to 10 second duration), substation equipment would be able to withstand 110% of nominal voltage.

4.0 THERMAL CRITERIA

4.1 Ratings methodology

Ameren's methodology for determining Facility Ratings is found in the Ameren FAC-008 Procedures document.

4.2 Application of Normal ratings

No facility may exceed its normal rating in the pre-contingency state following the occurrence of any operating condition in category P0 of the NERC Reliability Standard TPL-001-4 addressing Transmission System Planning Performance Requirements.

4.3 Application of Emergency ratings

No facility may exceed its applicable emergency rating in the post-contingency state following the occurrence of any operating condition in categories P1 through P7 of the NERC Reliability Standard TPL-001-4 addressing Transmission System Planning Performance Requirements.

4.4 Proposal of new projects

In consideration of uncertainty and tolerance margins in the planning process, new projects or facility upgrade may be proposed if the projected loading exceeds 95% of the applicable rating.

4.5 Steady State Cascading determination

As a proxy for cascading conditions in steady-state study work, facilities with loadings of 120% of emergency rating or greater should be considered to have tripped offline. As the lines would be tripped in the powerflow simulations, a growing number of facilities loaded above 120% of the emergency rating would indicate cascading, and particularly if the overloads extend beyond Ameren boundaries to neighboring transmission systems.

5.0 LIST OF REFERENCED DOCUMENTS

5.1 North American Electric Reliability Corporation (NERC) Reliability Standards.

5.2 Federal Energy Regulatory Commission (FERC) Order 661-A "Interconnection for Wind Energy", Issued December 12, 2005

5.3 Federal Energy Regulatory Commission (FERC) Order 827 "Reactive Power Requirements for Non-Synchronous Generation", Issued June 16, 2016

5.4 Ameren Documents

5.4.1 Transmission Facility Interconnection Procedures

5.4.2 End-User Connection Procedures

5.4.3 Generator Connection Procedures

5.4.4 Ameren FAC-008 procedure document: Ameren Facility Rating Criteria and Methodologies for Developing Transmission Facility Ratings

5.4.5 Ameren TPL-001 procedure document: TPL-ADM-0010-TP

5.4.6 Ameren TPL-007 procedure document: TPL-ADM-0070-TP

5.4.7 Ameren MOD-32 procedure document: MOD-ADM-0320-TP

5.4.8 Ameren VAR-001 procedure document: NOP-N16-7 Voltage and Reactive Control.doc

5.5 MISO Documents

5.5.1 MISO Tariff: Attachment X- GENERATOR INTERCONNECTION PROCEDURES (GIP)

EXHIBIT C

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

UNITED STATES OF AMERICA, Plaintiff, SIERRA CLUB, Plaintiff-Intervenor, v. AMEREN MISSOURI, Defendant.	Civil Action No. 4:11-cv-00077-RWS

DECLARATION OF TIM LAFSER IN SUPPORT OF AMEREN'S SUPPLEMENTAL BRIEF IN SUPPORT OF ITS MOTION TO MODIFY THE COURT'S REMEDY RULING

I, Tim Lafser, am over 18 years of age and make the following declaration pursuant to 18 U.S.C. § 1746:

1. I am employed by Union Electric Company d/b/a Ameren Missouri ("Ameren" or "Company") as Vice President of Power Operations. I have worked in several different capacities at Ameren during my career, including Director of Rush Island Energy Center ("Rush Island"), Director of Meramec Energy Center, Director of Trade Floor Operations, and Director of Transmission Operations. In my current role I am responsible for the operations, maintenance, and engineering support of all of Ameren Missouri's non-nuclear generation energy centers. This Declaration is based on my personal knowledge, and information available to me.

2. I am familiar with the reliability analysis performed by Ameren's transmission planners and the June 2022 Attachment Y study conducted by the Midcontinent Independent System Operator (MISO), which updated and supplemented MISO's February 2022 Y-2 study.

As summarized in the Declaration of my colleague Justin Davies, retiring Rush Island presents reliability issues that must be addressed to ensure reliable transmission and delivery of electricity to the public. Both MISO and Ameren's transmission planners have identified multiple reliability issues related to retiring Rush Island, and Ameren has identified a series of mitigation projects to address those issues. Those projects must be approved by MISO pursuant to the MISO Transmission Enhancement Project (MTEP) 2023 process with approval of those projects anticipated to occur in late summer 2022. Ameren is finalizing the engineering scope and procurement strategies for the projects and intends to move forward expeditiously pending formal approval.

3. In this Declaration, I summarize how Ameren proposes to greatly reduce its operations to reduce emissions while at the same time ensuring that the Rush Island units are available to address reliability concerns on the transmission network as well as availability needs as may be required by MISO during peak periods and emergency conditions. Demand for power generation within the MISO area is dynamic and fluctuates on an hourly, daily, and weekly basis depending upon a myriad of factors including weather, forced outages and load level (customer demand). Recognizing the difficulty in accurately predicting a set operating requirement, Ameren proposes an emission cap set at a level that addresses both reliability concerns and emergency operations such as those experienced at peak periods or Generation Alert Events issued by MISO. I describe below how Ameren developed emission caps for both Rush Island units which would limit plant operations until the mitigation projects described by Mr. Davies are implemented. Once those projects are in service, Rush Island can be permanently retired.

4. **Operational Needs for Transmission System Reliability.** Below, I describe the estimated operational needs to maintain system reliability and describe the correlation between

those estimated operations and the proposed SO2 emission cap. Throughout the period in which the Rush Island units are designated as SSR (System Support Resources), the units may be committed concurrently, or interchangeably on a single unit basis, depending upon MISO's needs. As discussed below, Rush Island's reduced operations will result in significantly lower emissions levels.

a. **Summer Peak Months (June, July, August, and September) Through Summer 2024:** Peak demand and electricity usage typically occurs during the summer air-conditioning season of June, July, August, and September. This summer peak period poses a reliability risk due to both voltage regulation issues and potential transmission line overloads. These risks will be mitigated by performing a bus upgrade at a substation adjacent to Rush Island (estimated completion date end of 2023) and installing four STATCOM devices on the transmission system. Based upon supply chain challenges, it is possible that the final STATCOM equipment set may not be placed into service until fall 2025, though installation could occur in late 2024 or spring 2025. The proposed emissions cap contemplates reduced operations of both Rush Island units.

b. **Winter Peak Months 2022-2023 (December, January, February):** Through the date that the capacitor bank project described in Mr. Davies' Declaration is expected to be completed at the Overton Substation—currently estimated at February 2023—the proposed emissions cap contemplates that both Rush Island units must remain online during the winter months to hold voltage and provide stable operations.

c. **Winter Peak Months 2023-2024 (December, January, February):** Replacement of the capacitor bank does not solve all overload issues, however, as Mr. Davies described, as there exists the potential for overload at critical locations such as along the Highway

44 corridor where a transmission line routes power into the St. Louis metropolitan area. Consequently, even after replacement of the capacitor bank, mitigating that overload risk requires installation of a larger capacity transformer at the Wildwood Substation near Wildwood, Missouri. Accordingly, during the winter peak months through February 2024, the proposed SO2 cap includes a single Rush Island unit that must remain fully operational to meet system needs until the Wildwood Substation transformer is in service. The proposed cap also contemplates that until that transformer is in service, Ameren would bring the second Rush unit online when ambient temperatures are forecasted to be below 20 degrees Fahrenheit. The second unit is necessary to ensure freeze protection of the Rush Island Energy Center, which could occur if the first Rush Island unit unexpectedly trips offline.

d. **Shoulder Months: Generally Offline Except for Emergencies.** During the shoulder months of March, April, May, October, and November, the Rush Island units are generally expected to be offline and not generating, unless MISO calls upon such units on an emergency basis (as described in Paragraphs 10 and 11 below).

5. **Important Operational Flexibility.** Ordering SO2 emissions to be capped at a specified level will provide MISO and Ameren with operational flexibility that is needed on a day-to-day basis while also providing a definitive mechanism with which to measure compliance. Operating conditions can vary every day. This includes natural variation of conditions on the transmission grid, variation in weather conditions, unplanned unit outages at both Rush Island and other nearby generating units. In addition to daily weather changes, increasing usage of renewables in MISO increasingly affect generation and transmission. MISO will need the ability to dispatch Rush Island with flexibility. An emissions cap—as opposed to a defined regime for operation—provides such flexibility.

6. To express the limited operations described above in terms of SO2 emissions, Ameren has estimated Rush Island generation necessary to address the specific transmission concerns identified in the MISO Attachment Y study: voltage regulation support deficiencies; transmission line overloading problems; and having the ability to quickly meet MISO's demands (through supply of energy) as and when needed. No operator, Ameren included, is able to predict future operations with precision. These estimates are based on transmission system modeling performed in connection with the Attachment Y study, and such modeling scenarios do not always match the reality of dynamic electric grid operations. Moreover, large coal-fired boilers cannot be turned on quickly. Rush Island is no exception, and it needs between 18 and 24 hours to reach full operational capacity from a cold start. Accordingly, in its estimated generation and proposed cap Ameren has included both hot and cold weather conditions that would require additional unit commitments, to maintain the availability of the Rush Island units to increase operations to meet MISO's needs.

7. To meet these various goals—transmission system reliability including voltage regulation support, the availability of sufficient capacity to meet MISO's generating needs, and the ability to be online and ready to increase operations to meet both MISO's fluctuating day-to-day energy needs and declared emergencies, all while ensuring the operational flexibility necessary to address conditions that change on a daily basis—Ameren is proposing plant-wide SO2 emissions caps, as set forth in the table immediately below. Due to the uncertainty regarding the installation date of the final STATCOM device (likely fall 2025, but perhaps as early as late 2024 or spring 2025), Ameren has proposed caps for 2025. The 2025 operations may be unnecessary if all STATCOMs are placed in service before those dates. In any event, the proposed caps reflect significantly reduced operation of, and emissions from, the Rush Island units:

Cap Period	SO2 Emissions Cap
9/1/2022 – 12/31/2022	2,600 tons
1/1/2023 – 12/31/2023	9,500 tons
1/1/2024 – 12/31/2024	9,500 tons
1/1/2025 – 2/28/2025	1,700 tons (if final STATCOM is not yet installed)
3/1/2025 – 9/30/2025	2,500 tons (if final STATCOM is not yet installed)

8. This represents a significant reduction in emissions as compared to recent years:

Year	SO2 Emissions
2017	22,167 tons
2018	18,484 tons
2019	13,201 tons
2020	17,321 tons
2021	19,529 tons
Average	**18,140 tons**

9. I understand that this cap-based approach has been used previously by MISO and FERC and will minimize the administrative burden on all stakeholders—MISO, the Independent Market Monitor (IMM), Ameren, the Plaintiffs, and the Court.

10. **Emergency Availability for Extreme Weather Conditions.** The foregoing discussion and proposed emissions caps, **do not include** emergency directives from MISO to operate, or to be ready to operate, to address extreme weather conditions or unexpected system demands. I understand that the reliability review as part of the Attachment Y process included modeling scenarios for extreme weather events such as those experienced in February 2021 during Winter Storm Uri. During that storm, Arctic weather drove high generation and transmission

outages and led to unprecedented flows across the MISO system to support neighboring systems, which collectively resulted in emergency declarations and load reductions. Prior to that storm, MISO issued a Cold Weather Alert, committed additional generation in advance of need, and extended start/stop times for generation resources to avoid start failures. For the Ameren system, all available generation was called upon, including the Rush Island units. Rush Island played a crucial role in preventing load shedding in Missouri and, due to its proximity to Illinois, also reduced the amount of load that needed to be shed in Illinois to mitigate additional overloads on Ameren's facilities. This example demonstrates the importance of being available to respond to emergency events and requests by MISO, such as Cold Weather Alerts. Mr. Davies in his Declaration describes how those modeling scenarios identified additional issues with the transmission system and proposed mitigation measures.

11. Emergency events can happen at any time of year, and in the past, MISO has averaged seven such emergency events annually. Assuming half of these events occur in shoulder seasons when the Rush Island units would not normally be operating, there could be additional operation needed to address any such emergencies. MISO may commit the units a day in advance of any emergency event. For Summer 2022, MISO is currently predicting that it will have insufficient resources to cover peak forecasts and that emergency resources may be needed. MISO described these unexpected resource constraints in a recent presentation.[1] As the presentation indicates, such emergency events could become more frequent until additional generation capacity and transmission resources are built. MISO must be able to call upon one or both Rush units to operate temporarily during brief but extreme periods when the grid can experience stress and a shortage of generating resources. Because these events are by their nature unpredictable, Ameren

[1] *See* MISO Seasonal Readiness Workshop Summer 2022 PowerPoint Presentations (available at https://cdn.misoenergy.org/20220428%20Summer%20Readiness%20Workshop624245.pdf).

has not included them in the proposed emissions caps set forth above, but it is critical that Rush Island be available to MISO at critical moments to prevent or lessen the impact to the public due to a shortage of adequate generation resources.

Executed on: 6/6/2022

Tim Lafser
Tim Lafser

EXHIBIT D

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

UNITED STATES OF AMERICA, Plaintiff, SIERRA CLUB, Plaintiff-Intervenor, v. AMEREN MISSOURI, Defendant.	Civil Action No. 4:11-cv-00077-RWS

DECLARATION OF BENJAMIN FORD [SUPPLY CHAIN PRESSURES] IN SUPPORT OF AMEREN'S SUPPLEMENTAL BRIEF IN SUPPORT OF ITS MOTION TO MODIFY THE COURT'S REMEDY RULING

I, Benjamin Ford, am over 18 years of age and make the following declaration pursuant to 18 U.S.C. § 1746:

1. This Declaration is made based on my personal knowledge and information available to me at Ameren Missouri and its affiliated companies (collectively "Ameren"). I have been employed by Ameren Services Company since 2018. Before that, I worked for Enbridge Gas Transmission and have worked in the supply chain industry for nearly twenty years, since 2006. I hold a degree in mechanical engineering from the University of Queensland, Australia.

2. Ameren Services Company provides business and administrative services to Ameren Corporation's family of companies including Ameren Missouri. I currently hold the position of Senior Director of Sourcing. Among our responsibilities, Sourcing provides procurement services to Ameren's various business groups in securing equipment and supplies from a vast network of vendors located domestically and abroad. My group also monitors disruptions in supply chains and, working with our business partners, develops strategies to reduce the impact on Ameren's operations.

3. As widely reported in the media, the COVID-19 pandemic created a global disruption in supply chains as manufacturers and vendors shut down operations. In addition, labor shortages in the United States have adversely impacted manufacturing as companies compete for qualified labor. Simultaneously, demand for products and equipment from the energy sector has increased globally and suppliers have found they are unable to add second or third shifts to meet production targets. As an illustration, while solar panels take only 3-4 weeks to manufacture, the order backlog is approximately two years. Similarly, the estimated lead time to procure transformers, switchgears, steel poles, regulators and other electrical equipment has doubled, and in some circumstance, now, tripled. To manage such supply change issues, Ameren has deferred non-priority projects, created emergency stockpiles for critical, time-sensitive projects, and redeployed redundant, back-up equipment within its system.

4. The supply chain is global with much manufacturing occurring abroad. The war in the Ukraine has exacerbated supply chain issues as critical infrastructure manufacturers are located in that region and rely on core steel produced in Russia. As a result, some vendors in Europe and the United States have greatly accelerated purchases from available suppliers, which in turn has created its own scarcity spiral throughout the marketplace. Core steel is used in transmission transformers that are part of the STATCOM equipment set described by my colleague, Justin Davies. Competition for core steel is ever increasing as that commodity is used in the electric car industry which is able to pay a price premium to "lock-in" supply. The scarcity of core steel and the limited number of global manufactures have increased the estimated time frames for obtaining transmission transformers.

5. I have reviewed the mitigation projects and associated timelines identified by Mr. Davies and Mr. Lafser in their Declarations. Ameren is developing scoping documents and once

those are finalized, Ameren's sourcing group will initiate procurement strategies to prioritize the execution of those projects. None of the projects are "off the shelf" and all require site specific engineering design and specialized manufacturing. The dates provided are the best available to Ameren at this time, but manufacturing delays could occur as labor shortages continue and trade disruptions create an uncertain business climate. Typically, manufacturing and delivery dates are not provided until purchase orders are placed but even then, the certainty of such dates is variable. Given the criticality of these projects, Ameren has already engaged with the supplier it anticipates using for the STATCOMs as recently as May 26, 2022. Once MISO approves the projects, Ameren will proceed with securing more firm commitments from qualified vendors with manufacturing targets that support completion of the underlying construction projects as quickly as conditions allow.

6. I declare the foregoing is true and accurate.

Executed on: 6-1-2022

Benjamin Ford

EXHIBIT E

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

UNITED STATES OF AMERICA, Plaintiff, SIERRA CLUB, Plaintiff-Intervenor, v. AMEREN MISSOURI, Defendant.	Civil Action No. 4:11-cv-00077-RWS

DECLARATION OF ANDREW WITMEIER IN SUPPORT OF AMEREN'S SUPPLEMENTAL BRIEF IN SUPPORT OF ITS MOTION TO MODIFY THE COURT'S REMEDY RULING

I, Andrew Witmeier, am over 18 years of age and make the following declaration pursuant to 18 U.S.C. § 1746:

1. I am employed by the Midcontinent Independent System Operator, Inc. ("MISO") as Director Resource Utilization. In that role, my responsibilities include overseeing teams that manage MISO's Generator Interconnection Queue as well as assessing generator requests for surplus, replacement, and/or retirement. I spent the first 17 years of my career in various operator and manager positions within MISO Operations, including as a Reliability Coordinator and Manager Reliability Coordination of MISO's central region, which includes the Ameren footprint. I have been in my current role since January 2020. This Declaration is based on my personal knowledge and information available to me.

2. I am familiar with MISO's analyses of changes in the makeup of its generation and transmission fleet, MISO's Renewable Integration Impact Assessment (RIIA), and the results of MISO's annual Planning Resource Auction (PRA).

3. MISO faces increasing challenges to system reliability and the ability to commit sufficient resources to supply electricity to customers within the MISO region. These challenges include declining reserve margins and fewer always-on "baseload" resources, due to retirements of thermal units. Moreover, aging units that remain in service are more prone to outages, rendering them potentially unavailable when they are needed most. At the same time, the installation of new capacity is not occurring at the same rate as the baseload retirements and capacity from certain resources are not always available to provide energy during times of need.

4. To prepare for the coming year's generation needs, and to ensure the availability of sufficient generating capacity to meet the region's needs, every year MISO holds a PRA. The results of the 2022-2023 PRA were announced on April 14, 2022. The auction results reflected the industry's ongoing shift away from coal-fired generation and increasing reliance on other resources. The results showed capacity shortfalls in both the north and central regions, even including the ongoing operation of Ameren Missouri's Rush Island plant, located in Zone 5, part of the central region.

5. The capacity shortfalls were reflected in the market pricing for the capacity, which is measured in megawatt-days. Clearing prices in Zone 5 surged to $236.66 per megawatt-day compared to approximately $5 a year ago. By comparison, capacity prices for MISO's south region were just $2.88 per megawatt-day.

6. As stated by MISO's President and Chief Operating Officer, "The reality for the zones that do not have sufficient generation to cover their load plus their required reserves is that they will have increased risk of temporary, controlled outages to maintain system reliability."

7. On April 28, MISO projected the need for increased, non-firm imports and potential emergency resources to meet the forecasted 2022 summer peak demand. In particular, J.T. Smith, MISO's Executive Director – Market Operations, again noted that the "north and central regions of MISO" are "at increased risk of temporary, controlled outages to preserve the integrity of the bulk electric system[.]"

8. While Resource Adequacy is generally the responsibility of the state regulatory authorities within the MISO region, MISO is in a unique position as the grid operator to inform state and environmental regulators on the regional impact of actions on grid reliability and customer impacts. Given the changes to the generating fleet, and the potential shortfalls in generating capacity, it is imperative that reliable generating resources be recognized for the regional supply and reliability value provided to the region's customers. Given the existing regional supply situation, resources need to remain online and available to provide capacity and transmission grid stability to meet the system's needs until sufficient replacement capacity is brought online.

9. Rush Island is not only registered and counted as a capacity resource in MISO's 2022-2023 PRA, but it has also been identified as necessary for the reliability of the grid surrounding the plant. MISO is responsible for studying all retirement requests for impacts to the grid from a transmission security standpoint. MISO has identified multiple reliability constraints that require the Rush Island plant to remain online as a System Support Resource until transmission

upgrades are in place that would allow the plant to suspend operation. The details associated with the Attachment Y report have been made available to the court.

Executed on: 6-7-2022 ______________________________

EXHIBIT F

https://www.wsj.com/articles/electricity-shortage-warnings-grow-across-u-s-11652002380

BUSINESS

Electricity Shortage Warnings Grow Across U.S.

Power-grid operators caution that electricity supplies aren't keeping up with demand amid transition to cleaner forms of energy

By Katherine Blunt

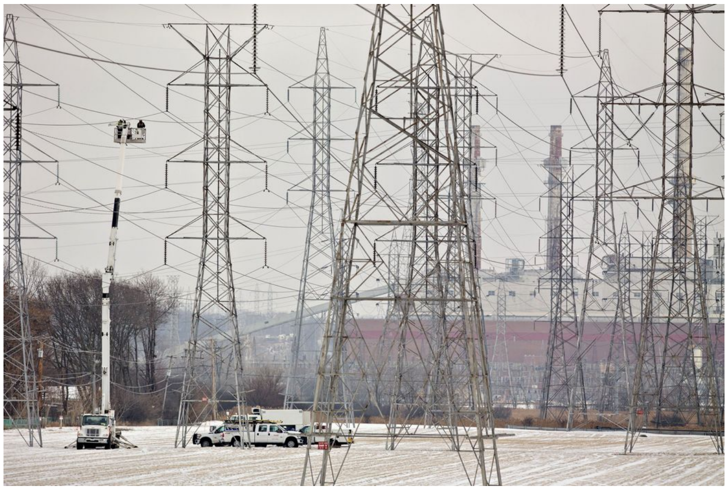
May 8, 2022 5:33 am ET

From California to Texas to Indiana, electric-grid operators are warning that power-generating capacity is struggling to keep up with demand, a gap that could lead to rolling blackouts during heat waves or other peak periods as soon as this year.

California's grid operator said Friday that it anticipates a shortfall in supplies this summer, especially if extreme heat, wildfires or delays in bringing new power sources online exacerbate the constraints. The Midcontinent Independent System Operator, or MISO, which oversees a large regional grid spanning much of the Midwest, said late last month that capacity shortages may force it to take emergency measures to meet summer demand and flagged the risk of outages. In Texas, where a number of power plants lately went offline for maintenance, the grid operator warned of tight conditions during a heat wave expected to last into the next week.

The risk of electricity shortages is rising throughout the U.S. as traditional power plants are being retired more quickly than they can be replaced by renewable energy and battery storage. Power grids are feeling the strain as the U.S. makes a historic transition from conventional power plants fueled by coal and natural gas to cleaner forms of energy such as wind and solar power, and aging nuclear plants are slated for retirement in many parts of the country.

The challenge is that wind and solar farms—which are among the cheapest forms of power generation—don't produce electricity at all times and need large batteries to store their output for later use. While a large amount of battery storage is under development, regional grid operators have lately warned that the pace may not be fast enough to offset the closures of traditional power plants that can work around the clock.



Speeding the build-out of renewable energy and batteries has become an especially difficult proposition amid supply-chain challenges and inflation. Most recently, a probe by the Commerce Department into whether Chinese solar manufacturers are circumventing trade tariffs on solar panels has halted imports of key components needed to build new solar farms and effectively brought the U.S. solar industry to a standstill.

Faced with the prospect of having to call for blackouts when demand exceeds supply, many grid operators are now grappling with the same question: How to encourage the build-out of batteries and other new technologies while keeping traditional power plants from closing too quickly.

“Every market around the world is trying to deal with the same issue,” said Brad Jones, interim chief executive of the Electric Reliability Council of Texas, which operates the state’s power grid. “We’re all trying to find ways to utilize as much of our renewable resources as possible…and at the same time make sure that we have enough dispatchable generation to manage reliability.”

The risk of outages resulting from supply constraints comes amid other challenges straining the reliability of the grid. Large, sustained outages have occurred with greater frequency over the past two decades, in part because the grid has become more vulnerable to failure with age and an uptick in severe weather events exacerbated by climate change. A push to electrify home heating and cooking, and the expected growth of electric vehicles, may increase power demand in coming years, putting further pressure on the system.

California regulators on Friday said as much as 3,800 megawatts of new supplies may face delays through 2025. Such delays would pose a major challenge for the state, which is racing to procure a huge amount of renewable energy and storage to offset the closure of several gas-fired power plants, as well as a nuclear plant. Gov. Gavin Newsom recently said he would consider moving to keep that nuclear plant, Diablo Canyon, online to reduce the risk of shortages.

“We need to make sure that we have sufficient new resources in place and operational before we let some of these retirements go,” said Mark Rothleder, chief operating officer of the California Independent

System Operator, which operates the state's power grid. "Otherwise, we are putting ourselves potentially at risk of having insufficient capacity."

The reliability question has stirred strong debate in Texas, where a freak winter storm last year caused power plants of all kinds to trip offline, forcing the grid operator to call for dayslong blackouts to keep supply in line with demand. Many problems played a part—some power plants weren't prepared for subfreezing temperatures, while others couldn't operate for lack of fuel—but the failures collectively exposed the vulnerability of the state's power market, and resulted in calls for change.

Texas is now debating what would be a major philosophical shift for its power market: paying power generators ahead of time for resources that might be needed, instead of just compensating them for actual power sold. That approach would largely benefit incumbent generators including NRG Energy Inc. and Vistra Corp., which own numerous conventional power plants with the potential to profit from such contracts.

The idea has prompted pushback from some battery and renewable-energy companies, including Eolian LP, which has proposed incentives for batteries, small gas turbines and other technologies capable of quickly ramping up to meet increases in electricity demand.

"The most important thing we heard after the freeze was we need to keep the lights on and make sure this grid is reliable," said Peter Lake, chairman of the Public Utility Commission of Texas. "There's nothing worse than turning Texas off."

The MISO, which recently warned of potential supply shortages resulting from higher-than-expected summer demand, has lately undertaken an effort to better value different types of resources based on their ability to support the grid at different times during the year and under various conditions. It is also working to improve the transfer of power across regions when needed.

MISO Chief Executive John Bear said those processes will help the grid operator as the energy transition progresses, but he foresees the risk of near-term shortages. The grid operator has more frequently resorted to emergency measures to shore up supplies in recent years.

“I am concerned about it,” Mr. Bear said. “As we move forward, we need to know that when you put a solar panel or a wind turbine up, it’s not the same as a thermal resource,” such as gas or coal.

Write to Katherine Blunt at Katherine.Blunt@wsj.com

Appeared in the May 9, 2022, print edition as 'Power Warnings Grow Across U.S.'.

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

UNITED STATES OF AMERICA, Plaintiff, SIERRA CLUB, Plaintiff-Intervenor, v. AMEREN MISSOURI, Defendant.	Civil Action No. 4:11-cv-00077-RWS

UNITED STATES' MEMORANDUM IN SUPPORT OF ITS MOTION TO STRUCTURE FURTHER CONSISTENT PROCEEDINGS PURSUANT TO THE EIGHTH CIRCUIT'S REMAND

This Court's September 2019 remedy order (ECF 1122) directed Ameren to bring its Rush Island facility into compliance with the Clean Air Act's requirements, and ordered further injunctive relief at Ameren's Labadie facility to mitigate the harm from the company's years of excess SO_2 pollution. Two events have changed the landscape since that order was entered. First, Ameren has decided it would rather retire Rush Island than install pollution controls there, and the company has informed the Midcontinent Independent System Operator as much with the submission of its (negotiated) Attachment Y request. (ECF 1208). Second, the Eighth Circuit vacated this Court's mitigation order at Labadie, remanding the matter for further consistent proceedings. Importantly, the Eighth Circuit did not overturn this Court's finding that reducing pollution exposures in downwind communities would remediate the harms from Ameren's violations. Nor did the Eighth Circuit question this Court's holding that mitigation efforts are warranted here.

In light of these developments, and cognizant of the harm from Ameren's violations at Rush Island, Plaintiffs ask that the Court continue to monitor Ameren's progress toward Rush Island's retirement to ensure that any emergent issues can be brought to the Court's attention quickly, thereby minimizing process delays that impact public health. Specifically, the Court should direct Ameren to:

1. Provide monthly status reports to the Court regarding its plan to retire Rush Island, and
2. Produce to Plaintiffs, on a monthly basis, all communications between Ameren and MISO concerning Rush Island's retirement and the Attachment Y or Attachment Y Alternatives studies undertaken by MISO to assess Ameren's retirement proposal.

Additionally, Plaintiffs ask that the Court direct Ameren to develop a suite of mitigation proposals to redress the company's harms to the public health and welfare, and establish a timeline for development and evaluation. As such, we further ask that the Court direct:

3. The Parties to meet and confer concerning potential areas of mitigation within 30 days;
4. Ameren develop and serve upon Plaintiffs by September 1, 2022 a suite of mitigation possibilities that takes into account the nature, extent, and location of Ameren's harms to

the public health and welfare, as found by the Court, and describes the scope, cost, and impact of each possibility; and

5. The Parties submit a joint proposed mitigation plan or competing plans with briefing and a proposal for further proceedings by November 1, 2022.

POSTURE

A. Though Now Proceeding, Ameren's Belated Turn Toward Retirement At Rush Island Follows A Pattern Of Denial And Delay.

Ameren took a calculated risk when it chose to modify its Rush Island boilers without complying with the Clean Air Act. As this Court concluded, "the standard for assessing PSD applicability was well-established" at the time of Ameren's illegal modification, and it was "well-known that the types of unpermitted projects Ameren undertook risked triggering PSD requirements." (ECF 1122 at 105 (internal quotations and citations omitted)). But instead of installing and operating the controls that would have protected communities from that pollution and saved hundreds of lives, Ameren spent more than a decade using ratepayer funds to delay compliance through litigation and pay for "fringe science" that denied its pollution's harms. (ECF 1122 at 145).

Ameren's stall tactics did not end with this Court's final order. Following the Order, Ameren sought a stay while it pursued its appeal. (ECF 1135). This Court partially denied that request, admonishing the company that it "must begin the process of complying with the ordered injunctive relief so that it can be in the position to immediately begin the more substantial phases of compliance upon the ruling of the Eighth Circuit." (ECF 1137 at 3). As the Court noted then: "A complete freeze on all ordered relief during the entire pendency of the appeal would cause injury to the public that significantly outweighs the potential harm to Ameren that would result from the relatively minimal unrecoverable costs of taking initial steps to comply." (ECF 1137 at 3). The Court thus ordered Ameren to proceed with PSD permitting and to "continue to prepare to quickly comply with the full injunction after the Eighth Circuit issues its ruling." (*Id.* at 4).

"Ameren did not comply with this order" and preliminary permitting efforts for the pollution controls ordered by the Court essentially stalled by October 2020. Oct. 28, 2021 Order (ECF 1175), at 2-5. As it turns out, Ameren was simultaneously studying the possibility of retiring Rush Island rather than controlling the facility. And as revealed in documents produced at the conclusion of this Court's February 7 hearing, the company had confidentially informed the PSC in September 2020 that "[r]etirement of Rush Island Energy Center by the end of 2024 is less costly than the energy center modifications" ordered by this Court. *See* Sept. 2020 Integrated Resource Plan, Ch. 9 [AM-REM-00568743] (Ex. 1) at -771. Though Ameren knew retirement was likely the least-cost option to achieve compliance by *at least* September 2020, the company did not take preliminary steps to study retirement further or identify any obstacles to that plan.

Had Ameren begun planning for its retirement effort in 2020,[1] we would know better what needs to be done to maintain grid reliability when the plant is shut down—and how long implementing those measures will take. Preparations for such work could have been accomplished already, just as this Court ordered Ameren to develop its pollution control plan so it could hit the ground running the moment the Eighth Circuit affirmed the need. As it is, the extent and timing of any reliability protections necessary to enable Rush Island's full retirement remain in doubt—and the tally of unpermitted pollution from Rush Island continues to grow.

B. As The Record Shows, Excess Emissions From Rush Island Continue To Accrue, Increasing Premature Death Risks In The Greater St. Louis Area And Beyond.

Excess sulfur dioxide (SO_2) pollution continues to stream into the air following Ameren's Clean Air Act violations at the Rush Island facility. "Once emitted, most SO_2 converts into fine particulate matter ($PM_{2.5}$), a pollutant known to cause increased risks of premature mortality, heart

[1] For instance, Ameren should have submitted an Attachment Y-2 request, which allows a utility to request a non-binding "informational"' study, in order to "make more knowledgeable decisions regarding *potential* decisions to retire." *Midcontinent Indep. Sys. Operator, Inc.*, 140 FERC P 61,237, ¶ 65, 2012 WL 4319785, *19 (Sept. 21, 2012) (emphasis added). Instead, Ameren chose to wait.

and lung disease, and other adverse health effects." (ECF 1122 at 117; *see also id.* at 146). $PM_{2.5}$ that results from Ameren's excess emissions affects air quality as far away as the east coast. (Id. at 86). But as Lyle Chinkin testified during the remedy trial, Rush Island's air quality impacts are most severe in the St. Louis area. (Remedy Tr. vol. 2B at 28:10–15). Mr. Chinkin's modeling showed that, day-by-day, Rush Island's SO_2 emissions pollution can have a profound impact on $PM_{2.5}$ concentrations in the St. Louis area—"one of the largest [impacts] I've seen from a single source on a single day" in "30 plus years" of air quality work. (Remedy Tr. vol. 2B at 19:15–23). And maps of the facility's annual average impacts on air quality paint a bullseye on the greater St. Louis area. (ECF 1122 at 86).

As the Court found, incremental increases in $PM_{2.5}$ concentrations lead to incremental increases of risks to human health and welfare at any concentration. (ECF 1122 at 97, 143). That pollution has already taken a toll of "hundreds or thousands" of premature deaths in downwind communities. (ECF 1122 at 89). And each year of uncontrolled Rush Island operations results in roughly 16,000 more tons of SO_2 pollution and scores more premature—and preventable—deaths. (*Id.* at 58, 90; *see also* ECF 1137 at 3). As Dr. Joel Schwartz testified at trial, the social cost of Ameren's excess SO_2 pollution from Rush Island is around $23,500 per ton. (*See* Remedy Tr. vol. 3A at 117:3). Thus, in the two years Ameren failed to take even preliminary steps toward the retirement it *knew* it would pursue once the Court's compliance order was affirmed, the company's excess emissions from the facility have imposed hundreds of millions of dollars in social costs on downwind communities—on the order of ***$500,000,000***.

C. The Eighth Circuit's Opinion Did Not Change The Fundamental Legal Framework Nor The Assessment Of Equities Supporting Mitigation Relief Here.

The legal framework and pertinent facts remain as they were at the time of this Court's Remedy Order.

The Clean Air Act authorizes enforcement actions against facilities' "owners and operators" for violations, and gives district courts the authority to "restrain such violation[s]," to "require compliance," and to "award any other appropriate relief" necessary. 42 U.S.C. § 7413. Such authority empowers district courts to "provide complete relief in light of the statutory purposes." *Mitchell v. Robert De Mario Jewelry, Inc.*, 361 U.S. 288, 291-92 (1960). "[A] court's equitable power to enforce a statute includes the power to provide remedies for past violations—an area in which the courts have settled authority and competence." *United States Pub. Int. Research Grp. v. Atl. Salmon of Me., LLC*, 339 F.3d 23, 31 (1st Cir. 2003).[2] Indeed, a court "may go beyond the matters immediately underlying its equitable jurisdiction and decide whatever other issues and give whatever other relief may be necessary under the circumstances. Only in that way can equity do complete rather than truncated justice." *Porter v. Warner Holdings Co.*, 328 U.S. 395, 398 (1946); *see also Natural Res. Def. Council v. SW Marine, Inc.*, 236 F.3d 985, 1000 (9th Cir. 2000) ("The authority to 'enforce' . . . is more than the authority to declare that the requirement exists and repeat that it must be followed."). Thus, as this Court already recognized, the Court has the authority to "order a full and complete remedy" for the harm caused by Ameren's violations, "and in doing so may go beyond what is necessary for compliance with the statute" at Rush Island. (ECF 1122 at 149 (*quoting United States v. Cinergy*, 582 F. Supp. 2d 1055, 1060-61 (S.D. Ind. 2008))).

After more than a decade of litigation, the critical facts supporting a remedial order are both clear and settled: the public health and welfare harms inflicted by Rush Island's excess SO_2 pollution

[2] *See also id.* at 33 ("Injunctive remedies for past harm commonly dictate future conduct so as to mitigate past harm."); *United States v. Deaton*, 332 F.3d 698, 713-14 (4th Cir. 2003) (upholding remedial injunction that required more than defendants would have had to do if they had simply obtained a Clean Water Act permit before the violations); *United States v. Cumberland Farms of Conn.*, 826 F.2d 1151, 1164-65 (1st Cir. 1987) (upholding issuance of "restorative order" to reverse effects of Clean Water Act violations); *United States v. Holtzman*, 762 F.2d 720, 724 (9th Cir. 1985) ("A federal court's equity jurisdiction affords it the power to enjoin otherwise lawful activity when necessary and appropriate in the public interest to correct or dissipate the evil effects of past unlawful conduct.") (citing cases).

are severe, but they are also redressable. The record—neither challenged by the defendant on appeal nor questioned by the Eighth Circuit—establishes that fine particulate matter resulting from Ameren's excess SO_2 pollution burdens downwind communities with increased risks of disease and death. (ECF 1122 at 117; *see also id.* at 146). But, as this Court found, reducing emissions and exposures in those downwind areas can work to repair that harm, reducing ambient $PM_{2.5}$ concentrations and so, incrementally, reducing the risks of adverse human health consequences faced by downwind communities and (eventually) restoring the status quo. (ECF 1122 at 96–100). After finding pertinent facts and carefully balancing the equities, this Court directed Ameren to perform mitigation projects at Labadie that would:

- offset Ameren's roughly 250,000 tons of excess SO_2 emissions
- over the course of 14 or 15 years
- at a cost of about $55 million in capital expenses and another $53 million per year in operating costs.

(ECF 1122 at 95–96, 151–52).

On appeal, the Eighth Circuit held that mitigation measures could not be ordered at Ameren's Labadie facility, apparently concerned that doing so would run afoul of the Act's Notice of Violations requirement.[3] (ECF 1170 at 32–33). But the Eighth Circuit did not upset this Court's broad equitable authority under the Clean Air Act to craft remedies that right wrongs and redress harms. (*See generally* ECF 1170). The Eighth Circuit did not question this Court's findings that the harms from Rush Island's excess emissions *could* be mitigated. (ECF 1170 at 15; *accord* ECF 1122 at 95–96). And the Eighth Circuit did not touch this Court's legal holdings that, after balancing the

[3] Though we recognize the decision controls this case, Plaintiffs continue to believe it was wrongly decided.

equities under *eBay*, those harms *should* be mitigated. (*Accord* ECF 1122 at 147–52).[4] Rather, the appellate court declared this Court's specific mitigation order involving the Labadie facility was improper, then remanded the matter for further proceedings. (ECF 1170 at 33, 34).

PROPOSAL

This Court has two issues before it: (1) Ameren has requested to retire, rather than control, the Rush Island plant, and (2) the Eighth Circuit vacated this court's specific mitigation injunction and remanded for further proceedings.

A. Retirement Proceedings

Plaintiffs recognize that Rush Island's prompt retirement will accomplish the compliance goals of this Court's remedy order by bringing facility emissions below the emissions limitations set by the Clean Air Act. (ECF 1197 at 2, 7). However, a *promise* or *proposal* to retire the facility does not protect the public health or welfare. As it stands, we do not know what specific reliability concerns MISO will identify, how long it will take Ameren to implement measures to address them, or how long Ameren will ultimately seek to continue its unpermitted operations at Rush Island before it can retire the facility. Plaintiffs recommend that this Court continue to take Ameren's motion to amend

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[4] Indeed, given the settled facts of this case, the Court's exercise of authority to redress harms here is squarely in line with longstanding principles of equity:

> [I]t is now settled, that a court of equity may take jurisdiction in cases of public nuisance, by an information filed by the attorney general. . . . [T]he jurisdiction has been finally sustained[] upon the principle that equity can give more adequate and complete relief than can be obtained at law. . . . [and] it may be exercised in those cases in which there is imminent danger of irreparable mischief before the tardiness of the law could reach it.

Mayor, etc. of City of Georgetown v. Alexandria Canal Co., 37 U.S. 91, 98 (1838). *See also United States v. Oakland Cannabis Buyers' Co-op.*, 532 U.S. 483, 496 (2001) (from the days of English common law, "courts of equity have enjoyed sound discretion to consider the necessities of the public interest when fashioning injunctive relief")· Absent mitigation efforts, as the record shows, downwind communities living with intolerable health risks as a result of Ameren's illegal pollution will continue to suffer scores of preventable premature deaths every year (ECF 1122 at 90)—an "imminent danger of irreparable mischief" if ever there was one.

the Remedy Order under advisement until such time the details of its retirement proposal are known and ready for review. In the meantime, Ameren has agreed to provide Plaintiffs with regular disclosures of the company's communications with MISO about its Attachment Y or Attachment Y Alternatives Study. However, to safeguard against further delays, which would only compound public health impacts of Ameren's violations and further add to the tally of excess emissions to be mitigated or offset, Plaintiffs request that this Court order the company to:

1. Provide monthly status reports to the Court regarding its plan to retire Rush Island, and
2. Produce to Plaintiffs, on a monthly basis, all communications between Ameren and MISO concerning Rush Island's retirement and the Attachment Y or Attachment Y Alternatives studies undertaken by MISO to assess Ameren's retirement proposal.

Such an order will ensure the retirement effort is moving expeditiously, and allow any issues with the retirement process to be brought to the Court's attention in a timely way. Once the extent of any necessary reliability protections comes into focus, this Court can set a schedule for Rush Island's retirement and a process by which Ameren can seek limited relief from that schedule as necessary.

B. Mitigation Proceedings

Plaintiffs believe it would be most efficient for Ameren to develop a suite of proposals to redress the harms from its violations for the Parties to consider and then bring to the Court.

After the Eighth Circuit's ruling, the opportunities for mitigation are fewer than they were—but there are still many options available. Of course, as an uncontrolled and substantial source of SO_2 pollution located just down the road from Rush Island, controlling Labadie Energy Center offered a unique opportunity to secure "complete"—if delayed—justice for the public health and welfare harms inflicted by Ameren's excess emissions. (ECF 1122 at 149; a*ccord Porter*, 328 U.S. at 398). With Labadie controls no longer an option, there is little chance a remedy can be fashioned to accomplish ton-for-ton mitigation of Ameren's long-accruing pollution exceedances. However, "[t]he linear concentration-response relationship for $PM_{2.5}$ exposure means that . . . ***any*** incremental decrease in exposure produces a positive impact on public health." (ECF 1122 at 97 (emphasis added)). As such, there remain opportunities for Ameren to accomplish meaningful mitigation, and to relieve the harm from its Rush Island violations. Plaintiffs recognize that other mitigation projects—even if such projects match the investment contemplated by the Labadie order—will likely not be as efficient at redressing the harm to downwind communities as the Labadie offsets would have been. But that does not change the severity of the harm from Ameren's violations, the equities of the case, or the urgent need for redress.

The menu for mitigating some of the harm from Ameren's violations is extensive. As an initial matter, Rush Island's retirement will, by itself, accomplish modest mitigation by reducing emissions beyond controlled levels for the years between the facility's accelerated retirement (whenever that is accomplished) and its previously scheduled retirement in 2039. The sooner Ameren is able to retire the facility, the sooner those offsets will begin to accrue.[5] In addition:

- Investments in clean energy infrastructure or renewable energy generation could serve to reduce regional emissions of SO_2, and so benefit downwind communities.[6]

- Urban green infrastructure—planting trees and other vegetation in urban areas—can mitigate local air pollution concentrations.[7]

- Applying high efficiency particulate air filtration in indoor settings has been shown to mitigate $PM_{2.5}$ exposures and health risks.[8]

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[5] Assuming Rush Island is fully retired by 2024, it will mitigate about 1,000 tons per year of SO_2 for about 15 years—a small but not insignificant repayment on its 250,000-ton pollution bill.

[6] EPA's Avoided Emissions and Generation Tool (available at https://www.epa.gov/avert) was designed to meet the needs of state air quality professionals, energy officials, and public utility commissions, and can help planners understand how renewable energy projects will lead to changes in pollution and air quality.

[7] Resources such as EPA's EnviroAtlas (available at https://www.epa.gov/enviroatlas) and the U.S. Forest Service's i-Tree software (available at https://www.itreetools.org) can help developers estimate the SO_2 and $PM_{2.5}$ pollution impacts of green infrastructure projects at a neighborhood and city scale.

[8] EPA collects resources and summarizes research involving indoor air quality and particle air cleaning (at https://www.epa.gov/indoor-air-quality-iaq/indoor-air-quality-science-and-technology).

So, for example, Ameren could build additional battery storage centers to manage and dispatch renewable energy, which could help offset SO_2 emissions impacts for hundreds of miles. It could develop urban greenscapes in and around St. Louis to mitigate Rush Island's pollution impacts in the regions where the facility's pollution impacts air quality the most. And it could distribute (or incentivize) indoor air filtration for schools and residents to provide meaningful interim relief from air pollution impacts while other mitigation projects are developed and implemented.

As these options make clear, Ameren has opportunities to remediate the harm from its violations. And there may be other options. But final injunctions must be specific, and many of the mitigation options available to Ameren require discussions—and potentially coordination—with other stakeholders such as affected community members, state or local officials, or even MISO. Crafting appropriate proposals will likely require outreach and investigation. As Ameren will ultimately be tasked with implementing any mitigation projects ordered by the Court, Plaintiffs suggest Ameren should take the first steps to develop the projects. Once developed, the Parties can confer and propose mitigation projects for this Court's consideration, in light of the established equities and under the familiar legal standards.

Therefore, Plaintiffs request that the Court further order that:

3. The Parties meet and confer concerning potential areas of mitigation within 30 days;

4. Ameren develop and serve upon Plaintiffs by September 1, 2022 a suite of mitigation possibilities that takes into account the nature, extent, and location of Ameren's harms to the public health and welfare, as found by the Court, and describes the scope, cost, and impact of each possibility; and

5. The Parties submit a joint proposed mitigation plan or competing plans with briefing and a proposal for further proceedings by November 1, 2022.

So does the Lawrence Berkeley National Laboratory (at https://iaqscience.lbl.gov/health-effects-outdoor-air-particles).

CONCLUSION

The United States requests that this Court structure remand proceedings to monitor Ameren's pursuit of Rush Island's retirement, and to oversee Ameren's development of mitigation proposals to redress the harms to the public health and welfare from its violations. Plaintiff-Intervener Sierra Club joins in this motion and concurs with this request.

Dated: June 2, 2021

Respectfully Submitted,

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Environment and Natural Resources Division
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CERTIFICATE OF SERVICE

I hereby certify that on June 2, 2022, I filed the foregoing under seal with the Clerk of Court using the CM/ECF system, and served an electronic copy on counsel for Ameren and Sierra Club via e-mail.

/s/ Elias L. Quinn
ELIAS L. QUINN

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

UNITED STATES OF AMERICA, Plaintiff, SIERRA CLUB, Plaintiff-Intervenor, v. AMEREN MISSOURI, Defendant.	Civil Action No. 4:11-cv-00077-RWS

UNITED STATES' MEMORANDUM IN SUPPORT OF ITS MOTION TO STRUCTURE FURTHER CONSISTENT PROCEEDINGS PURSUANT TO THE EIGHTH CIRCUIT'S REMAND

EXHIBIT 1

9. Integrated Resource Plan and Risk Analysis

Highlights

- *Ameren Missouri has developed a robust range of alternative resource plans that reflect different combinations of energy efficiency ("EE"), demand response ("DR"), various types of new renewable and conventional generation, energy storage, and retirement of each of its existing coal-fired generators.*
- *In addition to the scenario variables and modeling discussed in Chapter 2, one critical independent uncertain factor has been included in the final probability tree for risk analysis: demand-side management ("DSM") costs.*
- *Our risk analysis also includes the evaluation of a range of load growth.*

Ameren Missouri's modeling and risk analysis consisted of a number of major steps:

1. Identification of **alternative resource plan attributes**. These attributes represent the various resource options used to construct and define alternative resource plans – demand side resources, new renewable and non-renewable supply side resources, and retirement of existing supply side resources.
2. Development of the **baseline capacity position**, which reflects forecasted peak demand, reserve requirements and existing resources.
3. Development of **planning objectives** to guide the development of alternative resource plans.
4. Development of the **alternative resource plans**. The alternative resource plans were developed using the plan attributes identified in step 1, the base capacity position developed in step 2, and the planning objectives identified in step 3.
5. Identification and screening of **candidate uncertain factors**, which are key variables that can influence the performance of alternative resource plans.
6. **Sensitivity analysis** and selection of critical uncertain factors, which are key variables that are determined to have a significant impact on the performance of alternative resource plans.

AM-REM-00568743

7. **Risk analysis** of alternative resource plans, which is used to evaluate the performance of alternative resource plans under combinations of the scenarios discussed in Chapter 2 and the critical uncertain factors identified in step 6.

This chapter describes these various steps and the results and conclusions of our integration and risk analysis.

9.1 Alternative Resource Plan Attributes[1]

Development of alternative resource plans include considering various combinations of demand-side and supply-side resources to meet future capacity needs. However, alternative resource plans may also include elements or attributes that serve the other planning objectives described in Section 9.3. Including these elements can significantly affect the capacity position that needs to be considered when developing alternative resource plans. Figure 9.1 includes the attributes considered during the development of resource plans.

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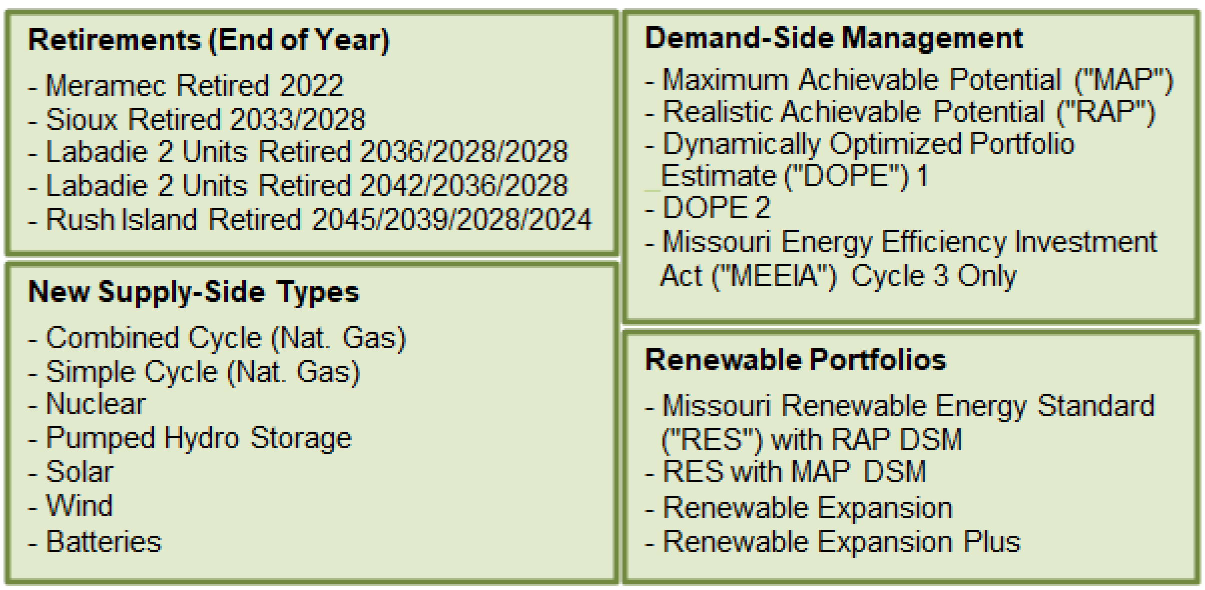
Figure 9.1 Attributes of Alternative Resource Plans[2]



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[1] 20 CSR 4240-22.060(1); 20 CSR 4240-22.060(3)

[2] Pursuant to the Motion for Protective Order filed concurrently with the filing of this IRP, and 20 CSR 4240-2.135(4)(A) and (B), the information for which protection is sought by the Motion has been marked "Highly Confidential" (denoted by three asterisks with two asterisks used for "Confidential" information), and is protected as such pending the Commission's ruling on the Motion.

9.2 Capacity Position

To determine the timing and need for resources, Ameren Missouri first developed its baseline capacity position, including:

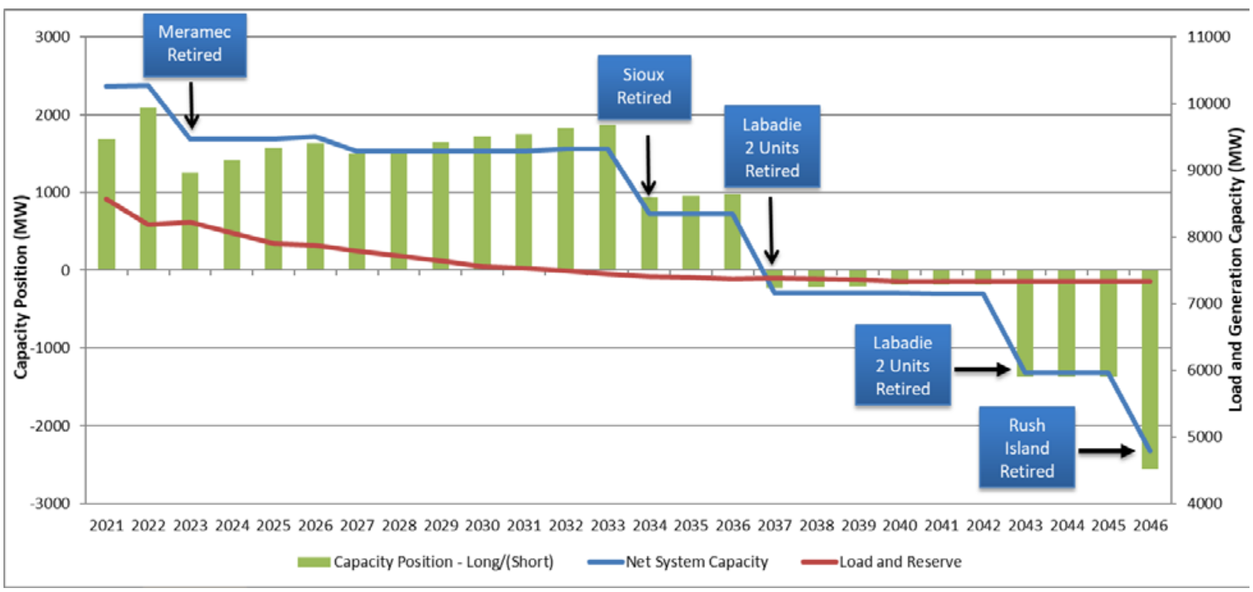
- Existing plant capabilities based on Ameren Missouri's annual generating unit rating update (i.e., August 2020 planned ratings)
- Existing obligations for capacity purchases and sales
- Peak demand forecast, as described in Chapter 3
- Planning reserve margin ("PRM") requirement, based on MISO's Planning Year 2020 Loss of Load Expectation ("LOLE") Study Report (November 2019). Table 9.1 shows the MISO System PRM from 2021 through 2029. The long-range PRM was assumed to continue at 18.3% through the remainder of the analysis period.

Table 9.1 MISO System Planning Reserve Margins 2021 through 2029

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029
PRM Installed Capacity	18.0%	17.9%	17.9%	18.2%	18.2%	18.1%	18.2%	18.2%	18.3%

Figure 9.2 shows Ameren Missouri's net capacity position with no new major generating resources.

Figure 9.2 Net Capacity Position – No New Supply-Side Resources (Baseline)



The chart shows the system capacity, customer needs (including the MISO reserve requirement), and capacity above/below the MISO requirement (i.e., long/short position). The customer needs include peak load reductions due to RAP EE, distributed energy resources ("DER"), and DR. The system capacity includes the capacity benefit of the RES Compliance portfolio. Retirement dates reflected in the base capacity position for existing coal-fired units are those established in Ameren Missouri's most recent depreciation study filed with the Missouri Public Service Commission ("MPSC") and are considered to be the base retirement dates.

Retirements and Modifications[3]

Ameren Missouri is considering retirement of some or all of its six older gas- and oil-fired CTG units – Fairgrounds, Meramec CTG-1, Meramec CTG-2, Mexico, Moberly, and Moreau – with a total summer net capacity of 263 MW, over the next 20 years. Chapter 4 - Table 4.3 provides a summary of the planned CTG retirements. The CTG retirements were included in all alternative resource plans.

Coal energy center retirements were also included in the capacity planning process. Meramec retirement by December 31, 2022 is included in all alternative resource plans. Two different Sioux retirement options were considered: 1) retirement by December 31, 2033 based on prior analysis of Ameren Missouri’s coal power plant life expectancy by Black and Veatch, and 2) retirement by December 31, 2028. Three different retirement options for Labadie were considered: 1) current retirement dates as determined by the Black and Veatch life expectancy study with two units retired by December 31, 2036 and two units retired by December 31, 2042, 2) two units retired by December 31, 2028 and two units retired by December 31, 2036, 3) all four units retired by December 31, 2028. Four retirement dates were evaluated for Rush Island: 1) retired by December 31, 2045, which is the current retirement date as determined by the Black and Veatch life expectancy study, 2) retired by December 31, 2039, 3) retired by December 31, 2028, and 4) retired by ******<u>December 31, 2024</u>******.

The alternative retirement dates were based on the ability to avoid significant ongoing costs, the potential for an explicit price on carbon starting in 2025 included in the scenarios described in Chapter 2, coupled with the time needed to ensure transmission upgrades are in place to continue to reliably serve our customers. ******<u>The 2024 Rush Island retirement date, along with wet flue gas desulfurization technology ("FGD") at Rush Island and dry sorbent injection system ("DSI") at Labadie</u>****** are included in order to evaluate specific potential outcomes pending a final judgment in the Rush Island New Source Review ("NSR") litigation which is under appeal and a decision by the federal court of appeals is not expected until 2021. Importantly, numerous potential

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[3] EO-2020-0047 1.D; EO-2020-0047 1.O

outcomes are possible, including reversal of the trial court's rulings on both liability and remedy, and the actual outcome may be different than the limited outcomes modeled.

DSM Portfolios

DER, EE, and DR programs as described in detail in Chapter 8 are included in the DSM portfolios. DSM programs not only reduce the peak demand but also reduce reserve requirements associated with those DRs. The following combinations of DSM portfolios were evaluated: 1) RAP, 2) MAP, 3) DOPE1, 4) DOPE2, and 5) No DSM after MEEIA Cycle 3. The No DSM portfolio reflects completion of Ameren Missouri's current program cycle with no further EE or DR during the planning horizon. Note that the recent MPSC approval of Ameren Missouri's request for a one-year extension of MEEIA programs occurred after the IRP analysis was underway, which means that the No Further DSM portfolio starts one year before that extension ends.[4]

Renewable Portfolios[5]

Compliance with Missouri's RES was updated to reflect current assumptions, including baseline revenue requirements and an updated 10-year forward-looking model which calculates the impact of the statutory 1% rate impact limitation.

Ameren Missouri performed its RES compliance analysis with the *2020 IRP RES Compliance Filing Model* (model). The model is designed to calculate the retail rate impact, as required by the Commission's RES rules.[6] This model determines the quantity of renewable energy needed to meet both the overall RES portfolio standard and the 2% solar portfolio standard "carve-out" absent any rate impact constraints. The model then determines the amount of renewable energy, both solar and non-solar that can be built without exceeding an average 1% revenue requirement increase over a ten-year period. Ameren Missouri's expected renewable energy credit (REC) position is presented in Figure 9.3.

[4] The extension of MEEIA Cycle 3 should not have a material impact on the analysis.
[5] EO-2020-0047 1.R
[6] 20 CSR 4240-20.100(5)

Figure 9.3 Ameren Missouri's RES REC Positions

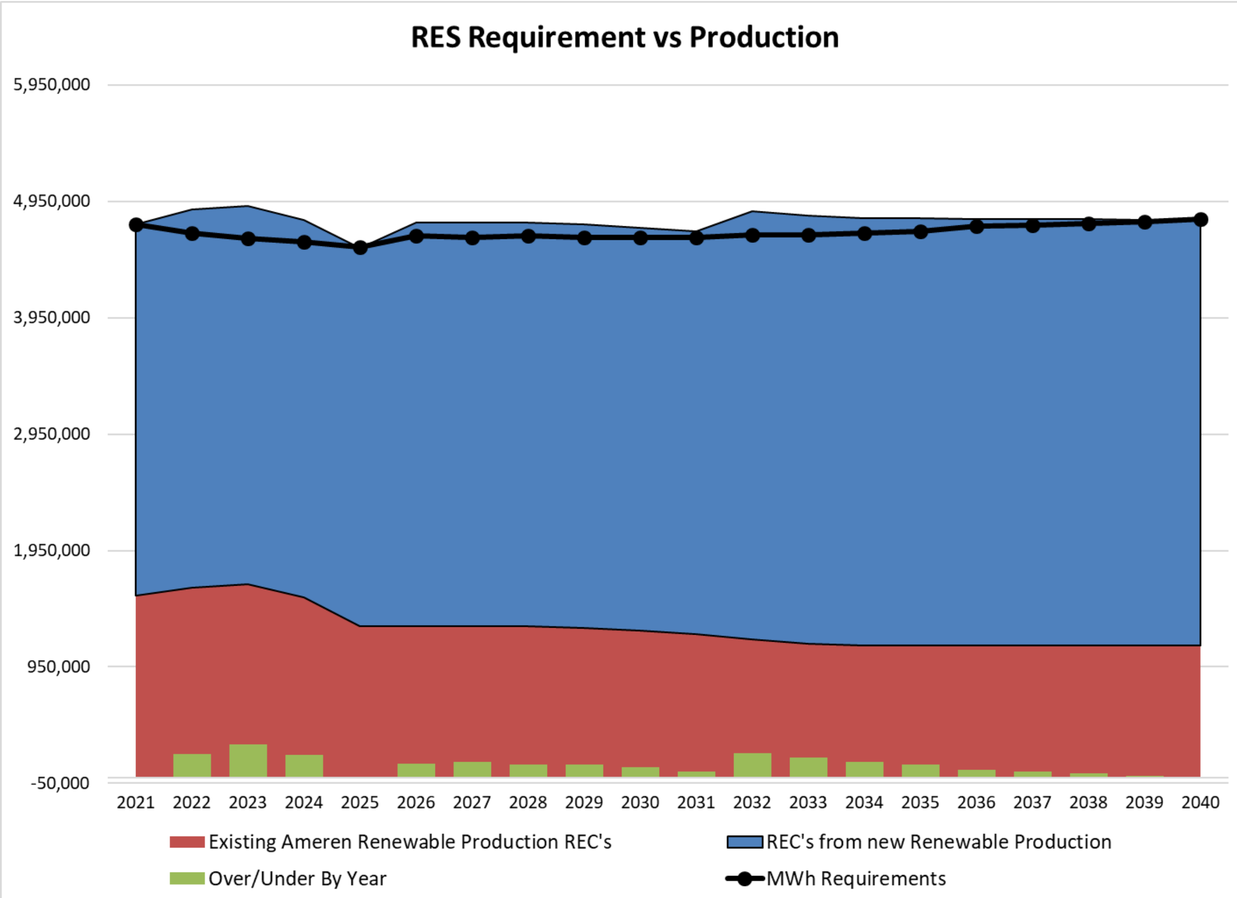


Figure 9.3 shows that Ameren Missouri expects to meet the overall REC requirement through 2040 primarily with owned renewable generation. Year-to-year compliance may also include banked RECs and purchased RECs. Starting in 2021, Ameren Missouri will be able to fully meet the overall standard using RECs generated by its existing qualifying resources, additional wind resources which will largely be completed by the end of 2020, with the remaining generation completed in the first quarter of 2021, and solar RECs acquired from customer rebate programs.

Table 9.2 shows the amounts of wind and solar resources added for various renewable portfolios, including RES compliance under different load cases. The RES compliance portfolio established by the previously described model is used for alternative resource plans and reflects wind resource additions that take advantage of Production Tax Credits, allowing full compliance with the RES while remaining under the one percent rate cap limitation. Appendix A shows the amounts of wind, and solar resources needed in Term 1 (2021-2030) and Term 2 (2031-2040).

When developing the RES compliance investment needs, consideration was given to the potential difference between RAP DSM investment vs MAP DSM investment. As MAP DSM results in more energy savings, the RES Compliance requirements are slightly lower than the requirements when RAP DSM is assumed.

In addition to the RES Compliance portfolios, we also included a "Renewable Expansion" and a "Renewable Expansion Plus" portfolio to evaluate the performance of additional solar and wind resources. The Renewable Expansion portfolio includes a total of 2,700 MW wind and 2,700 MW solar while the Renewable Expansion Plus portfolio includes a total of 3,900 MW wind and 4,000 MW solar resources.[7]

Table 9.2 shows the timing of new resources for renewables included in the alternative resource plans.

Table 9.2 Renewable Portfolios (Nameplate Capacity)

Renewable Additions		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
RES Compliance w/ RAP DSM	Wind	700	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	-	30	20	-	-	-	-	75	-	-	-	-	75	-	-	-	-	-	-	-
RES Compliance w/ MAP DSM	Wind	700	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	-	30	20	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable Expansion	Wind	700	-	-	300	-	-	-	300	-	-	300	-	300	-	300	-	300	-	200	-
	Solar	-	30	20	-	250	-	400	-	300	400	-	300	-	300	-	300	-	400	-	-
Renewable Expansion Plus	Wind	700	-	-	400	-	400	-	400	-	-	-	-	500	-	500	-	500	-	500	-
	Solar	-	30	295	-	375	-	400	-	400	400	-	400	-	400	-	400	-	400	-	500

With the Renewable Expansion Plus renewable portfolio, batteries were also included: 100 MW in each year from 2031 to 2035, 150 MW in each year from 2036 to 2043 for a total of 1,700 MW.

Other Supply-side Resources

After including DSM resources and the renewable portfolios, if the capacity shortfall in a given year met or exceeded the build threshold, then supply side resources are added to eliminate the shortfall. The build threshold was determined to be 300 MW regardless of the type of supply-side resource under consideration and reflects a level that Ameren Missouri trading staff assess as a reasonable level of capacity market dependence. The full rated capacity and the build thresholds for each supply side type are shown in Table 9.3. Ameren Missouri has assumed reliance on short-term capacity purchases to cover shortfalls that are less than the build threshold and has assumed that any long capacity position would be sold. The earliest in-service dates for each supply-side resource are

[7] EO-2020-0047 1.K

also shown in Table 9.3. The in-service date constraints represent the expectations for construction lead time as well as the commercial availability of each technology.

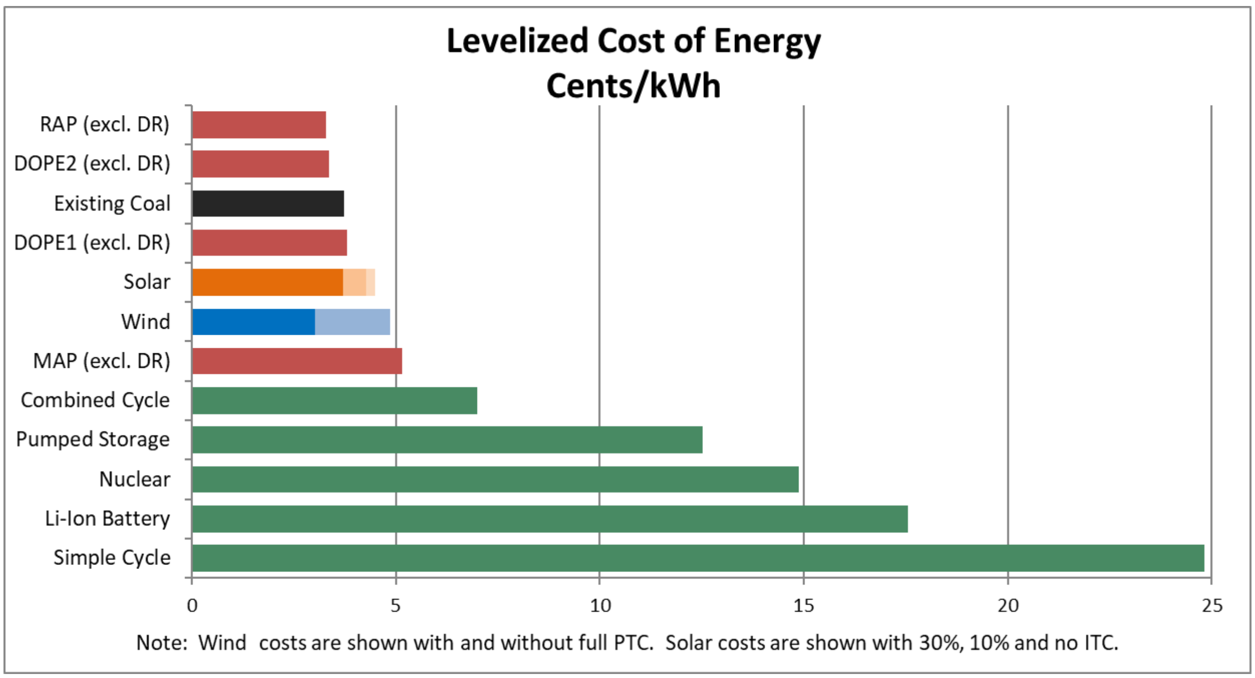
Table 9.3 Build Threshold for Supply Side Types

Supply Side Type	Capacity (MW)	Build Threshold (MW)	Earliest Year In-Service
CC-Natural Gas	824	300	2025
SC-Natural Gas	690 (3x230)	300	2025
Nuclear	1100	300	2030
Pumped Hydro	600	300	2029
Solar	800	300	2022

The remaining net capacity position was represented in the financial model as capacity purchases and sales priced at the market-based capacity costs as discussed in Chapter 2. The capacity purchases and sales were also adjusted for the various peak demand forecasts associated with each of the 15 scenarios and DSM impacts.

Figure 9.4 summarizes the levelized cost of energy ("LCOE") for all potential future resources evaluated in the alternative resource plans.

Figure 9.4 Levelized Cost of Energy – All Resources[8]



[8] 20 CSR 4240-22.010(2)(A)

9.3 Planning Objectives

The fundamental objective of Missouri's electric resource planning process is to provide energy to customers in a safe, reliable and efficient way, at just and reasonable rates while being in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies.[9] Ameren Missouri considers several factors, or planning objectives, that must be considered in meeting the fundamental objective. Planning objectives provide a guide to the decision making process while ensuring the resource planning process is consistent with business planning and strategic initiatives.

Five planning objectives were used in the development of alternative resource plans: Portfolio Transition (formerly Environmental/Resource Diversity); Financial/Regulatory; Customer Satisfaction; Economic Development; and Cost. These planning objectives, which are the same as those discussed in Ameren Missouri's IRP filings since 2011, were selected by Ameren Missouri decision makers and are discussed below.[10]

Portfolio Transition

Ameren Missouri has relied for many years on a portfolio that consists, in large part, of large, efficient coal-fired generators. Current and potential future environmental regulations may have a significant impact on Ameren Missouri's coal-fired fleet and its selection of future generation resources. Ameren Missouri seeks to transition its generation portfolio to one that is cleaner and more diverse in a responsible fashion. To test various options for advancing this transition, alternative resource plans were developed to include varying levels of DSM portfolios, renewables in addition to those required for RES compliance, new gas-fired generation, new nuclear generation, storage resources and early coal retirements.

Financial/Regulatory

The continued financial health of Ameren Missouri is crucial as it will need access to large amounts of capital in order to comply with RES and environmental regulations, invest in new supply side resources, and fund continued EE programs while maintaining or improving safety, reliability, affordability, and customers' ability to control their energy use and costs. While making its investment decisions, it is important for Ameren Missouri to consider factors that may influence its access to low-cost sources of capital.

[9] 20 CSR 4240-22.010(2)
[10] 20 CSR 4240-22.010(2)(C)

This includes measures of cash flow, profitability, and creditworthiness as well as assessment of risks associated with investment management and cost recovery.[11]

Customer Satisfaction

While there are many factors that can influence customer satisfaction, there are several that can be significantly affected by resource decisions. Ameren Missouri has focused on levelized annual rates, inclusion of EE, reliability, availability of DER and DR programs, inclusion of new clean energy resources, and significant reductions in CO_2 emissions to assess relative customer satisfaction expectations.[12]

Economic Development

Ameren Missouri assesses the relative economic development potential of alternative resource plans in terms of job growth opportunities associated with its resource investment decisions. Plans were rated on a relative scale based on direct jobs (FTE-years) required for both construction and operation.[13] We have assumed that second and third level economic impacts would not significantly affect the relative economic development potential of alternative resource plans, and therefore have not included such impacts in our assessment.

Cost

Ameren Missouri is mindful of the impact that its future resource choices will have on its customers' rates and bills. Maintaining reasonable costs while meeting its other planning objectives is of utmost importance to Ameren Missouri. Cost alone does not and should not dictate resource choices, but it is a very important factor in making resource decisions. Therefore, minimization of the present value of revenue requirements was used as the primary selection criterion.[14]

9.4 Determination of Alternative Resource Plans[15]

Twenty-one alternative resource plans were developed to incorporate different combinations of demand-side and supply side resource options, seek to fulfill Ameren Missouri's planning objectives, and answer key questions, including the following:

- Does inclusion of DSM programs reduce overall customer costs?

[11] 20 CSR 4240-22.060(2)(A)6
[12] 20 CSR 4240-22.060(2)(A)4
[13] 20 CSR 4240-22.060(2)(A)7
[14] 20 CSR 4240-22.060(2)(A)1; 20 CSR 4240-22.010(2)(B)
[15] 20 CSR 4240-22.060(3)

- What level of DSM – RAP, MAP, DOPE1 or DOPE2 – results in lower costs?
- Is early retirement of Rush Island Energy Center cost effective?
- Is early retirement of Labadie Energy Center cost effective?
- Is early retirement of Sioux Energy Center cost effective?
- Is early retirement of the Sioux and Rush Energy Centers cost effective?
- What is the impact of reducing SO_2 emissions further?
- What are the benefits of including renewables beyond those needed for RES compliance?
- What is the impact of pursuing only new renewables?
- How would our plans and customer costs be affected if DSM cost recovery and incentive needs are not met?
- How do various supply side resource options compare?

Table 9.4 provides a summary of the alternative resource plans.

***

Table 9.4 Alternative Resource Plans[16]

	Plan Name	DSM	Renewables	New Supply Side	Coal Retirements/ Modifications
A	RAP DSM - RES Compliance	RAP	RES Compliance	2 CCs in 2043, CC in 2046	Base
B	Renewable Expansion	RAP	Renewable Expansion	CC in 2046	Base
C	No New DSM - CCs	-	Renewable Expansion	CC in 2037, 2 CCs in 2043, CC in 2046	Base
D	No New DSM - All Solar	-	Renewable Expansion	6400 MW 2034-2046	Base
E	No New DSM - Pumped Hydro	-	Renewable Expansion	PS in 2037, CC in 2037, 2043, 2046	Base
F	No New DSM - AP1000	-	Renewable Expansion	Nuke 2037, CC in 2043, 2 CCs in 2046	Base
G	No New DSM - Simple Cycles	-	Renewable Expansion	SC 2037, CC in 2037, 2043, 2046	Base
H	MAP DSM - Renewable Expansion	MAP	Renewable Expansion	-	Base
I	MAP DSM - RES Compliance	MAP	RES Compliance	2 CCs in 2046	Base
J	DOPE1 DSM	DOPE	Renewable Expansion	CC in 2043, 2046	Base
K	DOPE2 DSM	DOPE	Renewable Expansion	CC in 2043, 2046	Base
L	Labadie Early Retirement - 4 units	RAP	Renewable Expansion	CC in 2034	Labadie 4U Dec-2028
M	Labadie Early Retirement - 2 units	RAP	Renewable Expansion	CC in 2046	Labadie 2U Dec-2028 Labadie 2U Dec-2036
N	Sioux Early Retirement	RAP	Renewable Expansion	CC in 2046	Sioux Dec-2028
O	Rush Early Retirement	RAP	Renewable Expansion	CC in 2043	Rush Island Dec-2028
P	Sioux-Rush Early Retirement	RAP	Renewable Expansion	CC in 2043	Sioux Dec-2028 Rush Island Dec-2039
Q	Sioux-Rush Early Retirement - No CCs	RAP	Renewable Expansion Plus	Battery 1700MW 2031-2043	Sioux Dec-2028 Rush Island Dec-2039
R	Rush Early Retirement 2	RAP	Renewable Expansion	CC in 2043	Rush Island Dec-2024
S	Rush FGD	RAP	Renewable Expansion	CC in 2046	Base Rush Island FGD
T	Rush FGD - Labadie DSI	RAP	Renewable Expansion	CC in 2046	Base Rush Island FGD Labadie DSI
U	Rush Early Retirement 2 - Labadie DSI	RAP	Renewable Expansion	CC in 2043	Rush Island Dec-2024 Labadie DSI

***

[16] 20 CSR 4240-22.010(2)(A); 20 CSR 4240-22.060(3); 20 CSR 4240-22.060(3)(A)1 through 8; 20 CSR 4240-22.060(3)(B); 20 CSR 4240-22.060(3)(C)1; 20 CSR 4240-22.060(3)(C)2; 20 CSR 4240-22.060(3)(C)3; EO-2020-0047 1.D; EO-2020-0047 1.K

Does inclusion of DSM programs reduce overall customer costs?

Plans B, H, J, and K include RAP, MAP, DOPE1 and DOPE2 level of DSM programs, respectively. Therefore, these plans can be compared against plans C, D, E, F, and G that have the same level of renewable portfolios but do not include DSM programs to assess the impact on cost and other performance measures due to inclusion of different levels of DSM.

What level of DSM -RAP, MAP, DOPE1 or DOPE2- results in lower costs?

Plans with the same attributes except for the level of DSM resources have been evaluated as described above and provide a direct comparison of the relative cost of the various DSM portfolios.

Is early retirement of Rush Island Energy Center cost effective?[17]

Plan O evaluates the cost effectiveness of early retirement of Rush Island Energy Center by the end of 2028.

Is early retirement of Labadie Energy Center cost effective?[18]

Plans L and M evaluate the cost effectiveness of early retirement of all four units by the end of 2028, and two units by the end of 2028 followed by two units by the end of 2036, respectively.

Is early retirement of Sioux Energy Center cost effective?[19]

Plan N evaluates the cost effectiveness of early retirement of Sioux Energy Center alone.

Is early retirement of Sioux and Rush Island Energy Centers cost effective?[20]

Plan P evaluates the cost effectiveness of early retirements of Sioux Energy Center by the end of 2028 and Rush Island Energy Center by the end of 2039.

[17] 20 CSR 4240-22.060(3)(A)7; EO-2020-0047 1.O
[18] 20 CSR 4240-22.060(3)(A)7; EO-2020-0047 1.O
[19] 20 CSR 4240-22.060(3)(A)7; EO-2020-0047 1.O
[20] 20 CSR 4240-22.060(3)(A)7; EO-2020-0047 1.O

What is the impact of potential outcomes of the active NSR litigation?[21]

Four plans are constructed in order to evaluate different potential outcomes for the active NSR litigation: *****Plan R includes Rush Island Energy Center retirement by the end of 2024, Plan S includes installation of FGD at Rush Island Energy Center in 2025, Plan T is similar to Plan S but also includes a DSI system installation at Labadie Energy Center in 2023, and Plan U includes early retirement of Rush Island Energy Center by the end of 2024 as well as addition of DSI system at Labadie Energy Center**.***

What are the benefits of including renewables beyond those needed for RES compliance?

To assess the relative benefits of including additional renewable resources, several alternative resource plans were developed that exceed the level of renewable investment indicated by the RES compliance model. Plans A and B with RAP DSM and Plans H and I with MAP DSM can be compared to assess the costs/benefits of additional renewables. Furthermore, Plans P and Q can be compared to assess additional renewables coupled with batteries. Also included is resource plan D that features solar as a major supply-side resource and the only supply-side resource addition during the planning horizon in addition to the 'renewable expansion' level of wind and solar resource additions.

What is the impact of pursuing only new renewables?

Plan D is the all renewables alternative resource plan without DSM beyond MEEIA Cycle 3.[22]

How do various supply-side resource options compare?

The relative performance of the new supply-side resources can be determined by comparing Plans C through G, and by comparing Plan P against Plan Q.

How would our plans and customer costs be affected if DSM cost recovery and incentive needs are not met?

Plans C through G also evaluate the impact if DSM cost recovery and incentive requirements are not met.

[21] EO-2020-0047 1.D
[22] 20 CSR 4240-22.060(3)(A)2

The type, size, and timing of resource additions/retirements for the alternative resource plans are provided in Appendix A and also in the electronic workpapers.[23]

Integration, sensitivity, and risk analyses for the evaluation of alternative resource plans were done assuming that rates would be adjusted annually for the 20-year planning horizon and 10 additional years for end effects, and by treating both supply-side and demand-side resources on an equivalent basis. Integration analysis was performed on the most likely scenario of the probability tree (Scenario 5) as explained in Chapter 2. Integration analysis present value of revenue requirements ("PVRR") results are shown below in Figure 9.5. Results for the remaining performance measures for integration analysis are provided in the workpapers.[24]

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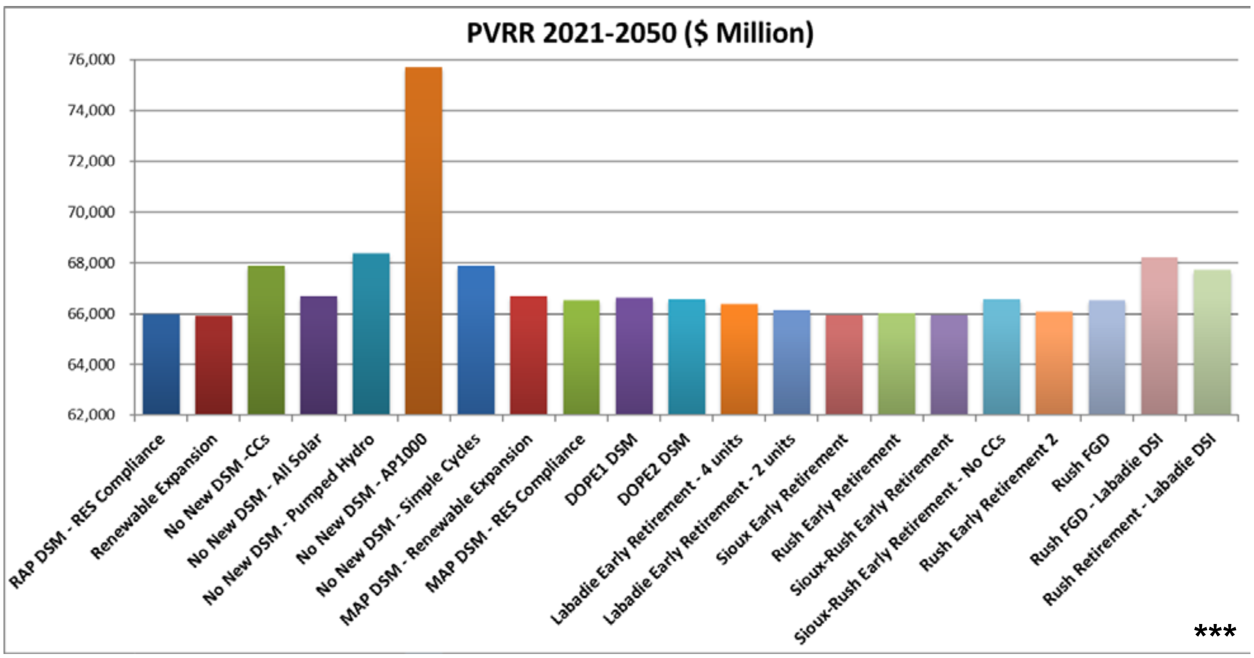
Figure 9.5 Integration PVRR Results[25]



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It should be noted that all costs and benefits in all analyses were expressed in nominal dollars, and Ameren Missouri's current discount rate of 6.04% was used for present worth and levelization calculations. Also, in all integration, sensitivity, and risk analyses, it was assumed that rates are adjusted annually (i.e., no regulatory lag).[26]

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[23] None of the alternative resource plans analyzed include any load-building programs 20 CSR 4240-22.060(3)(B); 20 CSR 4240-22.080(2)(D); 20 CSR 4240-22.060(3)(D)
[24] 20 CSR 4240-22.060(4)
[25] All plans include RAP DSM unless otherwise noted.
[26] 20 CSR 4240-22.060(2)(B)

9.5 Sensitivity Analysis

Sensitivity analysis involves determining which of the candidate independent uncertain factors are <u>critical</u> <u>independent</u> uncertain factors. Once identified in this step, critical uncertain factors were added to the scenario probability tree discussed in Chapter 2 to create the risk analysis probability tree.

9.5.1 Uncertain Factors[27]

Ameren Missouri developed a list of uncertain factors to determine which factors are critical to resource plan performance. Table 9.5 contains the list as well as information about the screening process.

Table 9.5 Uncertain Factor Screening

Uncertain Factor	Candidates?	Critical?	Included in Final Probability Tree?
Load Growth	✓	--	✓
Carbon Policy	✓ #	--	✓
Fuel Prices Coal	✓	✗	✗
Natural Gas	✓ #	--	✓
Nuclear	✗	✗	✗
Project Cost (includes transmission interconnection costs)	✓	✗	✗
Project Schedule	✓	✗	✗
Emissions Prices SO_2	✗	✗	✗
NO_x	✗	✗	✗
CO_2	✓ #	--	✓

[27] 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5) (B) through (F); EO-2020-0047 1.A(i)-(iii); 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5) (A) through (M)

Uncertain Factors	Candidate?	Critical?	Included in Final Probability Tree?
Purchased Power	✗	✗	✗
Forced Outage Rate	✓	✗	✗
DSM Cost Only	✓	✓	✓
DSM Load Impacts & Costs	✓	✗α	✗α
Foreseeable Demand Response Technologies	✓	✗β	✗β
Foreseeable Distributed Energy Resources	✓	✗β	✗β
Foreseeable Energy Storage Technologies	✓	✗	✗
Fixed and Variable O&M	✓	✗	✗
Return on Equity	✓	✗ε	✗ε
Interest Rates	✓	✗ε	✗ε

Included in the scenario probability tree
-- Not tested in sensitivity analysis
α DSM impacts and costs combined. Costs not the same costs as in "DSM Cost Only" sensitivity.
β Included as part of DSM load impacts and costs sensitivity
ε Return on Equity and Long-term Interest rates were combined

Chapter 2 describes how two of the candidate uncertain factors were determined to be critical dependent uncertain factors, which defined the nine scenarios described in that chapter. The two critical dependent uncertain factors are natural gas prices and CO_2 prices. Energy and capacity prices are an output of the scenarios, as described in Chapter 2, and reflect a range of uncertainty consistent with the scenario definitions.

A review of these candidates prior to the sensitivity analysis determined several could be eliminated without conducting a quantitative analysis.

- Nuclear Fuel Prices – Our 2011 and 2014 IRP analyses concluded that nuclear fuel prices were not critical to the relative performance of the alternative resource plans; the same conclusion is expected to be obtained should high/low nuclear prices be included in the sensitivity analysis, particularly given the significant increase in our assumption for nuclear capital costs.

- Purchased Power – Purchased power is excluded since Ameren Missouri is a member of MISO and Ameren Missouri has employed planning criteria that minimize our dependence on the market.
- SO_2 and NO_x Emissions Prices – SO_2 and NO_x Emissions Prices were excluded as candidates because of the expectation for very low prices as a result of current and expected environmental regulations.

There are two pairs of candidate independent uncertain factors that are highly correlated:

- Interest Rates and Return on Equity
- DSM Load Impacts and Costs

Including all the possible permutations of high/base/low would geometrically increase the size of the analysis, with some combinations being much less meaningful and less probable. Since the expectation is that these factors are highly correlated, we have made the simplifying assumption that the individual probability nodes for each pair be combined into a single probability node reflecting the high value for both, base value for both, and low value for both without explicitly considering the less likely and less meaningful joint probabilities.

In addition to including DSM load impacts and costs, Ameren Missouri also analyzed only DSM costs changing in high and low scenarios while the load impacts remain the same. It is important to note that the high and low case costs in the “DSM Cost Only” candidate uncertain factor are different than the high and low case costs in the “DSM Load Impacts and Costs” candidate factor. More detail on the DSM sensitivities can be found in Chapter 8.

Uncertain Factor Ranges[28]

We use the sensitivity analysis to examine whether or not candidate independent uncertain factors have a significant impact on the performance of alternative resource plans, as measured by their impact on PVRR.

The candidate uncertain factors are characterized by a 3-level range of values for this analysis; those 3 levels being low, base, and high values.

[28] 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

Unless the meaning of low, base, and high are treated in a standardized manner, the probability of occurrence for the value used for "low" for one uncertain factor could be significantly different than the probability of occurrence for the value used for "low" for other uncertain factors. Thus, for all of the uncertain factors, Ameren Missouri standardized the meaning of low to be the value found at the 5th percentile of a probability distribution of values for an uncertain factor, the value at the 50th percentile to be the base value, and the value at the 95th percentile to be the high value. The probability distribution for each candidate uncertain factor was inferred from a series of estimated values produced by subject matter experts for each uncertain factor.

For the majority of candidate uncertain factors, probability distributions were used to obtain the values for low, base, and high. This process began with subject matter experts providing/revising estimates of (A) an expected value, (B) estimates of deviations from that expected value, and (C) the probabilities of those deviations from the expected value. That information was used to create the probability distribution collectively implied by that data. Values at the 5th, 50th, and 95th percentiles of those implied probability distributions were then obtained for use as the values for low, base, and high for the various candidate independent uncertain factors. Appendix A contains the standard value, estimated deviation and probabilities for project costs, project schedule, fixed operations & maintenance ("FOM"), variable operations & maintenance ("VOM"), equivalent forced outage rate ("EFOR"), environmental capital expenditures, and transmission-retirement expenditures.

Example

The expected value for total project cost including transmission interconnection costs for the Greenfield Combined Cycle option is $1,245/kW-year (2019$). Project cost and some other candidate uncertain factors are characterized by differing standard values among various supply-side types, while standard values for some other candidate uncertain factors are not uniquely correlated to each supply side type. For example the Long Term Interest Rates uncertain factor does not differ depending on the supply-side type; it is the same across all supply-side types.

The subject matter experts, in this example, members of Ameren Missouri's generation organization, provided estimates of deviations from the standard value as well as the probabilities of those deviations. An example of that initial uncertainty distribution is shown in Table 9.6. In this example, the first of these estimates for project cost deviations was a -15% deviation from the expected

Table 9.6

CC Project Cost Uncertainty Distribution

Deviation	Probability
-15%	10%
-10%	20%
0%	50%
15%	15%
30%	5%

value with a 10% probability of occurring. These deviation estimates provide sufficient information to derive continuous probability distributions from which the low/base/high values can be derived.

The process of developing the probability distributions involve using the deviation estimates like the ones shown above, the probability distribution can be determined for the uncertain factor in question. An example of the result of analyzing deviation estimates is shown in Figure 9.6.

From this distribution, the deviation values for the low, base, and high values (84,1, 1.17) are obtained at the respective percentiles in Figure 9.6. By multiplying these values by the expected value $1,245/kW-year, we estimate the costs at the 5th, 50th, and 95th percentiles; e.g., the low value at the 5th percentile would be:

.84 x 1,245 = $1,046

Figure 9.6 Example of Probability Distribution---CC Project Cost

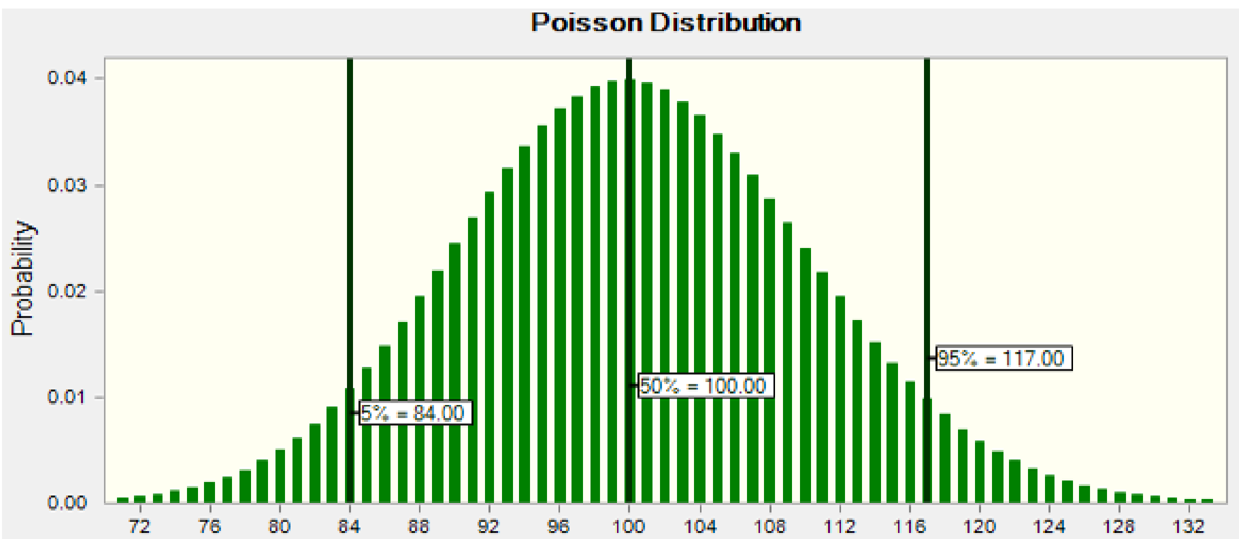

Figure 9.7 shows the resulting range of project costs, which also include interconnection costs estimates, for each new supply-side resource. For most of the technologies shown in Figure 9.7, base values found at 50th percentile were very close to their expected values. For the nuclear technology, however, the base value inferred from the probability distribution was 27% higher than the expected value- $11,302/kW vs $8,899/kW.

Figure 9.7 Resource-Specific Project Cost Ranges (2019$/kW)

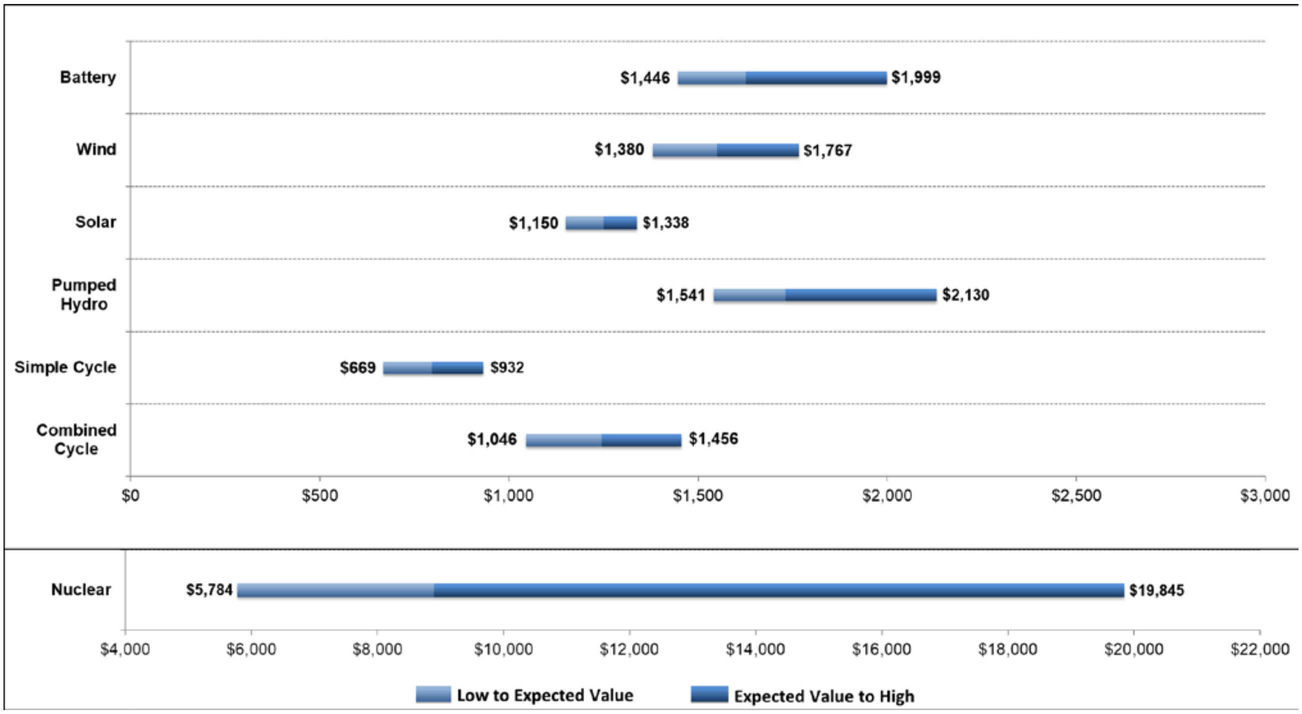

Table 9.7 Resource-Specific Uncertain Factor Ranges[29]

Uncertain Factor	Value	Probability	CC (Nat. Gas)	SC (Nat. Gas)	Pumped Hydro	Nuclear	Solar*	Wind*	Battery*
Project Cost ($/kW) 2019 $	Low	10%	$1,046	$669	$1,541	$5,784	$1,150	$1,380	$1,446
	Base	80%	$1,245	$796	$1,836	$11,302	$1,250	$1,550	$1,625
	High	10%	$1,456	$932	$2,130	$19,845	$1,338	$1,767	$1,999
Project Schedule (Months)	Low	10%	27	27	55	68	18	36	18
	Base	80%	36	36	73	91	24	48	24
	High	10%	48	48	95	119	32	63	32
Fixed O&M ($/kW-yr) 2019 $	Low	10%	$23.25	$6.98	$3.16	$102.54	$3.32	$25.74	$0.83
	Base	80%	$25.69	$8.18	$3.81	$126.02	$4.01	$31.07	$1.00
	High	10%	$29.30	$9.95	$4.76	$155.44	$5.03	$38.95	$1.26
Variable O&M ($/MWh) 2019 $	Low	10%	$0.98	$9.16	$2.50	$1.95	-	-	-
	Base	80%	$2.55	$10.90	$3.15	$2.41	-	-	-
	High	10%	$4.11	$12.64	$3.96	$3.05	-	-	-
EFOR (%)	Low	10%	1%	0%	0%	1%	-	-	-
	Base	80%	2%	5%	5%	2%	-	-	-
	High	10%	5%	10%	10%	3%	-	-	-

29 * Denotes that Ameren Missouri used a declining cost curve for solar, wind and batteries, and multipliers were applied to estimate base, low and high project costs. Assumed capacity factor for solar, wind and battery resources include effects of FOR.

Table 9.7 shows the uncertain factor ranges for the various candidate uncertain factors. It should be noted that, for the project schedule uncertainty, as the number of years in a project schedule change, the distribution of the cash flows was also updated to be consistent with those changes.

Table 9.8 contains the non-resource specific uncertain factor ranges analyzed.

Table 9.8 Non-Resource Specific Uncertain Factor Ranges

Uncertain Factors	Low	Base	High
Probability -->>	**10%**	**80%**	**10%**
Coal Price		Varies By Year	
Long Term Interest Rates	2.5%	3.7%	4.0%
Return on Equity	10.0%	10.5%	10.6%
DSM Load Impact and Cost			
MAP - EE&DER Load Impact	84%	100%	107%
MAP - EE&DER Cost	82%	100%	108%
MAP - DR Load Impact	99%	100%	116%
MAP - DR Cost	99%	100%	101%
RAP - EE&DER Load Impact	88%	100%	113%
RAP - EE&DER Cost	82%	100%	113%
RAP - DR Load Impact	99%	100%	116%
RAP - DR Cost	99%	100%	101%
DOPE1 - EE&DER Load Impact	100%	100%	100%
DOPE1 - EE&DER Cost	100%	100%	100%
DOPE1 - DR Load Impact	100%	100%	100%
DOPE1 - DR Cost	100%	100%	100%
DOPE2 - EE&DER Load Impact	100%	100%	100%
DOPE2 - EE&DER Cost	100%	100%	100%
DOPE2 - DR Load Impact	100%	100%	100%
DOPE2 - DR Cost	100%	100%	100%
DSM Cost Only			
MAP - EE&DER Cost	85%	100%	135%
MAP - DR Cost	85%	100%	125%
RAP - EE&DER Cost	80%	100%	140%
RAP - DR Cost	85%	100%	125%
DOPE1 - EE&DER Cost	80%	100%	170%
DOPE1 - DR Cost	85%	100%	170%
DOPE2 - EE&DER Cost	80%	100%	170%
DOPE2 - DR Cost	85%	100%	170%

As discussed in Chapter 2, long-range interest rate assumptions are based on the December 1, 2019, semi-annual Blue Chip Financial Forecast, a consensus survey of 44 economists. Ameren Missouri internal experts used this same set of data and process to develop a range of interest rate assumptions for use in the 2020 IRP. The high and low interest rate assumptions are based on the average of the 10 highest and 10 lowest forecasts from the survey. Additionally, the high and low forecasts for Treasury rates are used as inputs to the calculation of high and low ranges for allowed return on equity using the same process as discussed in Chapter 2.

Note that the DOPE1 and DOPE2 portfolios have no variations under the DSM Load Impact and Cost uncertainty. By definition, DOPE portfolios are "optimized" to provide a threshold load savings target. Any deviations in load savings would be proactively managed through the budget, with lesser or greater programming as needed. The DSM Cost Only sensitivities reflect a greater range of outcomes, to account for both traditional cost estimation risk and additional program management risk to achieve defined load reduction targets. Chapter 8 includes details on how low and high ranges were obtained for DSM portfolios.

9.5.2 Sensitivity Analysis Results[30]

To conduct the sensitivity analysis, each of the 21 alternative resource plans was analyzed using the varying value levels (low/base/high) for each of the candidate independent uncertain factors, for the most likely scenario in the probability tree (Scenario 5). An uncertainty-probability weighted result for PVRR was obtained for each plan for each relevant candidate uncertain factor. Finally, the results of using a “non-base” value were compared to the results of using an integration/base value for each plan for each candidate uncertain factor. The sensitivity analysis results for all of the candidate independent uncertain factors (resource-specific and non-resource specific) are presented in Appendix A.

The sensitivity analysis identified one critical independent uncertain factor: DSM Cost Only. Table 9.9 shows the change in PVRR ranking (i.e., number of positions the plan moved in the ranking) for the critical independent uncertain factor compared to the integration/base value.

[30] 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(7)(A); 20 CSR 4240-22.060(7)(C)1A

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Table 9.9 Critical Independent Uncertain Factors – Change in PVRR Ranking[31]

Plan		Integration Ranking	DSM Cost Only PWA	DSM Cost Only Low	DSM Cost Only High
A	RAP DSM - RES Compliance	4	0	0	0
B	Renewable Expansion	1	0	0	0
C	No New DSM - CCs	18	0	0	2
D	No New DSM - All Solar	15	1	0	7
E	No New DSM - Pumped Hydro	20	0	0	1
F	No New DSM - AP1000	21	0	0	0
G	No New DSM - Simple Cycles	17	0	0	2
H	MAP DSM - Renewable Expansion	14	-1	4	-3
I	MAP DSM - RES Compliance	10	-2	2	-4
J	DOPE1 DSM	13	0	-1	0
K	DOPE2 DSM	11	1	-2	-1
L	Labadie Early Retirement - 4 units	8	0	-1	-1
M	Labadie Early Retirement - 2 units	7	0	0	0
N	Sioux Early Retirement	2	0	0	0
O	Rush Early Retirement	5	0	0	0
P	Sioux-Rush Early Retirement	3	0	0	0
Q	Sioux-Rush Early Retirement - No CCs	12	1	0	1
R	Rush Early Retirement 2	6	0	0	0
S	Rush FGD	9	0	0	0
T	Rush FGD - Labadie DSI	19	0	0	0
U	Rush Early Retirement 2 - Labadie DSI	16	0	0	0

***

Table 9.10 shows the change in PVRR ($) for the critical independent uncertain factor compared to the integration/base values. The DSM Cost Only uncertain factor was selected as a critical independent uncertain factor because of the variety in the change in PVRR ranking.

[31] All plans include RAP DSM portfolio unless otherwise noted.

***

Table 9.10 Critical Independent Uncertain Factors – Change in PVRR (Million $)[32]

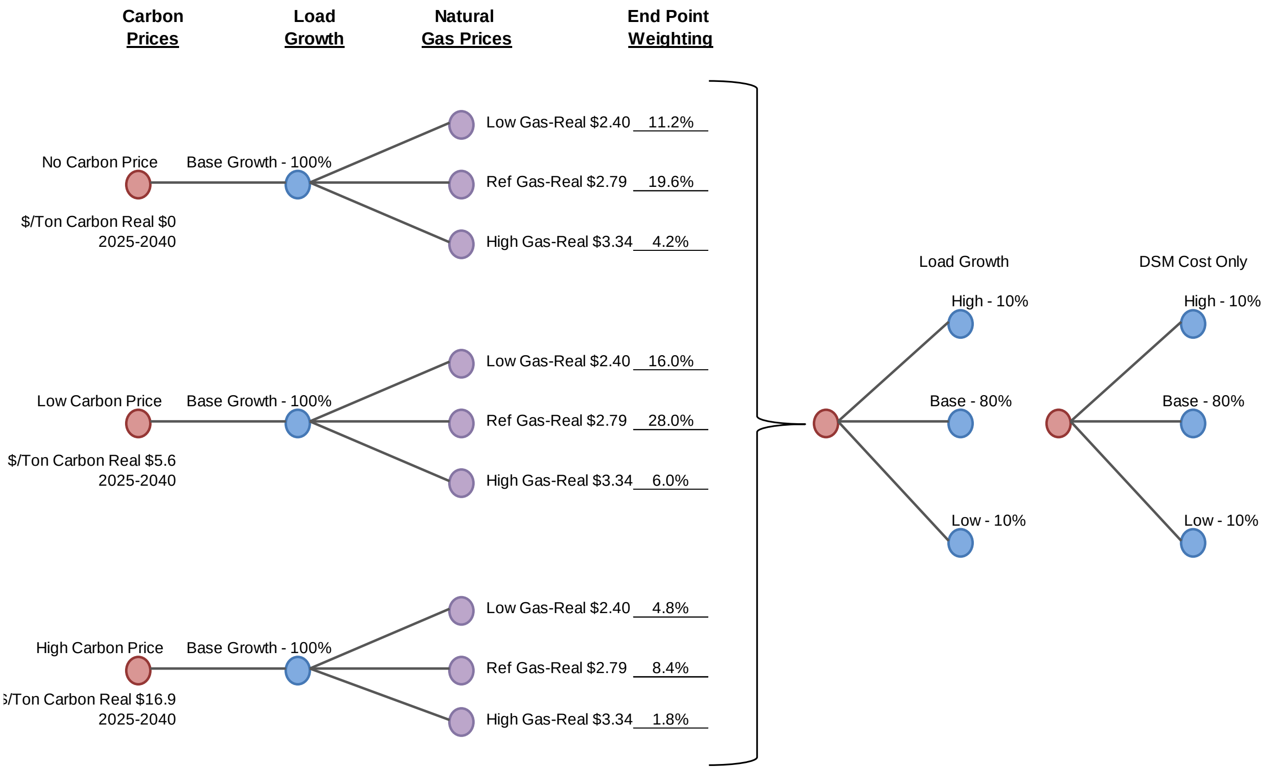
Plan		Integration	DSM Cost Only		
		PVRR	PWA	Low	High
A	RAP DSM - RES Compliance	66,000	19	(260)	447
B	Renewable Expansion	65,940	19	(260)	447
C	No New DSM - CCs	67,880	-	-	-
D	No New DSM - All Solar	66,709	-	-	-
E	No New DSM - Pumped Hydro	68,384	-	-	-
F	No New DSM - AP1000	75,700	-	-	-
G	No New DSM - Simple Cycles	67,877	-	-	-
H	MAP DSM - Renewable Expansion	66,758	71	(498)	1,210
I	MAP DSM - RES Compliance	66,611	71	(498)	1,210
J	DOPE1 DSM	66,678	43	(161)	587
K	DOPE2 DSM	66,598	35	(137)	486
L	Labadie Early Retirement - 4 units	66,397	19	(260)	447
M	Labadie Early Retirement - 2 units	66,155	19	(260)	447
N	Sioux Early Retirement	65,973	19	(260)	447
O	Rush Early Retirement	66,035	19	(260)	447
P	Sioux-Rush Early Retirement	65,977	19	(260)	447
Q	Sioux-Rush Early Retirement - No CCs	66,602	19	(260)	447
R	Rush Early Retirement 2	66,097	19	(260)	447
S	Rush FGD	66,555	19	(260)	447
T	Rush FGD - Labadie DSI	68,219	19	(260)	447
U	Rush Early Retirement 2 - Labadie DSI	67,761	19	(260)	447

***

Ameren Missouri low-base-high load growth cases along with the DSM Cost Only critical independent uncertain factor were added as nodes to the scenario probability tree that was developed in Chapter 2. The updated and expanded probability tree is shown in Figure 9.8, with the two uncertain factors shown on the right-hand side.

[32] All plans include RAP DSM portfolio unless otherwise noted.

Figure 9.8 Final Probability Tree Including Sensitivity Analysis Results[33]



9.6 Risk Analysis[34]

The Risk Analysis consisted of running each of the candidate resource plans in Table 9.4 through each of the branches on the final probability tree shown in Figure 9.8. The probability tree consisted of 81 different branches. Each branch is the combination of different value levels among the nine scenarios, themselves defined by combinations of the two critical dependent uncertain factors (gas prices, and environmental regulations/carbon policy), and the two critical independent uncertain factors (DSM cost and load growth). Each branch therefore represents a unique combination of the critical uncertain factors. Once all the combinations are calculated, the sum of the individual branch probabilities equals 100%.

[33] 20 CSR 4240-22.060(6)
[34] 20 CSR 4240-22.060(6)

9.6.1 Risk Analysis Results

The PVRR results of the risk analysis of the 21 alternative resource plans are shown in Figure 9.9. The levelized rate results for the risk analysis are shown in Figure 9.10. The PVRR results are lower for plans with RAP compared to plans without DSM. Plan B, with renewable expansion and RAP DSM has the lowest PVRR followed very closely by Plan P, which include the Sioux and Rush Island early retirements. Plan F (No DSM-Nuclear) exhibits the highest PVRR and the highest levelized rates followed by Plan E (No DSM-Pumped Hydro), which has the second highest PVRR, and by Plan I (MAP DSM-Res Compliance), which has the second highest levelized rates. Results for other performance measures can be found in Chapter 9 - Appendix A.

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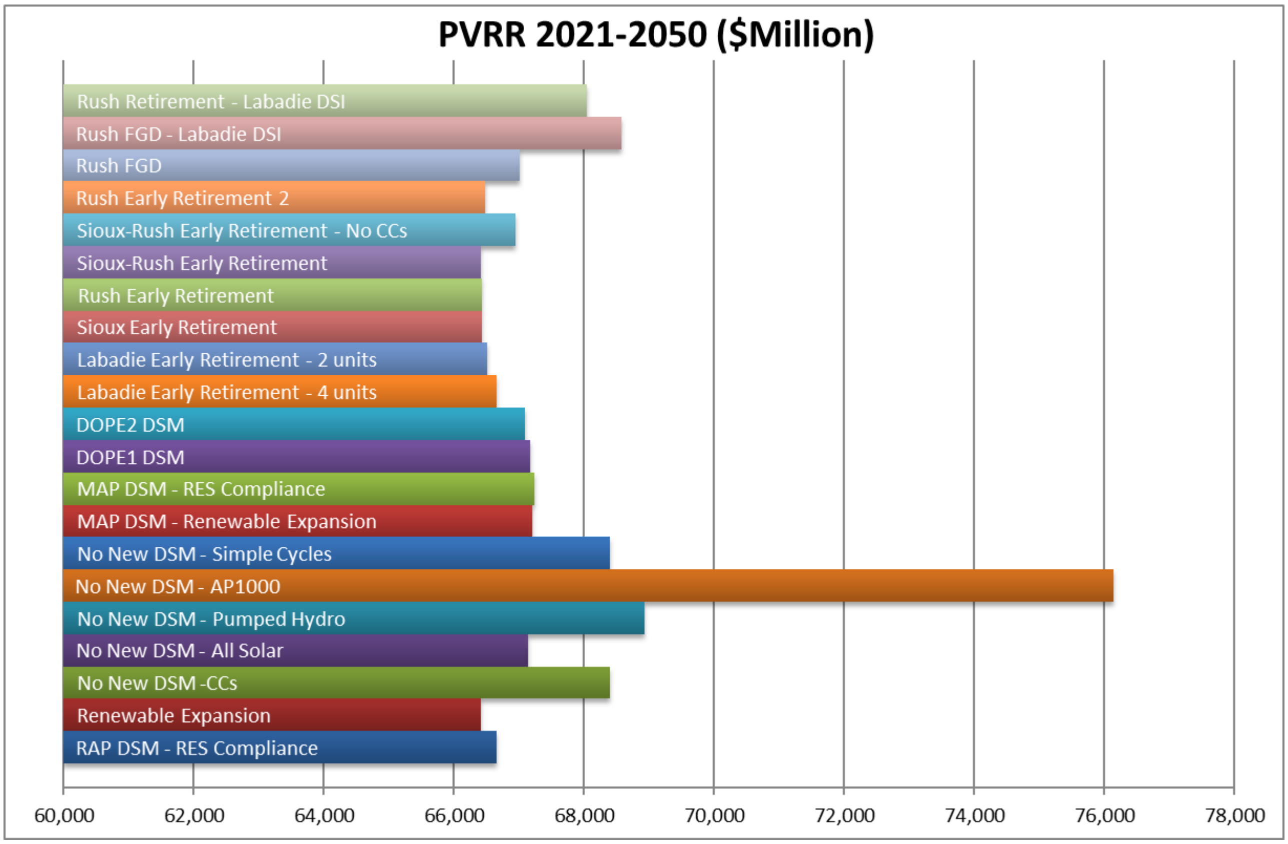
Figure 9.9 Probability-Weighted PVRR Results[35]



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[35] All plans include RAP DSM portfolio unless otherwise noted.

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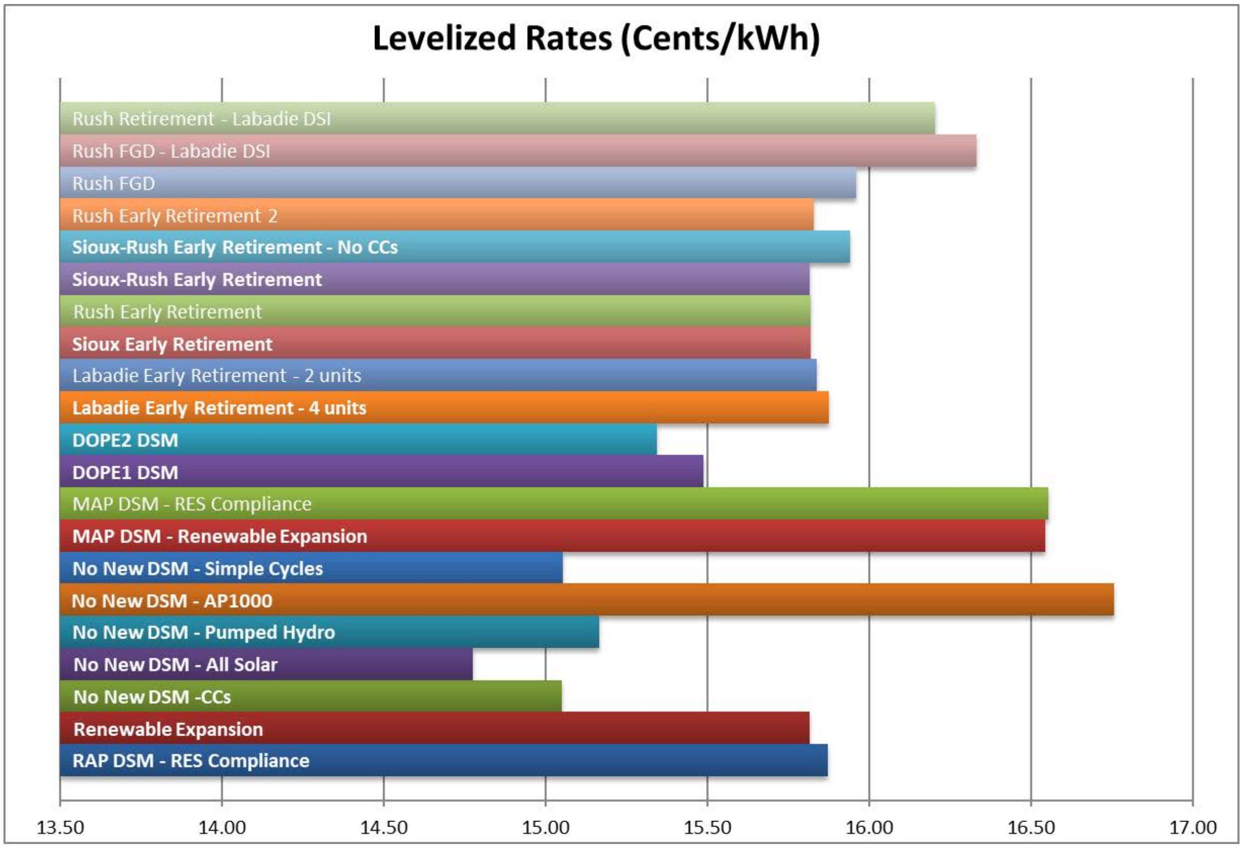
Figure 9.10 Probability-Weighted Levelized Rate Results[36]



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If decision making were solely based on PVRR and levelized rate impacts, then the analysis would be complete at this point. Since decision making is multi-dimensional, Ameren Missouri created a scorecard that embodies its planning objectives to evaluate the performance of alternative resource plans. With 21 alternative resource plans, Ameren Missouri can take a closer look at the performance of the plans by evaluating their relative strengths and weaknesses in meeting our planning objectives and whether other factors may be important in the selection of the preferred resource plan. Chapter 10 – Strategy Selection includes the additional analysis and decision-making considerations that lead to the selection of the Resource Acquisition Strategy.

[36] All plans include RAP DSM portfolio unless otherwise noted.

AM-REM-00568770

9.7 Conclusions from Integration and Risk Analysis

Below are several conclusions from the integration and risk analysis.

- RAP DSM results in the lowest PVRR compared to plans with different levels of DSM.
- Inclusion of DSM resources in general results in lower costs than the supply-side alternatives. This finding demonstrates that using an avoided capacity curve that excludes capacity impacts of DSM resources for cost effectiveness analyses (as explained in Chapter 2) is appropriate. Using a more restrictive capacity curve could have resulted in screening out DSM resources that ultimately prove to be the lowest cost option when compared to supply-side alternatives.
- Sioux 2028 and Rush Island 2039 retirement results in the lowest cost among the early retirement options while early retirement of Labadie's four units by the end of 2028 results in the highest costs among the same plans.
- *****<u>Adding an FGD and/or DSI result in significantly higher costs and levelized rates. Retirement of Rush Island Energy Center by the end of 2024 is less costly than the energy center modifications</u>.*****
- Plans with additional renewable resources beyond those included for RES compliance as in Plans B and H reduce costs and customer rates. Coupling even more renewable resources with batteries, on the contrary, results in higher cost and levelized rates.[37]
- Plan D, which assumes all future resource needs are met with only renewable resources, performs better than it did in the previous IRP due to reductions in the cost of solar resources; it is the 10th most costly alternative resource plan. From a cost standpoint, it is very competitive with other supply-side resources.
- Wind, solar, and natural gas combined cycle resources are attractive options for development due to their competitive overall cost, relatively low capital cost, and relatively short lead time.
- *****<u>The five highest cost alternative resource plans are those with no DSM or with FGD and DSI additions at the two energy centers</u>.***** The alternative resource plan including new nuclear is by far the most costly.

[37] 20 CSR 4240-22.060(4)(E)

9.8 Resource Plan Model

Ameren Missouri has used a modular approach to modeling for this IRP as it did in the 2017 IRP. Instead of using MIDAS or other off-the-shelf alternatives for integration and risk analyses, Ameren Missouri continues to use a combination of stand-alone models for 1) production costing, 2) market settlements, 3) revenue requirements, and 4) financial statements. Items 2-4 on this list are collectively referred to as the "Financial Model." This approach permitted analysts maximum flexibility, customization and trouble-shooting capabilities. It also lends itself to greater transparency for stakeholders by limiting the use of proprietary third-party software.

Ameren Missouri used a generation simulation model from Simtec, Inc., typically referred to as RTSim ("Real-Time Simulation") for production cost modeling.[38] RTSim provides a realistic simulation of an electric generating system for a period of a few days to multiple years.

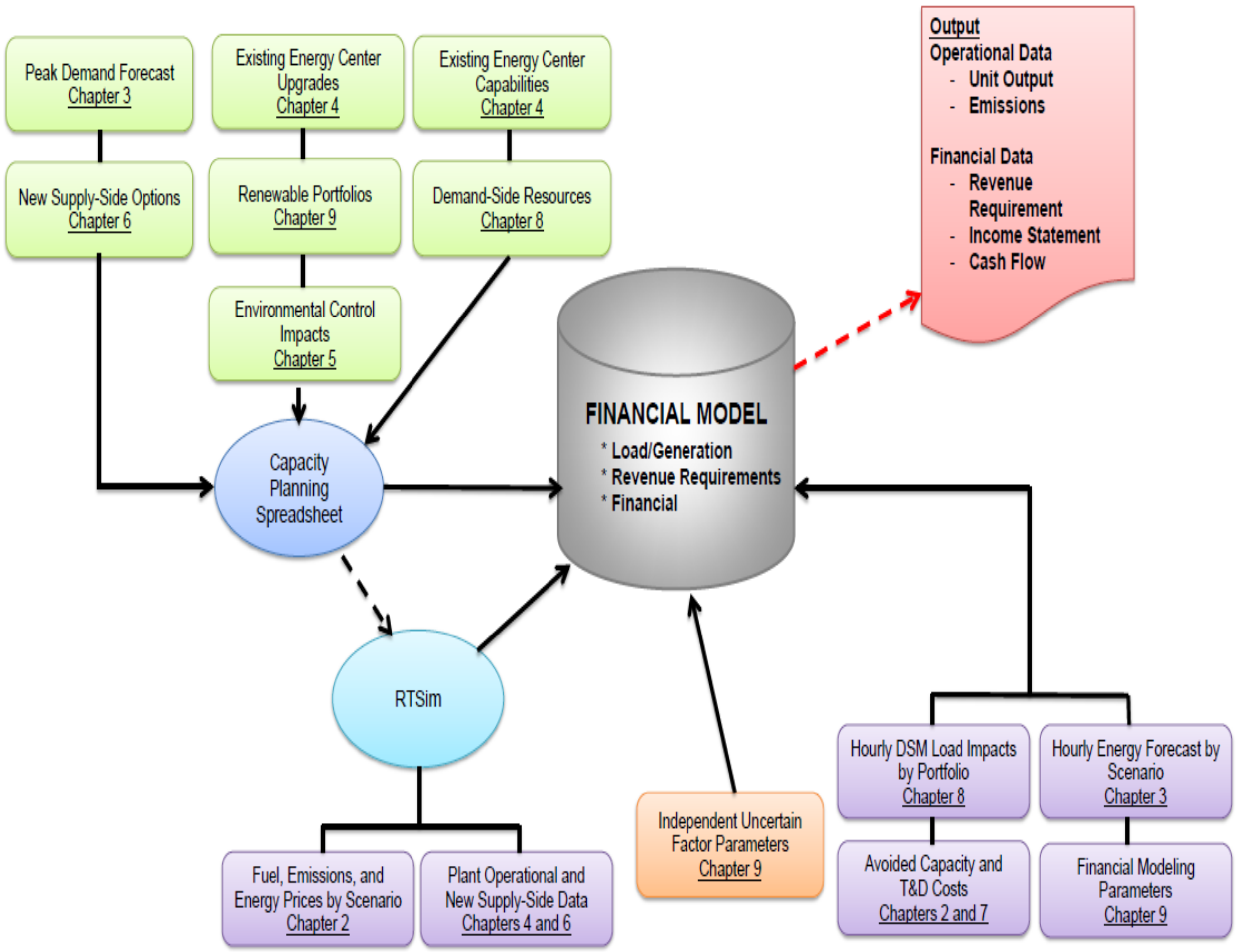
RTSim simulates hourly chronological dispatch of all system generating units, including unit commitment logic that is consistent with the operational characteristics and constraints of system resources. The model plans are based on a capacity planning spreadsheet, which was used to determine the timing of new resources. The RTSim model contains all unit operating variables required to simulate the units. These variables include, but are not limited to, heat rates, fuel costs, variable operation and maintenance costs, emission rates, emission allowance costs, scheduled maintenance outages, and full and partial forced outage rates. The generation fleet is dispatched competitively against market prices. The multi-area mode of the Ventyx Midas® model was used for the creation of forward price curves as described in Chapter 2.

Ameren Missouri developed its own revenue requirements and financial model using Microsoft Excel. This model incorporates the capacity position and RTSim outputs, as well as other financial aspects regarding costs external to the direct operation of units and other valuable information that is necessary to properly evaluate the economics of a resource portfolio. The financial portion of the model produces bottom-line financial statements to evaluate profitability and earnings impacts along with revenue requirement and various financial and credit metrics.

Figure 9.11 shows how the various assumptions are integrated into the financial model.

[38] 20 CSR 4240-22.060(4)(H)

Figure 9.11 Resource Plan Model Framework[39]



Future Plans for Modeling Tools

Ameren Missouri plans to continue to evaluate options for modeling tools for use in its resource planning process. Having developed a modular approach to our modeling, we have the flexibility to evaluate models with varying degrees of capabilities (production costing, market settlements, revenue requirements, and financial statements) that can be used in place of, and/or in combination with, the current modules. As a result, we expect that our modeling needs over time will be characterized more by evolution rather than the deployment of a single integrated solution. Our current modular approach was in large part an outcome of our evaluation of solutions that are currently commercially

[39] 20 CSR 4240-22.060(4)(H)

available. For example, we were unable to identify any available integrated solutions that produce full financial statements other than MIDAS, which is no longer being developed by Ventyx. Our current approach also allows us to expand our review of production costing solutions beyond those used primarily for long-term resource planning. We are currently using a production cost modeling software PowerSIMM for use in our fuel budgeting and short term trading support analysis which has the potential to support longer term analysis like the IRP.

We expect to continue our efforts to improve the efficiency, effectiveness, and transparency of our modeling tools into 2021. The nature and timing of any changes we make will largely be a function of our assessment of the currently available options. As we consider these options, we plan to share thoughts with other Missouri utilities and with our stakeholder group. This may or may not provide opportunities to move to a common modeling platform. Ameren Missouri will remain open to such an outcome while ensuring that its own tools and processes are able to support our business needs and objectives.

9.9 Compliance References

**UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION**

UNITED STATES OF AMERICA, Plaintiff, SIERRA CLUB, Plaintiff-Intervenor, v. AMEREN MISSOURI, Defendant.	Civil Action No. 4:11-cv-00077-RWS

UNITED STATES' MOTION TO STRUCTURE FURTHER CONSISTENT PROCEEDINGS PURSUANT TO THE EIGHTH CIRCUIT'S REMAND

This Court's September 2019 remedy order (ECF 1122) directed Ameren to bring its Rush Island facility into compliance with the Clean Air Act's requirements, and ordered further injunctive relief at Ameren's Labadie facility to mitigate the harm from the company's years of excess SO_2 pollution. Two events have changed the landscape since that order was entered. First, Ameren has decided it would rather retire Rush Island than install pollution controls there, and the company has informed the Midcontinent Independent System Operator as much with the submission of its (negotiated) Attachment Y request. (ECF 1208). Second, the Eighth Circuit vacated this Court's mitigation order at Labadie, remanding the matter for further consistent proceedings. Importantly, the Eighth Circuit did not overturn this Court's finding that reducing pollution exposures in downwind communities would remediate the harms from Ameren's violations. Nor did the Eighth Circuit question this Court's holding that mitigation efforts are warranted here.

In light of these developments, and as further explained in the attached memorandum in support of this motion, the United States asks that the Court order that:

1. Ameren provide monthly status reports to the Court regarding its plan to retire of Rush Island,

2. Ameren produce to Plaintiffs, on a monthly basis, all communications between Ameren and MISO concerning Rush Island's retirement and the Attachment Y or Attachment Y Alternatives studies undertaken by MISO to assess Ameren's retirement proposal,

3. The Parties meet and confer concerning potential areas of mitigation within 30 days;

4. Ameren develop and serve upon Plaintiffs by September 1, 2022 a suite of mitigation possibilities that takes into account the nature, extent, and location of Ameren's harms to the public health and welfare, as found by the Court, and describes the scope, cost, and impact of each possibility; and

5. The Parties submit a joint proposed mitigation plan or competing plans with briefing and a proposal for further proceedings by November 1, 2022.

Plaintiff-Intervener Sierra Club joins in this motion and concurs in this request.

Dated: June 2, 2022

Respectfully Submitted,

TODD KIM
Assistant Attorney General
Environment and Natural Resources Division
United States Department of Justice

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CERTIFICATE OF SERVICE

I hereby certify that on June 2, 2022, I filed the foregoing under seal with the Clerk of Court using the CM/ECF system, and served an electronic copy on counsel for Ameren and Sierra Club via e-mail.

/s/ Elias L. Quinn

Elias L. Quinn

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

UNITED STATES OF AMERICA, Plaintiff, SIERRA CLUB, Plaintiff-Intervenor, v. AMEREN MISSOURI, Defendant.	Civil Action No. 4:11-cv-00077-RWS

UNITED STATES' MEMORANDUM IN SUPPORT OF ITS MOTION TO STRUCTURE FURTHER CONSISTENT PROCEEDINGS PURSUANT TO THE EIGHTH CIRCUIT'S REMAND

EXHIBIT 1

9. Integrated Resource Plan and Risk Analysis

Highlights

- *Ameren Missouri has developed a robust range of alternative resource plans that reflect different combinations of energy efficiency ("EE"), demand response ("DR"), various types of new renewable and conventional generation, energy storage, and retirement of each of its existing coal-fired generators.*
- *In addition to the scenario variables and modeling discussed in Chapter 2, one critical independent uncertain factor has been included in the final probability tree for risk analysis: demand-side management ("DSM") costs.*
- *Our risk analysis also includes the evaluation of a range of load growth.*

Ameren Missouri's modeling and risk analysis consisted of a number of major steps:

1. Identification of **alternative resource plan attributes**. These attributes represent the various resource options used to construct and define alternative resource plans – demand side resources, new renewable and non-renewable supply side resources, and retirement of existing supply side resources.
2. Development of the **baseline capacity position**, which reflects forecasted peak demand, reserve requirements and existing resources.
3. Development of **planning objectives** to guide the development of alternative resource plans.
4. Development of the **alternative resource plans**. The alternative resource plans were developed using the plan attributes identified in step 1, the base capacity position developed in step 2, and the planning objectives identified in step 3.
5. Identification and screening of **candidate uncertain factors**, which are key variables that can influence the performance of alternative resource plans.
6. **Sensitivity analysis** and selection of critical uncertain factors, which are key variables that are determined to have a significant impact on the performance of alternative resource plans.

7. **Risk analysis** of alternative resource plans, which is used to evaluate the performance of alternative resource plans under combinations of the scenarios discussed in Chapter 2 and the critical uncertain factors identified in step 6.

This chapter describes these various steps and the results and conclusions of our integration and risk analysis.

9.1 Alternative Resource Plan Attributes[1]

Development of alternative resource plans include considering various combinations of demand-side and supply-side resources to meet future capacity needs. However, alternative resource plans may also include elements or attributes that serve the other planning objectives described in Section 9.3. Including these elements can significantly affect the capacity position that needs to be considered when developing alternative resource plans. Figure 9.1 includes the attributes considered during the development of resource plans.

***

Figure 9.1 Attributes of Alternative Resource Plans[2]

Retirements (End of Year)
- Meramec Retired 2022
- Sioux Retired 2033/2028
- Labadie 2 Units Retired 2036/2028/2028
- Labadie 2 Units Retired 2042/2036/2028
- Rush Island Retired 2045/2039/2028/2024

New Supply-Side Types
- Combined Cycle (Nat. Gas)
- Simple Cycle (Nat. Gas)
- Nuclear
- Pumped Hydro Storage
- Solar
- Wind
- Batteries

Demand-Side Management
- Maximum Achievable Potential ("MAP")
- Realistic Achievable Potential ("RAP")
- Dynamically Optimized Portfolio Estimate ("DOPE") 1
- DOPE 2
- Missouri Energy Efficiency Investment Act ("MEEIA") Cycle 3 Only

Renewable Portfolios
- Missouri Renewable Energy Standard ("RES") with RAP DSM
- RES with MAP DSM
- Renewable Expansion
- Renewable Expansion Plus

***

[1] 20 CSR 4240-22.060(1); 20 CSR 4240-22.060(3)

[2] Pursuant to the Motion for Protective Order filed concurrently with the filing of this IRP, and 20 CSR 4240-2.135(4)(A) and (B), the information for which protection is sought by the Motion has been marked "Highly Confidential" (denoted by three asterisks with two asterisks used for "Confidential" information), and is protected as such pending the Commission's ruling on the Motion.

9.2 Capacity Position

To determine the timing and need for resources, Ameren Missouri first developed its baseline capacity position, including:

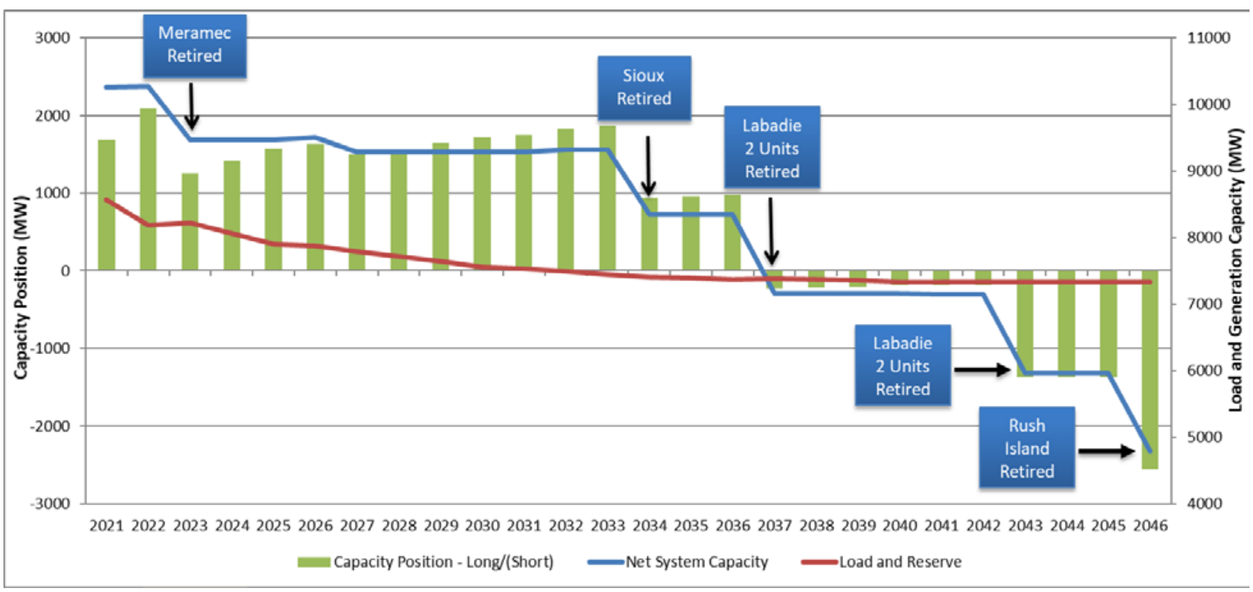
- Existing plant capabilities based on Ameren Missouri's annual generating unit rating update (i.e., August 2020 planned ratings)
- Existing obligations for capacity purchases and sales
- Peak demand forecast, as described in Chapter 3
- Planning reserve margin ("PRM") requirement, based on MISO's Planning Year 2020 Loss of Load Expectation ("LOLE") Study Report (November 2019). Table 9.1 shows the MISO System PRM from 2021 through 2029. The long-range PRM was assumed to continue at 18.3% through the remainder of the analysis period.

Table 9.1 MISO System Planning Reserve Margins 2021 through 2029

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029
PRM Installed Capacity	18.0%	17.9%	17.9%	18.2%	18.2%	18.1%	18.2%	18.2%	18.3%

Figure 9.2 shows Ameren Missouri's net capacity position with no new major generating resources.

Figure 9.2 Net Capacity Position – No New Supply-Side Resources (Baseline)



The chart shows the system capacity, customer needs (including the MISO reserve requirement), and capacity above/below the MISO requirement (i.e., long/short position). The customer needs include peak load reductions due to RAP EE, distributed energy resources ("DER"), and DR. The system capacity includes the capacity benefit of the RES Compliance portfolio. Retirement dates reflected in the base capacity position for existing coal-fired units are those established in Ameren Missouri's most recent depreciation study filed with the Missouri Public Service Commission ("MPSC") and are considered to be the base retirement dates.

Retirements and Modifications[3]

Ameren Missouri is considering retirement of some or all of its six older gas- and oil-fired CTG units – Fairgrounds, Meramec CTG-1, Meramec CTG-2, Mexico, Moberly, and Moreau – with a total summer net capacity of 263 MW, over the next 20 years. Chapter 4 - Table 4.3 provides a summary of the planned CTG retirements. The CTG retirements were included in all alternative resource plans.

Coal energy center retirements were also included in the capacity planning process. Meramec retirement by December 31, 2022 is included in all alternative resource plans. Two different Sioux retirement options were considered: 1) retirement by December 31, 2033 based on prior analysis of Ameren Missouri's coal power plant life expectancy by Black and Veatch, and 2) retirement by December 31, 2028. Three different retirement options for Labadie were considered: 1) current retirement dates as determined by the Black and Veatch life expectancy study with two units retired by December 31, 2036 and two units retired by December 31, 2042, 2) two units retired by December 31, 2028 and two units retired by December 31, 2036, 3) all four units retired by December 31, 2028. Four retirement dates were evaluated for Rush Island: 1) retired by December 31, 2045, which is the current retirement date as determined by the Black and Veatch life expectancy study, 2) retired by December 31, 2039, 3) retired by December 31, 2028, and 4) retired by *****<u>December 31, 2024</u>*****.

The alternative retirement dates were based on the ability to avoid significant ongoing costs, the potential for an explicit price on carbon starting in 2025 included in the scenarios described in Chapter 2, coupled with the time needed to ensure transmission upgrades are in place to continue to reliably serve our customers. *****<u>The 2024 Rush Island retirement date, along with wet flue gas desulfurization technology ("FGD") at Rush Island and dry sorbent injection system ("DSI") at Labadie</u>***** are included in order to evaluate specific potential outcomes pending a final judgment in the Rush Island New Source Review ("NSR") litigation which is under appeal and a decision by the federal court of appeals is not expected until 2021. Importantly, numerous potential

[3] EO-2020-0047 1.D; EO-2020-0047 1.O

outcomes are possible, including reversal of the trial court's rulings on both liability and remedy, and the actual outcome may be different than the limited outcomes modeled.

DSM Portfolios

DER, EE, and DR programs as described in detail in Chapter 8 are included in the DSM portfolios. DSM programs not only reduce the peak demand but also reduce reserve requirements associated with those DRs. The following combinations of DSM portfolios were evaluated: 1) RAP, 2) MAP, 3) DOPE1, 4) DOPE2, and 5) No DSM after MEEIA Cycle 3. The No DSM portfolio reflects completion of Ameren Missouri's current program cycle with no further EE or DR during the planning horizon. Note that the recent MPSC approval of Ameren Missouri's request for a one-year extension of MEEIA programs occurred after the IRP analysis was underway, which means that the No Further DSM portfolio starts one year before that extension ends.[4]

Renewable Portfolios[5]

Compliance with Missouri's RES was updated to reflect current assumptions, including baseline revenue requirements and an updated 10-year forward-looking model which calculates the impact of the statutory 1% rate impact limitation.

Ameren Missouri performed its RES compliance analysis with the *2020 IRP RES Compliance Filing Model* (model). The model is designed to calculate the retail rate impact, as required by the Commission's RES rules.[6] This model determines the quantity of renewable energy needed to meet both the overall RES portfolio standard and the 2% solar portfolio standard "carve-out" absent any rate impact constraints. The model then determines the amount of renewable energy, both solar and non-solar that can be built without exceeding an average 1% revenue requirement increase over a ten-year period. Ameren Missouri's expected renewable energy credit (REC) position is presented in Figure 9.3.

[4] The extension of MEEIA Cycle 3 should not have a material impact on the analysis.
[5] EO-2020-0047 1.R
[6] 20 CSR 4240-20.100(5)

Figure 9.3 Ameren Missouri's RES REC Positions

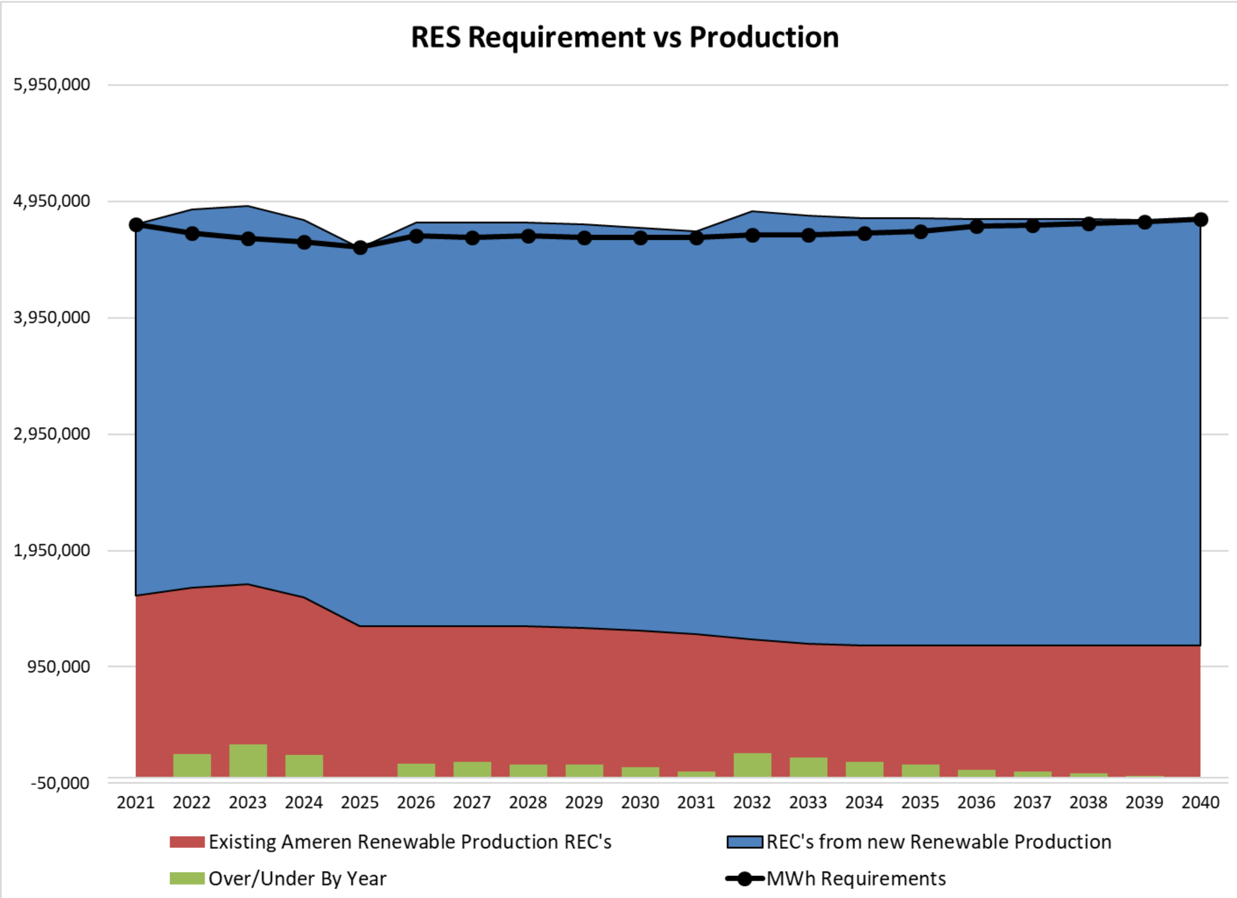


Figure 9.3 shows that Ameren Missouri expects to meet the overall REC requirement through 2040 primarily with owned renewable generation. Year-to-year compliance may also include banked RECs and purchased RECs. Starting in 2021, Ameren Missouri will be able to fully meet the overall standard using RECs generated by its existing qualifying resources, additional wind resources which will largely be completed by the end of 2020, with the remaining generation completed in the first quarter of 2021, and solar RECs acquired from customer rebate programs.

Table 9.2 shows the amounts of wind and solar resources added for various renewable portfolios, including RES compliance under different load cases. The RES compliance portfolio established by the previously described model is used for alternative resource plans and reflects wind resource additions that take advantage of Production Tax Credits, allowing full compliance with the RES while remaining under the one percent rate cap limitation. Appendix A shows the amounts of wind, and solar resources needed in Term 1 (2021-2030) and Term 2 (2031-2040).

When developing the RES compliance investment needs, consideration was given to the potential difference between RAP DSM investment vs MAP DSM investment. As MAP DSM results in more energy savings, the RES Compliance requirements are slightly lower than the requirements when RAP DSM is assumed.

In addition to the RES Compliance portfolios, we also included a "Renewable Expansion" and a "Renewable Expansion Plus" portfolio to evaluate the performance of additional solar and wind resources. The Renewable Expansion portfolio includes a total of 2,700 MW wind and 2,700 MW solar while the Renewable Expansion Plus portfolio includes a total of 3,900 MW wind and 4,000 MW solar resources.[7]

Table 9.2 shows the timing of new resources for renewables included in the alternative resource plans.

Table 9.2 Renewable Portfolios (Nameplate Capacity)

Renewable Additions		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
RES Compliance w/ RAP DSM	Wind	700	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	-	30	20	-	-	-	-	75	-	-	-	-	75	-	-	-	-	-	-	-
RES Compliance w/ MAP DSM	Wind	700	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	-	30	20	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable Expansion	Wind	700	-	-	300	-	-	-	300	-	-	300	-	300	-	300	-	300	-	200	-
	Solar	-	30	20	-	250	-	400	-	300	400	-	300	-	300	-	300	-	400	-	-
Renewable Expansion Plus	Wind	700	-	-	400	-	400	-	400	-	-	-	-	500	-	500	-	500	-	500	-
	Solar	-	30	295	-	375	-	400	-	400	400	-	400	-	400	-	400	-	400	-	500

With the Renewable Expansion Plus renewable portfolio, batteries were also included: 100 MW in each year from 2031 to 2035, 150 MW in each year from 2036 to 2043 for a total of 1,700 MW.

Other Supply-side Resources

After including DSM resources and the renewable portfolios, if the capacity shortfall in a given year met or exceeded the build threshold, then supply side resources are added to eliminate the shortfall. The build threshold was determined to be 300 MW regardless of the type of supply-side resource under consideration and reflects a level that Ameren Missouri trading staff assess as a reasonable level of capacity market dependence. The full rated capacity and the build thresholds for each supply side type are shown in Table 9.3. Ameren Missouri has assumed reliance on short-term capacity purchases to cover shortfalls that are less than the build threshold and has assumed that any long capacity position would be sold. The earliest in-service dates for each supply-side resource are

[7] EO-2020-0047 1.K

also shown in Table 9.3. The in-service date constraints represent the expectations for construction lead time as well as the commercial availability of each technology.

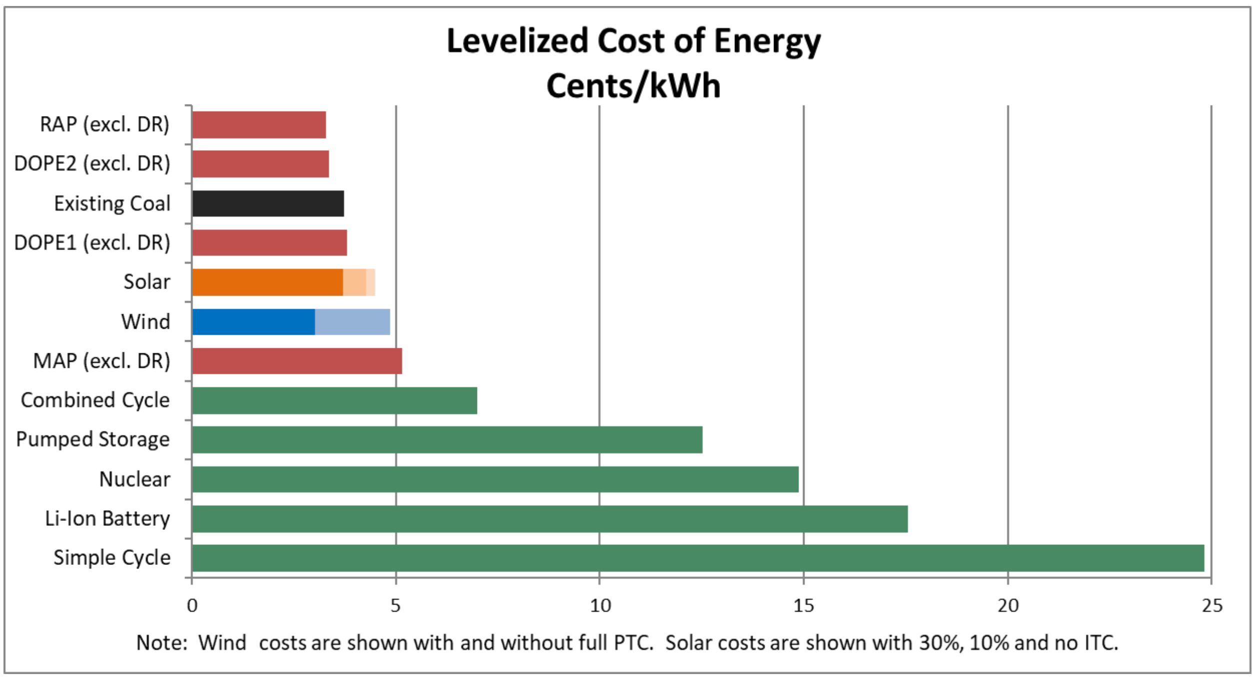
Table 9.3 Build Threshold for Supply Side Types

Supply Side Type	Capacity (MW)	Build Threshold (MW)	Earliest Year In-Service
CC-Natural Gas	824	300	2025
SC-Natural Gas	690 (3x230)	300	2025
Nuclear	1100	300	2030
Pumped Hydro	600	300	2029
Solar	800	300	2022

The remaining net capacity position was represented in the financial model as capacity purchases and sales priced at the market-based capacity costs as discussed in Chapter 2. The capacity purchases and sales were also adjusted for the various peak demand forecasts associated with each of the 15 scenarios and DSM impacts.

Figure 9.4 summarizes the levelized cost of energy ("LCOE") for all potential future resources evaluated in the alternative resource plans.

Figure 9.4 Levelized Cost of Energy – All Resources[8]



[8] 20 CSR 4240-22.010(2)(A)

9.3 Planning Objectives

The fundamental objective of Missouri's electric resource planning process is to provide energy to customers in a safe, reliable and efficient way, at just and reasonable rates while being in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies.[9] Ameren Missouri considers several factors, or planning objectives, that must be considered in meeting the fundamental objective. Planning objectives provide a guide to the decision making process while ensuring the resource planning process is consistent with business planning and strategic initiatives.

Five planning objectives were used in the development of alternative resource plans: Portfolio Transition (formerly Environmental/Resource Diversity); Financial/Regulatory; Customer Satisfaction; Economic Development; and Cost. These planning objectives, which are the same as those discussed in Ameren Missouri's IRP filings since 2011, were selected by Ameren Missouri decision makers and are discussed below.[10]

Portfolio Transition

Ameren Missouri has relied for many years on a portfolio that consists, in large part, of large, efficient coal-fired generators. Current and potential future environmental regulations may have a significant impact on Ameren Missouri's coal-fired fleet and its selection of future generation resources. Ameren Missouri seeks to transition its generation portfolio to one that is cleaner and more diverse in a responsible fashion. To test various options for advancing this transition, alternative resource plans were developed to include varying levels of DSM portfolios, renewables in addition to those required for RES compliance, new gas-fired generation, new nuclear generation, storage resources and early coal retirements.

Financial/Regulatory

The continued financial health of Ameren Missouri is crucial as it will need access to large amounts of capital in order to comply with RES and environmental regulations, invest in new supply side resources, and fund continued EE programs while maintaining or improving safety, reliability, affordability, and customers' ability to control their energy use and costs. While making its investment decisions, it is important for Ameren Missouri to consider factors that may influence its access to low-cost sources of capital.

[9] 20 CSR 4240-22.010(2)
[10] 20 CSR 4240-22.010(2)(C)

This includes measures of cash flow, profitability, and creditworthiness as well as assessment of risks associated with investment management and cost recovery.[11]

Customer Satisfaction

While there are many factors that can influence customer satisfaction, there are several that can be significantly affected by resource decisions. Ameren Missouri has focused on levelized annual rates, inclusion of EE, reliability, availability of DER and DR programs, inclusion of new clean energy resources, and significant reductions in CO_2 emissions to assess relative customer satisfaction expectations.[12]

Economic Development

Ameren Missouri assesses the relative economic development potential of alternative resource plans in terms of job growth opportunities associated with its resource investment decisions. Plans were rated on a relative scale based on direct jobs (FTE-years) required for both construction and operation.[13] We have assumed that second and third level economic impacts would not significantly affect the relative economic development potential of alternative resource plans, and therefore have not included such impacts in our assessment.

Cost

Ameren Missouri is mindful of the impact that its future resource choices will have on its customers' rates and bills. Maintaining reasonable costs while meeting its other planning objectives is of utmost importance to Ameren Missouri. Cost alone does not and should not dictate resource choices, but it is a very important factor in making resource decisions. Therefore, minimization of the present value of revenue requirements was used as the primary selection criterion.[14]

9.4 Determination of Alternative Resource Plans[15]

Twenty-one alternative resource plans were developed to incorporate different combinations of demand-side and supply side resource options, seek to fulfill Ameren Missouri's planning objectives, and answer key questions, including the following:

- Does inclusion of DSM programs reduce overall customer costs?

[11] 20 CSR 4240-22.060(2)(A)6
[12] 20 CSR 4240-22.060(2)(A)4
[13] 20 CSR 4240-22.060(2)(A)7
[14] 20 CSR 4240-22.060(2)(A)1; 20 CSR 4240-22.010(2)(B)
[15] 20 CSR 4240-22.060(3)

- What level of DSM – RAP, MAP, DOPE1 or DOPE2 – results in lower costs?
- Is early retirement of Rush Island Energy Center cost effective?
- Is early retirement of Labadie Energy Center cost effective?
- Is early retirement of Sioux Energy Center cost effective?
- Is early retirement of the Sioux and Rush Energy Centers cost effective?
- What is the impact of reducing SO_2 emissions further?
- What are the benefits of including renewables beyond those needed for RES compliance?
- What is the impact of pursuing only new renewables?
- How would our plans and customer costs be affected if DSM cost recovery and incentive needs are not met?
- How do various supply side resource options compare?

Table 9.4 provides a summary of the alternative resource plans.

***

Table 9.4 Alternative Resource Plans[16]

	Plan Name	DSM	Renewables	New Supply Side	Coal Retirements/ Modifications
A	RAP DSM - RES Compliance	RAP	RES Compliance	2 CCs in 2043, CC in 2046	Base
B	Renewable Expansion	RAP	Renewable Expansion	CC in 2046	Base
C	No New DSM - CCs	-	Renewable Expansion	CC in 2037, 2 CCs in 2043, CC in 2046	Base
D	No New DSM - All Solar	-	Renewable Expansion	6400 MW 2034-2046	Base
E	No New DSM - Pumped Hydro	-	Renewable Expansion	PS in 2037, CC in 2037, 2043, 2046	Base
F	No New DSM - AP1000	-	Renewable Expansion	Nuke 2037, CC in 2043, 2 CCs in 2046	Base
G	No New DSM - Simple Cycles	-	Renewable Expansion	SC 2037, CC in 2037, 2043, 2046	Base
H	MAP DSM - Renewable Expansion	MAP	Renewable Expansion	-	Base
I	MAP DSM - RES Compliance	MAP	RES Compliance	2 CCs in 2046	Base
J	DOPE1 DSM	DOPE	Renewable Expansion	CC in 2043, 2046	Base
K	DOPE2 DSM	DOPE	Renewable Expansion	CC in 2043, 2046	Base
L	Labadie Early Retirement - 4 units	RAP	Renewable Expansion	CC in 2034	Labadie 4U Dec-2028
M	Labadie Early Retirement - 2 units	RAP	Renewable Expansion	CC in 2046	Labadie 2U Dec-2028 Labadie 2U Dec-2036
N	Sioux Early Retirement	RAP	Renewable Expansion	CC in 2046	Sioux Dec-2028
O	Rush Early Retirement	RAP	Renewable Expansion	CC in 2043	Rush Island Dec-2028
P	Sioux-Rush Early Retirement	RAP	Renewable Expansion	CC in 2043	Sioux Dec-2028 Rush Island Dec-2039
Q	Sioux-Rush Early Retirement - No CCs	RAP	Renewable Expansion Plus	Battery 1700MW 2031-2043	Sioux Dec-2028 Rush Island Dec-2039
R	Rush Early Retirement 2	RAP	Renewable Expansion	CC in 2043	Rush Island Dec-2024
S	Rush FGD	RAP	Renewable Expansion	CC in 2046	Base Rush Island FGD
T	Rush FGD - Labadie DSI	RAP	Renewable Expansion	CC in 2046	Base Rush Island FGD Labadie DSI
U	Rush Early Retirement 2 - Labadie DSI	RAP	Renewable Expansion	CC in 2043	Rush Island Dec-2024 Labadie DSI

***

[16] 20 CSR 4240-22.010(2)(A); 20 CSR 4240-22.060(3); 20 CSR 4240-22.060(3)(A)1 through 8; 20 CSR 4240-22.060(3)(B); 20 CSR 4240-22.060(3)(C)1; 20 CSR 4240-22.060(3)(C)2; 20 CSR 4240-22.060(3)(C)3; EO-2020-0047 1.D; EO-2020-0047 1.K

Does inclusion of DSM programs reduce overall customer costs?

Plans B, H, J, and K include RAP, MAP, DOPE1 and DOPE2 level of DSM programs, respectively. Therefore, these plans can be compared against plans C, D, E, F, and G that have the same level of renewable portfolios but do not include DSM programs to assess the impact on cost and other performance measures due to inclusion of different levels of DSM.

What level of DSM -RAP, MAP, DOPE1 or DOPE2- results in lower costs?

Plans with the same attributes except for the level of DSM resources have been evaluated as described above and provide a direct comparison of the relative cost of the various DSM portfolios.

Is early retirement of Rush Island Energy Center cost effective?[17]

Plan O evaluates the cost effectiveness of early retirement of Rush Island Energy Center by the end of 2028.

Is early retirement of Labadie Energy Center cost effective?[18]

Plans L and M evaluate the cost effectiveness of early retirement of all four units by the end of 2028, and two units by the end of 2028 followed by two units by the end of 2036, respectively.

Is early retirement of Sioux Energy Center cost effective?[19]

Plan N evaluates the cost effectiveness of early retirement of Sioux Energy Center alone.

Is early retirement of Sioux and Rush Island Energy Centers cost effective?[20]

Plan P evaluates the cost effectiveness of early retirements of Sioux Energy Center by the end of 2028 and Rush Island Energy Center by the end of 2039.

[17] 20 CSR 4240-22.060(3)(A)7; EO-2020-0047 1.O
[18] 20 CSR 4240-22.060(3)(A)7; EO-2020-0047 1.O
[19] 20 CSR 4240-22.060(3)(A)7; EO-2020-0047 1.O
[20] 20 CSR 4240-22.060(3)(A)7; EO-2020-0047 1.O

What is the impact of potential outcomes of the active NSR litigation?[21]

Four plans are constructed in order to evaluate different potential outcomes for the active NSR litigation: *****Plan R includes Rush Island Energy Center retirement by the end of 2024, Plan S includes installation of FGD at Rush Island Energy Center in 2025, Plan T is similar to Plan S but also includes a DSI system installation at Labadie Energy Center in 2023, and Plan U includes early retirement of Rush Island Energy Center by the end of 2024 as well as addition of DSI system at Labadie Energy Center**.***

What are the benefits of including renewables beyond those needed for RES compliance?

To assess the relative benefits of including additional renewable resources, several alternative resource plans were developed that exceed the level of renewable investment indicated by the RES compliance model. Plans A and B with RAP DSM and Plans H and I with MAP DSM can be compared to assess the costs/benefits of additional renewables. Furthermore, Plans P and Q can be compared to assess additional renewables coupled with batteries. Also included is resource plan D that features solar as a major supply-side resource and the only supply-side resource addition during the planning horizon in addition to the 'renewable expansion' level of wind and solar resource additions.

What is the impact of pursuing only new renewables?

Plan D is the all renewables alternative resource plan without DSM beyond MEEIA Cycle 3.[22]

How do various supply-side resource options compare?

The relative performance of the new supply-side resources can be determined by comparing Plans C through G, and by comparing Plan P against Plan Q.

How would our plans and customer costs be affected if DSM cost recovery and incentive needs are not met?

Plans C through G also evaluate the impact if DSM cost recovery and incentive requirements are not met.

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[21] EO-2020-0047 1.D
[22] 20 CSR 4240-22.060(3)(A)2

The type, size, and timing of resource additions/retirements for the alternative resource plans are provided in Appendix A and also in the electronic workpapers.[23]

Integration, sensitivity, and risk analyses for the evaluation of alternative resource plans were done assuming that rates would be adjusted annually for the 20-year planning horizon and 10 additional years for end effects, and by treating both supply-side and demand-side resources on an equivalent basis. Integration analysis was performed on the most likely scenario of the probability tree (Scenario 5) as explained in Chapter 2. Integration analysis present value of revenue requirements ("PVRR") results are shown below in Figure 9.5. Results for the remaining performance measures for integration analysis are provided in the workpapers.[24]

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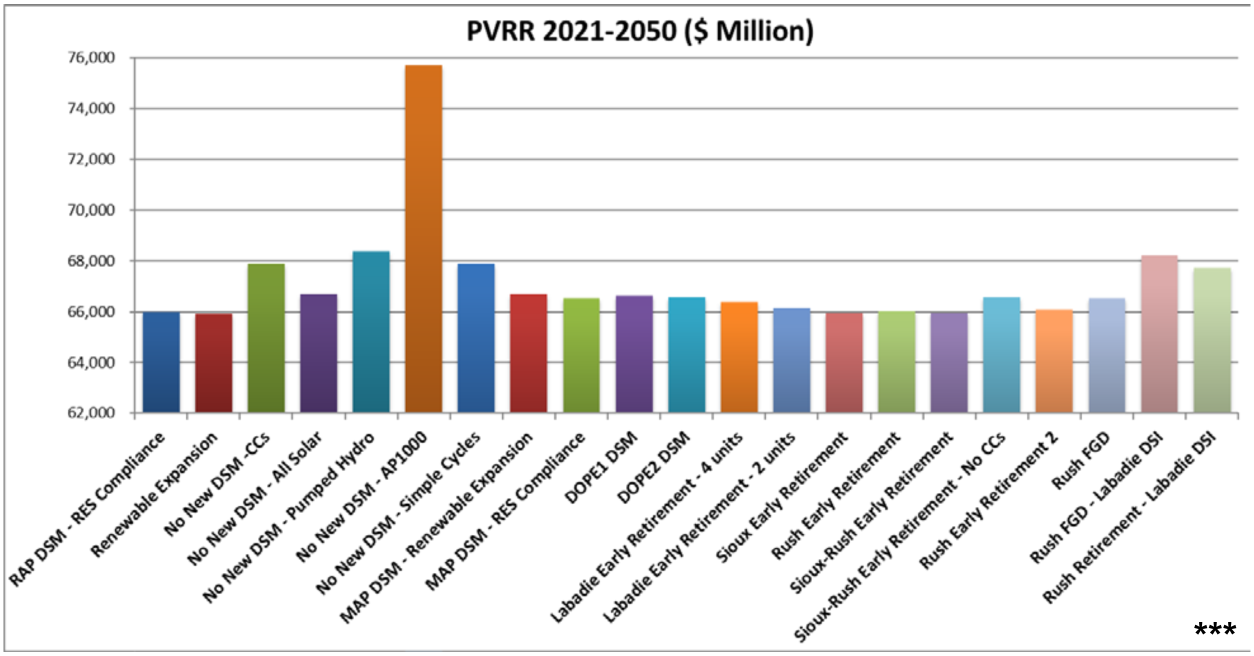
Figure 9.5 Integration PVRR Results[25]



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It should be noted that all costs and benefits in all analyses were expressed in nominal dollars, and Ameren Missouri's current discount rate of 6.04% was used for present worth and levelization calculations. Also, in all integration, sensitivity, and risk analyses, it was assumed that rates are adjusted annually (i.e., no regulatory lag).[26]

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[23] None of the alternative resource plans analyzed include any load-building programs
20 CSR 4240-22.060(3)(B); 20 CSR 4240-22.080(2)(D); 20 CSR 4240-22.060(3)(D)
[24] 20 CSR 4240-22.060(4)
[25] All plans include RAP DSM unless otherwise noted.
[26] 20 CSR 4240-22.060(2)(B)

9.5 Sensitivity Analysis

Sensitivity analysis involves determining which of the candidate independent uncertain factors are critical independent uncertain factors. Once identified in this step, critical uncertain factors were added to the scenario probability tree discussed in Chapter 2 to create the risk analysis probability tree.

9.5.1 Uncertain Factors[27]

Ameren Missouri developed a list of uncertain factors to determine which factors are critical to resource plan performance. Table 9.5 contains the list as well as information about the screening process.

Table 9.5 Uncertain Factor Screening

Uncertain Factor	Candidates?	Critical?	Included in Final Probability Tree?
Load Growth	✓	--	✓
Carbon Policy	✓ #	--	✓
Fuel Prices Coal	✓	✗	✗
Natural Gas	✓ #	--	✓
Nuclear	✗	✗	✗
Project Cost (includes transmission interconnection costs)	✓	✗	✗
Project Schedule	✓	✗	✗
Emissions Prices SO_2	✗	✗	✗
NO_x	✗	✗	✗
CO_2	✓ #	--	✓

[27] 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5) (B) through (F); EO-2020-0047 1.A(i)-(iii); 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5) (A) through (M)

Uncertain Factors	Candidate?	Critical?	Included in Final Probability Tree?
Purchased Power	✗	✗	✗
Forced Outage Rate	✓	✗	✗
DSM Cost Only	✓	✓	✓
DSM Load Impacts & Costs	✓	✗α	✗α
Foreseeable Demand Response Technologies	✓	✗β	✗β
Foreseeable Distributed Energy Resources	✓	✗β	✗β
Foreseeable Energy Storage Technologies	✓	✗	✗
Fixed and Variable O&M	✓	✗	✗
Return on Equity	✓	✗ε	✗ε
Interest Rates	✓	✗ε	✗ε

Included in the scenario probability tree

-- Not tested in sensitivity analysis

α DSM impacts and costs combined. Costs not the same costs as in "DSM Cost Only" sensitivity.

β Included as part of DSM load impacts and costs sensitivity

ε Return on Equity and Long-term Interest rates were combined

Chapter 2 describes how two of the candidate uncertain factors were determined to be critical dependent uncertain factors, which defined the nine scenarios described in that chapter. The two critical dependent uncertain factors are natural gas prices and CO_2 prices. Energy and capacity prices are an output of the scenarios, as described in Chapter 2, and reflect a range of uncertainty consistent with the scenario definitions.

A review of these candidates prior to the sensitivity analysis determined several could be eliminated without conducting a quantitative analysis.

- Nuclear Fuel Prices – Our 2011 and 2014 IRP analyses concluded that nuclear fuel prices were not critical to the relative performance of the alternative resource plans; the same conclusion is expected to be obtained should high/low nuclear prices be included in the sensitivity analysis, particularly given the significant increase in our assumption for nuclear capital costs.

- Purchased Power – Purchased power is excluded since Ameren Missouri is a member of MISO and Ameren Missouri has employed planning criteria that minimize our dependence on the market.
- SO_2 and NO_x Emissions Prices – SO_2 and NO_x Emissions Prices were excluded as candidates because of the expectation for very low prices as a result of current and expected environmental regulations.

There are two pairs of candidate independent uncertain factors that are highly correlated:

- Interest Rates and Return on Equity
- DSM Load Impacts and Costs

Including all the possible permutations of high/base/low would geometrically increase the size of the analysis, with some combinations being much less meaningful and less probable. Since the expectation is that these factors are highly correlated, we have made the simplifying assumption that the individual probability nodes for each pair be combined into a single probability node reflecting the high value for both, base value for both, and low value for both without explicitly considering the less likely and less meaningful joint probabilities.

In addition to including DSM load impacts and costs, Ameren Missouri also analyzed only DSM costs changing in high and low scenarios while the load impacts remain the same. It is important to note that the high and low case costs in the “DSM Cost Only” candidate uncertain factor are different than the high and low case costs in the “DSM Load Impacts and Costs” candidate factor. More detail on the DSM sensitivities can be found in Chapter 8.

Uncertain Factor Ranges[28]

We use the sensitivity analysis to examine whether or not candidate independent uncertain factors have a significant impact on the performance of alternative resource plans, as measured by their impact on PVRR.

The candidate uncertain factors are characterized by a 3-level range of values for this analysis; those 3 levels being low, base, and high values.

[28] 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

Unless the meaning of low, base, and high are treated in a standardized manner, the probability of occurrence for the value used for "low" for one uncertain factor could be significantly different than the probability of occurrence for the value used for "low" for other uncertain factors. Thus, for all of the uncertain factors, Ameren Missouri standardized the meaning of low to be the value found at the 5th percentile of a probability distribution of values for an uncertain factor, the value at the 50th percentile to be the base value, and the value at the 95th percentile to be the high value. The probability distribution for each candidate uncertain factor was inferred from a series of estimated values produced by subject matter experts for each uncertain factor.

For the majority of candidate uncertain factors, probability distributions were used to obtain the values for low, base, and high. This process began with subject matter experts providing/revising estimates of (A) an expected value, (B) estimates of deviations from that expected value, and (C) the probabilities of those deviations from the expected value. That information was used to create the probability distribution collectively implied by that data. Values at the 5th, 50th, and 95th percentiles of those implied probability distributions were then obtained for use as the values for low, base, and high for the various candidate independent uncertain factors. Appendix A contains the standard value, estimated deviation and probabilities for project costs, project schedule, fixed operations & maintenance ("FOM"), variable operations & maintenance ("VOM"), equivalent forced outage rate ("EFOR"), environmental capital expenditures, and transmission-retirement expenditures.

Example

The expected value for total project cost including transmission interconnection costs for the Greenfield Combined Cycle option is $1,245/kW-year (2019$). Project cost and some other candidate uncertain factors are characterized by differing standard values among various supply-side types, while standard values for some other candidate uncertain factors are not uniquely correlated to each supply side type. For example the Long Term Interest Rates uncertain factor does not differ depending on the supply-side type; it is the same across all supply-side types.

The subject matter experts, in this example, members of Ameren Missouri's generation organization, provided estimates of deviations from the standard value as well as the probabilities of those deviations. An example of that initial uncertainty distribution is shown in Table 9.6. In this example, the first of these estimates for project cost deviations was a -15% deviation from the expected

Table 9.6

CC Project Cost Uncertainty Distribution

Deviation	Probability
-15%	10%
-10%	20%
0%	50%
15%	15%
30%	5%

value with a 10% probability of occurring. These deviation estimates provide sufficient information to derive continuous probability distributions from which the low/base/high values can be derived.

The process of developing the probability distributions involve using the deviation estimates like the ones shown above, the probability distribution can be determined for the uncertain factor in question. An example of the result of analyzing deviation estimates is shown in Figure 9.6.

From this distribution, the deviation values for the low, base, and high values (84,1, 1.17) are obtained at the respective percentiles in Figure 9.6. By multiplying these values by the expected value $1,245/kW-year, we estimate the costs at the 5th, 50th, and 95th percentiles; e.g., the low value at the 5th percentile would be:

.84 x 1,245 = $1,046

Figure 9.6 Example of Probability Distribution---CC Project Cost

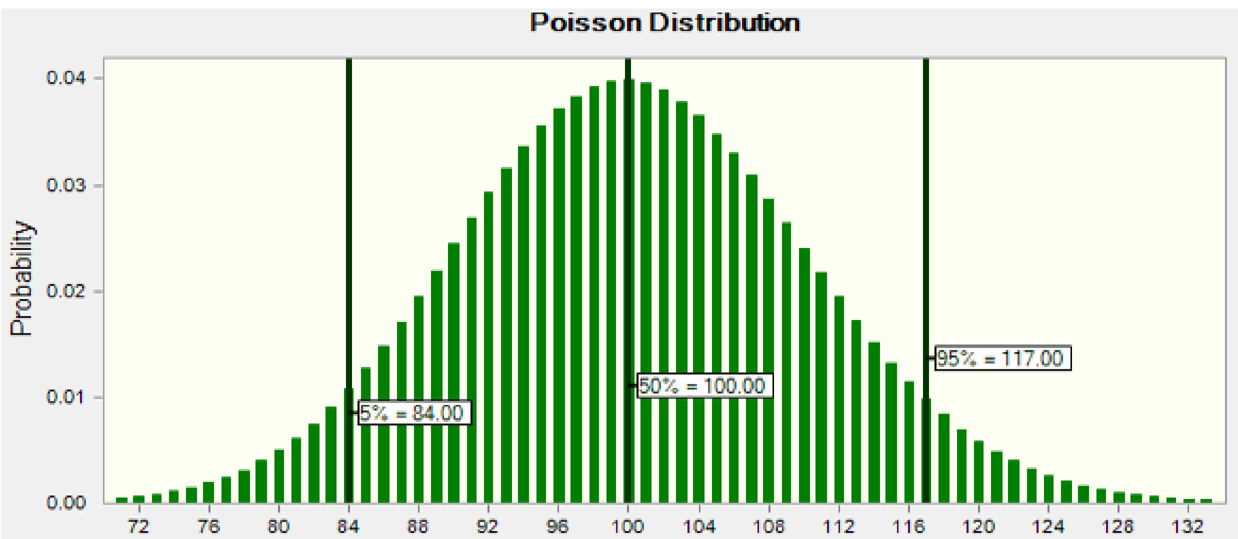

Figure 9.7 shows the resulting range of project costs, which also include interconnection costs estimates, for each new supply-side resource. For most of the technologies shown in Figure 9.7, base values found at 50th percentile were very close to their expected values. For the nuclear technology, however, the base value inferred from the probability distribution was 27% higher than the expected value- $11,302/kW vs $8,899/kW.

Figure 9.7 Resource-Specific Project Cost Ranges (2019$/kW)

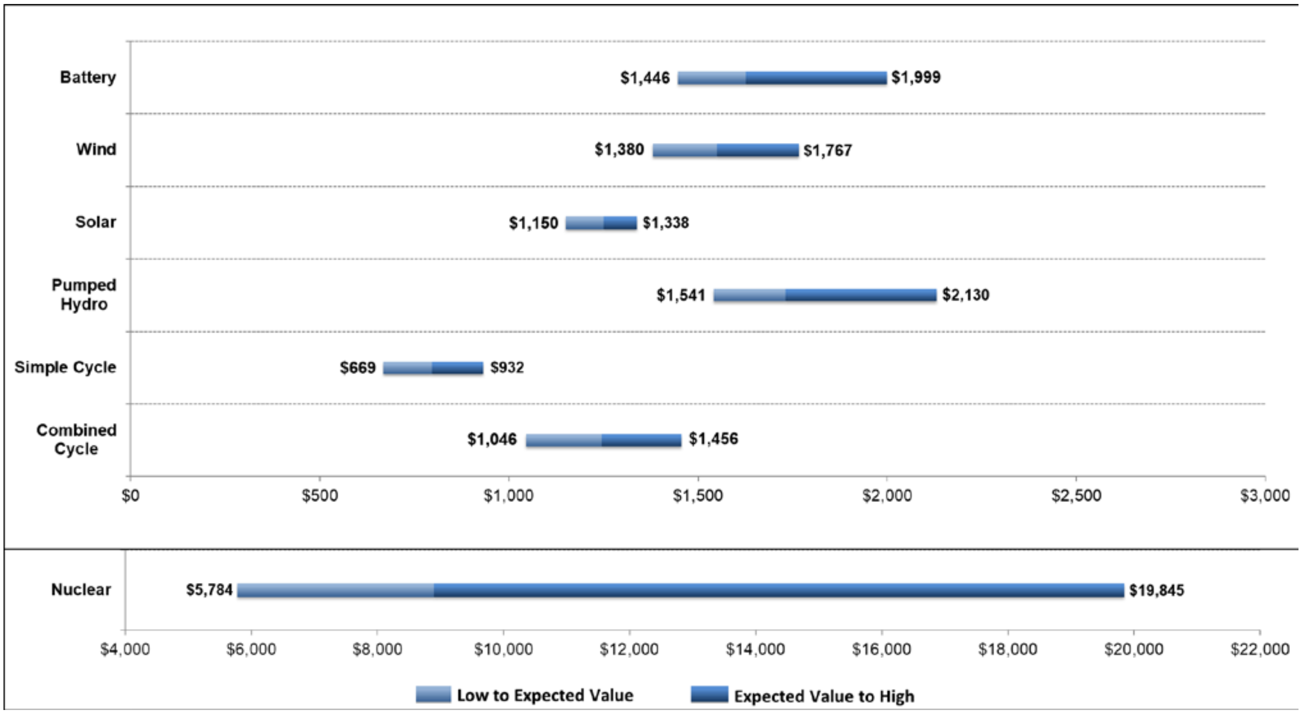

Table 9.7 Resource-Specific Uncertain Factor Ranges[29]

Uncertain Factor	Value	Probability	CC (Nat. Gas)	SC (Nat. Gas)	Pumped Hydro	Nuclear	Solar*	Wind*	Battery*
Project Cost ($/kW) 2019 $	Low	10%	$1,046	$669	$1,541	$5,784	$1,150	$1,380	$1,446
	Base	80%	$1,245	$796	$1,836	$11,302	$1,250	$1,550	$1,625
	High	10%	$1,456	$932	$2,130	$19,845	$1,338	$1,767	$1,999
Project Schedule (Months)	Low	10%	27	27	55	68	18	36	18
	Base	80%	36	36	73	91	24	48	24
	High	10%	48	48	95	119	32	63	32
Fixed O&M ($/kW-yr) 2019 $	Low	10%	$23.25	$6.98	$3.16	$102.54	$3.32	$25.74	$0.83
	Base	80%	$25.69	$8.18	$3.81	$126.02	$4.01	$31.07	$1.00
	High	10%	$29.30	$9.95	$4.76	$155.44	$5.03	$38.95	$1.26
Variable O&M ($/MWh) 2019 $	Low	10%	$0.98	$9.16	$2.50	$1.95	-	-	-
	Base	80%	$2.55	$10.90	$3.15	$2.41	-	-	-
	High	10%	$4.11	$12.64	$3.96	$3.05	-	-	-
EFOR (%)	Low	10%	1%	0%	0%	1%	-	-	-
	Base	80%	2%	5%	5%	2%	-	-	-
	High	10%	5%	10%	10%	3%	-	-	-

[29] * Denotes that Ameren Missouri used a declining cost curve for solar, wind and batteries, and multipliers were applied to estimate base, low and high project costs. Assumed capacity factor for solar, wind and battery resources include effects of FOR.

Table 9.7 shows the uncertain factor ranges for the various candidate uncertain factors. It should be noted that, for the project schedule uncertainty, as the number of years in a project schedule change, the distribution of the cash flows was also updated to be consistent with those changes.

Table 9.8 contains the non-resource specific uncertain factor ranges analyzed.

Table 9.8 Non-Resource Specific Uncertain Factor Ranges

Uncertain Factors	Low	Base	High
Probability -->>	**10%**	**80%**	**10%**
Coal Price		Varies By Year	
Long Term Interest Rates	2.5%	3.7%	4.0%
Return on Equity	10.0%	10.5%	10.6%
DSM Load Impact and Cost			
MAP - EE&DER Load Impact	84%	100%	107%
MAP - EE&DER Cost	82%	100%	108%
MAP - DR Load Impact	99%	100%	116%
MAP - DR Cost	99%	100%	101%
RAP - EE&DER Load Impact	88%	100%	113%
RAP - EE&DER Cost	82%	100%	113%
RAP - DR Load Impact	99%	100%	116%
RAP - DR Cost	99%	100%	101%
DOPE1 - EE&DER Load Impact	100%	100%	100%
DOPE1 - EE&DER Cost	100%	100%	100%
DOPE1 - DR Load Impact	100%	100%	100%
DOPE1 - DR Cost	100%	100%	100%
DOPE2 - EE&DER Load Impact	100%	100%	100%
DOPE2 - EE&DER Cost	100%	100%	100%
DOPE2 - DR Load Impact	100%	100%	100%
DOPE2 - DR Cost	100%	100%	100%
DSM Cost Only			
MAP - EE&DER Cost	85%	100%	135%
MAP - DR Cost	85%	100%	125%
RAP - EE&DER Cost	80%	100%	140%
RAP - DR Cost	85%	100%	125%
DOPE1 - EE&DER Cost	80%	100%	170%
DOPE1 - DR Cost	85%	100%	170%
DOPE2 - EE&DER Cost	80%	100%	170%
DOPE2 - DR Cost	85%	100%	170%

As discussed in Chapter 2, long-range interest rate assumptions are based on the December 1, 2019, semi-annual Blue Chip Financial Forecast, a consensus survey of 44 economists. Ameren Missouri internal experts used this same set of data and process to develop a range of interest rate assumptions for use in the 2020 IRP. The high and low interest rate assumptions are based on the average of the 10 highest and 10 lowest forecasts from the survey. Additionally, the high and low forecasts for Treasury rates are used as inputs to the calculation of high and low ranges for allowed return on equity using the same process as discussed in Chapter 2.

Note that the DOPE1 and DOPE2 portfolios have no variations under the DSM Load Impact and Cost uncertainty. By definition, DOPE portfolios are "optimized" to provide a threshold load savings target. Any deviations in load savings would be proactively managed through the budget, with lesser or greater programming as needed. The DSM Cost Only sensitivities reflect a greater range of outcomes, to account for both traditional cost estimation risk and additional program management risk to achieve defined load reduction targets. Chapter 8 includes details on how low and high ranges were obtained for DSM portfolios.

9.5.2 Sensitivity Analysis Results[30]

To conduct the sensitivity analysis, each of the 21 alternative resource plans was analyzed using the varying value levels (low/base/high) for each of the candidate independent uncertain factors, for the most likely scenario in the probability tree (Scenario 5). An uncertainty-probability weighted result for PVRR was obtained for each plan for each relevant candidate uncertain factor. Finally, the results of using a "non-base" value were compared to the results of using an integration/base value for each plan for each candidate uncertain factor. The sensitivity analysis results for all of the candidate independent uncertain factors (resource-specific and non-resource specific) are presented in Appendix A.

The sensitivity analysis identified one critical independent uncertain factor: DSM Cost Only. Table 9.9 shows the change in PVRR ranking (i.e., number of positions the plan moved in the ranking) for the critical independent uncertain factor compared to the integration/base value.

[30] 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(7)(A); 20 CSR 4240-22.060(7)(C)1A

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Table 9.9 Critical Independent Uncertain Factors – Change in PVRR Ranking[31]

Plan		Integration Ranking	DSM Cost Only PWA	DSM Cost Only Low	DSM Cost Only High
A	RAP DSM - RES Compliance	4	0	0	0
B	Renewable Expansion	1	0	0	0
C	No New DSM - CCs	18	0	0	2
D	No New DSM - All Solar	15	1	0	7
E	No New DSM - Pumped Hydro	20	0	0	1
F	No New DSM - AP1000	21	0	0	0
G	No New DSM - Simple Cycles	17	0	0	2
H	MAP DSM - Renewable Expansion	14	-1	4	-3
I	MAP DSM - RES Compliance	10	-2	2	-4
J	DOPE1 DSM	13	0	-1	0
K	DOPE2 DSM	11	1	-2	-1
L	Labadie Early Retirement - 4 units	8	0	-1	-1
M	Labadie Early Retirement - 2 units	7	0	0	0
N	Sioux Early Retirement	2	0	0	0
O	Rush Early Retirement	5	0	0	0
P	Sioux-Rush Early Retirement	3	0	0	0
Q	Sioux-Rush Early Retirement - No CCs	12	1	0	1
R	Rush Early Retirement 2	6	0	0	0
S	Rush FGD	9	0	0	0
T	Rush FGD - Labadie DSI	19	0	0	0
U	Rush Early Retirement 2 - Labadie DSI	16	0	0	0

***

Table 9.10 shows the change in PVRR ($) for the critical independent uncertain factor compared to the integration/base values. The DSM Cost Only uncertain factor was selected as a critical independent uncertain factor because of the variety in the change in PVRR ranking.

[31] All plans include RAP DSM portfolio unless otherwise noted.

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Table 9.10 Critical Independent Uncertain Factors – Change in PVRR (Million $)[32]

Plan		Integration	DSM Cost Only		
		PVRR	PWA	Low	High
A	RAP DSM - RES Compliance	66,000	19	(260)	447
B	Renewable Expansion	65,940	19	(260)	447
C	No New DSM - CCs	67,880	-	-	-
D	No New DSM - All Solar	66,709	-	-	-
E	No New DSM - Pumped Hydro	68,384	-	-	-
F	No New DSM - AP1000	75,700	-	-	-
G	No New DSM - Simple Cycles	67,877	-	-	-
H	MAP DSM - Renewable Expansion	66,758	71	(498)	1,210
I	MAP DSM - RES Compliance	66,611	71	(498)	1,210
J	DOPE1 DSM	66,678	43	(161)	587
K	DOPE2 DSM	66,598	35	(137)	486
L	Labadie Early Retirement - 4 units	66,397	19	(260)	447
M	Labadie Early Retirement - 2 units	66,155	19	(260)	447
N	Sioux Early Retirement	65,973	19	(260)	447
O	Rush Early Retirement	66,035	19	(260)	447
P	Sioux-Rush Early Retirement	65,977	19	(260)	447
Q	Sioux-Rush Early Retirement - No CCs	66,602	19	(260)	447
R	Rush Early Retirement 2	66,097	19	(260)	447
S	Rush FGD	66,555	19	(260)	447
T	Rush FGD - Labadie DSI	68,219	19	(260)	447
U	Rush Early Retirement 2 - Labadie DSI	67,761	19	(260)	447

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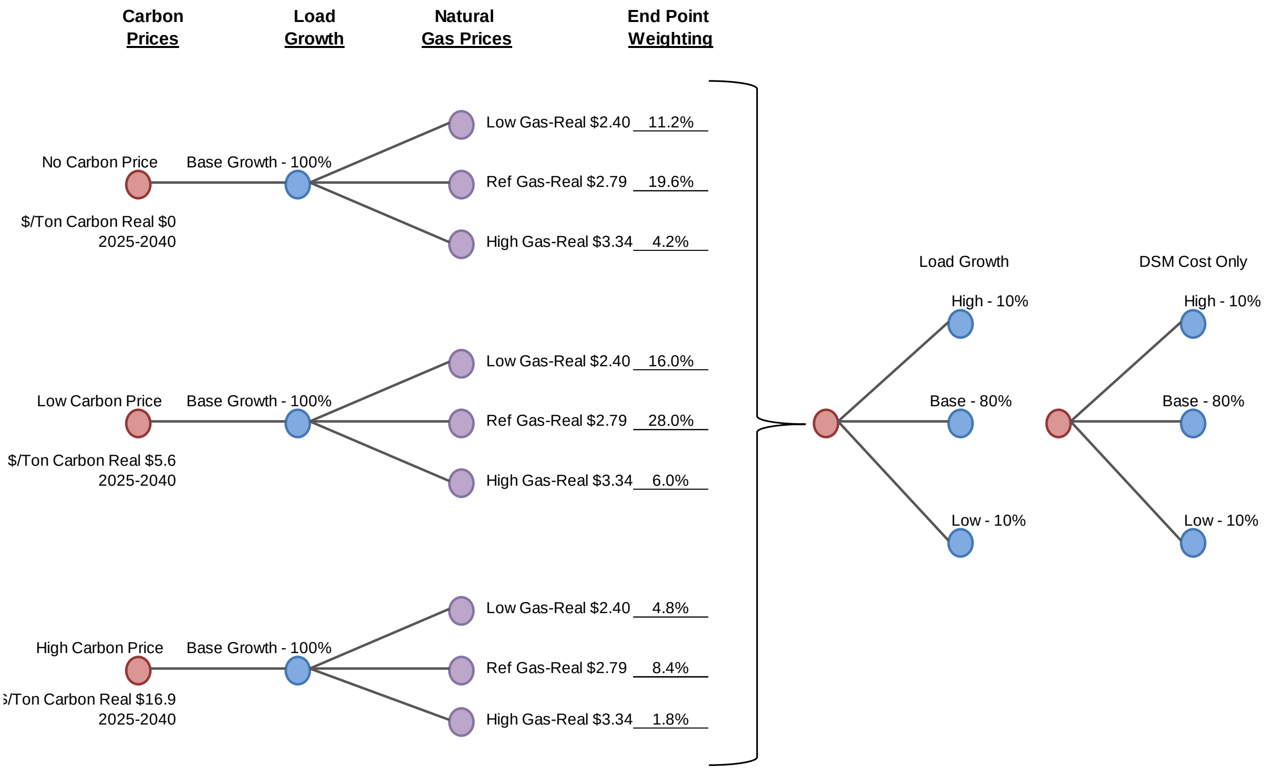
Ameren Missouri low-base-high load growth cases along with the DSM Cost Only critical independent uncertain factor were added as nodes to the scenario probability tree that was developed in Chapter 2. The updated and expanded probability tree is shown in Figure 9.8, with the two uncertain factors shown on the right-hand side.

[32] All plans include RAP DSM portfolio unless otherwise noted.

Figure 9.8 Final Probability Tree Including Sensitivity Analysis Results[33]



9.6 Risk Analysis[34]

The Risk Analysis consisted of running each of the candidate resource plans in Table 9.4 through each of the branches on the final probability tree shown in Figure 9.8. The probability tree consisted of 81 different branches. Each branch is the combination of different value levels among the nine scenarios, themselves defined by combinations of the two critical dependent uncertain factors (gas prices, and environmental regulations/carbon policy), and the two critical independent uncertain factors (DSM cost and load growth). Each branch therefore represents a unique combination of the critical uncertain factors. Once all the combinations are calculated, the sum of the individual branch probabilities equals 100%.

[33] 20 CSR 4240-22.060(6)
[34] 20 CSR 4240-22.060(6)

9.6.1 Risk Analysis Results

The PVRR results of the risk analysis of the 21 alternative resource plans are shown in Figure 9.9. The levelized rate results for the risk analysis are shown in Figure 9.10. The PVRR results are lower for plans with RAP compared to plans without DSM. Plan B, with renewable expansion and RAP DSM has the lowest PVRR followed very closely by Plan P, which include the Sioux and Rush Island early retirements. Plan F (No DSM-Nuclear) exhibits the highest PVRR and the highest levelized rates followed by Plan E (No DSM-Pumped Hydro), which has the second highest PVRR, and by Plan I (MAP DSM-Res Compliance), which has the second highest levelized rates. Results for other performance measures can be found in Chapter 9 - Appendix A.

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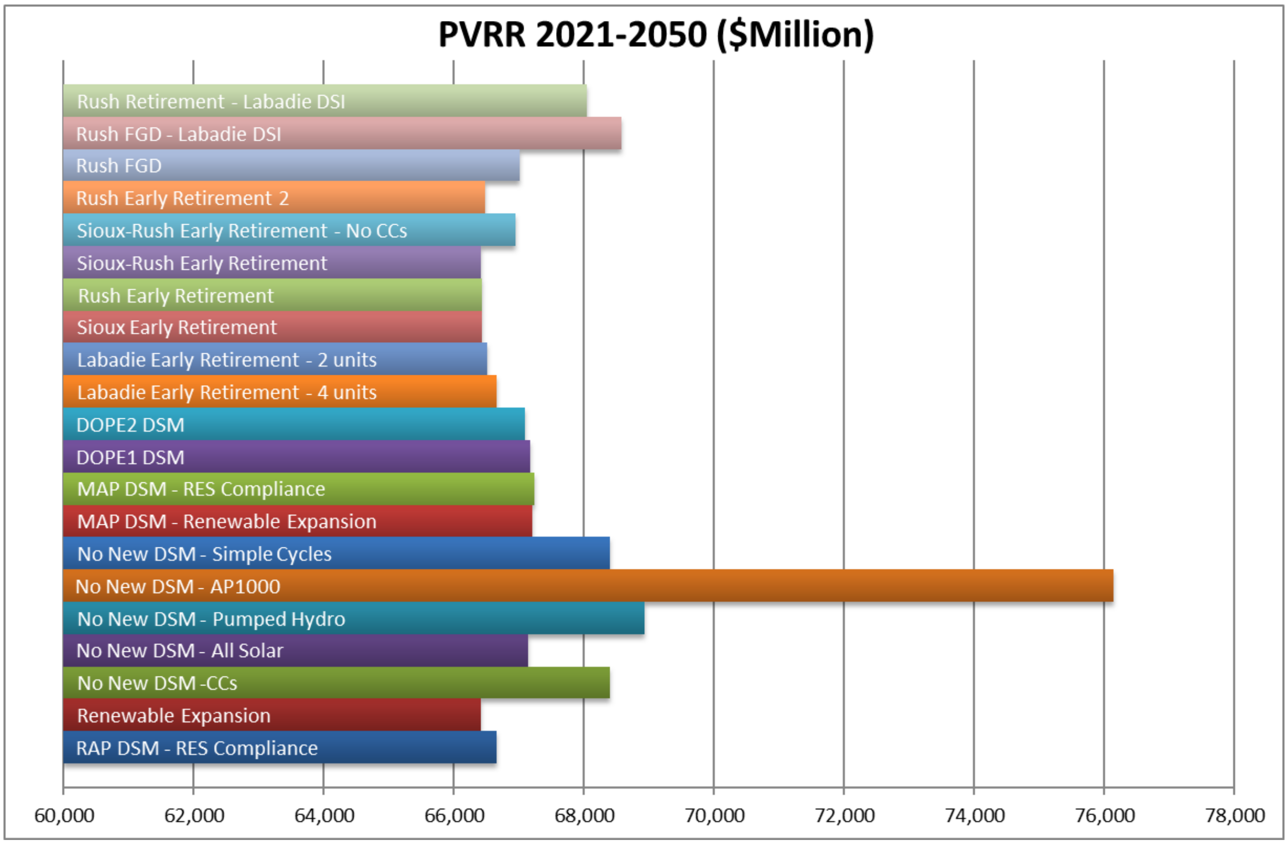
Figure 9.9 Probability-Weighted PVRR Results[35]



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[35] All plans include RAP DSM portfolio unless otherwise noted.

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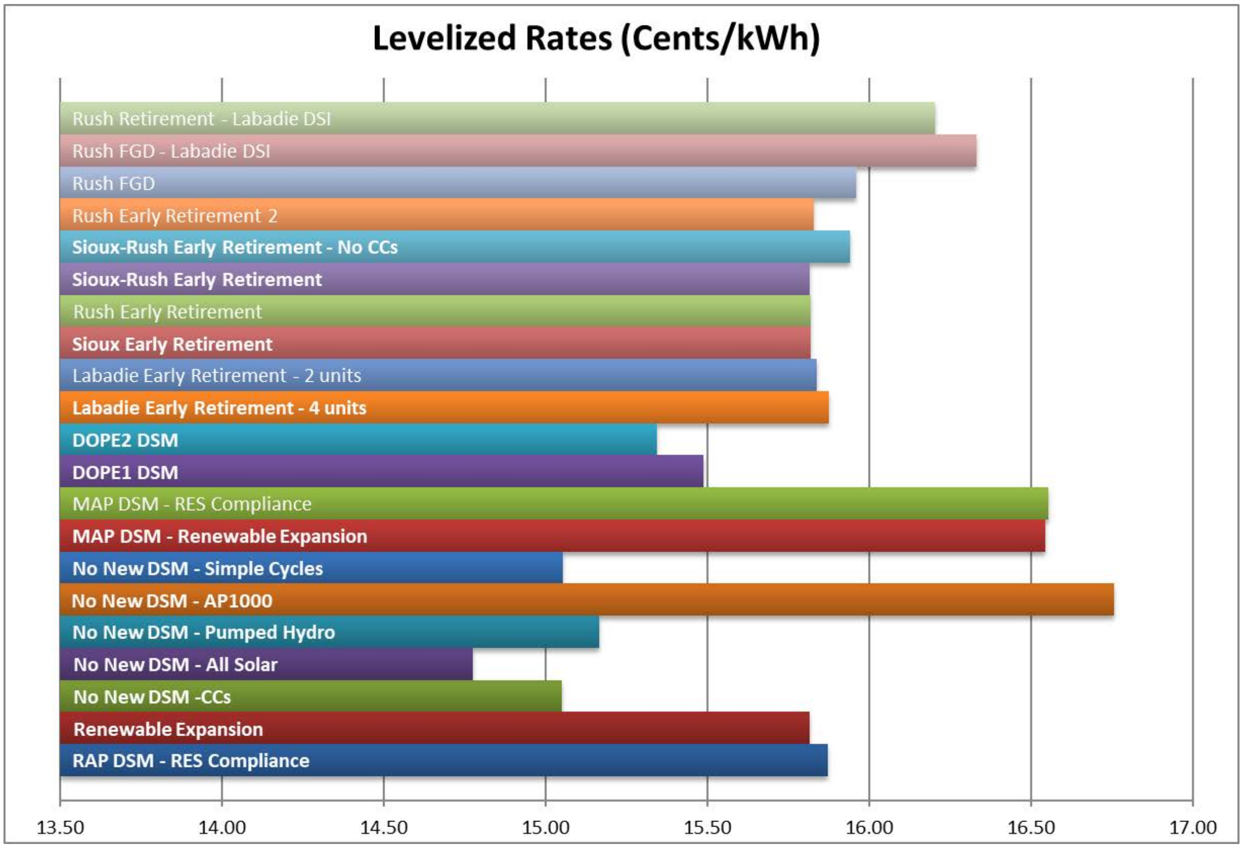
Figure 9.10 Probability-Weighted Levelized Rate Results[36]



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If decision making were solely based on PVRR and levelized rate impacts, then the analysis would be complete at this point. Since decision making is multi-dimensional, Ameren Missouri created a scorecard that embodies its planning objectives to evaluate the performance of alternative resource plans. With 21 alternative resource plans, Ameren Missouri can take a closer look at the performance of the plans by evaluating their relative strengths and weaknesses in meeting our planning objectives and whether other factors may be important in the selection of the preferred resource plan. Chapter 10 – Strategy Selection includes the additional analysis and decision-making considerations that lead to the selection of the Resource Acquisition Strategy.

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[36] All plans include RAP DSM portfolio unless otherwise noted.

9.7 Conclusions from Integration and Risk Analysis

Below are several conclusions from the integration and risk analysis.

- RAP DSM results in the lowest PVRR compared to plans with different levels of DSM.
- Inclusion of DSM resources in general results in lower costs than the supply-side alternatives. This finding demonstrates that using an avoided capacity curve that excludes capacity impacts of DSM resources for cost effectiveness analyses (as explained in Chapter 2) is appropriate. Using a more restrictive capacity curve could have resulted in screening out DSM resources that ultimately prove to be the lowest cost option when compared to supply-side alternatives.
- Sioux 2028 and Rush Island 2039 retirement results in the lowest cost among the early retirement options while early retirement of Labadie's four units by the end of 2028 results in the highest costs among the same plans.
- *****<u>Adding an FGD and/or DSI result in significantly higher costs and levelized rates. Retirement of Rush Island Energy Center by the end of 2024 is less costly than the energy center modifications</u>.*****
- Plans with additional renewable resources beyond those included for RES compliance as in Plans B and H reduce costs and customer rates. Coupling even more renewable resources with batteries, on the contrary, results in higher cost and levelized rates.[37]
- Plan D, which assumes all future resource needs are met with only renewable resources, performs better than it did in the previous IRP due to reductions in the cost of solar resources; it is the 10th most costly alternative resource plan. From a cost standpoint, it is very competitive with other supply-side resources.
- Wind, solar, and natural gas combined cycle resources are attractive options for development due to their competitive overall cost, relatively low capital cost, and relatively short lead time.
- *****<u>The five highest cost alternative resource plans are those with no DSM or with FGD and DSI additions at the two energy centers</u>.***** The alternative resource plan including new nuclear is by far the most costly.

[37] 20 CSR 4240-22.060(4)(E)

9.8 Resource Plan Model

Ameren Missouri has used a modular approach to modeling for this IRP as it did in the 2017 IRP. Instead of using MIDAS or other off-the-shelf alternatives for integration and risk analyses, Ameren Missouri continues to use a combination of stand-alone models for 1) production costing, 2) market settlements, 3) revenue requirements, and 4) financial statements. Items 2-4 on this list are collectively referred to as the "Financial Model." This approach permitted analysts maximum flexibility, customization and trouble-shooting capabilities. It also lends itself to greater transparency for stakeholders by limiting the use of proprietary third-party software.

Ameren Missouri used a generation simulation model from Simtec, Inc., typically referred to as RTSim ("Real-Time Simulation") for production cost modeling.[38] RTSim provides a realistic simulation of an electric generating system for a period of a few days to multiple years.

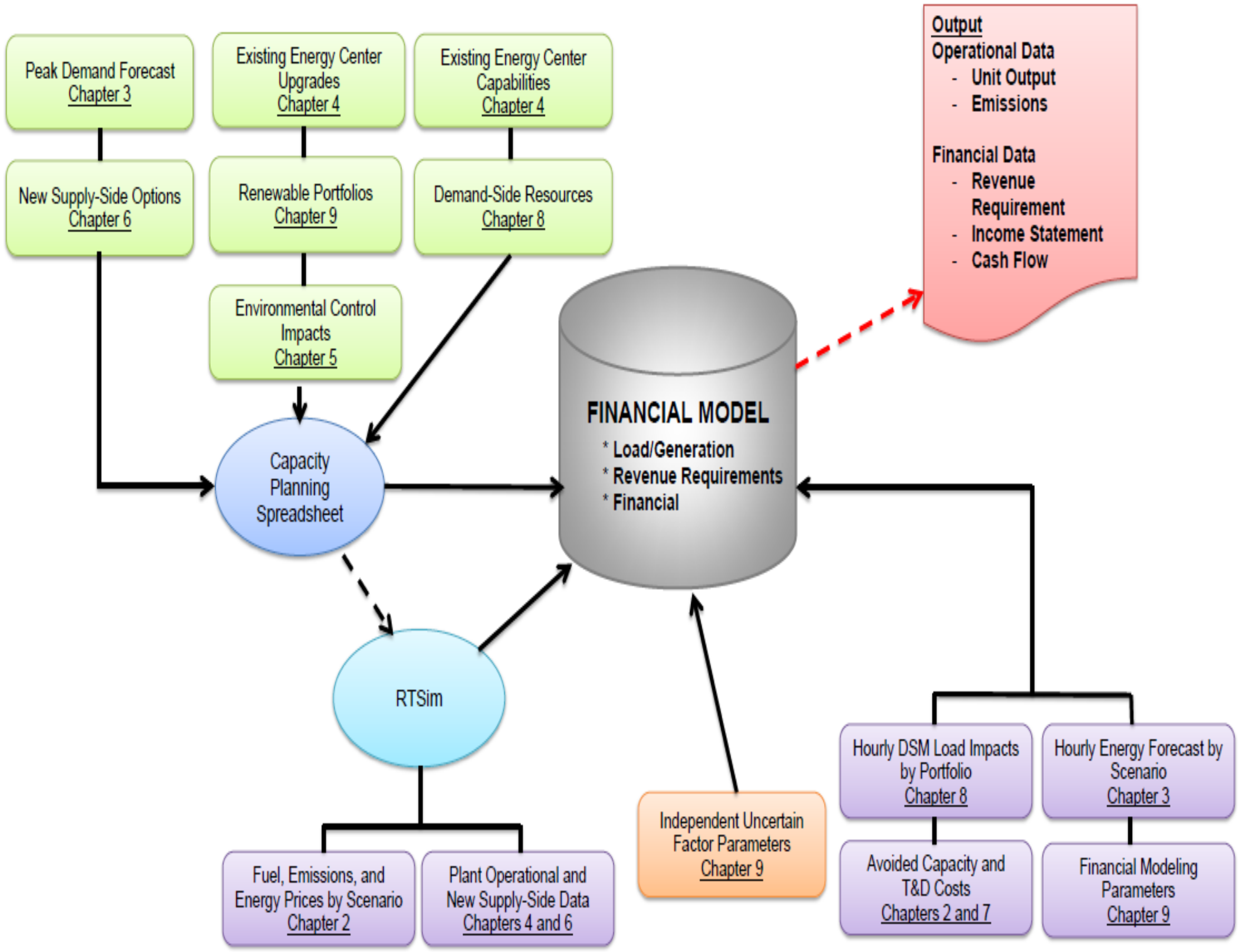
RTSim simulates hourly chronological dispatch of all system generating units, including unit commitment logic that is consistent with the operational characteristics and constraints of system resources. The model plans are based on a capacity planning spreadsheet, which was used to determine the timing of new resources. The RTSim model contains all unit operating variables required to simulate the units. These variables include, but are not limited to, heat rates, fuel costs, variable operation and maintenance costs, emission rates, emission allowance costs, scheduled maintenance outages, and full and partial forced outage rates. The generation fleet is dispatched competitively against market prices. The multi-area mode of the Ventyx Midas® model was used for the creation of forward price curves as described in Chapter 2.

Ameren Missouri developed its own revenue requirements and financial model using Microsoft Excel. This model incorporates the capacity position and RTSim outputs, as well as other financial aspects regarding costs external to the direct operation of units and other valuable information that is necessary to properly evaluate the economics of a resource portfolio. The financial portion of the model produces bottom-line financial statements to evaluate profitability and earnings impacts along with revenue requirement and various financial and credit metrics.

Figure 9.11 shows how the various assumptions are integrated into the financial model.

[38] 20 CSR 4240-22.060(4)(H)

Figure 9.11 Resource Plan Model Framework[39]



Future Plans for Modeling Tools

Ameren Missouri plans to continue to evaluate options for modeling tools for use in its resource planning process. Having developed a modular approach to our modeling, we have the flexibility to evaluate models with varying degrees of capabilities (production costing, market settlements, revenue requirements, and financial statements) that can be used in place of, and/or in combination with, the current modules. As a result, we expect that our modeling needs over time will be characterized more by evolution rather than the deployment of a single integrated solution. Our current modular approach was in large part an outcome of our evaluation of solutions that are currently commercially

[39] 20 CSR 4240-22.060(4)(H)

available. For example, we were unable to identify any available integrated solutions that produce full financial statements other than MIDAS, which is no longer being developed by Ventyx. Our current approach also allows us to expand our review of production costing solutions beyond those used primarily for long-term resource planning. We are currently using a production cost modeling software PowerSIMM for use in our fuel budgeting and short term trading support analysis which has the potential to support longer term analysis like the IRP.

We expect to continue our efforts to improve the efficiency, effectiveness, and transparency of our modeling tools into 2021. The nature and timing of any changes we make will largely be a function of our assessment of the currently available options. As we consider these options, we plan to share thoughts with other Missouri utilities and with our stakeholder group. This may or may not provide opportunities to move to a common modeling platform. Ameren Missouri will remain open to such an outcome while ensuring that its own tools and processes are able to support our business needs and objectives.

9.9 Compliance References

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

UNITED STATES OF AMERICA,	)	
Plaintiff,	)	
SIERRA CLUB,	)	
Plaintiff-Intervenor,	)	
v.	)	Case No. 4:11 CV 77 RWS
AMEREN MISSOURI,	)	
Defendant.	)	

ORDER

Ameren represents that the parties wish to hold a status conference to discuss several issues in this case. I believe this would be beneficial. The parties should be prepared to address all of the issues raised in both the United States' motion for relief regarding the structure of further consistent proceedings on remand, ECF No. [1212], and Ameren's memorandum in support of its motion to alter judgment, ECF No. [1213]. If the parties wish to file written responses to each other's most recent filings, they shall do so no later than June 21, 2022.

Accordingly,

IT IS HEREBY ORDERED that a status hearing is set for **Friday, June 24, 2022** at **11:00 a.m. IN PERSON** in Courtroom 16 South.

Rodney W. Sippel

RODNEY W. SIPPEL
UNITED STATES DISTRICT JUDGE

Dated this 9th day of June, 2022.