MISSOURI PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

KEITH MAJORS

Schedules KM-d1 through KM-d6

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

CASE NO. ER-2024-0319

Jefferson City, Missouri
December 2024

Keith Majors
Case Participation

Cases to which I have been assigned and have filed testimony, Staff report, or memorandum are shown in the following table:

Utility	Case Number	Issues	Exhibits
Spire Missouri	GR-2025-0026	ISRS	Staff Memorandum
Ameren Missouri	ER-2024-0319	Rush Island, Storm Costs	Direct Testimony
Evergy West	ER-2024-0189	Transmission Expense, Plant Investment	Direct, Rebuttal, Surrebuttal Testimony
Spire Missouri	GA-2024-0257	CCN	Staff Memorandum
Ameren Missouri	EF-2024-0021	Policy, Retired Plant Securitization	Rebuttal, Surrebuttal Testimony
Confluence Rivers	WR-2023-0006 & SR-2023-0007	Policy, Revenue Requirement	Direct, Rebuttal, and Surrebuttal Testimony
Ameren Missouri - Electric	ER-2022-0337	Revenues, Allocations, Bad Debt, Rush Island	Direct, Rebuttal, and Surrebuttal Testimony
Spire Missouri	GO-2022-0171	ISRS	Staff Memorandum
Evergy Metro and Evergy West	ER-2022-0129 & ER-2022-0130	Revenues, Jurisdictional Allocations, Bad Debt, Sibley Retirement	Direct, Rebuttal, Surrebuttal Testimony
Ameren Missouri	ER-2021-0240 & GR-2021-0241	Facilities Transactions	Surrebuttal Testimony
Spire Missouri	GR-2021-0108	Corporate Allocations, Rate Case Expense	Staff Report, Rebuttal, Surrebuttal
MAWC	SA-2021-0074	CCN	Staff Memorandum
Evergy Metro and Evergy West	EO-2021-0032	Various	Staff Report
Spire Missouri	GO-2021-0030 & GO-2021-0031	ISRS	Staff Memorandum
Raytown Water	WR-2020-0264	Various	Staff Memorandum
Summit Natural Gas	GA-2020-0251	CCN	Staff Memorandum
Liberty Utilities	WM-2020-0174	CCN	Staff Memorandum
Missouri American Water Company (MAWC)	WA-2019-0366	CCN	Staff Memorandum
Ameren Missouri	ER-2019-0335	Allocations, Affiliation Transactions	Staff Report
MAWC CCN	SA-2019-0367	CCN	Staff Memorandum
United Services	SA-2019-0161	CCN	Staff Memorandum
KCP&L & KCP&L GMO	ER-2018-0145 & ER-2018-0146	Synergy and Transition Costs Analysis, Transmission Revenue and Expense	Staff Report
Laclede Gas and Missouri Gas Energy	GR-2017-0215 & GR-2017-0216	Synergy and Transition Costs Analysis, Corporate Allocations	Staff Report, Rebuttal, Surrebuttal

Utility	Case Number	Issues	Exhibits
KCP&L & KCP&L GMO	ER-2016-0156 & ER-2016-0285	Income Taxes, Pension & OPEB	Staff Report, Rebuttal, Surrebuttal
KCP&L & KCP&L GMO	EO-2016-0124	Pensions, Rate Comparison	Staff Report
KCP&L & KCP&L GMO	EC-2015-0309	Affiliate Transactions, Allocations	Surrebuttal Testimony
KCP&L	ER-2014-0370	Income Taxes, Pension & OPEB, Revenues	Staff Report, Rebuttal, Surrebuttal
KCP&L	EU-2015-0094	DOE Nuclear Waste Fund Fees	Direct Testimony
KCP&L	EU-2014-0255	Construction Accounting	Rebuttal Testimony
Veolia Kansas City	HR-2014-0066	Income Taxes, Revenues, Corporate Allocations	Staff Report
Missouri Gas Energy	GR-2014-0007	Corporate Allocations, Pension & OPEB, Incentive Compensation, Income Taxes	Staff Report, Rebuttal, Surrebuttal
Missouri Gas Energy ISRS	GO-2013-0391	ISRS	Staff Memorandum
KCP&L & KCP&L GMO	ER-2012-0174 & ER-2012-0175	Acquisition Transition Costs, Fuel, Legal and Rate Case Expense	Staff Report, Rebuttal, Surrebuttal
Missouri Gas Energy ISRS	GO-2011-0269	ISRS	Staff Memorandum
Noel Water Sale Case	WO-2011-0328	Sale Case Evaluation	Staff Recommendation
KCP&L & KCP&L GMO	ER-2010-0355 & ER-2010-0356	Acquisition Transition Costs, Rate Case Expense	Staff Report, Rebuttal, Surrebuttal
KCP&L Construction Audit & Prudence Review	EO-2010-0259	AFUDC, Property Taxes	Staff Report
KCP&L, KCP&L GMO, & KCP&L GMO – Steam	ER-2009-0089, ER-2009-0090, & HR-2009-0092	Payroll, Employee Benefits, Incentive Compensation	Staff Report, Rebuttal, Surrebuttal
Trigen Kansas City	HR-2008-0300	Fuel Inventories, Rate Base Items, Rate Case Expense, Maintenance	Staff Report
Spokane Highlands Water Company	WR-2008-0314	Plant, CIAC	Staff Recommendation
Missouri Gas Energy ISRS	GO-2008-0113	ISRS	Staff Memorandum

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

[PROPOSED] STIPULATED ORDER

Pursuant to the Court's powers to impose an equitable remedy (ECF #1315 at 12), and pursuant to the stipulation of the Parties, the Court orders the mitigation relief set forth below. With notice from the United States that nothing in its public comment process warrants withdrawal from this proposal, the Court finds this stipulated remedy to balance "what is necessary, what is fair, and what is workable." *Class v. Norton*, 376 F. Supp. 496, 501 (D. Conn. 1974) *aff'd in part and rev'd in part on other grounds*, 505 F.2d 123 (2d Cir. 1974) (*quoting Lemon v. Kurtzman*, 411 U.S. 192, 200 (1973)).

Accordingly,

IT IS HEREBY ORDERED THAT:

Ameren Missouri ("Ameren") shall implement two mitigation projects:

(1) A project to support the distribution of stand-alone HEPA purifier devices to residential customers within Ameren's service territory located predominantly in Eastern Missouri, prioritizing distribution to low-income households, and

(2) A project to promote the transition to electric school buses for schools in the St. Louis metropolitan and surrounding areas with the charging stations necessary to support these vehicles.

The Parties recognize that the targets regarding the number of stand-alone HEPA purifiers and electric buses may not be achievable due to lack of participant interest or other factors outside of Ameren's control. In the event certain benchmarks are not met when implementing these programs, Ameren shall administer funds for the purpose of implementing weatherization and energy efficiency upgrades.

I. RESIDENTIAL HEPA PURIFIER PROGRAM:

A. <u>Program Objective</u>: In this program (the "HEPA Purifier Program") Ameren shall offer $200 vouchers to at least 125,000 residential account holders for the purchase of a stand-alone High Efficiency Particulate Air (HEPA) purifier device, sourced by a qualified vendor.

B. Program Parameters: Prioritizing low-income and/or disadvantaged[1] communities, Ameren will identify and select residential customers within its service territory to receive the offers. Customers will be solicited via mail, email, or bill insert with a QR code or link to a dedicated website, where vouchers can be used to obtain a free HEPA purifier. Eligible customers may also place a phone order through Ameren's customer service department. Ameren shall make its first 25,000 offers to residents in census tracts within service territory zip codes with median income levels at or near the midpoint income level of the 125,000 account holders. During this initial solicitation, Ameren shall endeavor to identify and address any distribution or other implementation issues that may arise with initiation of the program. Following the initial solicitation, Ameren will make offers to residential customers within service territory zip codes in order of census tract, starting with the lowest median income and moving to the highest median income, until at least 125,000 offers have been tendered. A sample of census tract numbers and corresponding zip codes of eligible residential customers is appended hereto as Exhibit A. All taxes and shipping will be paid by Ameren.

C. Offer and Reminder Parameters: Offers will expire not less than 90 days from the date of issue. Offer recipients shall be provided at least one reminder to participate ("Reminder Notice"), sent approximately 30 days after the offer, except that residential customers in census tracts where information available to Ameren indicates that the median area income is $25,000 or less shall be provided at least two Reminder Notices, sent approximately 30 days and 60 days after the offer. For all offer recipients, a final reminder ("Expiration Notice") will be sent at least 14 days before the expiration of the offer period. The method of delivery of Reminder Notices and Expiration Notices will be via mail, email, or bill insert, at Ameren's discretion.

---

[1] For purposes of this Order, "disadvantaged" communities are those that are marginalized, underserved, and overburdened by population, where the census tract faces both significant environmental or climate burdens as well as socio-economic burdens, as identified by the Council on Environmental Quality's Climate and Economic Screening Tool, https://screeningtool.geoplatform.gov/en/.

D. Purifier Parameters: Ameren and/or its vendor shall select a HEPA purifier model or models that achieve a minimum Clean Air Delivery Rate ("CADR") of 195.[2]

E. Program Deadlines: Within ninety (90) days of entry of this Order, Ameren shall create a dedicated website to process customer redemption requests, finalize marketing plans, and line up sourcing of the HEPA purifier products. Offers may occur in stages, with the first series of offers to be made not later than 120 days of entry of this Order. The program will remain open until Ameren tenders at least 125,000 offers and the customers' opportunity to accept those offers has expired.

F. Escrowed Funds for Weatherization and Energy Efficiency Projects: Customer demand for, and uptake of, the $200 offers for HEPA purifiers is uncertain. If Ameren has implemented the HEPA Purifier Program in accordance with the program requirements set forth above and 75,000 or more vouchers have been redeemed, then Ameren shall be deemed to have satisfied its obligations under the HEPA Purifier Program and no further actions are required. But if fewer than 75,000 vouchers have been redeemed, Ameren shall administer (or provide for the administration of) the sum of $5,000,000 (Five Million Dollars) for the Weatherization Program described in Section III below.

II. ELECTRIC BUSES AND CHARGING INFRASTRUCTURE PROGRAM:

A. Program Objective: In this program (the "Bus Program") Ameren shall deposit $36,000,000.00 (Thirty-Six Million Dollars) (the "Bus Funds") in an escrow account to be used with the goal, depending upon individual school district needs and participation, of procuring and putting into service eighty (80) zero-emissions, all-electric buses ("Electric Buses") to replace class 4-8 school buses with a gross vehicle rating greater than 14,001lbs. Additionally, Ameren shall administer the Bus

[2] Air purifiers with a CADR of 195 are effective at cleaning a room approximately 300 square feet in size. *See* https://www.epa.gov/indoor-air-quality-iaq/guide-air-cleaners-home#tips.

Funds to include one charging station (with no fewer than two charging ports) per Electric Bus. Each charging station shall include a vendor warranty of not less than twenty-four months.

B. Program Parameters: Ameren may partner with one or more third-party organizations to implement this program, provided that Ameren limits the use of Bus Funds for any administrative expenses associated with implementation of the Bus Program to no greater than 10% of the Bus Funds. For clarity, vendor and engineering costs attributable to site design, facility and/or utility service upgrade costs to support electrification, and the costs of charging station installation and manufacturing are all deemed to be project costs; they do not count as administrative costs. In coordination with any implementation partners, Ameren will develop criteria for program participation that prioritize school districts and service areas with low-income students/users and/or disadvantaged communities, including the Special School District of St. Louis County.

C. Program Deadlines: Within ninety (90) days of entry of this Order, Ameren shall initiate negotiations with bus manufacturers to define base specifications, including, if necessary, adjustments to meet specific school district needs. Solicitations to participating school districts shall occur no later than August 1, 2025. The placement of Electric Bus procurement orders and/or the issuance of selection awards to school districts may occur on a rolling basis and shall be completed no later than December 31, 2026. Ameren may deposit the Bus Funds into escrow in three annual increments or in one lump sum with the first annual increment or lump sum being deposited within thirty (30) days of entry of this Order.

D. Decommissioning Replaced Diesel Buses: Except as provided below, the provision of an Electric Bus to a school district under this program shall be conditioned on the decommissioning of a diesel bus. So that school districts are able to provide transportation on a reliable basis, confirmation of decommissioning shall be required within 18 months of the delivery of an Electric Bus. Replaced diesel buses shall be decommissioned as follows:

a. Where the diesel bus being replaced is model-year 2010 or older, it shall be scrapped or rendered inoperable by cutting a 3-inch hole in the engine block of the retired vehicle and disabling its chassis by cutting the vehicle's frame rails in half. It shall then be made available for recycling.

b. Where the replaced vehicle is model-year 2011 or newer, it shall be scrapped, sold, or donated.

Where a school district does not already own or control a diesel bus, it will not be required to decommission a diesel bus to receive an Electric Bus under this program. Any costs associated with decommissioning buses shall be borne by the school districts. In certifying the completion of the Bus Program, Ameren may rely on a school district's or its implementation partner's certification that decommissioning has occurred.

E. Escrowed Funds for Weatherization and Energy Efficiency Project: Schools' demand for, and uptake of, Electric Buses for their fleets is uncertain. As of December 31, 2026, any Bus Funds that have not been spent on or allocated to purchases of Electric Buses, associated charging stations, and Bus Program administration costs shall be committed to the Weatherization Funds as described in Section III below.

F. Bus Program Completion: The Bus Program shall be deemed complete when: (a) all Bus Funds have been spent or allocated in accordance with the requirements set forth in Sections II(A) through II(E) above, and (b) the Weatherization Funds, if any, have been spent in accordance with the requirements of the Weatherization Program in Section III below. Ameren's certification of completion may rely on the certifications of any vendors or implementation partners. For clarity, subject to the limitation on administration costs provided in Paragraph II(B), in no event shall Ameren be required to fund or spend more than $36,000,000.00 (Thirty-Six Million Dollars) on the Bus Program.

III. WEATHERIZATION AND ENERGY EFFICIENCY PROJECTS

A. Program Objective: The funding, if any, that is allocated pursuant to Sections I(F) and II(E) above (the "Weatherization Funds"), shall be used by Ameren to administer weatherization and energy efficiency projects that will reduce energy consumption by residential buildings in Ameren's service area (the "Weatherization Program"). Examples of such projects include installation of floor, wall, and attic insulation; sealing of windows and doors; duct sealing; and passive solar retrofits.

B. Program Participation: As a condition to receiving Weatherization Funds, participating organizations must agree to expend such funds within three (3) years of receipt.

C. Program Parameters: Ameren may partner with one or more third-party organizations to implement the Weatherization Program, provided that Ameren limits those organizations' administrative expenses to no greater than 10% of the Weatherization Funds. Ameren will (in coordination with any implementation partners) develop criteria for program participation that prioritizes districts and service areas with low-income and disadvantaged communities. Activities undertaken to implement this program shall not include the replacement of combustion appliances but shall otherwise be administered in accordance with Missouri Department of Natural Resources (MDNR) policies (*see*, *e.g.*, https://dnr.mo.gov/document-search/missouri-weatherization-assistance-program-technical-manual-2023). Such activities shall be conducted by appropriately qualified and licensed contractors.

D. Program Completion: The Weatherization Program shall be deemed complete when all Weatherization Funds have been spent in accordance with the requirements set forth in Sections III(A) through III(C) above. Ameren's certification of completion may rely on the certifications of any vendors or implementation partners.

IV. CERTIFICATIONS AND COMPLETION

By stipulating to this order, Ameren certifies to this Court the truth and accuracy of each of the following:

1. That, other than in compliance with this Order, Ameren is not required to perform the work necessary to complete the mitigation projects by any federal, state, or local law or regulation, and it is not required to perform the work necessary for these mitigation projects by any agreement, grant, or as injunctive relief awarded in any other action in any forum;

2. That the projects are not actions that Ameren was committed to performing or implementing other than in resolution of this Order;

3. That Ameren has not received and will not receive credit for any of these mitigation projects in any other enforcement action or as a resolution of claims before any other tribunal, and

4. That any activity performed pursuant to this Order will not be funded—in whole or in part—by any other program, such as EPA's Clean School Bus Program or existing weatherization subsidies.

5. For clarity, Ameren's agreement herein shall not preclude it from participating in or funding other programs that relate to bus or electric vehicle electrification, weatherization or energy efficiency, or HEPA purifier distribution, so long as any other such programs are not funded by the projects established herein.

V. REPORTING

By January 31st and July 31st of each year following this Order and until such time as all mitigation projects are complete, Ameren shall file a report that specifies:

1. The completion date of the HEPA Purifier Program website;

2. The number of HEPA purifier vouchers offered and the number redeemed;

3. The number of Electric Buses ordered by school districts and whether or not such school districts agreed to decommission diesel buses and an estimate as to when, as provided herein, such decommission shall occur;

4. The amount of funds, if any, allocated to the Weatherization Program pursuant to Section I(F) and II(E) above; and

5. The identity of any organizations with which Ameren has partnered for the implementation of the Weatherization Program.

Ameren shall file a notice with this Court certifying its compliance with and completion of each of this Order's mitigation project requirements, once Ameren has satisfied all such requirements. Ameren's certification of compliance may be based on certifications of compliance provided by its implementation partners.

VI. ENTIRE AGREEMENT

All of the terms and requirements of this Stipulated Order are set forth herein. Ameren has not agreed to any other performance, compliance, reporting, or certification obligations other than those expressly set forth herein.

____

RODNEY W. SIPPEL
UNITED STATES DISTRICT JUDGE

So ORDERED this ___ day of _______, 2024.

Company Name: GMO Electric
Case Description: 2010 GMO Elec Rate Case
Case: ER-2010-0356

Response to Majors Keith Interrogatories – Set MPSC_20100628
Date of Response: 07/13/2010

Question No. :0125
Is GMO seeking recovery of the $3 million civil penalty levied against Jeffery Energy Center in the January 2010 settlement agreement listed on page 15 of the 2009 GPE Annual Report?

RESPONSE:
No. In January 2010, outside the test year in this case, GMO recorded its 8% share of the civil penalty below the line and is therefore not seeking recovery of this cost.

Response by Leigh Anne Jones, Accounting

Attachment: Q0125 GMO Verification.pdf

Verification of Response

Kansas City Power & Light Company
AND
KCP&L Greater Missouri Operations

Docket No. ER-2010-0356

The response to Data Request #______0125______ is true and accurate to the best of my knowledge and belief.

Signed: Tom Rush

Date: July 13, 2010

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

UNITED STATES OF AMERICA,	)	
	)	
Plaintiff,	)	
	)	
vs.	)	Case No. 4:11 CV 77 RWS
	)	
AMEREN MISSOURI,	)	
	)	
Defendant.	)	

MEMORANDUM OPINION AND ORDER

"'Why don't you go up to the Range?' somebody said to me.
'The air is pure, and they have the best water on earth.'"

- W.P. Kinsella
Shoeless Joe

TABLE OF CONTENTS

INTRODUCTION

Plaintiff the United States of America, acting at the request of the Administrator of the United States Environmental Protection Agency ("EPA"), filed this suit against defendant Ameren Missouri ("Ameren") on January 12, 2011. The United States alleges that Ameren committed various violations of the Clean Air Act, 42 U.S.C. § 7401 *et seq.*, the Missouri State Implementation Plan, and Ameren's Rush Island Plant Title V Permit when it allegedly undertook major modifications at its Rush Island Plant in Festus, Missouri without obtaining the required permits. For the reasons that follow, I conclude the United States has established that Ameren violated the Clean Air Act and its operating permit by carrying out the Rush Island projects without obtaining the required permits, installing best-available pollution control technology, and otherwise meeting applicable requirements.

The modern Clean Air Act was passed in 1970 in order "'to speed up, expand, and intensify the war against air pollution in the United States with a view to assuring that the air we breathe throughout the nation is wholesome once again.'" *United States v. Duke Energy Corp.* ("*Duke Energy 2010*"), No. 1:00 CV 01262, 2010 WL 3023517, at *2 (M.D.N.C. July 28, 2010) (quoting H.R. Rep. No. 91-1146, at 1 (1970), reprinted in 1970 U.S.C.C.A.N. 5356). By 1977, Congress had determined that earlier programs "did too little" to achieve air quality goals and added the New Source Review program ("NSR"), including the Prevention of Significant Deterioration ("PSD") provisions at issue in this case. *See Envtl. Def. v. Duke Energy Corp.*, 549 U.S. 561, 567-68 (2007) ("*Duke Energy 2007*"); *New York v. EPA*, 413 F.3d 3, 12-13 (D.C. Cir. 2005). The PSD program is designed to *prevent* significant increases in pollution, an objective built into the very name of the program. *United States v. Ameren Missouri ("Ameren SJ Decision")*, Case No. 4:11 CV 77 RWS, 2016 WL 728234, at *13 (E.D. Mo. Feb. 24, 2016).

The program is designed to prevent future significant increases in pollution, in part, by requiring major-emitting facilities to employ state-of-the-art pollution controls.

When it enacted the PSD program, Congress required all new major-emitting facilities to comply with PSD requirements by installing state-of-the-art pollution controls at the time of construction. Recognizing the expense and burden of installing such controls, however, Congress did not require facilities then in existence to immediately install pollution controls. Rather, Congress allowed these facilities to continue to operate without installing such controls on the condition that if they ever modified their facilities, they would calculate the impact of those modifications, report the planned modifications to the EPA, obtain the requisite permits, and install the required pollution control technologies at that time. PSD rules apply to "major modifications," which occur when there is a "physical change" or change in the method of operation of a major stationary source that would significantly increase net emissions. *See Ameren SJ Decision*, 2016 WL 728234, at *4. An increase of 40 tons or more per year of sulfur dioxide ("SO_2"), the pollutant discussed in this case, is "significant" under the regulations. 40 C.F.R. § 52.21(b)(23)(i).

Congress enacted these modification provisions to ensure that facilities that were grandfathered into the program would not be allowed "perpetual immunity" from PSD's requirements. *Ala. Power Co. v. Costle*, 636 F.2d 323, 400 (D.C. Cir. 1979). Under the PSD program:

> [O]ld plants [are treated] more leniently than new ones because of the expense of retrofitting pollution-control equipment. But there is an expectation that old plants will wear out and be replaced by new ones that will be subject to the more stringent pollution controls that the Clean Air Act imposes on new plants. One thing that stimulates replacement of an old plant is that aging produces more frequent breakdowns and so reduces a plant's hours of operation and hence its output.

United States v. Cinergy Corp., 458 F.3d 705, 709 (7th Cir. 2006).

Ameren's Rush Island plant includes two coal-fired electric generating units, Units 1 and 2. These units went into service in 1976 and 1977 and were grandfathered into the PSD program. Neither unit has air pollution control devices for SO_2. The Rush Island plant currently emits about 18,000 tons of SO_2 per year. The Rush Island units are big sources of pollution, so even small performance improvements or increases in unit availability can lead to a 40-ton increase in SO_2. It only takes an availability improvement of 0.3% or an additional 21 hours of operation at full power for the Rush Island units to emit more than 40 tons of SO_2.

By 2005, some of the major boiler components in Units 1 and 2 were causing problems that forced Ameren to frequently take the units out of service and made the units underperform, reducing the amount of electricity Ameren could generate and sell from the units. Ameren decided to fix these problems by replacing the problem components with new, redesigned components. Courts in PSD enforcement actions have long recognized that "[i]f the repair or replacement of a problematic component renders a plant more reliable and less susceptible to future shut-downs, the plant will be able to run consistently for a longer period of time," burning more coal and emitting more pollution. *United States v. Ala. Power Co.*, 730 F.3d 1278, 1281 (11th Cir. 2013); *see also United States v. Ohio Edison*, 276 F. Supp. 2d 829, 834-35 (S.D. Ohio 2003). When these conditions occur, as they did here, they trigger a utility's obligation to conduct PSD review, secure the appropriate permits, and install required pollution controls.

This standard for assessing PSD applicability was well-established when Ameren planned its component replacement projects for Units 1 and 2. Ameren's testifying expert conceded that the method used by the United States' experts—which showed that Ameren should have expected the projects to trigger PSD rules—has been "well-known in the industry" since 1999.

But Ameren did not do any quantitative PSD review for the project at Unit 1 and performed a late and fundamentally flawed PSD review for Unit 2. And Ameren did not report its planned modifications to the EPA, obtain the requisite permits, or install state-of-the-art pollution controls. Instead, Ameren went ahead with the projects, spending $34 to $38 million on each unit to replace the problem components. It executed these projects as part of "the most significant outage in Rush Island history," taking each unit completely offline for three to four months. Ameren's engineers justified the upgrade work to company leadership on the basis that the new components would eliminate outages and the investment would be returned in recovered operations.

The evidence shows that by replacing these failing components with new, redesigned components, Ameren should have expected, and did expect, unit availability to improve by much more than 0.3%, allowing the units to operate hundreds of hours more per year after the project. And Ameren should have expected, and did expect, to use that increased availability (and, for Unit 2, increased capacity) to burn more coal, generate more electricity, and emit more SO_2 pollution.

Now that the projects have been completed, the evidence shows that Ameren's expected operational improvements actually occurred. Replacement of the failing components increased availability at both units by eliminating hundreds of outage hours per year. Unit 2 capacity also increased. Ameren's employees have admitted that those availability increases would not have happened but for the projects. As a result of the operational increases, the units ran more, burned more coal, and emitted hundreds of tons more of SO_2 per year.

In response to these projects, the United States filed this suit against Ameren, alleging that Ameren violated the Clean Air Act, the Missouri State Implementation Plan, and Ameren's

Rush Island Plant Title V Permit by performing major modifications on Units 1 and 2 without obtaining the required permits, installing state-of-the-art pollution control technology, or otherwise complying with applicable requirements.

Previously, in ruling on the parties' summary judgment motions, I set out several of the legal standards at issue in this case. *See Ameren SJ Decision*, 2016 WL 728234, at *13 (ruling on the parties' various motions for partial summary judgment and evidentiary motions); *United States v. Ameren Missouri*, 158 F. Supp. 3d 802, 804 (E.D. Mo. 2016) (denying Ameren's motion for full summary judgment). I held a twelve day non-jury trial beginning on August 22, 2016. The parties filed post-trial briefs and proposed findings of fact and conclusions of law on September 30, 2016 and argued outstanding evidentiary issues that were raised at trial. On October 12, 2016, the parties filed responses to each other's post-trial briefs.

After consideration of the testimony given at trial, the exhibits introduced into evidence, the parties' briefs, and the applicable law, I make the following findings of fact and conclusions of law, which largely adopt those proposed by the United States. As discussed below, I conclude the United States has established that Ameren should have expected, and did expect, the projects at Rush Island to increase unit availability (and, for Unit 2, to increase capacity), which enabled Ameren to run its units more, generate more electricity, and emit significantly more pollution. The United States has also established that Ameren actually emitted significantly more pollution as a result of the projects. Ameren has failed to establish that either the routine maintenance or demand growth defenses apply to shield it from liability. As a result, I conclude that the United States has established by a preponderance of the evidence that Ameren violated the PSD and Title V provisions of the Clean Air Act.

FINDINGS OF FACT

I. BACKGROUND CONCERNING THE DEFENDANT, THE RUSH ISLAND PLANT, AND THE APPLICABLE REGULATIONS

A. The Defendant

1. Defendant Ameren Missouri is a Missouri corporation. Defendant's incorporated name is Union Electric Company, but Defendant conducts business under the name Ameren Missouri. Answer to Third Amended Complaint ("Answer"), at ¶ 10 (ECF No. 250); Joint Stipulations of Fact ("Joint Stip."), at ¶ 1 (ECF No. 743).

2. As a corporate entity, Ameren is a "person" within the meaning of the Clean Air Act Section 302(e), 42 U.S.C. 7602(e) and 10 C.S.R. 10-6.020(2). Answer, at ¶ 11; Joint Stip., at ¶ 2.

3. At all times relevant to this case, Ameren has been the owner and/or operator of the Rush Island Plant in Festus, Jefferson County, Missouri. Answer, at ¶¶ 12, 57; Joint Stip., at ¶ 3.

B. The Rush Island Coal-Fired Power Plant

4. The Rush Island coal-fired power plant ("Rush Island Plant") consists, in part, of Units 1 and 2, which are coal-fired electric generating units. Rush Island Units 1 and 2 went into commercial service in 1976 and 1977, respectively. Answer, at ¶¶ 13, 59; Joint Stip., at ¶ 4.

5. The Rush Island units were originally designed to have an approximately 30-year life. Testimony of U.S. Power Plant Expert Bill Stevens, Trial Transcript Volume ("Tr. Vol."), 1-B 50:24-51:4, 69:4-11. The components of large units like the Rush Island units typically have a life of between 30 and 40 years. Stevens Test., Tr. Vol. 1-B 81:19 – 82:1.

6. The Rush Island units were designed as baseload units, meaning they generally operate every hour that they are available to run. Design Data Report (Pl. Ex. 297), at AUE-00022523, 22526; Testimony of Retired Ameren Vice President Charles Naslund, Tr. Vol. 6-A, 55:4-7; Anderson Dep., Dec. 4, 2013, Tr., 63:21 – 64:6; Pope Dep., Sept 20, 2013, Tr. 121:18 – 122:11; Testimony of U.S. Utility System Modeling Expert Dr. Ezra Hausman, Tr. Vol. 4-B, 26:15-10; Testimony of EPA Engineer Jon Knodel, Tr. Vol. 1-A, 75:16 – 75:24; 76:21–76:25.

7. The Rush Island units are among Ameren's most cost-effective units and carry much of the system load. Retired Ameren executive vice president Charles Naslund described the units as "two workhorses." Naslund Test., Tr. Vol. 6-A, 50:3-12.

8. Burning coal at Rush Island Units 1 and 2 generates combustion gases containing sulfur dioxide ("SO_2"). The SO_2 gases at Rush Island Units 1 and 2 are passed through a smokestack directly to the atmosphere, as neither unit has air pollution control devices for SO_2. Testimony of U.S. Emissions Expert Ranajit Sahu, Tr. Vol. 5, 43:9 – 44:24; Knodel Test., Tr. Vol. 1-A, 73:7 – 73:9.

9. The Rush Island plant currently emits about 18,000 tons per year of SO_2. Knodel Testimony, Tr. Vol. 1-A, 73:16 – 73:18. If Ameren operated scrubbers at Rush Island that achieved emissions reductions comparable to other plants in the region that currently operate scrubbers, SO_2 emissions would be reduced to several hundred tons per year. Knodel Test., Tr. Vol. 1-A, 108:3 – 108:5.

C. Facts Concerning General Applicability of the Prevention of Significant Deterioration Program

10. The Clean Air Act's New Source Review ("NSR") program consists of a Prevention of Significant Deterioration ("PSD") program and a Nonattainment New Source

Review program. The PSD program applies in areas that are in attainment with the National Ambient Air Quality Standards ("NAAQS") for a particular pollutant or are unclassifiable. 42 U.S.C. §§ 7471, 7475. Knodel Test., Tr. Vol. 1-A, 52:11 - 53:4.

11. The Rush Island Plant is located approximately 50 miles south of St. Louis, Missouri, in the southern tip of Jefferson County, which is currently designated as in nonattainment with the NAAQS for SO_2. Knodel Test., Tr. Vol. 1-A, 53:8 – 53:15 At the time of the 2007 and 2010 projects at issue in this case, Jefferson County was classified as in attainment with the NAAQS for SO_2. Answer, at ¶ 19.

12. At all times relevant to this case, the Rush Island Plant has been a fossil-fuel fired steam electric plant of more than 250 million British thermal units per hour heat input, and has had the potential to emit more than 100 tons per year of SO_2. The Rush Island Plant is a "major emitting facility" as defined by 42 U.S.C. § 7479(1), and a "major stationary source" as defined by 40 C.F.R. § 52.21(b)(1) and 42 U.S.C. § 7602(j). Answer, at ¶¶ 58, 59; Knodel Test., Tr. Vol. 1-A, 53:16 – 54:1.

13. Rush Island Units 1 and 2 are each a "major emitting facility" as defined by 42 U.S.C. § 7479(1), a "major stationary source" as defined by 40 C.F.R. § 52.21(b)(1), and an "electric utility steam generating unit" as defined by 40 C.F.R. § 52.21(b)(31). Joint Stip., at ¶ 5.

14. At the time of the 2007 and 2010 projects, the applicable EPA-approved Missouri PSD regulations were found in the 2003 version of 40 C.F.R. § 52.21, as incorporated into Missouri Rule 10 C.S.R. 10-6.060. Before a major source of air pollution located in such an area designated as in attainment with the NAAQS undergoes a "major modification," the owner or operator of the source must obtain a PSD permit that imposes emission limits. *See* January 21,

2016 Memorandum and Order (ECF No. 711); 40 C.F.R. § 52.21(a)(2), (j); 71 Fed. Reg. 36,486 (June 27, 2006).

15. The PSD regulations define "major modification" as "any physical change … that would result in" a significant net emission increase in actual emissions from a major stationary source. *See* January 21, 2016 Memorandum and Order (ECF No. 711); 40 C.F.R. § 52.21(a)(2)(i).

16. Under the PSD regulations, a "physical change" does not include "routine maintenance, repair and replacement." 40 C.F.R. § 52.21(a)(2)(iii).

17. Under the PSD regulations, a "significant" increase in SO_2 is 40 tons per year. 40 C.F.R. § 52.21(b)(23)(i).

D. Notice of the Violations Alleged in the Complaint

18. The EPA issued a Notice of Violation on January 26, 2010, and issued amended Notices of Violation on October 14, 2010 and May 27, 2011. The Notices of Violation identified, *inter alia*, the alleged violations arising from the 2007 and 2010 major modifications of Rush Island Units 1 and 2 that are at issue in this case. Answer, at ¶ 6; Joint Stip., at ¶ 6.

19. The Notices of Violation were provided to Ameren and the State of Missouri, in accordance with 42 U.S.C. § 7413(a). Answer, at ¶ 6; Joint Stip., at ¶ 7.

20. The United States filed its original Complaint on January 12, 2011 (ECF No. 1), an Amended Complaint on June 28, 2011 (ECF No. 36), a Second Amended Complaint on October 30, 2013 (ECF No. 165), and a Third Amended Complaint on April 24, 2014 (ECF No. 249). The Amended Complaint, Second Amended Complaint, and Third Amended Complaint alleged, *inter alia*, violations arising from the 2007 and 2010 major modifications of Rush Island

Units 1 and 2 that are at issue in this case, and were filed more than 30 days after notice of the violations was provided as required by 42 U.S.C. § 7413(a). Joint Stip., at ¶ 8.

21. The United States provided notice of the commencement of this action to the State of Missouri, as required by 42 U.S.C. § 7413(b). Knodel Test., Tr. Vol. 1-A, 87:4 - 87:23.

II. FACTS CONCERNING THE 2007 AND 2010 BOILER UPGRADES AT RUSH ISLAND UNITS 1 AND 2

22. The major modifications in this case arise from construction projects undertaken by Ameren in 2007 and 2010 at Rush Island Units 1 and 2. The 2007 major modification occurred at Rush Island Unit 1 during a major boiler outage that began on February 17, 2007 and ended on May 28, 2007. The 2010 major modification occurred at Rush Island Unit 2 during a major boiler outage that began on January 1, 2010 and ended on April 9, 2010. Stevens Test., Tr. Vol. 2-A, 24:9 -24:15; 2007 Post Outage Report (Pl. Ex. 34), at AM-02252210; 2010 Post Outage Report (Pl. Ex. 46), at AM-02739973.

A. The Boiler Components at Issue and Their Role in Burning Coal to Generate Electricity

23. Rush Island Units 1 and 2 each include a large boiler where coal is burned to convert water into steam. The boilers are comprised of a number of major components, including the economizers, reheaters, lower slope panels, and air preheaters at issue. The economizer, reheater, and lower slope panels are each comprised of bundles of steel tubes designed to carry high-temperature, high-pressure steam to the turbines. Altogether, the boilers in large coal-fired units like those at Rush Island are constructed of hundreds of miles of tubing. Exposing the steel tube bundles in the major boiler components to the heat from burning coal converts water into steam. The steam is sent to the turbines, including a high pressure turbine, an intermediate pressure turbine, and a low pressure turbine. The turbines spin a generator, which

produces electricity. Unlike the tubular boiler components, the air preheater does not consist of steel tube bundles; it consists of metal heat exchanging surfaces that preheat additional air used for combustion of coal in the boiler. Stevens Test., Tr. Vol. 1-B, 55:9 - 55:13, 57:13 - 61:6; *see also* Welcome to Rush Island Plant Presentation (Pl. Ex. 35), at AM-02253169-173.

24. The Rush Island boiler house is approximately 270 feet tall from the ground to the rooftop. Stevens Test., Tr. Vol. 1-B, 95:10-16. Each boiler is approximately 230 feet tall. Stevens Test., Tr. Vol. 1-B, 95: 10-18; Welcome to Rush Island Presentation, (Pl. Ex. 35), at AM-02253171. Each furnace is approximately 60 feet wide and 50 feet deep. Stevens Test., Tr. Vol. 1-B, 96:2-5.

25. The specific boiler components at issue in the major modifications are the economizer, reheater, lower slopes, and air preheaters that were replaced at Rush Island Unit 1 in 2007, and the economizer, reheater, and air preheaters that were replaced at Rush Island Unit 2 in 2010. Knodel Test., Tr. Vol. 1-A, 81:9 - 82:8; Stevens Test., Tr. Vol. 1-B, 46:2-12.

26. The Rush Island economizers are located in the convection section of each boiler. Stevens Test., Tr. Vol. 2-A, 29:11-24. The purpose of the economizer, which is the first tubular heat exchanging component in the boiler, is to take heat from the hot gases in the boiler and transfer it to high pressure boiler feedwater. When it leaves the economizer, the water is close to turning into steam. It then flows to a steam drum before being circulated through waterwall tubes that form the walls of the boiler furnace, and on to a section of the boiler known as the superheating section, before being sent as steam to the high pressure turbine. Stevens Test., Tr. Vol. 1-B, 58:12 – 60:6.

27. Each economizer at Rush Island Unit 1 and 2 weighed approximately 600 tons. Stevens Test., Tr. Vol. 2-A, 34:22 – 35:7. The original Unit 1 and Unit 2 economizers had

identical designs. They each had two banks – an upper and a lower bank – with 276 assemblies per bank, and had a spiral-finned design, with a staggered arrangement. The diameter of each tube was 1.75 inches. Stevens Test., Tr. Vol. 2-A, 29:25 - 30:18; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080276; Ameren's Response to Request for Admission ("RFA") Nos. 362, 364, 365, 367 (ECF. No. 785-1).

28. The Rush Island reheaters are located at the top of each boiler's furnace. Stevens Test., Tr. Vol 2-A, 41:14-42:13. The purpose of the reheater is to reheat steam after it has passed through the high pressure turbine, before being sent back to the intermediate and low pressure turbines. Stevens Test., Tr. Vol. 1-B, 60:7 – 60:17.

29. The original Rush Island reheaters each had a front section and a rear section. The front section had 72 side-by-side assemblies, each of which was over 50 feet tall. The front assemblies were spaced on ten inch centers. The original front section had a sloped bottom, which created a close clearance between the bottom of the reheaters' front section and each boiler's nose. The rear section had 145 assemblies, each of which was around 26 feet tall. Both the front and rear reheater sections were spaced, not platenized, meaning there was no material that connected one tube to the next. Stevens Test., Tr. Vol. 2-A 42:2 - 43:2; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080428; RFA Nos. 386, 387, 389, 390.

30. Rush Island's lower slope tubes are part of the waterwall tubes and are located in the bottom of the furnace area of the boiler. Stevens Test., Tr. Vol. 1-B, 61:15-24, Tr. Vol. 2-A, 51:2 -51:19.

31. In addition to the economizers, reheaters, and lower slopes, the other primary boiler components at issue in this case are the air preheaters, which help warm combustion air entering the boiler. Forced draft ("FD") fans are used to push combustion air into the boiler, and

before entering the furnace the cold combustion air passes through the lower portion of the air preheater. Once in the furnace, the air mixes with pulverized coal and creates flue gas which heats the water and steam in the boiler tube components. Among other things, the flue gas contains tiny particles of ash known as flyash. Stevens Test., Tr. Vol. 1-B, 57:13 – 58:11; Tr. Vol. 2-A, 56:21-57:11.

32. The hot flue gas resulting from coal combustion flows up through the furnace and then from the back pass of the boiler down through the top of the air preheater, before going to the electrostatic precipitator and then being sucked out by induced draft ("ID") fans and sent up the stack. During this process, the air preheater rotates, allowing the hot flue gas exiting the boiler to warm up the forced draft air that is entering the boiler. Stevens Test., Tr. Vol. 2-A 13:10-14, 56:21-58:8; Testimony of U.S. Power Plant Expert Robert Koppe, Tr. Vol. 3-A, at 16:16-17:2.

33. Rush Island Units 1 and 2 each have two air preheaters. Each air preheater is approximately 40 feet tall and is located approximately 100 feet from ground level. Stevens Test., Tr. Vol. 2-A 13:10-14, 67:21-68:5. Each air preheater weighed at least a couple hundred tons. Stevens Test., Tr. Vol. 2-A 59:3-6.

34. The original Rush Island air preheaters were Ljungstrom regenerative air preheaters. Specification No. EC-5491 (Pl. Ex. 10), at AM-00080275. Each original air preheater had three layers: a hot layer, an intermediate layer, and a cold layer. RFA Nos. 329, 332. Each layer was made up of air preheater baskets of various sizes. There were 216 hot end baskets, and each basket was 42 inches thick. There were 216 intermediate end baskets, and each basket was 16 inches thick. RFA No. 333, 334. There were 24 cold end baskets, and each basket was 12 inches thick. Stevens Test., Tr. Vol. 2-A 57:12 - 58:21; RFA No. 335.

35. Because the tubes that comprise the economizers, reheaters, and lower slopes are in constant contact with flue gas and/or combusting coal, these tubes are subject to deterioration over the life of the boiler and eventually develop leaks, which require repair or replacement. When the tubes degrade and the walls become too weak, the high pressure steam or water can burst through, resulting in a boiler tube leak. Large leaks require a unit to shut down while the portion of the tube that ruptured is repaired, which typically lasts two to three days. Koppe Test., Tr. Vol. 3-A, at 14:16-15:9; Stevens Test., Tr. Vol. 1-B, 65:15 - 66:7.

36. Typically, the length of tube replaced when fixing a boiler tube leak would be on the order of several feet of tube. Stevens Test., Tr. Vol. 1-B, 79:4 - 79:19. Such repairs would be part of the day-to-day responsibility of plant maintenance staff and would involve no design changes to the component. Stevens Test., Tr. Vol. 1-B, 65:15 – 66:15, 69:4 – 69:11.

37. Similarly, on occasion some cold end air preheater baskets might need to be replaced due to corrosion. Stevens Test., Tr. Vol. 2-A, 58:14-21.

38. It is well known in the industry that a well-designed section of new boiler tubes should have almost no leaks at all for the first 20 years, before the tubes eventually begin to wear out and start to fail. Koppe Test., Tr. Vol. 3-A 50:11-50:16; Vasel Dep., Aug. 15, 2013, Tr. 131:11-132:24 (Ameren was not expecting any tube leaks with the new economizer).

39. In light of the harsh conditions in which they operate, boiler components typically have a finite design life of between 20 to 40 years of operation. Stevens Test., Tr. Vol. 1-B 83:5-15. At that point, routine maintenance may no longer be sufficient to maintain desired operations, and an alternate approach may be required to optimize and extend the life of the unit. Vol. 1-B, Stevens Test., 82:2-20.

40. As a result, if a utility like Ameren wants to operate a boiler like the Rush Island boilers beyond 25 to 35 years, one strategy would be to replace the major boiler components, including the reheater. Stevens Test., Tr. Vol. 1-B 83:5-21, 84:5-6. Likewise, an economizer should be expected to last approximately 35 years and lower slope tubes should be expected to last approximately 40 years. Stevens Test., Tr. Vol. 1-B 83:22-84:4, 84:7-8. Ameren's expert witness, Mr. Jerry Golden, similarly testified that the typical life of a reheater is about 30 years, the typical life of an economizer is about 35 years, and the typical life of a lower furnace is about 40 years. Golden Test., Tr. Vol. 8-A, 18:2 – 18:11.

41. Life extension activities historically have been considered in the utility industry to be different than typical maintenance activities. The distinction was explained by Mr. Stevens, and is also discussed in an authoritative engineering text published by Babcock and Wilcox known as the "Steam Book." Stevens Test., Tr. Vol. 1-B 76:7 – 76:16, 78:4-7, 80:6-17.

42. According to the Steam Book, prior to the 1980s, it was assumed that older plants would be torn down to make room for newer, larger, more efficient units, and it was common to retire plants after 35 to 40 years of service. That assumption changed when utilities began to engage in life extension activities. The concept of "Life Extension and Upgrades" is discussed in a chapter in the Steam book by that name, while routine maintenance is discussed separately. Golden Test., Tr. Vol. 8-A, 32:16-33:8; Stevens Test., Tr. Vol. 1-B, 78:4-79:3.

43. The Steam Book describes a case-study involving the replacement of an economizer as a "life extension" project. In that life extension case study, a staggered economizer at a coal-fired generating unit was experiencing pluggage and gas flow resistance, resulting in erosion and tube failures. It was replaced with a new, redesigned, in-line

economizer, which alleviated the operational problems and allowed for higher availability and reliability. Stevens Test., Tr. Vol. 1-B 84:19-87:19.

44. By contrast, typical maintenance activities on coal-fired fired boilers are those done on a day-to-day basis to keep the power plant running in its current condition. Such typical maintenance includes things like replacing small sections of tubing, not replacing entire boiler components. Stevens Test., Tr. Vol. 1-B 64:15-66:15; 77:23-78:3, 78:20-79:19, 80:6-12.

45. Similarly, Ameren's Work Order Procedure Manual defines routine maintenance activities as those that "relate to work performed regularly by Ameren employees or contractors on an ongoing basis in the customary and normal course of business to operate or maintain facilities and equipment." Ameren Work Order Procedure (Pl. Ex. 7), at AM-00066968; Stevens Test., Tr. Vol. 1-B 71: 15-72:7. Such routine activities are not subject to the requirements of Ameren's Work Order Procedures. Pl. Ex. 7, at AM-00066960, 66968; Stevens Test., Tr. Vol. 1-B 72:9-14; Moore Dep., Sept. 16, 2014, Tr. 22:11-22.

46. Ameren's Administrative Design Control Manual provides that any activity that changes "any design or operating feature of the plant that is described by drawings or other design documents" is not considered routine maintenance. Ameren Administrative Procedure Design Control Manual (Pl. Ex. 495), at AM-0223699; Stevens Test., Tr. Vol. 2-A, 70:24-71:2.

B. Operational Problems Leading up to the 2007 and 2010 Boiler Upgrades

47. The Rush Island Units were originally designed to burn Southern Illinois Bituminous Coal. Rush Island Resurfacing Study (Pl. Ex. 20), at AM-00499384; Stevens Test., Tr. Vol. 1-B, 100:24 -101:4, Tr. Vol. 2-A, 92:10-92:15. Around 1990, Rush Island began to burn coal from the Powder River Basin in Wyoming, known as PRB coal. Stevens Test., Tr. Vol. 1-B, 101:5-14. By 1995, the Rush Island units were burning 100 percent PRB coal. Stevens

Test., Tr. Vol. 1-B, 101:15-20; Meiners Test., Tr. Vol. 7-A, 102:10-12; Meiners Dep., April 8, 2014, Tr. 237:9-238:11; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080275; Project Approval Package (Pl. Ex. 3), at AM-00072837.

48. Ameren chose to switch to PRB coal, which has less sulfur, in order to comply with the Clean Air Act's separate "Acid Rain" rules. As Ameren explained in an internal 1992 Acid Rain "Compliance Strategy" document, "a significant advantage of a fuel switch strategy is that it delays an irreversible decision to construct scrubbers." Report from Union Electric: Compliance Strategy, Clean Air Act Amendments (Pl. Ex. 798), at AUE-00020365; Knodel Test., Tr. Vol. 1-A, 102:16-21.

49. The Acid Rain rules are part of a program under Title IV of the 1990 Clean Air Act Amendments designed to reduce by about 50% precursors of acid rain, or acid deposition, from coal-fired power plants. These pollutants include SO_2 and nitrogen oxides. Knodel Test., Tr. Vol. 1-A, 55:13-19; *see* 42 U.S.C § 7651 *et seq*.

50. According to retired Ameren senior vice president Charles Naslund, PRB coal is the cheapest fuel option for the Rush Island plant, and Ameren has the cheapest fuel costs in the regional transmission area, known as the Midcontinent Independent System Operator ("MISO") area. "So when I bid in my units, basically my units are always picked up pretty much baseload because I'm the cheapest." Naslund Dep., Sept. 18, 2014, Tr. 144:17 – 145:7; Knodel Test., Tr. Vol. 1-A, 104:22-105:09. The economic advantage provided by burning cheaper coal than their competitors means Rush Island Units 1 and 2 run a higher percentage of the time. Naslund Test., Tr. Vol. 6-A, 48:7-49:3.

51. Although PRB coal was cheaper and had less sulfur, it differed in other important characteristics, including having a lower heating value and higher moisture content, meaning that

more coal needed to be burned to achieve the same output from the units. Stevens Test., Tr. Vol. 1-B, 101:21-102:15; Pope Dep., Sept. 20, 2013, Tr. 71:18-72:9. Because the Rush Island plant was not designed for coal with these characteristics, Ameren knew that switching to PRB would eventually cause operational problems at the units. Meiners Dep., April 8, 2014, Tr. 237:9-238:1; Pope Dep., Sept. 20, 2013, Tr. 73:12-74:12. For instance, Ameren's Acid Rain Compliance Strategy specifically identified the fact that "the low heat content and the higher moisture of these coals generally result in operational problems that reduce capability." Report from Union Electric: Compliance Strategy, Clean Air Act Amendments (Pl. Ex. 798), at AUE-00020397.

52. The anticipated problems from switching to PRB coal for which the units were not designed were realized, causing related operational problems across the entire boiler. These problems worsened over time, and by the mid-2000's, these components were also suffering from additional operational problems due to age-related deterioration, including tube leaks in the boiler components. Fred Pope, Rush Island's former General Manager of Engineering and Technical Services, said Ameren took interim measures to "defer as long as we could the potential component replacements that…we anticipated would eventually come as the result of individual components reaching the end of their life, and we recognized that when that occurred, we would…..adjust the design of those components…to accommodate western coal." Pope Dep., Sept. 20, 2013, Tr. 73:12-74:11.

53. As described further below, these operational problems included boiler tube leaks, slagging, fouling, and plugging, which adversely affected the economizers, reheaters, lower slopes, and air preheaters. These problems, which were extensively described in Ameren's documents, forced each of the units to be completely shut down (in outages) for periods of time,

or to have their electricity generation limited to less than full power (derated) for periods of time. Stevens Test., Tr. Vol. 1-B 102:16-102:24, 105:18-105:20, 107:6 - 109:13; Tr. Vol. 2-A, 7:16-8:20, 59:7-60:22, 63:22-65:7; Koppe Test., Tr. Vol. 3-A, 14:5-15; *see* Project Approval Package (Pl. Ex. 1), at AM-0072580 (noting "tube leaks" and "load reductions due to flyash pluggage" at Unit 1), 72585 (recounting that "switch to 100% PRB coals has caused flyash pluggage" and noting boiler tube leaks at Unit 1), 590 (describing need for Unit 1 replacements following switch to PRB coal); Project Approval Form (Pl. Ex. 2), at AM-00072829 (noting "tube leaks" and "load reductions due to flyash pluggage" at Unit 2); Project Approval Package (Pl. Ex. 3), at AM-00072831 & 837 (same statements for Unit 2); Project Approval Package (Pl. Ex. 6), at AM-00072912 (describing "major boiler modifications" at both units to address components "experiencing an increase in tube leaks" and planned redesigns for PRB coal); July 15, 2005 Email (Pl. Ex. 45) at AM-0266037, 38 (noting derates due to "permanently plugged" air preheaters); September 18, 2009 Memo (Pl. Ex. 26), at AM-00954160 (Unit 2 air preheaters "have continued to foul"); October 15, 2009 Memo (Pl. Ex. 23), at AM-00926322-323 (describing problems in Unit 2 reheater and economizer following switch to PRB coal); Specification No. EC-5491 (Pl. Ex. 10), at AM-00080276-279 (describing problems in Unit 1 and 2 boiler components); Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966724-725, 731-736, 740-742, 745, 750-753 (describing problems in components).

1. Boiler tube leaks

54. As discussed above, boiler tube leaks occur in tubular components such as economizers, reheaters, and lower slopes, and large leaks require a unit to shut down for repairs which typically last two to three days. FOF 35.

55. The rates of boiler tube failures are generally unlike the failure rates that may occur in other equipment in a boiler. Other boiler equipment tends to have failure rates that stay constant with time as long as the utility keeps up with its maintenance. But as boiler tube components degrade and reach the end of their useful life, their failure rates increase with time and become repetitive given the miles of deteriorated tubing, any inch of which can fail. As the component reaches the end of life, the failures will keep increasing even though the utility repairs specific leaks. Koppe Test., Tr. Vol. 3-A, 52:8-54:15.

56. The Rush Island Units were experiencing boiler tube leaks in the years leading up to the 2007 and 2010 major boiler outages, particularly in the three boiler tube components at issue in this case. Koppe Test., Tr. Vol. 3-A 14:5-15. As Ameren's documents described the situation for the Rush Island plant as of 2005, "[t]here were a total of 10 reheat leaks in the reheaters in 2004 alone" along with "a total of 4 economizer tube leaks" and "12 lower slope tube leaks." Project Approval Package (Pl. Ex. 3), at AM-00072837; *see also id*. at AM-00072831 (noting problems that were "causing tube leaks" in the lower slopes and that "[t]here have been tube leaks in the economizer sections and reheater pendants"); Project Approval Package (Pl. Ex. 1), at AM-00072585, 72590 (identical document for Unit 1); 2008 State of the System Presentation (Pl. Ex. 15), at AM-00196730-735 (presentation identifying lost megawatt-hours from boiler tube leaks at both units).

2. Slagging and fouling

57. Slagging is the accumulation of liquid ash on the walls of the furnace and on components that are located at the top of the furnace, including superheaters and reheaters. Slag condenses or solidifies, eventually becoming like rock or concrete. Slag can bridge between tubes causing plugging, which limits flow through the unit. Slag can also fall down through the

furnace, causing tube leaks in the lower slope tubes. Stevens Test., Tr. Vol. 1-B, 104:23 – 105:17; Tr. Vol. 2-A, 51:02-52:25

58. Slag buildup on the reheaters would fall to the bottom of the furnace, causing damage to the lower slope tubes. Stevens Test., Tr. Vol. 2-A 44:1-21; Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966735; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080278; Boll Dep., Sept. 5, 2014, Tr. 68:11-70:5. The slag falls caused "a vast number of gouges" on the lower slope tubes, which would often require a unit shutdown to repair. Pl. Ex. 28, AM-00966722, at 745. The slag falls at the Rush Island units were at times as large as an automobile. Stevens Test., Tr. Vol. 2A, 54:2-14; Boll Dep., Sept. 5, 2015, Tr. 69:22-70:5. In addition, the lower slope tubes were experiencing problems related to 30 years of exposure to liquid ash and molten slag. Stevens Test., Tr. Vol. 2-A 51:20 – 52:25, 54:2 – 14; Pl. Ex. 28, at AM-00966745; Project Approval Package (Pl. Ex. 1), at AM-00072585; Project Approval Package (Pl. Ex. 3), at AM-00072831.

59. Before the 2007 major boiler outage, Ameren undertook efforts to repair the tube leaks caused by falling slag. For instance, Ameren would pad-weld over areas eroded by flowing slag and would replace leaking sections of tubes. However, because the buildup of slag was a recurring problem that was not being controlled adequately, problems continued. Stevens Test., Tr. Vol. 2-A 54:15-55:8.

60. Fouling is the deposit of solid particles of ash on heat transfer surfaces. When fouling builds up on itself, it can plug the gas flow path between boiler tubing, limiting gas flow across the component, and through the unit. Fouling also leads to higher velocity gas flows through the areas that are not plugged, which causes erosion and tube failures. Stevens Test., Tr. Vol 1-B, 102:16-103:23, Tr. Vol. 2-A, 32:7-32:23.

3. Pluggage

61. Pluggage at Rush Island Units 1 and 2 occurred in the reheaters and economizer boiler tube components and in the air preheaters. Pluggage in boiler tube components occurs when ash material bridges the spaces between tubes, limiting gas flow. Stevens Test., Tr. Vol. 1-B, 103:24 - 104:4, 104:16 - 104:22. Ash also accumulates on the air preheater surfaces, restricting flue gas flow through the air preheaters and reducing the unit's output. Stevens Test., Tr. Vol. 2-A 59:7 - 60:22; July 15, 2005 Email (Pl. Ex. 45), at AM-0266037, 38; September 18, 2009 Memo (Pl. Ex. 26), at AM-000954160; Koppe Test., Tr. Vol. 3-A, 14:11-14:15, 17:5-17:11.

62. Ameren's documents specifically identified the switch to PRB coal as the reason for increased flyash pluggage and load reductions. Project Approval Package (Pl. Ex. 1), at AM-00072585 ("The switch to 100% PRB coals has caused flyash pluggage in the reheater and economizer. The pluggage in the existing staggered economizer has caused load reductions."); Rush Island Resurfacing Study (Pl. Ex. 20) at AM-00499388 ("changing fuels resulted in economizer performance problems…and maintenance problems…"); Bosch Dep., June 12, 2014, Tr. 38:25 – 39:7; *see also* July 15, 2005 Email (Pl. Ex. 45) at AM-0266037, 38 (noting derates due to "permanently plugged" air preheaters).

63. Mr. Koppe and Mr. Stevens explained that the boiler components were all suffering from the same underlying pluggage problem that collectively contributed to limiting air and gas flow through the boiler, thus reducing the amount of coal that could be burned. Stevens Test., Tr. Vol. 1-B, 108:13-109:13; Koppe Test., Tr. Vol. 3-A, 28:7-14, 29:2-8; see also Koppe Test., Tr. Vol. 4-A, at 46:23-47:18 (discussing the cumulative effect of the air preheaters,

reheater, and economizer pressure differentials on overall pressure drop throughout the boiler and its impact on the ID fans).

64. Jeff Shelton, an Ameren trial witness, similarly testified that because they all collectively contribute to the problem, the air preheaters, economizer, and reheater have to be looked at together when considering the effects of pluggage on the unit's ability to generate. Shelton Test., Tr. Vol. 10-A, 106:13-24.

65. Pluggage in the economizer with PRB ash was exacerbated by the original economizer's staggered alignment design, which created a torturous flow path for the flue gas and ash. Together with the switch to PRB coal, the economizers' staggered alignment also resulted in erosion, thinning, and tube leaks. Stevens Test., Tr. Vol. 2-A 30:19 - 32:14, 33:9-22, 40:11-19.

66. Ameren attempted to remedy the problems in the economizer through soot blowing and off-line cleanings, but these efforts did not solve the problem. Pluggage and erosion kept occurring, and the end of the economizers' lives were approaching. Stevens Test., Tr. Vol. 2-A 32:7-23.

67. The original design of the reheaters also exacerbated pluggage due to PRB coal. The spacing of the reheaters, along with the use of PRB coal, led to pluggage of the gas lanes through the reheaters. Contemporaneous documents indicated that "fouling is a daily concern," that pluggage occurred in certain areas of the reheater across the entire boiler width, and that shotguns and dynamite needed to be used to remove the pluggage. Stevens Test., Tr. Vol 2-A, 43:3-45:13; Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966735.

68. Ameren attempted to address the problems with the reheaters through cleanings, including soot blowing, and even dynamite. Strubberg Dep., Nov. 5, 2013, Tr. 162:7-19, 174:9-

23. However, because of end of life considerations, it became necessary to replace the reheaters. Stevens Test., Tr. Vol. 2-A, 44:22 – 45:13, 47:20-24.

69. The original air preheaters also consistently experienced pluggage. With the switch to PRB coal, ash accumulated on the air preheater surfaces and built up on itself. Ultimately, the pluggage also led to an end-of-life situation for the air preheaters. Stevens Test., Tr. Vol. 2-A 59:7 – 60:22. As an internal Ameren email stated, "It sounds like we have to live with the load limitations on RI due to fan capacity limits. Is there anything else we should look at, or as Jon suggests, is this beyond recovery due to the permanently plugged air heaters." July 15, 2005 Email (Pl. Ex. 45), at AM-0266037; Cardinale Dep., July 31, 2014, Tr. 84:3 – 21 (air preheater fouling was "permanent"); *see also* September 18, 2009 Memo (Pl. Ex. 26), at AM-000954160 (noting continued air preheater fouling).

70. The specific mechanisms by which pluggage from PRB coal restricted air and gas flow and limited boiler operation were explained by Mr. Koppe. As noted previously, each boiler's FD fans push air in through the air preheaters where it is warmed up before it enters the furnace areas of the boiler. Koppe Test., Tr. Vol. 3-A 16:16-20. The very hot gases then flow up through all of the boiler tube components and back through the other side of the air preheaters, through the precipitator, and then are sucked out by ID fans, before going out the stack. Koppe Test., Tr. Vol. 3-A 16:20-17:2. When pluggage gets bad enough, it is no longer possible to push enough air into the furnace to burn as much coal as could otherwise be burned. That reduces the amount of coal that is burned, which reduces the amount of steam that is generated, which reduces the amount of electricity that is produced. Koppe Test., Tr. Vol. 3-A, 17:3-11.

71. Pluggage limited the amount of coal that could be burned in several ways. First, pluggage impacted the pressure differentials (also known as "delta P") across the air preheater and economizer, which limited air and gas flow and reduced the amount of coal that could be burned. As discussed above, the hot gases flow through the boiler as air is pushed into the boiler by FD fans and pulled by ID fans. The amount of air pushed into the furnace has to be in balance with the amount of gas that goes out of the furnace. As a component gets plugged, it takes more pressure to push the gas through it. The "delta P" represents the change in pressure from the inlet to the outlet of the various boiler components. When the pressure drop gets too high, the amount of gas flow out of the furnace must be reduced, which requires reducing the amount of air coming into the furnace, which reduces the amount of coal the boiler can burn. Koppe Test., Tr. Vol. 3-A, 17:12-18:21.

72. Second, pluggage also impacted the FD and ID fans. As pluggage got worse, the ID fans, which create a vacuum to suck air out of the boiler, had to work harder and harder to pull air, and eventually got to the point where they were "fan-limited" and could not suck any more without damaging equipment. Cardinale Dep., July 31, 2014, Tr. 103:17-205:17. So the ID fans had to reduce power, which also reduced the amount of coal that could be burned. Koppe Test., Tr. Vol. 3-A., 19:18-20:16.

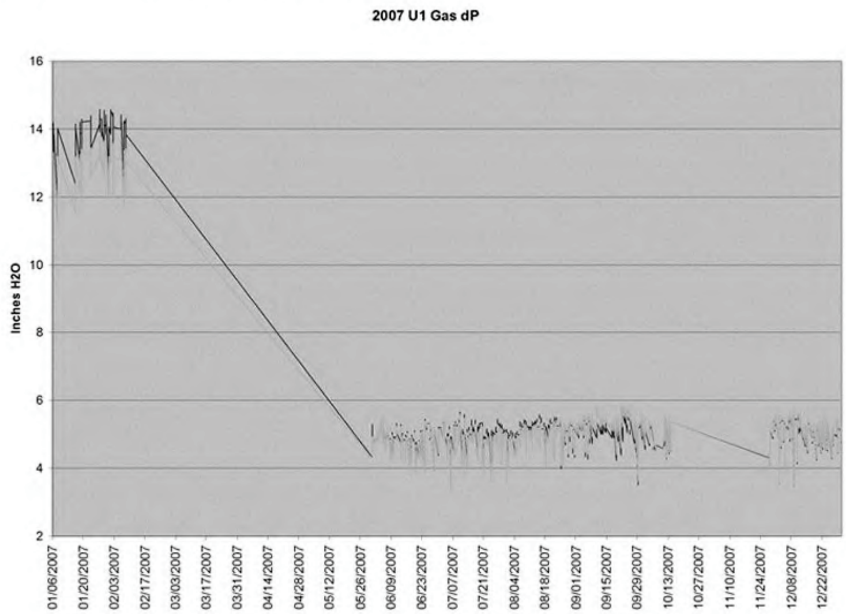
73. As the air preheaters plugged up more and more, the FD fans also had to work harder and harder to get air into the boiler. Bosch Dep., June 12, 2014, Tr. 38:25 – 40:11. Eventually the FD fans were maxed out and they could not push any more air, which limited the amount of coal that could be burned. Bosch Dep., June 12, 2014, Tr. 39:19 – 40:11. This typically happened in the summertime. Koppe Test., Tr. Vol. 3-A, at 20:17-21:11; Koppe Test., Tr. Vol. 4-A 44:13-23 ("on the rare occasions when I have before seen units limited by FD fans,

it is because the pluggage has gotten so severe in the summer months the FD fans use up all their margin and can't push any more air"); Birk Dep., Sept. 24, 2013, Tr. 194:7-16; *see also* July 2005 email, Pl. Ex. 45 (discussing "permanently plugged air heaters" and noting that the units "run out of FD fans when ambient temps come up in the summer months").

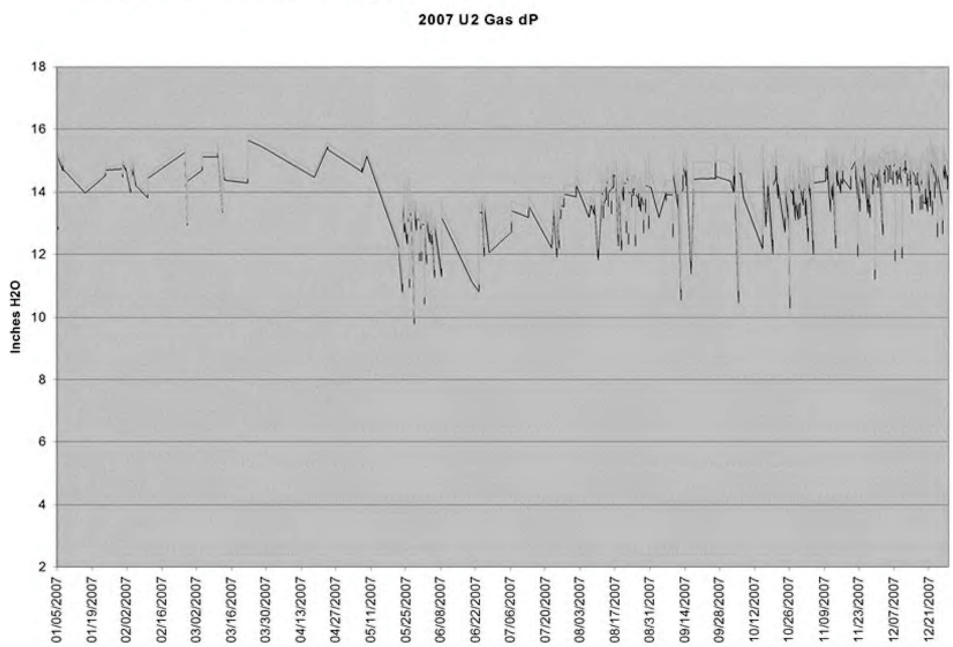
74. In the short term, Ameren coped with pluggage by shutting the units down periodically to conduct high-pressure washes to try to clean out some of the pluggage. Koppe Test., Tr. Vol. 3-A 22:3-12.; Stevens Test., Tr. Vol. 2-A, 59:7-22; Cardinale Dep., July 31, 2014, Tr. 41:15-43:10. This ameliorated the problem somewhat, but it did not solve it. Koppe Test., Tr. Vol. 3-A 22:3-12. The pressure drop would improve somewhat following a cleaning, but "much of the deposits in the air heater were so hard that they couldn't be removed even with a high-pressure wash." *Id*. at 25:12-21; Stevens Test., Tr. Vol. 2-A, 66:8-23; Cardinale Dep., July 31, 2014, Tr. 84:3-21.

75. Evidence of these problems was specifically discussed in company presentations to Ameren executives and memorialized in documents such as the 2008 "State of the System" report. 2008 State of the System (Pl. Ex. 15), AM-00196593, at AM-00196898-923; Meiners Test., Tr. Vol. 7-B, 58:20-59:8 (State of the System presentations were an opportunity to review the performance of plant equipment with Ameren executives). For instance, the 2008 State of the System report included a graphical representation of the high differential pressure problems caused by pluggage, showing very high differential pressure ranging from 12 to over 14 inches of water pressure at the beginning of 2007 at both Unit 1 and Unit 2. The two graphs are found in Pl. Ex. 15, at AM-00196909-10:

2007 U1 Gas dP



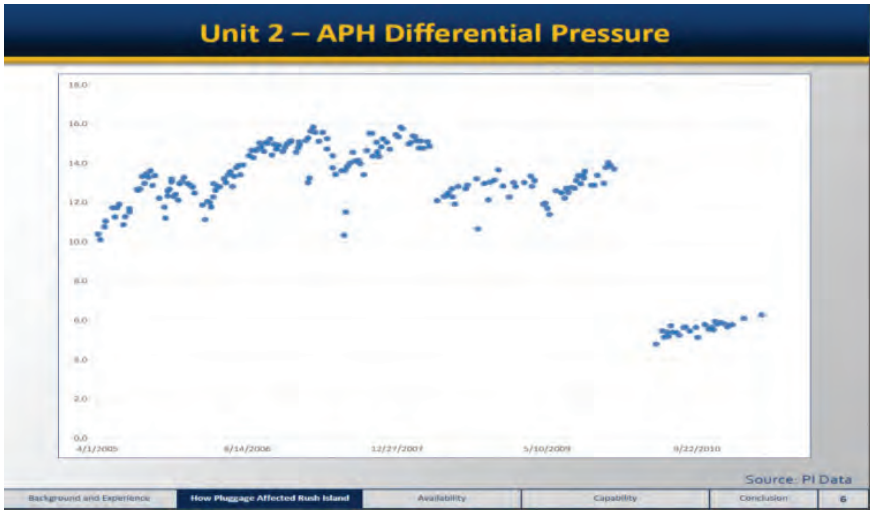
2007 U2 Gas dP



76. At Unit 1, the graphs indicate that differential pressure at Unit 1 dramatically dropped from about 14 inches of water pressure in early 2007 down to 4 to 6 inches of water pressure after the Unit 1 air preheaters were replaced in the Spring of 2007. Pl. Ex. 15, at AM-00196909. At Unit 2, the graph shows the permanence of the pluggage. As compared to the dramatic improvement achieved at Unit 1 due to the boiler component replacements, the Unit 2 graph shows only a very small improvement in differential pressure (from 14 down to 12 inches) following a washing of Unit 2 in the Spring of 2007, which almost immediately crept back up to 14 inches. Pl. Ex. 15, at AM-00196910. Koppe Test., Tr. Vol. 3-A, at 23:15 – 26:3.

77. The differential pressures described in the 2008 State of the System report before the boiler components were replaced were extremely high and caused load reductions. Koppe Test., Tr. Vol. 3-A, at 24:12-25:4. Ameren's trial witnesses Joseph Sind and Andrew Williamson referred to such differential pressures as "extremely high" and indicative of "high pluggage." Sind Test., Tr. Vol. 9-B, at 26:16 – 18 (air preheater differential pressures above even 11 inches are "extremely high"); Williamson Test. Tr. Vol. 9-B, at 44:4-11 (air heater differential pressure of 15 inches indicates "high pluggage").

78. Mr. Koppe's analysis of the company's operational data showed that the same high differential pressures reported in the 2008 State of the System report plagued Unit 2 throughout the years leading up to the 2010 major boiler outage. As Mr. Koppe's review of Ameren's data demonstrated, Unit 2's differential pressure at full load ranged between 10 and 16 inches of water in the years leading up to the projects, before dramatically improving following the 2010 major boiler outage. Koppe Test., Tr. Vol. 3-A 25:22-27:17 (discussing Koppe demonstrative 6).



79. Rush Island's operational data was also compiled in periodic full load tests, which Ameren generally performed on a weekly basis in order to determine the maximum output the unit could achieve at that time. Koppe Test., Tr. Vol. 3-B, 35:17-36:4. During full load tests, the unit tries to generate as much output as it can. Sind Test., Tr. Vol. 9-B, at 30:1-7; Williamson Test., Tr. Vol. 9-B, 42:11-20 (former Rush Island Superintendent of Operations testifying that he reviewed full load tests on a regular basis so he could understand what the capability of the units were); *see also* November 2007 email (Pl. Ex. 130), at AM-02635983 (Rush Island performance engineer James Bosch discussing full load test results after being asked to determine the "capacity" of Unit 1).

80. Plaintiff's Exhibit 928 is a compilation of these full load tests at Unit 2. In addition to reporting actual data such as pressure differentials, each full load test included a row for a possible narrative description of what was limiting load at the time. *See* Pl. Ex. 928, at Spreadsheet Cell B.2 ("Load Limited by"). In addition to the consistently high reported differential pressures, the full load tests performed during the PSD baseline period for Unit 2 (March 2005 to April 2007) are replete with examples where Ameren engineers went out of their

way to indicate in the narrative description of the load test reports that load was limited by the pluggage that is at issue in this case.[1]

81. Ameren also specifically quantified the generation losses due to the boiler components in company presentations. For instance, the 2008 State of the System presentation attributes 185,286 megawatt-hours of lost production at Unit 2 in 2007 to the air preheaters, as compared to only 15,197 megawatt-hours during that same year at Unit 1, which was the year the air preheaters were replaced at Unit 1. 2008 State of the System (Pl. Ex. 15), at AM-00196900.

82. Ameren trial witness David Strubberg conceded that the reported Unit 1 losses were smaller due to the replacement of the air preheaters. Strubberg Test., Tr. Vol. 8-A, 80:12-81:22 (discussing excerpt of presentation in Pl. Ex. 14). Similarly, a July 2006 email from Mr. Strubberg concerning the potential risks of postponing the Unit 1 major boiler outage estimated an approximately 35 MW load reduction due to pluggage. Strubberg Test., Tr. Vol. 8-A, 90:11-91:10.

83. The pluggage at Unit 2 continued to get worse in the years leading up to the 2010 major boiler outage. As ash plugged up the economizer or air preheater, some of it could be removed relatively easily. But a hard layer of ash deposit would form on the surfaces that could

[1] *See* Pl. Ex. 928, at Cell O.2 ("FD Fan Capacity"), W.2 ("ID FAN SUCT PS"), Y.2 ("ID Fan suction press"); AJ.2 ("ECON PLUGGAGE ID FAN SUCT). AK.2 ("Due to pluggage in boiler, it limits ID fan suction pressure"); AL.2 ("limited by the ID fan suction pressure…Boiler is plugged"); AO.2 ("ID suction Supht [sic] plugged Econ plugged"); AP.2 ("ID Fan Suction (Plugged Boiler)"); AQ.2 ("ID Fan Suction (Plugged Boiler)"), BD.2 ("02 blr pluggage"), BF.2 ("FD FANS"); BV.2 ("APH Pluggage"), BW.2 ("APH Pluggage"), BX.2 ("APH Pluggage"), BY.2 ("APH Pluggage"), BZ.2 ("ID Fan Suction Pressure"), CA.2 ("ID FAC SUCTION PRESS."), CC.2 ("ID Fan Suction"); CE.2 ("Blr Pluggage"), CH.2 ("APH Pluggage), CI.2 ("Suction Press."), CJ.2 ("APH Pluggage"), CK.2 ("APH Pluggage"), CN.2 ("ID Fan Suction Pressure"), CO.2 ("APH Pluggage"), CP.2 ("ID suc press Blr & APH's plugged"), CQ.2 ("APH Pluggage"), CR.2 ("ID FAN SUCT"), CS.2 ("APH Pluggage"), CT.2 ("Aph Pluggage"), CU.2 ("APH Pluggage"), CV.2 ("ID fan suction pressure").

not be removed "short of going in with a chisel and chiseling it out inch by inch. So as time went on, the thickness of these hard layers increased and that means that even after washing these components, the pressure drops were still very high." Koppe Test., Tr. Vol. 3-B, 20:1 – 21:7. This inability to remove the load limitations with high pressure washes was specifically identified in project justification documents for Unit 2. An Ameren memo reported: "A high pressure wash can restore some of the pressure loss, but the gains are dimensioning [sic] with an ever increasing accumulation of hardened fly ash." September 18, 2009 Memo (Pl. Ex. 26), at AM-000954160.

84. By 2008, pluggage of the Unit 2 air preheaters had gotten so bad that Ameren had to install a bypass as a temporary measure to allow gas to get around the pluggage. Koppe Test., Tr. Vol. 3-B, 21:8-21:19; Caudill Test., Tr. Vol. 10-B, 40:25-41:7; Cardinale Dep., July 31, 2014, Tr. 103:17-105:17 ("What they did on Unit 2, put in a pipe bypass around the air preheater because they really had serious pluggage problems."). The effect of the bypass would be to increase the electrical output of the unit and decrease its efficiency. Koppe Test., Tr. Vol. 3-B, 21:25 – 22:10; Cardinale Dep., July 31, 2014, Tr. 43:1-45:10 ("certainly bypassing the air preheater is not something you want to do"). Out of all the plants that Mr. Koppe has assessed throughout his career, he has never seen another example of such a bypass being installed. Koppe Test., Tr. Vol. 3-B, 21:20 – 21:24.

85. The effects of pluggage were also well-documented in other contemporaneous documents. Ameren described the pluggage at Unit 2 in a letter it sent to EPA's Clean Air Markets Division in 2008, "Unit 2 generation has been limited to approximately 90 percent of normal load since the middle of 2007 due to gas flow restrictions in the air preheater." April 7, 2008 Letter (Pl. Ex. 934), at AM-00015890-MDNR. When shown the document at trial, Ameren

capability expert witness Mr. Marcus Caudill referred to that amount as a "huge" load limitation. Caudill Test., Tr. Vol. 10-B, 39:19 – 41:14.

86. Similarly, in a December 16, 2009 email, which was written after the boiler work had been performed on Unit 1 but before it had been performed on Unit 2, Ameren employee Jeff Shelton wrote that the difference between the Unit 1 and Unit 2 capabilities grew bigger in the summer "due to draft limitations on Unit 2 and that following the boiler work this outage, we expect Unit 2 to not be as limited in the summer due to the draft issues." December 6, 2009 Email (Pl. Ex. 508), at AM-02248370; Shelton Test., Tr. Vol. 10-A, 93:21-94:18.

87. Mr. Shelton recognized that Unit 2 was draft limited in prior years as well. For instance, Mr. Shelton observed in 2008 that Unit 2 "ran into limitations due to gas path pluggage and air heater dps." December 18, 2008 Email (Pl. Ex. 542); at AM-02462552; Shelton Test., Tr. Vol. 10-A, 96:3-97:4.

88. In light of this evidence, Ameren's expert witness on the capability of the units, Marcus Caudill, agreed that Rush Island Units 1 and 2 were experiencing pluggage that was causing load reductions and derates prior to the 2007 and 2010 outages. Caudill Test., Tr. Vol. 10-B 35:18-22.

4. Availability losses caused by the replaced components prior to the 2007 and 2010 outages as reported to the Generating Availability Data System

89. Ameren uses the Generating Availability Data System ("GADS") to collect and track operating data for the Rush Island plant, including event data and performance data. The event data tracks causes of lost generation such as derates and full outages, while performance data tracks statistics such as generation, fuel usage, and hours of operation. Anderson Test., Tr. Vol. 7-A, 5:22-6:14.

90. Plaintiff's expert Mr. Robert Koppe, who has been a power plant performance consultant since the 1970s, had a leading role in developing the GADS database, including writing the manual that all utilities use in deciding how to report their data. Koppe Test., Tr. Vol. 3-A 7:18 – 11:4. Mr. Koppe developed the original list of cause codes that all utilities use to report events in GADS. *Id*. at 10:17-11:4, 40:9-13.

91. Throughout his career, Mr. Koppe has been hired by dozens of utilities to analyze the performance of their generating units. Koppe Test., Tr. Vol. 3-A 11:5-20. He has analyzed performance issues relating to hundreds of generating units. *Id*. at 13:17-25.

92. GADS is an industry-wide database that collects information on the performance of power plants and the effects that various problems have on that performance. Koppe Test., Tr. Vol. 3-A 10:5-11. GADS was developed so that utilities could improve the performance of their generating units. *Id*. at 10:12-16.

93. Whenever a unit has a problem that limits the amount of electricity it can generate, it is supposed to be reported as an "event" in the GADS data. That could be because the unit was operable but its maximum output was reduced (derated) or because the unit could not operate at all because it was in an outage. Koppe Test., Tr. Vol. 3-A 31:1-9.

94. A statistic known as equivalent availability takes account of the effects of such deratings and outages on the availability of the unit to operate. Koppe Test., Tr. Vol. 3-A at 30:1-19. A derating reflects times when the unit was not capable of operating at its maximum output due to an equipment problem. *Id.*

95. Staff at the Rush Island plant contemporaneously record event data that identifies the causes of lost availability. These event data are then further reviewed for accuracy on a

monthly basis before being uploaded into the company's GADS system. Anderson Test., Tr. Vol. 7-A, 15:9-18.

96. The Ameren performance engineer at the Rush Island plant who was responsible for ensuring the accuracy of the GADS event data was James Bosch. Anderson Test., Tr. Vol. 7-A 42:9-15; Koppe Test., Tr. Vol. 3-A 32:25 – 33:3; Meiners Test., Tr. Vol. 7-B, 38:13-24.

97. It is common for utilities to track the causes of their unavailability so that they can quantify the effects that each problem or component is having on availability. In order to improve availability, utilities need to know what the problems are. Koppe Test., Tr. Vol. 3-A at 31:17-24.

98. Ameren is no different. Unit availability, particularly at low-cost units like the Rush Island units, is very important to Ameren. The company tracks availability "quite closely" and awards salary bonuses under its "Key Performance Indicator" program to some employees based in part on meeting availability targets. Naslund Test., Tr. Vol. 6-B, 8:7-16; Response to Interrogatory No. 65 (ECF No. 823); Moore Rule 30(b)(6) Dep., Sept. 16, 2014, 123:12-124:15; February 6, 2007 Email (Pl. Ex. 103), at AM-02272420.

99. The Key Performance Indicator bonuses are paid for by Ameren's customers. Moore Rule 30(b)(6) Dep., Sept. 16, 2014, 124:16-125:9.

100. Improving unit availability was always a goal for Ameren. If a unit is experiencing forced outages, the company would like it to perform better. Naslund Test, Tr. Vol. 6-B, 11:17-24; 13:15-18. Mr. Naslund, vice president of power operations, told the 1500 Ameren employees under his supervision that perfect availability would be 100%. *Id.*; Generation Times Article (Pl. Ex. 930), at AM-02583221.

101. Staff at the Rush Island plant use GADS data to assess the status of the plant's equipment, and to adjust their predictions of future availability. Anderson Test., Tr. Vol. 7-A 59:25-60:6; Vasel Dep., Aug. 15, 2013, Tr. 83:22-25.

102. The availability targets set by the company are identified down to the tenth of a percentage point. The company also uses availability predictions to know how much coal to buy. Naslund Test., Tr. Vol 6-B, 10:20-11:9; *see also* February 6, 2007 Email (Pl. Ex. 103), at AM-02272420 (discussing proposal to adjust availability KPI bonus target by half a percentage point).

103. Ameren specifically used GADS data to analyze whether to do major capital projects. Koppe Test., Tr. Vol. 3-A at 31:25-34:3. Mr. Bosch, who did not testify at trial, reiterated the importance of such data to the capital project justification process in a 2002 email: "In order to place capital projects in the budget, they must be justified through the EVA program. EVA is a corporate justification software package which incorporates all the required components to derive a recommendation for project approval. ***The most compelling input in the justification calculation is lost generation. These lost generation figures are compiled and easily accessible in the NERC/GADS reporting program.***" June 25, 2002 Email (Pl. Ex. 99), at AM-02254509 (emphasis added); Bosch Dep., June 12, 2014, Tr. 73:11-74:8; Pope Dep., Sept. 20, 2013, Tr. 25:17-26:4 (management needed to know that there was an economic benefit before approving an investment).

104. Ameren's EVA Program, or Economic Value Added program, was used to compare two scenarios from a financial point of view in order to justify projects and look at the alternatives. Boll Dep. Tr., Dec. 12, 2013, 126:15-127:11; Generation EVA Instructions, (Pl. Ex. 331), at AM-00491836. The company's financial model for justifying projects based on their

availability impacts is capable of determining the effect on anticipated revenue of as little as a 0.1 percentage point change in expected availability. Meiners Test., Tr. Vol. 7-B, 44:23-45:1; June 15, 2009 CPOC Email (Pl. Ex. 895), at 02632840.

105. Ameren also uses GADS availability data to report the causes of lost generation at a plant to financial analysts on quarterly conference calls. Anderson Test., Tr. Vol. 7-A, 16:12 – 16:19.

106. In this case, Mr. Koppe looked at every single event reported in the GADS data for the 60 months prior to the project and determined which ones "would not have occurred but for the problems at issue in the components at issue in this case." Koppe Test., Tr. Vol. 3-A, 34:7-12. Mr. Koppe reviewed each GADS event and description as reported by Ameren for the relevant time period and then reviewed other sources of information to understand the cause of each event. Koppe Test., Tr. Vol. 3-A, 38:18-39:3.

107. Mr. Koppe specifically included the GADS data for the PSD baseline period for Unit 1 that has been used by Ameren in this litigation (February 2005 to January 2007). During that baseline period, problems in the economizer, reheater, lower slopes, and air preheaters caused Unit 1 to lose 336.1 equivalent full power hours of generation per year, which is equivalent to roughly 14 days of operation per year. Koppe Test., Tr. Vol. 3-A, 45:15-46:24. The unit was completely shut down in outages for 246.4 hours per year due to problems in the components at issue and lost the equivalent of another 89.7 full power hours of operation due to deratings. *Id*. These losses were widespread and covered a large fraction of all the months in the baseline. Koppe Test., Tr. Vol. 3-A, 46:25-47:6.

108. Mr. Koppe also specifically reviewed the GADS data for the PSD baseline period for Unit 2 used by Ameren in this litigation (April 2005 to March 2007). During the baseline

period, problems in the economizer, reheater, and air preheaters caused Unit 2 to lose approximately 245 equivalent full power hours of availability per year. The unit was completely shut down in outages for 145.5 hours per year due to problems in the components at issue and lost the equivalent of another approximately 100 full power hours of operation due to deratings. Koppe Test., Tr. Vol. 3-A, 74:7 – 75-2; Sahu Test., Tr. Vol. 5 78:20-79:13.

109. The deratings experienced at Units 1 and 2 were not short-term or one-time events. For instance, Unit 1 was continuously derated for the entire months of June, July, August, September, and October 2006, meaning that the unit was continuously derated every single day of each of those months. Unit 2 similarly experienced continuous derates. Anderson Test., Tr. Vol. 7-A, 50:21-52:16.

110. Mr. Koppe's compilation of derates included certain GADS events identified as "FD fan capacity" limitations because the units would not have been limited by FD fan capacity had it not been for pluggage in the air preheater. Koppe Test., Tr. Vol. 4-A, at 60:9-61:3; *see also* Koppe Test., Tr. Vol; 3-A, 96:19-97:18.

111. Rush Island Plant staff similarly attributed such fan capacity problems to the boiler components at issue. For instance, a spreadsheet attached to an April 30, 2006 email from Robert Meiners indicates that plant staff determined that Units 1 and 2 were experiencing load limitations during the summer of 2005 that would be eliminated once the reheaters, economizers, and air preheaters were replaced. *See* April 30, 2006 Email and Attached Condition Assessment (Pl. Ex. 106), at Rush Island Spreadsheet Tab, Line 63 (noting that "FD Fans" at Unit 1 and Unit 2 "[c]urrently limit load during summer, but should be eliminated with boiler pressure part and APH"); Anderson Test., Tr. Vol. 7-A, 49:8-25.

112. As described by Ameren's engineers at the time, the output of the Rush Island units was limited due to "fan capacity limits" resulting from the "permanently plugged air heaters" at the units. July 15, 2005 Email (Pl. Ex. 45) at AM-0266037 (also noting that the "Unit 2 Air Pre-heater delta P's [were] running at 12 inches at full load" and that the "baskets will have to be replaced on the APH's to make an impact on FD fans"); July 21, 2004 Email (Pl. Ex. 555), at AM-02485899; *see also* FOF 80 & n.2 (summarizing descriptions in weekly full load tests). The limitation on the unit's ability to operate was estimated to cost Ameren approximately $25,000 per day. July 15, 2005 Email (Pl. Ex. 45), at AM-02666038.

5. Reduction in the maximum capability of Unit 2 prior to the 2010 outage

113. In addition to lost availability due to outages and derates as reported in GADS, the switch to PRB coal also resulted in a significant reduction in the reported maximum hourly capability of the units prior to the major boiler outages. Koppe Test., Tr. Vol. 3-A 90:11-91:4, Vol. 4-A, 33:10-34:2.

114. The capability of a unit is the maximum electric output that it can produce at that time if asked to do so. Koppe Test., Tr. Vol. 3-A, 84:14-23. The terms "capability" and "capacity" are often used interchangeably. *Id*. at 85:25-86:5

115. Ameren issued annual capability tables, which "represent the expected average output of each unit based on typical ambient conditions." *See, e.g.*, 2011 Capability Table (Pl. Ex. 257), at AM-00067232. The reported capability of a unit is an estimate of what the utility expects the capability of the unit to be in the following year. Koppe Test., Tr. Vol. 3-A, 84:23-85:2. The magnitude of a reported derating is affected by the reported capability. *Id*. 85:3-10; *see* December 2010 Capability Table (Pl. Ex. 257), at AM-00067232.

116. Gross capability or gross electrical output is the amount of electricity that the generator produces. Net capability or net electrical output is the amount of electricity that goes out to the grid. The difference between net and gross capability is the electricity the plant itself uses to operate, otherwise referred to as auxiliary load. Koppe Test., Tr. Vol. 3-A, 85:11-17; Koppe Test., Tr. Vol. 3-B, 11:6-15; Shelton Test., Tr. Vol. 10-A, 84:10-15.

117. A reduction in auxiliary load is an improvement in net efficiency, but it does not affect the amount of coal that the unit is capable of burning. It just means that less power is used to run the plant and more power is sent to the grid. Generator output is the same, heat input is the same, but more megawatts can be sent to the grid. Koppe Test., Tr. Vol. 3-B, 11:16-12:4; Shelton Test., Tr. Vol. 10-A, 85:8-10.

118. Ameren lowered the reported capability of Unit 2 substantially from 2005 to 2006. The reduction was about 10 megawatts in the winter and 20 megawatts in the summer. Unit 2's reported capability remained essentially the same until 2010 and then increased substantially in 2010 and 2011. Koppe Test., Tr. Vol. 3-A, 88:13-23.

119. The reduction in reported capability was the result of the effects of pluggage. Koppe Test., Tr. Vol. 3-A, 90:11-91:4. In 2005, pluggage caused Unit 2 to frequently not be able to meet its reported capability. Koppe Test., Tr. Vol. 4-A, 33:10-34:2. Similarly, Unit 2 was unable to meet its reported capability in the summer of 2005 due to FD fan capacity limitations. January 4, 2006 Email (Pl. Ex. 157), at AM-027432293; Koppe Test., Tr. Vol. 3-A, 91:9-95:11. The reason the fans were running out of capacity in the summer was because of pluggage in the boiler, specifically pluggage in the air preheater. Koppe Test., Tr. Vol. 3-A, 96:19-97:18. As Ameren documents describe it, the output of the Rush Island units was limited due to "fan capacity limits" resulting from the "permanently plugged air heaters" at the units.

July 15, 2005 Email (Pl. Ex. 45), at AM-02666037. Such problems with summer capacity were also identified in the project justification documents for Unit 2, where Ameren reiterated that "the current air preheater baskets have continued to foul to the extent that fans are load limited particularly in the summer months." September 18, 2009 Memo (Pl. Ex. 26), at AM-000954160; *see also* Cardinale Dep., July 31, 2014, Tr. 84:3 – 21 (noting that air preheater fouling was "permanent").

120. The capability of Unit 2 prior to the 2010 major boiler outage was also measured in Ameren's weekly full load tests. The average capability of Rush Island Unit 2 as measured by Ameren in all of the full load tests that were conducted during the PSD baseline period (March 2005 to April 2007) was only 620 gross megawatts. Koppe Test., Tr. Vol. 3-B, 35:17-36:4, 45:12-46:5; *see* Pl. Ex. 928 (Rule 1006 summary of full load tests for Unit 2).

121. In the years leading up to the 2010 major boiler outage at Unit 2, Ameren further quantified the megawatt capability loss that was due to the boiler components at issue. In Ameren's 2008 annual "State of the System" presentation in 2008, it assigned "25-30 MW" to the Unit 2 "BLR/AHS replacement" in addition to another 13 megawatts that could be gained from replacing the low pressure turbine. 2008 State of the System (Pl. Ex. 15), at AM-00196628.

122. Ameren assigned 22.5 megawatts to the reheater, economizer, and air preheater in a financial analysis for the 2010 major boiler outage. Economic Value Added (EVA) Financial Analysis for Unit 2 (Pl. Ex. 48), at "Data Entry" Sheet; Koppe Test., Vol. 3-B, 30:4-32:23. The 22.5 megawatt value was a weighted average based on Ameren's estimate that the component replacements would allow Unit 2 to produce 30 more megawatts of capacity during the three summer months and 20 more megawatts for the remainder of the year. Koppe Test., Tr. Vol. 3-

B, at 27:7-32:23; see Pl. Ex. 48, at "Data Entry" Sheet; July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465690 ("30 MW gain in summer (3 mos), 20 MW gain balance of year from Reheater, Economizer and APH investment").

123. Ameren's final work order authorizations for the reheater, economizer, and air preheater, completed in the fall of 2009, similarly described that the "combined" effect of these component replacements would result in a "gain of 30 MW in the summer and 20 MW in the winter" at Unit 2. October 15, 2009 Memo (Pl. Ex. 23), at AM-00926323; *see* September 18, 2009 Memo (Pl. Ex. 26), at AM-00954160 (same language in air preheater justification that "gain of 30 MW in the summer and 20 MW in the winter will be obtained with the combined reheater, economizer, and air preheater replacements").

124. Ameren witness David Boll testified in his deposition that these predicted additional megawatts represented "regained capacity" that had been lost due to the inability to pull gas flow through the plugged air preheaters. Boll Test., Tr. Vol. 8-B, 51:23-52:4, 54:21-25.

125. A summary of the anticipated benefits of the work written in 2010 similarly referred to the fact that "[a]pproximately 30 Megawatts of unit capacity will be recovered during the hottest months because of lower gas flow pressure drops through the new economizer and air preheaters." March 31, 2010 Email re Newsletter (Pl. Ex. 893), at AM-02229417.

C. The Approval and Engineering Process for the 2007 and 2010 Major Modifications

126. The formal approval and engineering process for the 2007 and 2010 major boiler projects began at least three years prior to the first outage. The replacement of all four components was considered together for planning purposes, beginning as early as 2004. For instance, by December 2004, Ameren had created a preliminary budget for replacement of the Unit 1 economizer, reheater, lower slope tubes, and air preheaters, at an estimated capital cost of

more than $25 million. Stevens Test., Tr. Vol. 2-A 5:2-7; December 20, 2004 Generating Engineering Budget Project Proposal (Pl. Ex. 323); RFA 393.

127. A 500-page Project Book for Unit 1 was compiled as a reference for the work to be completed during the Unit 1 outage. The replacement of the economizer, reheater, lower slope tubes and air preheaters were coordinated by Alstom Power and generally treated together within the Project Book. Rush Island Unit 1 Project Book (Pl. Ex. 63), at AUE-00156352 (collectively referring to "Reheater, Economizer, Lower Slope, Air Heater Rotor Replacements" as a single major project); *id*. at 365 (same), 519 (same), 539 (same); Stevens Test., Tr. Vol. 2-A. 17:1- 18:10.

128. The documentation in the Project Book also confirmed that one purchase order for engineering, materials, and construction services was issued to Alstom Power as early as 2005, which included the replacement of the economizer, reheater, lower slope tubes, and air preheaters. Pl. Ex. 63, at AUE-00156395-398.

129. The replacements of the economizers, reheaters, lower slopes, and air preheaters were all approved under Ameren's Work Order Procedures. Stevens Test., Tr. Vol. 1-B 72:15-21, 91:19 – 92:3.

130. While the air preheaters were also subject to their own work order justification process, the air preheater justification documents specifically combined the air preheater replacements with the reheater, economizer, and lower slopes as part of a "major refurbishment" at both Unit 1 and Unit 2. October 5, 2005 Memo (Pl. Ex. 6), at AM-00072912; Stevens Test., Tr. Vol. 2-A 9:24-10:18.

131. Similarly, prior to replacing the Unit 2 air preheaters, Ameren reiterated its reliance on the "combined" effect of the air preheaters, reheater, and economizer for purposes of

justifying the replacements. September 18, 2009 Memo (Pl. Ex. 26), at AM-00954160; October 15, 2009 Memo (Pl. Ex. 23), at AM-00926323 (same); *see also id*. at AM-00926322 ("Load reductions of 30 MW in the summer and 20 MW for the remainder of the year can be avoided with the new boiler components and the re-designed air preheater.").

132. Ameren's documents also indicate that the replacement of all the components was combined to "gain efficiencies in procurement, design and installation" and described the air preheater replacements as "part of a Major Mechanical Work Package to include the Economizer, Reheater and Lower Slope portion of the boiler." Project Approval Package (Pl. Ex. 1), at AM-00072590; Project Approval Package (Pl. Ex. 4), at AM-00072859; Stevens Test., Tr. Vol. 2-A 10:19-11:18, 13:23-14:7.

133. The engineering specification issued by Ameren called for bids from outside engineering firms for the design, fabrication, and installation of the boiler components at Rush Island Units 1 and 2. Ameren consolidated the replacement of the economizer, reheater, lower slope tubes, and air preheaters for purposes of issuing the specifications. Specification No. EC-5491 (Pl. Ex. 10); Stevens Test., Tr. Vol. 2A 15:19 - 16:13.

134. Ameren provided specific design requirements for the replacement components, including a number of significant design changes that were intended to upgrade and improve the performance of the boiler as a whole. Stevens Test., Tr. Vol. 2-A, 32:24-33:22, 34:8-12, 45:14-46:25, 55:9-56:4, 66:5-67:9; October 15, 2009 Memo (Pl. Ex. 23), at AM-00926322 (noting combined project objectives of redesigned economizer and air preheater).

135. In contrast with routine work undertaken at utility plants, the replacement of the economizers, reheaters, lower slopes, and air preheaters required approvals of executives at the highest level of the company, including Ameren's CEO. The approval process required at least

10 layers of approval review. Stevens Test., Tr. Vol. 2-A 7:5-15, 13:15-22; Project Approval Package (Pl. Ex. 1), at AM-00072580; Project Approval Form (Pl. Ex. 2), at AM-00072829; Project Approval Package (Pl. Ex. 4), at AM-00072850; Project Approval (Pl. Ex. 5), at AM-00072906.

136. In August of 2005, Gary Rainwater, then the Ameren CEO, authorized the expenditure of $23,148,000 to replace the economizer, reheater, and lower slope panels at Rush Island Unit 1. Stevens Test., Tr. Vol. 2-A 7:5-15; Project Approval Package (Pl. Ex. 1), at AM-00072580. Mr. Rainwater also authorized the expenditure of $24,988,000 for the same work at Unit 2. Project Approval Form (Pl. Ex. 2), at AM-00072829. Earlier in the spring of 2005, Ameren Missouri Chief Operating Officer Thomas R. Voss authorized the expenditure of approximately $6.9 million for the design, fabrication, and installation of new air preheaters at Unit 1, and, in October of 2005, authorized approximately $7.5 million for similar work at Unit 2. Stevens Test., Tr. Vol. 2-A 13:15-22; Project Approval Package (Pl. Ex. 4), at AM-00072850; Project Approval (Pl. Ex. 5), at AM-00072906.

137. After the 2007 major boiler outage at Unit 1, Unit 2 went through a second justification process in 2009. The Unit 2 major boiler outage had to be approved by an additional committee known as the Capital Project Oversight Committee (“CPOC”), Ameren’s CEO Warner Baxter, and the full Board of Directors. Meiners Test., Tr. Vol. 7-B, 45:8-25, 46:6-47:11; May 16, 2009 Email (Pl. Ex. 347), at AM-02637756. On August 14, 2009, Mr. Baxter reported that the outage had been approved. August 14, 2009 Email (Pl. Ex. 553), at AM-02480812.

D. Ameren Justified Replacing the Economizers, Reheaters, Lower Slopes, and Air Preheaters Because They Would Improve Operations and Allow the Units to Generate More

138. Ameren's contemporaneous project authorization documents identified the new economizers, reheaters, lower slopes, and air preheaters as components that were "improved" and "redesigned" in order to fix the operational problems that had been caused by burning PRB coal and age-related deterioration. Stevens Test., Tr. Vol. 2-A, 8:21- 9:6; Project Approval Package (Pl. Ex. 1), at AM-00072580; Project Approval Package (Pl. Ex. 3), at AM-00072831; Boll. Dep. Tr., Dec. 12, 2013, 164:24-165:26, 168:19-169:6; Birk Dep., Sept. 24, 2013, Tr. 194:1-16; Meiners Dep., April 8, 2014, Tr. 237:18-238:11; Pope Dep., Sept. 20, 2013, Tr. 73:12-74:11.

139. Ameren described the planned "major boiler modifications for Rush Island 1 and 2" as follows:

> For several years we have been planning major refurbishment of the Rush Island 1 and 2 boilers, which have operated for nearly 30 years without replacing any of the major components. The major scope elements include the following major components which are experiencing an increase in tube leaks and fatigue issues, and have been redesigned to improve future operation and maintenance:
>
> - Reheater – redesigned for PRB coal
> - Economizer – redesigned for PRB coal
> - Lower Slope – ruggedized design to better withstand slag falls
> - Air Preheater – redesigned for ease of future basket replacement.

Project Approval Package (Pl. Ex. 6), at AM-00072912; Stevens Test., Tr. Vol. 2-A 9:24-10:18.

140. Ameren's expert Jerry Golden agreed that the components replaced at Rush Island were redesigned. Golden Test., Tr. Vol. 8-A, 10:6-10; see also RFA Nos. 377 to 383, 386-387, 389-390, 395-401, 407. Further descriptions of these redesigns are provided below.

141. *Economizer Redesign*: The design of the new economizers was substantially different from the original design. The redesigned economizers were in-line, rather than the original staggered design, which allowed gas to flow through the boiler more easily. The new economizer design made the economizers less subject to fouling and pluggage. Stevens Test., Tr. Vol. 2-A 32:24 – 33:22; 34:8-12; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080325-329; Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966728-730.

142. *Reheater Redesign*: The design for the new preheaters was significantly different from the original design. Stevens Test., Tr. Vol., 2-A 45:14 - 18; Boll Dep. Tr., Sept. 5, 2014, 68:11-70. The spacing between the tubes was increased from 10 to 15 inch centers, and the number of front assemblies was reduced from 72 to 48. The bottom of the reheaters was changed from a sloped bottom that closely tracked the boilers' nose to a horizontal bottom. The number of rear assemblies was decreased from 145 to 96 assemblies, and their height was increased. Similar to the design change for the front assemblies, the spacing between each tube was increased. Additionally, both the front and rear assemblies were platenized. Together, these changes allowed more space for gas and ash to flow through the reheaters without plugging or fouling. Stevens Test., Tr. Vol. 2-A 45:14 - 46:25; October 15, 2009 Memo (Pl. Ex. 23), at AM-00926322; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080329-332; Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966737-738.

143. *Lower Slopes Redesign*: The design for the new lower slope tubes at Unit 1 was a different design than the original lower slope tubes. Specifically, the new lower slope tubes had a thicker wall to prevent tube leak problems caused by slag falls. The space between each tube was decreased, adding greater strength to assist in slag fall protection. Additionally, the structural support was replaced to provide additional strength. Together, these changes made

the lower slope tubes stiffer, more rigid, and less likely to be crushed so easily. Stevens Test., Tr. Vol. 2-A 55:9 - 56:4; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080332-334; Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966748-749.

144. *Air Preheaters Redesign*: The new, redesigned air preheaters were changed from the original three-layer Ljungstrom regenerative basket design to a two-layer design. The new two-layer air preheaters had a hot end layer and a cold end layer. In each air preheater, each layer had 24 baskets, each of which was 29 inches deep. While the original air preheaters each had 456 baskets, the new air preheaters had only 48 baskets total. The design was changed in order to minimize the outage time required for cleaning the baskets in the future. Stevens Test., Tr. Vol. 2-A 57:12 - 58:21, 66:5 - 67:9; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080279, 348-353; RFA Nos. 331, 334.

145. Ameren specifically justified performing these boiler upgrades because they were expected to reduce forced outages due to tube leaks, eliminate load reductions, and increase the capability and availability of the units to operate. One of the specific expectations identified in the project justifications was that the replacements would eliminate outage time due to the components for the next 20 years. Stevens Test., Tr. Vol. 2-A 7:16-8:20, 25:12 – 26:11, 27:13-23, 59:7-60:22; 63:22-65:7; Golden Test., Tr. Vol. 8-A 12:14 – 13:8.

146. These expected improvements were explicitly stated in Ameren's project justification documents. For instance, after describing the "new, improved, redesigned" economizer, reheater, and lower slopes, **Ameren's project authorization for Unit 1 stated that "as a result" of the replacements, "Rush Island will eliminate forced outages due to reheater tube leaks for 20 years, eliminate 30 to 50 MW load reductions due to flyash pluggage of the current economizer, and reduce the number of tube leaks caused by slag**

falling on the furnace lower slopes." Project Approval Package (Pl. Ex. 1), at AM-00072580 (emphasis added); *see also* Project Approval Package (Pl. Ex. 4), at AM-00072858 (noting expected improvement in pressure drop across the air preheater, and two week reduction in future outage costs due to quicker basket replacements); October 15, 2009 Memo (Pl. Ex. 23), at AM-00926322 (project objectives include avoiding "load reductions" and "minimizing future forced boiler outages for the next 20 years"); September 18, 2009 Memo (Pl. Ex. 26), at AM-0954160 (noting that air preheater replacement "will reduce the gas side pressure loss across the air preheaters from 14 to 5 inches" of water pressure, and that project would result in a megawatt "gain").

147. Ameren expected that the work would reduce the number of forced outages due to these components "to zero." Project Approval Package (Pl. Ex. 1), at AM-00072585-586 ("Flyash pluggage of the economizer will be eliminated or greatly reduced due to the in-line spiral fin economizer… Forced outages due to tube leaks in the reheater and economizer will be reduced to zero."); *see also id*. at 590 ("completing this project will eliminate all the problems"); Project Approval Form (Pl. Ex. 2), at AM-00072829 (same statements for Unit 2); Project Approval Package (Pl. Ex. 3), at AM-00072831-833, 837 (same statements for Unit 2); Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966731, 740, 750 (identifying avoided costs associated with avoiding derates and outages due to boiler tube leaks); *see also* Vasel Dep., Aug. 15, 2013, Tr. 131:11-132:24.

148. Ameren ultimately decided not to replace the lower slopes at Unit 2 during the 2010 major boiler outage and therefore adjusted the overall availability improvement expected from the work downwards by 0.1% from 4.3% to 4.2%. June 15, 2009 CPOC Email (Pl. Ex. 895), at AM-02632840; Meiners Test., Tr. Vol. 7B, 34:9-35:25.

149. Further evidence of Ameren's expectation of availability improvements is found in Plaintiff's Exhibit 126, which was a presentation that Mr. Meiners made to senior executives at a business plan meeting. Meiners Test., Tr. Vol. 7-B, 27:21-24, 28:18-20. One of the purposes of the presentation was to discuss component replacements and the condition of the reheater, economizer, air preheater, and lower slopes. *Id*. 28:10-17. At the end of the presentation, Mr. Meiners presented a graph showing that Rush Island's availability would increase by almost 5%, from about 90% in 2005-2006 to 95% in the first year after both major boiler outages had been completed. *Id*. 31:15-21

150. Ameren's experts agreed that the expressed purpose of the work at each unit was the same: to improve capability and eliminate deratings. For instance, Mr. Golden confirmed that the work at both units was intended to eliminate pluggage and fouling of the economizers and reheaters, to eliminate future forced and maintenance outages caused by tube leaks, and to eliminate pluggage problems and deratings from the air preheaters. Golden Test., Tr. Vol. 8-A, 10:11-21, 13:16 – 13:21.

151. Mr. Golden also agreed that the purpose of replacing the lower slopes at Unit 1 was to eliminate tube leaks in the lower slope and damage resulting from slag falls and erosion following the switch to PRB coal. Golden Test., Tr. Vol. 8-A, 10:22-25.

152. Ameren's expert Mr. Caudill conceded that the expected benefits of replacing the components included reducing forced outages and eliminating or greatly reducing flyash pluggage at the units. As Mr. Caudill put it, "[b]asically that's what Ameren expected" based on a review of Ameren's project justifications. Caudill Test., Tr. Vol. 10-B, 36:10-37:2, 37:17-38:10.

153. Mr. Caudill also agreed that pluggage in the reheater, economizer, and air preheaters contributed to high differential pressure, which Ameren expected to reduce as a result of replacing the reheater, economizer, and air preheaters. Caudill Test., Tr. Vol. 10-B, 34:17-35:1, 35:14-17. In addition to eliminating load reductions, such improvements in differential pressure can result in some increase in net efficiency, but not gross efficiency. Caudill Test., Tr., Vol. 10-B, 35:11-13; Koppe Test., Tr. Vol. 3-B, 11:16-12:4, 28:18-29:4. Mr. Caudill conceded that Ameren did not justify the replacement of the economizers, reheaters, and air preheaters based on any expectation that they would result in an improvement in gross unit efficiency. Caudill Test., Tr. Vol. Vol. 10-B, 44:24-45:12.

154. Mr. Caudill also conceded that Rush Island Units 1 and 2 were experiencing pluggage that was causing load reductions and derates prior to the 2007 and 2010 outages and that eliminating pluggage that is causing derates will allow a unit to generate at a higher gross load. Caudill Test., Tr. Vol. 10-B, 35:18-22, 37:3-16.

155. Ameren's final, updated justification for the 2010 major boiler outage reflected the company's expectation that the replacements would enable the unit to operate more and to produce more megawatts when operating. The justification identified two types of performance improvements from the boiler work: a capacity increase and an equivalent availability improvement. As described in a 2009 work order authorization request:

> A gain of 30 MW in the summer and 20 MW in the winter will be obtained with the combined reheater, economizer and air preheater replacements. …. Also included in the justification is an approximate 3-4% improvement in equivalent availability of the unit.
>
> **Assumptions**: It is assumed that these boiler modifications will result in an improved operation of the unit that is at least equal to, if not better, than that currently experienced with Unit 1 which had similar modifications in 2007. This includes fewer load restrictions, improved equivalent availability and elimination of potential catastrophic failure of the economizer.

October 15, 2009 Memo (Pl. Ex. 23), AM-00926323; *see also id*. at AM-00926322 ("Load reductions of 30 MW in the summer and 20 MW for the remainder of the year can be avoided with the new boiler components and the re-designed air preheater."); Stevens Test., Tr. Vol. 2-A, 25:12- 26:11; 27:3-23.

156. The justification of additional generation from the replacements is also found in the financial analysis tool that was used to justify the 2010 outage. The availability gain used in the final financial analysis was the equivalent of "15 days of generation." Economic Value Added (EVA) Financial Analysis for Unit 2 (Pl. Ex. 48); Meiners Test., Tr. Vol. 7-B, 18:6-11, 18:21-19:16.

157. Ameren's final financial evaluation separately included a 22.5 MW "projected annual increase … in plant capacity" as a result of the replacement of the reheater, economizer, and air preheater. Economic Value Added (EVA) Financial Analysis for Unit 2 (Pl. Ex. 48), at "Data Entry" Sheet; Koppe Test., Tr. Vol. 3-B, 30:4-32:23. This capacity increase was based on Ameren's estimate that the component replacements would allow Unit 2 to produce 30 more MW of capacity during the three summer months and 20 MW for the remainder of the year. Koppe Test., Tr. Vol. 3-B, at 27:7-32:23; Pl. Ex. 48, at "Data Entry" Sheet; July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465690 ("30MW gain in summer (3 mos), 20MW gain balance of year from Reheater, Economizer and APH investment").

158. The 22.5 MW increase in capacity was separate from the availability input used in the model. July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465690 (describing megawatt capability "gain" from boiler upgrade separately from 4.2% equivalent availability impact); Koppe Test., Tr. Vol. 3-B 30:8-31:7. It represented an increase over the capability that

Unit 2 was able to achieve during the pre-project period. Koppe Test., Tr. Vol. 3-B, 28:2-12. The financial impact included significant "incremental power sales" that were calculated to have a favorable impact on ratepayers, shareholders, and earnings. July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465691.

159. These boiler capacity and availability gains were also identified separately from an additional 15 megawatt capability gain from replacing the LP turbine with a more efficient design. July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465690 (describing gains separately in project economic analysis).

160. During the final 2009 approval process for the Unit 2 outage, Mr. Meiners reiterated the accuracy of these forecasts to Ameren's CEO, Mr. Baxter. May 16, 2009 Email (Pl. Ex. 347), at AM-02637756 ("I do believe the model is now a much more accurate representation of the economic benefits."); Meiners Test., Tr. Vol. 7-B, at 46:9-47:11.

E. Implementation of the 2007 and 2010 Major Modifications

161. Ameren installed the new economizer, reheater, two air preheaters, and lower slope panels at Rush Island Unit 1 during an outage that began on February 17, 2007 and ended on May 28, 2007. 2007 Post Outage Report (Pl. Ex. 34), at AM-02252210.

162. On January 24, 2007, almost one month before the Unit 1 major boiler outage was to start, there were already 54 contractors on site. The previous week, 17 truckloads of tubing arrived on site and a crane was being constructed for use in replacing the reheater. Rush Island Project Book (Pl. Ex. 63), at AUE-00156343; Overhead Photo of Laydown Areas (Pl. Ex. 414), AM-00222751. This level of activity on-site, a month before the work had even started, is not typical of routine maintenance at a power plant. Stevens Test., Tr. Vol. 2-A, 18:14-19:19.

163. Ameren installed the new economizer, reheater, and two air preheaters at Rush Island Unit 2 during an outage that began on January 1, 2010 and ended on April 6, 2010. Vol. 2A, Stevens Test., 24:9-15; 2010 Post Outage Report (Pl. Ex. 46), at AM-02739973.

164. The replacements took years to design and plan and required the special fabrication of components that were not otherwise available at the Rush Island plant. Specification No. EC-5491 (Pl. Ex. 10), at AM-00080233; Rush Island Project Book (Pl. Ex. 63), at AUE-00156362. Ameren's expert, Jerry Golden, acknowledged at trial that these replacements were not *de minimis* activities. Golden Test., Tr. Vol. 8-A, 33:9-18.

165. The size and extent of the components replaced during the 2007 and 2010 major boiler outages was massive, with the economizers, reheaters, and air preheaters each weighing hundreds of thousands of pounds. Stevens Test., Tr. Vol. 2-A, 13:10-14, 34:22-35:7, 50:11-13, 59:3-6, 67:21-68:5. For example, the new reheaters included two outlet headers that weighed 36,000 pounds each and 144 reheater tube assemblies, including 48 front pendant assemblies that were each approximately 49 feet tall and 96 rear pendant assemblies that were each approximately 35 feet tall. Stevens Test., Tr. Vol 2-A, 45:14-46:25, 50:10-13; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080330-332; RFA Nos. 386-387, 390, 395-398. If the Rush Island economizer's tubing was laid from end-to-end, the length of tubing would stretch around 140 miles. Stevens Test. Tr. Vol. 1-B, 79:20 – 80:5.

166. Given the complexity of the replacements, the components needed to be designed, engineered, and constructed by outside contractors, such as Alstom Power - the original manufacturer of the boilers, and numerous other contractors. The work involved was substantial, requiring hundreds of thousands of man-hours, and was well beyond the capacity of Ameren's

own staff. Stevens Test., Tr. Vol. 2-A, 21:18 – 22: 18; 2007 Post Outage Report (Pl. Ex. 34), at AM-02252259, 260; 2010 Post Outage Report (Pl. Ex. 46), at AM-02739979.

167. Heavy machinery was required to facilitate the removal of old components and installation of new, redesigned components. Multiple monorails were installed in order to maneuver the components. Stevens Test., Tr. Vol. 2-A, 18:24-19:11; 36:6-18; 38:11-19. Multiple large cranes were constructed to remove and lower the old assemblies to the ground and lift the new assemblies to the necessary height within the boiler. Each outage required the construction of two Manitowoc 888 cranes, as well as several other cranes, including Manitowoc 222 and 2250 cranes. Stevens Test., Tr. Vol. 2-A, 18:14-19:19; 48:12-20; 2007 Post Outage Report (Pl. Ex. 34), at AM-0225210; 2010 Post Outage Report (Pl. Ex. 46), at AM-02739973. The largest Manitowoc crane had to be tall enough to remove 50-foot reheater assemblies through the roof at an approximately 270 foot elevation. Stevens Test., Tr. Vol. 2-A, 48:4 -15.

168. The process of removing each old component and installing each new component was highly complex. For the boiler components, each original assembly was cut out and removed one-by-one. Stevens Test., Tr. Vol 2-A, 36:11-19. Cuts had to be made in the side of the boiler lagging and walls at various elevations, including one at around a 200 foot elevation, as well as in the roof of the boiler house. Stevens Test., Tr. Vol. 2-A, 38:11-19, 47:25- 48:3. It would take months to facilitate the removal and re-installation. Stevens Test., Tr. Vol. 2-A, 38:25 – 39:9; 49:2 – 7. Many craftsmen were involved in the cutting and welding process. Stevens Test., Tr. Vol. 2-A, 50:20-51:1.

169. The 2007 major boiler outage at Rush Island Unit 1 lasted 100 days and required more than 1,000 workers and 448,539 total hours of labor, of which 402,109 hours were performed by contractors. Ninety-one percent of the work done during the Unit 1 major boiler

outage was performed by contractors. While other work was performed, the replacement of the economizer, reheater, air preheaters, and lower slope panels was the most significant and costly work performed during the outage. Stevens Test., Tr. Vol. 2-A, 21:18 – 22: 18; 2007 Post Outage Report (Pl. Ex. 34), at AM-0225259, 260.

170. The 2010 major boiler outage at Rush Island Unit 2 lasted approximately 100 days and required more than 350,000 hours of labor, of which 290,953 hours were performed by contractors. An average of 360 contractor staff worked two 10-hour shifts six days a week during the outage. 2010 Post Outage Report (Pl. Ex. 46), at AM-02739976.

171. The 2007 and 2010 major boiler outages were significantly different than typical power plant maintenance, repair, and replacement activities undertaken on a day-to-day basis. Ameren itself did not characterize the replacement of major components such as the reheaters, economizers, air preheaters, and lower slopes at issue in this case as "routine." Instead, Ameren described the work as "major boiler modifications" and identified the work as not recurring and not routine in its project documents. Stevens Test., Tr. Vol. 1-B, 65:24- 66:10, 66:8-71:2; Vol. 2-A, 9:24- 10:18, 11:19-12:2; October 5, 2005 Memo (Pl. Ex. 6), at AM-00072912; Project Approval Package (Pl. Ex. 1), at AM-00072591; Project Approval Package (Pl. Ex. 3), at AM-00072838; RFA No. 460.

172. The 2007 and 2010 major boiler outages were unprecedented events for Rush Island Units 1 and 2. After the 2007 major boiler outage, Ameren's Vice President Mark Birk referred to the outage as the "most significant outage in Rush Island history." May 29, 2007 Email (Pl. Ex. 31). Mr. Birk specifically called out the replacement of several components – including the economizer, reheater, lower slope, and air preheaters – as distinct from "the routine maintenance that had to be performed" during the outage. *Id*. The 2010 major boiler

outage was similarly referred to as "among the most significant in [company] history." Jerry Odehnal Report (Pl. Ex. 40); *see* Vasel Dep., Aug. 15, 2013, Tr. 272:2-23 (describing exhibit 40); see also 2010 State of the System presentation , Pl. Ex. 41, at AM-02493747 (distinguishing the air preheater, reheater and economizer replacements from the "routine maintenance" done during the 2010 outage).

173. By the time of their replacements in 2007 and 2010, the reheaters, economizers, and air preheaters were more than 30 years old, nearing the end of their expected lives. These components had never before been replaced at Rush Island Units 1 and 2. Stevens Test. Tr. Vol. 1-B, 50:24-51:4, 81:19-82:1, 84:9-13; 108:13-109:3; Tr. Vol. 2-A, 9:24-10:18, 43:3-25; Golden Test., Tr. Vol. 8-A, 16:7-16; Vasel Dep., Aug. 15, 2013, Tr. 131:11-132:6; October 5, 2005 Memo (Pl. Ex. 6), at AM-00072912 ("units have operated for nearly 30 years without replacing any of the major components"); Unit 2 ELT Progress Report (Pl. Ex. 110), at AM-02465689 ("The MBO [major boiler outage] is being undertaken to change out 2 major boiler components and the APH that are end of life…"); Unit 2 ELT Progress Report (Pl. Ex. 456), at AM-00953927.

174. Projects such as the economizer, reheater, air preheater, and lower slope replacements are not performed frequently during the life of a typical utility unit. Stevens Test., Tr. Vol. 1-B, 91:11-18. Ameren's expert Mr. Golden agreed that the typical life of a reheater is about 30 years, the typical life of a primary economizer is about 35 years, and the typical life of a lower slope is about 40 years. Golden Test. Tr. Vol. 8-A, 18:2-11. Mr. Golden also testified that complete air heater replacements (including the rotor and all baskets), like the ones done at Rush Island, are not done frequently at any unit. Golden Test., Tr. Vol. Vol. 8-A, 19:9-15.

175. Even looking exclusively to how common work is performed across the utility industry, Mr. Golden was able to identify few, if any, projects that rival the 2007 and 2010 major boiler outages at other Ameren plants or elsewhere in the utility industry. Mr. Golden has worked on 14 NSR cases since 2000 on behalf of electric utilities. Golden Test., Tr. Vol. 8-A, 6:3-16. During that time, he has collected a list of 18,300 projects undertaken at coal-fired power plants that he says are both capital projects and cost more than $100,000. Golden Test., Tr. Vol. 8-A, 25:11-14; 25:24-26:2, 26:13-16. However, Mr. Golden was not able to identify *any* coal-fired unit in the electric utility industry that has replaced the economizer, the reheater, the lower slopes, and the air preheater together. Golden Test., Tr. Vol. 8-A, 19:3-8; *see also* Vasel Dep., Aug. 15, 2013, Tr. 154:11-24 (unable to recall any other outage at Ameren when all components were replaced).

176. Similarly, even for the relatively few air preheater replacements that Mr. Golden did identify (35 out of approximately 1,200 coal-fired generating units operating in 2007), Mr. Golden was unable to testify that all were complete replacements or were comparable to those at Rush Island. Golden Test., Tr. Vol. 8-A, 20:2-23, 28:3-12, 28:17-29:5.

F. The Cost of the 2007 and 2010 Major Modifications

177. Replacement of the reheater, economizer, air preheaters, and lower slope at Rush Island Unit 1 ultimately cost approximately $34 million. Stevens Test. Tr. Vol 2A, 22:24-23:3; Golden Test., Tr. Vol. 8-A, 23:7-10.

178. Replacement of the reheater, economizer, and air preheaters at Rush Island Unit 2 ultimately cost more than $38 million. Stevens Test., Tr. Vol 2-A, 28:5-9; Golden Test., Tr. Vol. 8A, 23:7-10.

179. Ameren's budget for the Rush Island plant is divided into an Operation and Maintenance ("O&M") component and a Capital component. Stevens Test., Tr. Vol. 1-B, 89:23-90:3.

180. A capital project is one that would improve the value of the asset. Stevens Test., Tr. Vol. 1-B, 91:1-10.

181. The component replacements at issue in this case were capital projects. The projects were actually funded out of Ameren's capital budget rather than its O&M budget. Stevens Test., Tr. Vol. 1-B, 89:23-90:3, Vol. 2-A 5:12-17; Golden Test., Tr. Vol. 8-A, 23:14-15.

182. Costing $34 to $38 million, the boiler component replacements at Unit 1 and 2 were the costliest capital projects ever done at the Rush Island plant. Golden Test., Tr. Vol. 8-A, 23:7-19. By way of comparison, Rush Island's entire annual O&M budget for the Rush Island plant was about $25 million. Meiners Test., Tr. Vol. 7-B, 23:24-24:2.

183. The boiler component replacement projects were among the most expensive boiler projects that Ameren identified to EPA as ever having been undertaken at any of its plants. Knodel Test., Tr. Vol. 1-A, 81:9 – 82:8.

III. THE 2007 AND 2010 BOILER UPGRADES EACH RESULTED IN A SIGNIFICANT NET EMISSIONS INCREASE OF SO_2 WITHIN THE MEANING OF THE PSD REGULATIONS

184. The 2007 and 2010 boiler upgrades triggered PSD if: (1) Ameren should have expected them to result in a significant (i.e., more than a 40 tons-per-year) SO_2 increase; or (2) a 40 tons-per-year SO_2 increase related to the boiler upgrades actually occurred. *Ameren SJ Decision*; *see also* 40 C.F.R. § 52.21(a)(2)(iv)(*b*), (*c*).

185. As described further below, Ameren should have expected the 2007 and 2010 boiler upgrades to increase the availability of the units, thereby resulting in more than 40 tons per

year of increased SO_2 emissions. At both units, these availability improvements resulted from eliminating significant outages and derates that had been plaguing the boilers prior to the upgrades. Removing the problems that had been limiting their pre-project availability should have been expected to increase their post-project operations and emissions. In addition, for at least the 2010 boiler upgrade, Ameren should have expected the new economizer, reheater, and air preheaters to increase the maximum megawatt generating capability of the unit, resulting in increased annual emissions.

186. In addition, availability and hours of operation of Units 1 and 2 actually increased by an amount greater than that required to trigger PSD, just as Ameren expected, as did the megawatt capability of Unit 2.

187. Evidence for these expected and actual increases is found in Ameren's documents and project justifications, in its GADS and other operational data, and in the results of a computer modeling program called ProSym that Ameren uses to simulate the operations of its generating units. The United States' emissions experts, Mr. Koppe, Dr. Sahu, and Dr. Hausman, explained how this evidence demonstrates that the availability and capability improvements at Rush Island Units 1 and 2 would be expected to, and did, far exceed the 40 tons-per-year PSD threshold for $SO_{2.}$ After a brief overview, the specific evidence supporting a finding that the 2007 and 2010 boiler upgrades resulted in significant SO_2 increases is reviewed in further detail below.

A. Overview

188. The Rush Island units are low-cost, baseload units, meaning that they will operate any additional hours that they are made available to operate. FOF 6. As some of the most cost-effective units in a large and interconnected electricity supply system that is vastly larger than

any individual unit, it was not a lack of demand that was holding the units back prior to the 2007 and 2010 boiler upgrades. These "work horse" units were already made to run every hour they were available to run. What held the units back prior to their upgrades was the forced outages and load limitations that were plaguing the boilers as a result of burning a coal for which they were not designed, along with the fact that key boiler components had degraded as they neared the end of their design lives. Fixing those problems was expected to, and did, result in increased operations.

189. Because they lack SO_2 pollution controls, the Rush Island units are very large sources of air pollution. FOF 8, 9. The large size of the units means that very small changes in performance can result in increased SO_2 emissions of more than 40 tons per year.

190. For example, it only takes 21 additional hours of full power operation at either unit to produce more than 40 tons of SO_2. Sahu Test., Vol. 5, 41:3-7, 45:25-46:4. Given that it typically takes two to three days to recover from even a single outage (FOF 35), eliminating just one outage would result in more than 40 additional tons per year of SO_2. Sahu Test., Vol. 5, 46:17-47:2, 62:2-63:10, 94:5-95:23; August 15, 2005 Presentation (Ex. 332), at AM-00966775, 794 (showing *inter alia* that one outage due to the economizer lasts three days).

191. Measured in terms of equivalent availability, it takes only about a 0.3 percentage point (i.e., one-third of a percentage point) increase in availability to produce more than 40 additional tons per year of SO_2 from these units. Hausman Test., Tr. Vol. 4-B, 66:15-25.

192. Similarly, increasing the capability of Rush Island Unit 2 by just 1.7 megawatts would result in an increase in SO_2 emissions of at least 40 tons per year. Sahu Test., Vol. 5, 41:11-14; 46:5-11; Hausman Test., Tr. Vol. 4-B, 58:4-60:2 (one megawatt increase in capacity produces 23 additional tons of SO2).

B. GADS-Based Emissions Calculations for Rush Island Units 1 and 2

193. The United States presented emissions calculations utilizing data generated by Ameren which was transmitted to the North American Electric Reliability Council ("NERC") and maintained in NERC's Generating Availability Data System. As explained above in Subsection II.B.4, GADS is an industry-wide database that collects information on the performance of power plants and the effects that various problems have on that performance. Ameren and other utilities use GADS data to track the causes of outages and derates so that they can assess the status of plant equipment and predict future availability. FOF 89, 92. As also described above, Ameren specifically uses GADS data to calculate "lost generation" when performing financial calculations to determine whether to perform capital projects. FOF 103.

194. Plaintiff's expert Mr. Koppe, who has been a power plant performance consultant for four decades and helped develop the GADS database, reviewed Ameren's GADS data to determine which outages and derates were caused by problems with the boiler components at issue in this case. FOF 90, 91, 106.

195. Mr. Koppe then quantified the expected effect of the 2007 and 2010 upgrades on availability. In performing his analyses, Mr. Koppe used the same basic approach that he used to assess expected performance impacts in his work for utilities over the past 40 years. Koppe Test., Vol. 3-A, 35:6-9 ("I've seen it used by many different utilities, including Ameren, and I've seen it in various industry publications.")

196. Mr. Koppe concluded that the company should have expected, and did expect, the 2007 and 2010 boiler upgrades to eliminate all of the availability losses that were due to the economizers, reheaters, lower slopes, and air preheaters. Koppe Test., Vol. 3-A, 48:24-49:6; *see also* Sahu Test., Vol. 5, 95:24-97:2. Ameren's project justifications were based on this very

assumption. Koppe Test., Tr. Vol. 3-A, 49:24-51:14. *See* FOF 145, 146, 147. Similarly, the effects of pluggage on the units were expected to be eliminated for at least decades into the future. Koppe Test., Vol. 3-A, 54:16-55:3.

197. Based on Ameren's documents and data, and relying on his decades of experience in the industry, Mr. Koppe then made an engineering judgment on the improvements in availability that would be expected to result from the 2007 and 2010 boiler upgrades. In order to determine whether eliminating the causes of unavailability related to the components at issue would result in an overall increase in unit availability, Mr. Koppe assessed the condition of the rest of the equipment at Rush Island Units 1 and 2 in order to ensure that other problems would not be expected to offset the performance improvements expected from the boiler upgrades. As Mr. Koppe explained, the boiler components replaced by Ameren were the "things that were really hurting them" in terms of availability, as they alone were causing roughly half of all the lost productivity at the units during the baseline period. Koppe Test., Vol. 3-A, 47:7-12; 75:3-11. "[P]roblems with all the rest of the equipment were only half of the losses, and here you had four problems that were half of all the lost productivity." *Id*. 48:2-8. However, he wanted to be sure that "the level of maintenance that was being done" on the remaining parts of the unit that were not being upgraded was sufficient to maintain the overall very good level of performance that those remaining components had experienced. Koppe Test., Vol. 3-A, 56:12-56:25.

198. As part of this review of the entire unit, Mr. Koppe reviewed GADS data and other contemporaneous company data and documents describing the overall condition of the units. Mr. Koppe reviewed, for example, reports identifying all of the maintenance and capital projects done during the outage, unit condition assessments prepared by company engineers, and presentations made by plant engineers to management about the condition of the unit. Koppe

Test., Vol. 3-A, 34:13-21, 51:20-57:17; *see also* GADS Events Data (Pl. Ex. 925), 2007 and 2010 Outage Reports (Pl. Ex. 34 and 46), Condition Assessments (Pl. Ex. 106 and 606), and State of the System Presentations (Pl. Ex. 15, 41, and 111). Based on his review of this evidence, Mr. Koppe concluded that the overall effect of everything else at the plant on availability would not offset the availability gains from the components at issue. Koppe Test., Vol. 3-A, 51:20- 66:5-67:3.

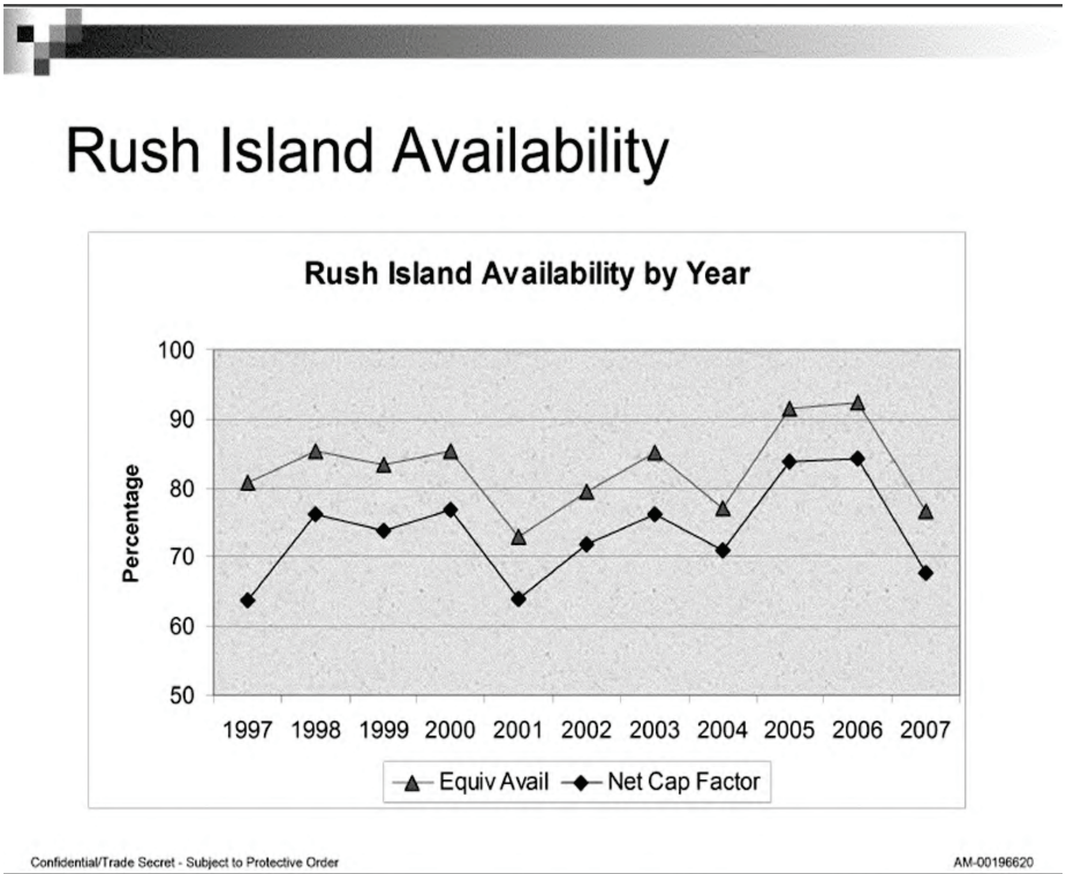
199. Evidence that other problems would not be expected to offset the performance improvements from the 2007 and 2010 boiler upgrades was also provided by Ameren witnesses at trial. As Mr. Naslund testified, as part of the new "super outage" concept that he championed, the company proactively addressed everything that might cause problems in the next six years at a unit to ensure the unit would run as well as possible and "improve unit availability." Naslund Test., Tr. Vol. 6-B 7:1- 8:6. After implementing the super outage process, forced outages in fact went down and availability went up. Naslund Test., Tr. Vol. 6-B, 6:19-25. Mr. Strubberg similarly testified that he was responsible for a condition-based maintenance program called the PRO/PMO program that helped keep the balance of individual components at high availability, and by doing that, it helped keep the units at high availability. Strubberg Test., Tr. Vol. 8-A, 35:21-23, 38:23-24, 39:21-25, 61:5-9, 77:8-12.

200. Once the expected impact on availability is determined for a unit, the next question is to determine whether that increased availability will actually be used to operate more in the future. Whether or not increased availability will result in an additional hour of operation in the future can sometimes be a "tricky question" for some units, "but it's not for these units, because these units operate for almost every single hour that they are able to operate. So if you increase the number of hours a unit is available to operate, that will result in an increase in the

number of hours the unit does operate." Koppe Test., Vol. 3-A, 35:17-26; *see also* Naslund Dep., Sept. 18, 2014, at 55:2-55:7.

201. This direct relationship between availability and generation at Rush Island was also confirmed by modeling performed by Dr. Hausman. As Dr. Hausman explained, if availability is improved, it means the unit can run more hours or it can run at a higher level for more hours. Hausman Test., Tr. Vol. 4-B, 39:9-13. For a relatively low-cost baseload unit, if it is able to produce more, it typically will produce more. As Dr. Hausman explained: "I think that's a fairly fundamental way to look at electricity markets. If I were to run a model and it ran less or used less fuel, there would be something very strange in that." Hausman Test., Tr. Vol. 4-B, 39:16–40:4; *see also id.* at 36:12–21. Dr. Hausman found exactly such a linear relationship between availability improvements and generation at Rush Island. Hausman Test., Tr. Vol. 4-B, 64:10-64:20, 71:7-25.

202. This direct relationship between availability and generation at baseload units like Rush Island was also obvious from presentations prepared by Ameren itself on the importance of availability, which showed availability tightly tracking plant generation. Strubberg Test., Tr. Vol. 8-A, 100:4-6, 100:15-17; 2008 State of the System (Pl. Ex. 15), at AM-00196620.



203. The data also shows a relationship between unit availability and SO_2 pollution, as Ameren's expert Michael King acknowledged at trial. King Test., Tr. Vol. 6-B, 86:2-23.

204. The extraordinarily high use of Rush Island's availability was also confirmed in the GADS data that Mr. Koppe reviewed, which included data on how often the units were placed in a status known as "reserve shutdown." When a unit is in reserve shutdown, it is available to operate but does not for economic reasons. Koppe Test., Tr. Vol. 3-A, at 36:22-37:1.

205. The Rush Island units did not spend a single hour in reserve shutdown during the PSD baseline periods. Koppe Test., Tr. Vol. 3-A, 37:2-7; Naslund Dep., Sept. 18, 2014, Tr. 54:21-55:7; RFA Nos. 189, 192, 193, 203. In the five years before the projects, one of the units operated every single hour it was available, and the other operated 99.9% of the time. Koppe Test., Tr. Vol. 3-A, 37:8-18. That means that if a Rush Island unit "is available to operate another hour, it will operate for that hour; and that, of course, requires burning more coal and generating more emissions." Koppe Test., Tr. Vol. 3-A, 37:19-24; Naslund Test. Vol. 6-A, 50:3-13 (describing Rush Island units as "two workhorses"), 45:3-20 (since 2005, the Rush Island units "were staying up on load at much higher levels around the clock"), 48:7-49:3 (because the Rush Island units are among the cheapest units in MISO, they run a higher percentage of time); Naslund Dep., Sept. 18, 2014, Tr. 55:4-7.

206. Mr. Koppe's quantification of increased unit availabilities caused by the 2007 and 2010 boiler upgrades was then translated into emissions increases by Dr. Sahu, a combustion engineer and environmental permitting engineer, who has performed PSD calculations hundreds of times. Sahu Test., Vol. 5, 34:24-38:14. Dr. Sahu did not assume that Ameren would generate at full capacity every additional hour that it generated. Instead, he applied the same utilization factor that the units experienced during the PSD baseline period. Sahu Test., Tr. Vol 5, 51:5-53:16, 75:3-77:20.

207. Using the same baseline utilization factor is consistent with the fact that the units are baseload units that are used whenever they are available. In addition, the historic utilization factor of the units remained relatively stable, and Ameren documents indicate that it expected the utilization factor of the units to remain relatively stable going forward. Sahu Test., Tr. Vol. 5

57:15-58:21; September 9, 2006 Email and attached critical review spreadsheet (Pl. Ex. 333), at Rush 1 and Rush 2 tabs.

208. Use of a constant utilization factor was also confirmed by Ameren's witnesses. Ameren expert Marc Chupka opined in his expert report that it "would be reasonable to assume a constant utilization factor for projecting future emissions at least for some period of time" after the projects at issue in this case. Chupka Test., Tr. Vol. 8-B, 77:3-18. Similarly, Sandra Ringelstetter's work papers identified the baseline utilization factor and the utilization factor projected by Ameren for both Unit 1 and Unit 2. For Unit 1, the utilization factor was projected to stay basically the same (a change of 0.09%), while for Unit 2 it was projected to increase by about 2%. Def. Ex. NE, at "RI U1 2007 Summary" and "RI U1 2010 Summary."

209. Using the same utilization factor from the baseline period specifically eliminates the impact of other factors that could cause an increase in utilization of a unit when its availability improves, thus isolating just the effect of the boiler upgrades. For instance, whereas Ms. Ringelstetter identified a 2% increase in utilization factor at Unit 2, Dr. Sahu's use of the baseline utilization factor excludes any effects of increased demand on the units by calculating just the increase that is due to the availability improvements made possible by the upgrades. Sahu Test., Tr. Vol. 5, 75:18-76:5, 153:21-25.

210. In addition, as Dr. Sahu described, the general approach of applying a utilization factor to calculate the additional generation from an expected availability improvement is consistent with Ameren's practices and is well understood in the industry. The same basic formula is found in Ameren's availability worksheets, which translate availability improvements into generation for fuel budgeting purposes, as well as industry documents such as a 1985 study publication of the Electric Power Research Institute ("EPRI"). Sahu Tr., Vol. 5, 53:17-57:5. For

instance, Ameren's availability worksheets provide the following formula for calculating "expected annual plant generation" from an availability change: "Total Net mwhrs" equals "Plant Equiv. Avail. X Utilization Factor." Availability Worksheet (Pl. Ex. 250), at Spreadsheet Tab "Instructions." The 1985 EPRI study provides a similar formula. *See* Economic Evaluation of Plant-upgrading Investments (Pl. Ex. 241), at AME_RHK000011. Similarly, although Ameren has criticized Dr. Sahu's use of utilization factors as applied to both outages and derates in this case, Ameren itself uses utilization factors in a similar way outside of this litigation. For instance, in using a utilization factor to estimate future generation, Ameren's availability worksheets specifically defines the utilization factor as "the percent of mwhrs used after outages and derates." Availability Worksheet (Pl. Ex. 250), at Spreadsheet Tab "Instructions."

211. Dr. Sahu's emission calculations also used the same SO_2 emission factor from the baseline period. As with holding the utilization factor constant, reasons for using the baseline emission factor in the calculation of post-change emissions include the fact that Ameren documents indicate that the emission factor was expected to remain fairly stable. Sahu Test. Tr. Vol. 58:22-59:24, 89:6-89:13, September 9, 2006 Email and attached critical review spreadsheet (Pl. Ex. 333), at Rush 1 and Rush 2 tabs.

212. In addition, the project justification documents for the 2007 and 2010 boiler upgrades made no mention of *any* expected improvements in the gross efficiency of the units, a point that was conceded by Ameren's capability expert. Caudill Test., Tr. Vol. Vol. 10-B, 44:24-45:12; *see also* Sahu Test., Tr. Vol. 5 108:3-21.

213. While Ameren argued that it expected small reductions in auxiliary load as a result of the boiler upgrades, such reductions would result in an improvement in net efficiency, not gross efficiency, and as a result do not affect the amount of coal that the unit is capable of

burning. Rather, they just mean that less power is used to run the plant, so more of the gross generation recovered by the boiler upgrades could be sent to the grid. Koppe Test., Tr. Vol. 3-B, 11:16-12:4; Shelton Test., Tr. Vol. 10-A, 85:8-10. As Dr. Sahu explained, all of his calculations are based on gross megawatts because gross is what relates to how much SO_2 comes out of the boiler. Sahu Test., Tr. Vol. 5 52:16-24, 84:20-24.

214. Similarly, while Ameren did expect some improvement in efficiency at Unit 2 due to the contemporaneous replacement of the low pressure turbine, Dr. Sahu accounted for that in his calculations by factoring out both the additional megawatt capability of the new turbine and the heat rate of the turbine. Sahu Test. Tr. Vol. 5 84:9 – 85:1, 135:23-136:8, 137:9-15; 138:3-10, 181:21 – 182:4. Dr. Sahu's treatment of the low pressure turbine on the expected SO_2 emission rate was consistent with how Ameren itself treated the expected effect of the turbine outside of this litigation. For instance, Ameren's financial analysis was based on the assumption that the turbine-related efficiency improvements would allow Unit 2 to produce more megawatts, but would not result in the unit burning any less coal. Pl. Ex. 48, at "Data Entry" sheet (rows 149-152, col. D (and comment box) (showing that Ameren did not include efficiency benefit inputs for "decrease in fuel usage")), Pl. Ex. 110, at AM-02465690; Koppe Test., Vol. 3-B, at 29:9-32:9. As Dr. Sahu noted, Ameren's financial analysis shows that there was no expected fuel decrease associated with the capacity increase. Sahu Test. Tr. Vol. 5, 97:3 - 99:4.

215. Use of a constant emission factor was also corroborated by the United States' other experts. As Dr. Hausman explained, when a baseload unit like the Rush Island units is modified to become more efficient, it allows the unit to generate more electricity while consuming the same amount of coal. Hausman Test., Tr. Vol. 4-B, 37:6–18. Because a baseload plant has essentially an unlimited market for its very low-cost power, if it becomes more

efficient, it will burn the same amount of coal but produce more energy than it can sell into the market. Hausman Test., Tr. Vol. 4-B, 38:7–11. As a result, as Mr. Koppe also explained, the separate efficiency gain from the turbine would result in increased megawatts but would not change the full load heat input to the boiler. Koppe Test., Tr. Vol. 3-B, 29:9-32:9. This was also consistent with Ameren employee Jeff Shelton's testimony that a more efficient turbine can allow a unit to make more megawatts with the same amount of heat input. Shelton Test., Tr. Vol. 10-A, 85:14-20, 85:5-9.

216. Finally, use of a constant emission rate was also borne out by Ameren's operating data as reported to EPA, which confirmed that the post-project emission rate at Unit 1 stayed relatively constant, and actually increased somewhat at Unit 2 as compared to the PSD baseline periods. Sahu Test., Tr. Vol. 5, 109:14-22. At Unit 1, reported heat rate deteriorated slightly, from 9,282 Btu/Kwh to 9,447 Btu/Kwh, and the unit emitted approximately 21 more pounds per hour of SO_2 than it had in the baseline. Sahu Test., Tr. Vol. 5 110:6-111:6; Knodel Test., Tr. Vol. 1-A, 110:8-24. At Unit 2, reported heat rate deteriorated from 8,800 Btu/Kwh to 9,676 Btu/Kwh, and the unit emitted approximately 456 more pounds per hour of SO_2 than it had in the baseline. Knodel Test., Tr. Vol. 1-A, 111:8-20. Sahu Test. Tr. Vol. 5, 112:21-24. As a result, for every additional hour that Rush Island Units 1 and 2 were able to operate in the post project period, they actually emitted more SO_2 per hour.

217. Because Dr. Sahu's calculation is based on the incremental impact of the projects on unit performance calculated by Mr. Koppe, his entire predicted increase is related to the project. Sahu Test., Tr. Vol. 5, 49:21 – 50:3, 60:13-18, 61:15-17, 73:6 – 74:4, 77:11-20, 84:15 – 87:10.

218. Ameren presented testifying expert Michael King to critique the approach used by Mr. Koppe and Dr. Sahu. But Mr. King agreed that Mr. Koppe and Dr. Sahu "have the appropriate experience to estimate the effect of modifying a power plant on generation [and] emissions." King Test., Tr. Vol., 6-B, 65:17-21.

219. Another Ameren testifying expert, Marc Chupka, conceded that the method used by Mr. Koppe and Dr. Sahu for determining PSD emissions increases has at least been "well-known in the industry" since the first enforcement cases were filed in 1999. Mr. Koppe testified that he and Dr. Sahu had used the same basic formula in this case that he and other utilities have used for decades. Koppe Test., Tr. Vol. 3-A, 35:6-9; *see also* Sahu Test., Tr. Vol. 5, 53:17-57:5 (discussing Ameren and industry documents). Mr. Chupka himself has been asked to analyze utility projects using the same method employed by Mr. Koppe and Dr. Sahu numerous times. Chupka Test., Tr. Vol. 8-B, 74:14-21, 75:5-10.

1. Results of projected emissions increase calculations based on the GADS data at Rush Island Unit 1

220. As described further below, Ameren should have expected an increase of at least 600 tons per year of SO_2 emissions over the PSD baseline emissions as a result of the availability improvements caused by the 2007 boiler upgrade.

221. The PSD "baseline" period used by Ameren for Unit 1 in this litigation was the highest 24-month period of emissions in the five years before the 2007 boiler upgrade, which was February 2005 through January 2007. During that period, Unit 1 emitted 14,874 tons per year of SO_2. Sahu Test., Tr. Vol. 5, 49:8-20; Knodel Test., Tr. Vol. 1-A, 95:6-25.

222. During this baseline period, problems in the economizer, reheater, lower slopes, and air preheaters caused Unit 1 to lose 336.1 equivalent full power hours of generation per year,

which is roughly equivalent to 14 days of operation per year. Koppe Test., Tr. Vol. 3-A, 45:15-46:24. The unit was completely shut down in outages for 246.4 hours per year due to problems in the components at issue and lost the equivalent of another 89.7 full power hours of operation due to deratings. *Id*.

223. As explained by Mr. Koppe, the problems associated with the Unit 1 reheater, economizer, air preheater, and lower slopes caused about 50% of all the availability losses at Unit 1 during the baseline period. Koppe Test., Tr. Vol. 3-A, 47:7-12; 48:2-8.

224. These problems reduced Unit 1's availability during the baseline period by 3.8 percentage points. Sahu Test., Tr. Vol. 5, 63:11-64:5. Unit 1's availability was 92.1% during the baseline. Koppe Test., Tr. Vol. 3-A, 48:9-11. The average annual availability of Unit 1 over the entire five-year pre-project period was 87.5%. *Id*. 48:15-23

225. Based on his analysis of Ameren's operating data, including GADS, as well as contemporaneous documents, Mr. Koppe concluded that Ameren should have expected the 2007 boiler upgrade to eliminate all of the availability losses in the baseline period related to problems in the reheater, economizer, lower slopes, and air preheater components. Koppe Test., Tr. Vol. 3-A, 48:24-49:6, 66:5-12; *see also* Sahu Test., Tr. Vol. 5, 95:24-97:2.

226. Company documents and witnesses confirm that Ameren actually had such an expectation. Ameren expected that as a result of the 2007 boiler upgrade, availability losses attributable to the replaced components would be completely eliminated for years in the future. Meiners Test., Vol. 7-B, 40:1-18 ("Q. Right. If you do the project, in the future you won't have those causes of unavailability, right? A. Correct."); Boll. Test., Vol. 8-B, 46:11-47:10 ("that's probably a good bet"); FOF 145, 146, 147.

227. Based on his review of company documents and data, as well as his experience in the industry and his assessment of the overall condition of the rest of the unit, Mr. Koppe concluded that Ameren should have expected that the 2007 boiler upgrade would result in a substantial increase in the overall equivalent availability of Rush Island Unit 1. Koppe Test., Tr. Vol. 3-A, 34:13-21, 51:20-55:17, 66:5-12. The impact of the project alone would be to increase the availability of Unit 1 by 3.8 percentage points over baseline availability by eliminating all 336.1 EFPH of availability losses related to the reheater, economizer, lower slopes, and air preheater. Koppe Test., Tr. Vol. 3-A, 48:24-49:6; *see also* Sahu Test., Tr. Vol. 5, 95:24-97:2. If the four components had not been replaced, the availability of the unit would have been expected to decrease. Koppe Test., Tr. Vol. 3-A, 66:13-67:3.

228. Similar projected increases can be found in Ameren's availability forecasts. For example, the forecast for the 2006 Fuel Budget projected that Unit 1's long-term average availability would be 95.0% as a result of the "boiler improvements" done during the Unit 1 outage. This represents an increase of 7.5% over Unit 1's five-year pre-project average and about a 3% increase over Ameren's high baseline emissions period (a 3 percentage point improvement is the equivalent of about 10 more days of operation). Koppe Test., Tr. Vol. 3-A, 61:20-65:8; Meiners Test., Vol. 7-B, 39:16-25; September 23, 2005 Email (Pl. Ex. 214); September 28, 2005 Email attaching Availability Worksheet (Pl. Ex. 215), at Rush tab.

229. Ameren's 2006 Fuel Budget forecast showed a 4.2 percentage point improvement in Unit 1's forced outage rate after the work. Def. Resp. to Interrogatory No. 68; Boll Test., Vol. 8-B, 42:19-44:1. Ameren's Rule 30(b)(6) witness, David Boll, admitted in deposition testimony that the 4.2% improvement in the outage rate was "most probably due to the major outage" and could provide no other reason for the improvement. Boll Test., Tr. Vol. 8-B, 44:2-45:5; Boll

Dep. Dec. 12, 2013, Tr. 122:13-123:2; Aug. 17, 2007 Email and Attached Spreadsheet (Pl. Ex. 523), AM-02264672.

230. Similarly, Rush Island Plant Manager Robert Meiners gave a presentation to Ameren senior executives in which he discussed the condition of the reheater, economizer, air preheater, and lower slopes on Rush Island Unit 1 and the efforts to replace those components. At the end of the presentation, Mr. Meiners presented a graph showing that Rush Island's long-term availability would increase by almost 5 percentage points, from about 90% in 2005-2006 to 95% after both outages had been completed. Mr. Meiners admitted that even a one percent change in availability would be a significant change. Meiners Test., Tr. Vol. 7-A, 68:8-18; Tr. Vol. 7-B, 27:21-24, 28:10-20, 31:15-21, 33:4-6; Rush Island Business Plan Presentation (Pl. Ex. 126), at AM-02625397.

231. Before the Unit 1 project had been approved, Ameren was not forecasting an increase in availability; instead its forecasts were that availability would remain flat – 91%. That is because all of the other work done during the 2007 outage would maintain availability but would not cause an increase in availability. Koppe Test., Tr. Vol. 3-A, 65:13-66:4, 66:13-67:3.

232. Based on Mr. Koppe's availability analysis, and consistent with his review of company data and documents, Dr. Sahu translated the increased operations that were expected to result from the 2007 boiler upgrade into emissions and determined that the expected SO_2 increase from such operations was far more than 40 tons per year. Sahu Test., Vol. 5, 39:23-25, 40:21-24, 102:7-10, 113:22 – 114:1. Specifically, Dr. Sahu calculated that Ameren should have expected a net emissions increase of 607.8 tons per year of SO_2 over the PSD baseline emissions as a result of the replacement of the economizer, reheater, lower slopes, and air preheater. Sahu Test., Tr. Vol. 5, 49:8-50:14, 57:15-59:5, 92:22-93:17; 115:17-20.

233. Even without counting the effects of derates and focusing just on the outages caused by the components, the 2007 boiler upgrade would allow the unit to operate 246 more hours or about 10 more days per year by eliminating the outages associated with the reheater, economizer, lower slopes, and air preheaters. By itself, this would cause a more than 400 ton-per-year increase in emissions of SO_2. Koppe Test., Tr. Vol. 3-A, 49:12-23; Sahu Test., Vol. 5, 65:12-66:22.

2. Rush Island Unit 1 actual emission increases

234. Just as Ameren expected, Unit 1 experienced a substantial increase in availability following the 2007 boiler upgrade. In 2008, Rush Island Unit 1 had an equivalent availability of 96.77%. This was the highest equivalent availability of any unit in the entire Ameren system in 2008. Unit 1's equivalent availability in 2008 was higher than any 24-month period of equivalent availability since the Rush Island plant first began tracking availability data in 1982 and higher than any 12-month period since 1990. Anderson Test., Tr. Vol. 7-A 55:8-17, 56:22-58:2; Meiners Test., Tr. Vol. 7-B, 49:9-15, 55:18-23, 56:12-16; Strubberg Test., Tr. Vol. 8-A, 94:3-8, 95:1-4; Def. Resp. to RFA 299; Jan. 9, 2009 Email (Pl. Ex. 104), at AM-02272427 ("Rush Island 1 had the highest EAF [equivalent availability factor] at 96.77%"); *see also* Koppe Test., Tr. Vol. 3-A 67:4-69:3.

235. Rush Island Plant management received significant salary bonuses relating the Rush Island's availability in the year 2008, whereas they had received no such bonuses for the year before. Strubberg Test., Vol. 8-A, 100:23-102:3; Def. Response to Interrogatory No. 65.

236. In April 2009, Rush Island Unit 1 set an "all-time record run for days on line," breaking the "old plant record of 211 days [that] was set in 1990." April 7, 2009 Email re: "Rush Island Unit 1 Record Run" (Pl. Ex. 105), at AM-02276058; Strubberg Test., Tr. Vol. 8-A,

60:7-61:18 (admitting that Unit 1 had an equivalent availability of more than 98% during this period). Ameren Vice President Mark Birk specifically called out the replacement of the "reheater, economizer, and lower slopes" in 2007 as having "paid off" when he reported Unit 1's record availability to Ameren's CEO Warner Baxter. April 7, 2009 Email re: "Rush Island Unit 1 Record Run" (Pl. Ex. 105), at AM-02276058; *see also* Koppe Test., Tr. Vol. 3-A 69:12-70:12.

237. The GADS data confirmed that the cause of the improved availability was the improved performance of the components at issue that were replaced as part of the 2007 boiler upgrade. As Ameren should have expected, and did expect, all of the availability losses due to problems in the reheater, economizer, lower slopes, and air preheater were eliminated after the 2007 boiler upgrade. As a result, component-related availability losses were reduced from 336.1 EFPH per year to zero. Availability losses due to everything else also decreased slightly. Koppe Test., Tr. Vol. 3-A, 70:17-71:2, 81:8-17; Sahu Test., Tr. Vol. 5, 64:8-21.

238. Further reflecting the actual performance improvements resulting from the 2007 boiler upgrade, Ameren's reported GADS data further show that Unit 1's equivalent availability actually increased over the baseline period by 4.3 percentage points, from 92.1% to 96.4% in the relevant post-project period. *Id.*; Sahu Test., Vol. 5, 64:24-65:3; Koppe Test., Tr. Vol. 3-A, 71:18-72:14.

239. None of the availability improvements that actually occurred at Unit 1 would have happened if the reheater, economizer, lower slopes, and air preheater had not been replaced. Koppe Test., Tr. Vol. 3-A, 66:13-67:3; Meiners Test., Vol. 7-B, 57:11-16.

240. Similarly, Ameren's reported GADS data shows that Unit 1's operating time increased from 8,208 hours per year in the baseline to 8,568 hours per year during the highest post-project period of emissions, for an increase of 360 hours. This increase in operating hours

included the effect of eliminating the 246 outage hours per year during the baseline period that were caused by problems associated with the reheater, economizer, lower slopes, and air preheater. Koppe Test., Tr. Vol. 3-A, 73:3-15; Sahu Test., Tr. Vol. 5, 65:12-66:22, 109:7-13.

241. There is no question that these increased hours of operation were accompanied by more heat input. Annual heat input increased from 43,957,163 MMBtu per year in the baseline period to 45,442,171 MMBtu per year in the relevant post-project period. Sahu Test., Vol. 5, 109:25-110:5.

242. Similar increases are shown in Ameren's certified Continuous Emissions Monitoring System ("CEMS") data, which show that Unit 1 operated more hours and emitted more pollution per hour during the relevant post-project period as compared to the baseline period. The CEMS data show that Unit 1's operating time increased by 320 hours per year, from 8,278 hours per year in the baseline to 8,598 hours per year in the applicable post-project period. Furthermore, when it was operating, Unit 1 emitted 21 more pounds per hour of SO_2 than it had in the baseline (increasing from 3,593 pounds per hour in the baseline to 3,614 pounds per hour in the post-project period). Knodel Test., Tr. Vol. 1-A, 109:7-16, 110:8-111:7, 112:14-24.

243. Ameren's CEMS data also show that in 2008, the first calendar year after the 2007 boiler upgrade, Rush Island Unit 1 emitted more SO_2 than it had in any year since 1995. Knodel Test., Tr. Vol. 1-A 82:9-19. During the relevant post-project period, Unit 1 emitted 15,539 tons per year of SO_2, which is 665 tons per year more than Unit 1 actually emitted during the baseline period. Sahu Test., Tr. Vol. 5, 49:8 – 20, 111:7-16; Knodel Test., Tr. Vol. 1-A, 95:6-25.

244. Eliminating 246 outage hours by replacing the reheater, economizer, lower slopes, and air preheater, by itself, equates to SO_2 emissions of more than 400 tons per year. Sahu Test.,

Tr. Vol. 5, 41:3-7, 45:25-46:4, 65:12-66:22. Because all of the availability losses caused by the reheater, economizer, and air preheater in the baseline were eliminated (336 EFPH and 246 outage hours), (Koppe Test., Vol. 3-A, 67:7-73:19), it is clear that at least 40 tons of the overall 665 ton increase in actual emissions is related to the increased equivalent availability and additional operating hours enabled by the replacement of these components. Sahu Test., Tr. Vol. 5, 39:13-17, 64:6-66:22.

3. Results of projected emissions increase calculations based on the GADS data at Rush Island Unit 2

245. As described further below, Ameren should have expected an increase of approximately 400 tons per year of SO_2 emissions over the PSD baseline emissions as a result of the availability improvements caused by the 2010 boiler upgrade.

246. The PSD "baseline" period used by Ameren for Unit 2 in this litigation was the highest 24-month period of emissions in the five years before the 2010 boiler upgrade, which was April 2005 through March 2007. During that period, Unit 2 emitted 14,287.7 tons per year of SO_2. Sahu Test., Tr. Vol. 5, 72:17-73:5; Knodel Test., Tr. Vol. 1-A, 91:4-17.

247. During this baseline period, problems in the economizer, reheater, and air preheaters caused Unit 2 to lose approximately 245 equivalent full power hours of availability per year. The unit was completely shut down in outages for 145.5 hours per year due to problems in the components at issue and lost the equivalent of another approximately 100 full power hours of operation due to deratings. Koppe Test., Tr. Vol. 3-A, 74:7 – 75-2; Sahu Test., Tr. Vol. 5 78:20-79:19.

248. These problems reduced Unit 2's equivalent availability during the baseline period by 2.8 percentage points. Sahu Test., Tr. Vol. 5, 119:6-17; Koppe Test., Tr. Vo. 3-A

76:17-22. According to the company's GADS events data, Unit 2's availability was 94.5% during the baseline. The average annual availability of Unit 2 over the entire five-year pre-project period was about 92%. Koppe Test., Vol. 3-A, 75:3-75:23, 76:17-22.

249. The problems associated with the Unit 2 reheater, economizer, and air preheaters caused about 50% of all the availability losses at Unit 2 during the baseline period. Koppe Test., Tr. Vol. 3-A, 75:3-11; Sahu Test., Tr. Vol. 5, 79:20-80:12.

250. Based on his analysis of Ameren's operating data, including GADS, as well as other company documents, Mr. Koppe concluded that, just as at Unit 1, Ameren should have expected the 2010 boiler upgrade to eliminate all of the availability losses in the baseline period related to problems in the reheater, economizer, and air preheaters. Koppe Test., Vol. 3-A, 76:23-77:5.

251. As at Unit 1, based on his review of company documents and data, as well as his experience in the industry and his assessment of the overall condition of the rest of the unit, Mr. Koppe concluded that Ameren should have expected that the 2010 boiler upgrade would result in a substantial increase in the overall equivalent availability of Rush Island Unit 2. Koppe Test., Vol. 3-A, 34:7-21, 55:4-57:22, 73:25-74:2, 77:9-79:14, 84:4-13. The impact of the project alone would be to increase the availability of Unit 2 by 2.8 percentage points over baseline availability by eliminating all 243 EPFH of availability losses related to the reheater, economizer, and air preheaters. Koppe Test., Vol. 3-A, 76:23-77:8.

252. Similar projected increases can be found in Ameren's project documents and availability forecasts, which indicate that Ameren should have expected and did expect that Unit 2's equivalent availability would be similar to what Unit 1 achieved after the 2007 boiler upgrade. Koppe Test., Tr. Vol. 3-A, 77:9-20; Meiners Test., Tr. Vol. 7-B, 50:14-51:2.

253. For instance, Ameren updated its financial justification for the Unit 2 outage in 2009, and included in that justification was the expectation that Unit 2's availability would be as high as Unit 1's availability was in 2008 – almost 97%. Koppe Test., Tr. Vol. 3-A, 77:21-78:19; Meiners Test., Tr. Vol. 7-B, 45:8-25, 48:4-49:5, 50:14-51:2; Unit 2 ELT Progress Report, (Pl. Ex. 110), at AM-02465690; Updated Financial Analysis (Pl. Ex. 48), at "Data Entry" tab (row 155, col. F (and hidden comment: "4.3% gain related to outage work (u2 vs. u1)"). That would be a 4.3 percentage point improvement in equivalent availability over what Unit 2 had experienced in 2008, and would represent about 15 additional days of operation for Unit 2. *Id.*; Meiners Test., Vol. 7-B, 18:22-19:16 (the EAF input in the analysis was the equivalent of "15 days of generation").[2] Mr. Meiners personally assured Ameren's CEO Warner Baxter that inputs used in the updated financial analysis for the Unit 2 outage were accurate. Meiners Test., Tr. Vol. 7-B, 46:9-47:11; May 16, 2009 Email (Pl. Ex. 347), at AM-02637756 ("I do believe the model is now a much more accurate representation of the economic benefits.").

254. Unit 1's availability in 2008 was 96.77%. During the same year, Unit 2's availability was 92.42%. RFAs 299 and 300; Anderson Test., Tr. Vol. 7-A, 55:8-17, 56:22-58:2; Meiners Test., Tr. Vol. 7-B, 49:9-20.

255. All or essentially all of the 4.2 percentage point improvement was related to the components at issue. All of the other work done during the outage was done to keep the performance of the rest of the unit from getting worse but would not improve availability. Koppe Test., Vol. 3-A, 78:23-79:6; Koppe Test., Tr. Vol. 4-A, 99:22-100:2, 103:14-104:25; *see also* Meiners Test., Tr. Vol. 7-B, at 57:11-16 (none of the availability improvement would have

[2] As discussed above, the final EAF input was adjusted downward by 0.1%, from 4.3% to 4.2%, as result of eliminating the lower slope replacement from the final scope of the project. FOF 148.

occurred if the components at issue had not been replaced); February 6, 2007 Email (Pl. Ex. 103) ("In reality, until we have the economizer replacement, Unit 2's forced outage is going to get worse, not better.").

256. Ameren's updated Full Work Order Authorization for the reheater and economizer replacements similarly indicated that Ameren expected the "boiler modifications [to] result in an improved operation of the unit that is at least equal to, if not better, than that currently expected with Unit 2 which had similar modifications in 2007." The authorization quantified this amount as an expected "3-4% improvement in the equivalent availability of the unit." October 15, 2009 Memo (Pl. Ex. 23), at AM-00926323; Birk Dep., Sept. 24, 2013, Tr. 194:1-195:13. Mr. Meiners confirmed that the availability input used for the justification was almost 97%. Meiners Test., Tr. Vol. 7-B, 50:14-51:2.

257. Ameren also should have expected Unit 2's long-term average equivalent availability to increase from 92% to 95%. Because there is a 2-3% variation in long-term forecasts, Ameren understood that Unit 2's highest annual availability after the 2010 boiler upgrade would be 97-98%. Koppe Test., Tr. Vol. 3-A, 76:17-22, 79:7-14; Meiners Test., Tr. Vol. 7-B, 54:14-55:6; Hausman Test., Tr. Vol. 4-B, 65:9–19. Other forecasts done before the boiler upgrade also predicted greater than 95% as a long term availability after the Unit 2 outage. *See* Updated 2008 Fuel Budget forecast (Pl. Ex. 252) (projecting 97% EAF for Unit 2 after outage); Meiners Test, Vol. 7-B, 51:18-52:7.

258. Based on Mr. Koppe's availability analysis, and consistent with his review of company data and documents, Dr. Sahu translated the increased operations that were expected to result from the 2010 boiler upgrade into emissions increases, and determined that the expected SO_2 increase from such operations was far more than 40 tons per year. Sahu Test., Tr. Vol. 5,

39:23-25, 40:21-24, 78:13-19, 99:13-100:11, 102:7-10, 113:22 – 114:1. Specifically, Dr. Sahu calculated that Ameren should have expected a net emissions increase of 414.5 tons per year of SO_2 due solely to the improvements in equivalent availability that Ameren should have expected from the replacement of the economizer, reheater, and air preheater. Sahu Test., Tr. Vol. 5, 73:6-74:14, 115:17-20.

4. Rush Island Unit 2 actual emission increases based on availability

259. Just as Ameren expected, Unit 2 experienced a substantial increase in availability following the 2010 boiler upgrade. During the relevant post-project period, as Ameren should have expected and did expect, there were no availability losses at all due to the reheater, economizer, and air preheater. Availability losses due to all the rest of the equipment at the unit essentially stayed the same. Koppe Test., Tr. Vol. 3-A, 80:7-23; Sahu Test., Tr. Vol. 5, 80:13-81:1, 82:13-83:5; *see also* Pl. Ex. 746 (work paper showing no GADS events for reheater, economizer, and air preheater during post-project period).

260. Overall equivalent availability increased by 2.9 percentage points, from 94.5% in the baseline to 97.4% during the first 12 months after the 2010 boiler upgrade, the relevant post-project period in the case. Unit 2's equivalent availability during this period was higher than any 24-month period in the history of the plant, going back to when Ameren first began tracking availability data in 1982, and higher than any 12-month period since 1987. Koppe Test., Tr. Vol. 3-A, 88:24-89:6; Anderson Test., Tr. Vol. 7-A, 58:3-9, 58:24-59:13; *see also* Sahu Test., Tr. Vol. 5, 81:2-15; Pl. Ex. 746.

261. Ameren's witness, Scott Anderson, referred to the increase in Unit 2's availability before and after the 2010 outage as "night and day." Anderson Test., Tr. Vol. 7-A, 58:7-9 (It is "obvious that the plant went way too long without a planned outage before correcting the

problems that it had. I mean, it's night and day."). Ameren had specifically called Mr. Anderson to discuss what the GADS data showed about the availability of the Rush Island units. Anderson Test., Tr. Vol. 7-A, 31:23-32:19.

262. None of the availability improvements at Unit 2 would have occurred if the reheater, economizer, and air preheater had not been replaced. Koppe Test., Tr. Vol. 3-A, 66:13-67:3; Meiners Dep., Tr. Vol. 7-B, 57:11-16.

263. According to Ameren's GADS data, Unit 2's operating time increased from 8,408 hours/year in the baseline period to 8,583 hours/year in the applicable post-project period, for an increase of 175 hours per year. This increase in operating hours included the effect of eliminating 146 outage hours per year in the baseline period caused by problems associated with the reheater, economizer, and air preheater. Sahu Test., Vol. 5, 83:8-22, 112:6-11, 158:3-8; Koppe Test., Vol. 3-A, 83:20-84:3; *see also* Koppe Test., Tr. Vol. 4-A, 115:18-25 (If "half of all the outage time that's occurring is eliminated by the projects and the effect of all the other equipment in the unit stays the same, … then the availability of the unit as a whole increases, and it increases specifically because the projects have eliminated boiler tube leaks in these sections and have eliminated the effects of pluggage.").

264. There is no question that these increased hours of operation were accompanied by more heat input. Annual heat input increased from 42,326,578 MMBtu per year in the baseline period to 47,660,058 MMBtu per year in the post-project period. Sahu Test., Tr. Vol. 5, 112:17-20.

265. Similar increases are shown in Ameren's certified CEMS data, which show that Unit 2 operated more hours and emitted more pollution per hour during the relevant post-project period as compared to the baseline period. The CEMS data show that Unit 2's operating time

increased by 123 hours per year, from 8,478 hours per year in the baseline to 8,601 hours per year in the applicable post-project period. Furthermore, when it was operating, Unit 2 emitted 456 more pounds per hour of SO_2 than it had in the baseline (increasing from 3,371 pounds per hour in the baseline to 3,827 pounds per hour in the post-project period). Knodel Test., Tr. Vol. 1-A, 109:7-16, 111:8-20, 112:3-10, 113:1-21.

266. Ameren's CEMS data also show that in 2011, the first calendar year after the 2010 boiler upgrade, Rush Island Unit 2 emitted more SO_2 than it had in any year since 1995. Knodel Test., Tr. Vol. I-A 82:9-19. During the applicable period of highest post-project emissions, Unit 2 emitted 16,458.1 tons per year of SO_2, which is 2,171 tons per year more than Unit 2 actually emitted during the baseline period. Sahu Test., Tr. Vol. 5, 74:15-18, 78:9-12, 112:25-113:3; Knodel Test., Tr. Vol. 1-A, 97:11-98:5.

267. Because all of the availability losses and outage hours caused by the reheater, economizer, and air preheater in the baseline were eliminated (243 EFPH and 146 outage hours), and it only takes an additional 21 hours of operation for Rush Island Unit 2 to emit 40 tons of SO_2, at least 40 tons of the overall increase in emissions at Unit 2 are related to the increased equivalent availability and operating hours enabled by the replacement of these components. Sahu Test., Tr. Vol. 5, 80:13-84:4, 115:10-116:4, 165:15-25.

C. Emissions Increases Based on Unit 2 Capability Analyses

268. In addition to improving the availability of both units, the 2010 boiler upgrade should have been expected to increase the capability of Rush Island Unit 2. As described further below, because Unit 1 experienced a capability increase after the 2007 boiler upgrade, Ameren should have expected – and did expect – a similar increase to occur after the 2010 boiler upgrade at Unit 2. Koppe Test., Tr. Vol. 3-B, 19:20-25.

1. The expected capability and efficiency impact of the Unit 2 boiler upgrade

269. In October 2007, Ameren engineers noted that Unit 1 had experienced an increase in capability due to the boiler component replacements, and Rush Island Supervising Engineer Gregory Vasel asked the Plant's Performance Engineer James Bosch to quantify that increase: "I looked at the 2006 [project justification] for the U2 economizer, reheater, and lower slope, and it projects *no* increase in capacity. I asked Mr. Bosch to quantify the capacity increase we've realized on U1, as well as the aux power reduction we're seeing with running one of our ID fans in low speed. … I communicated this to Leo Reid, who is working on the [project justification] for Bob Schweppe." Vasel Email (Pl. Ex. 130), at AM-02635983 (emphasis in original); Koppe Test., Tr. Vol. 3-B, 12:17-13:4.

270. Mr. Bosch reviewed full load tests from before and after the Unit 1 outage and determined that there had been a 19 MW increase in Unit 1's gross capability (from 611 MW to 630 MW). Pl. Ex. 130, at AM-02635983. Ameren project engineer Leo Reid incorporated a "16MW increase in generating capacity" into an updated financial analysis for the Unit 2 project. *Id*. at AM-02635982. In assessing what caused the capacity increase, Mr. Vasel instructed Mr. Bosch to look at the "delta P reductions of the [air preheater] vs. ([reheater] + economizer) …" *Id*. at AM-02635981. The updated financial analysis was provided by Mr. Vasel to Ameren's Director of Power Operations Robert Meiners, and was described as the "best information" that the plant had at the time. *Id*.

271. Mr. Koppe reviewed Ameren's full load tests and Plant Information data ("PI data") for Unit 1 and confirmed Mr. Bosch's analysis showing a 19 megawatt increase in capability had occurred at Unit 1. Mr. Koppe also reviewed the Plant Information data and other company documents and confirmed that there was a "dramatic drop" in the differential pressures

in the air preheater and economizer after the Unit 1 boiler upgrade. For example, a graph presented in Ameren's 2008 State of the System meeting indicates a "tremendous reduction" in the air preheater delta P from 14 to 5 inches of water. An air preheater delta P of 14 inches is "extremely high," and a reduction to 5 inches shows that Unit 1's capability was no longer limited by the effects of pluggage. Koppe Test., Vol. 3-A, 22:13-25:4; Vol. 3-B, 13:5-23; 2008 State of the System, Pl. Ex. 15, at AM-00196909; *see also* Sind Test., Vol. 9-B, 26:16-18 (air preheater differential pressures above 11 inches are "extremely high"); Cardinale Dep., July 31, 2014, Tr. 84:3-21; *see* FOF 75, 76 (showing graphs).

272. Ameren subsequently increased Unit 1's capability rating to 630 MW gross. Mr. Bosch reported the results of his quantification of a 19 MW increase in an email dated November 1, 2007. Vasel Email (Plaintiff's Exhibit 130), at AM-02635983. The document officially revising the 2008 capability stated that the increase was based on plant staff's request to reflect performance improvements following the spring 2007 outage during which the reheater, economizer, and air preheaters were replaced. Shelton Test., Tr. Vol. 10-A, 89:10-23.

273. In February 2008, Rush Island Plant Manager David Strubberg gave a presentation at a State of the System meeting in which he discussed the "Future Priorities" for Rush Island. Among the priorities discussed by Mr. Strubberg was a "25-30 MW" capability increase expected as a result of the boiler component and air preheater replacements and a separate 13 MW capability increase expected due to the replacement of the LP turbine. 2008 State of the System (Pl. Ex. 15), at AM-00196628; Koppe Test., Vol. 3-B, at 24:2-25:2.

274. A few months later, in June 2008, Rush Island Superintendent of Operations Andrew Williamson was asked by Ameren's Dispatch Coordinator Steve Schoolcraft to estimate the predicted capability of Unit 2 following the outage. Mr. Williamson noted: "We did

experience a substantial increase on Rush 1 due to increased boiler performance with the new RH/Econ/APHs and should reasonably expect the same for Rush 2." June 2008 Email (Pl. Ex. 267), at AM-02660313. Mr. Williamson predicted that Unit 2's capability would be 625 MW (net), which is about 655 MW (gross), after the outage. Of this, Mr. Williamson predicted that the boiler component replacements at issue, alone, would increase Unit 2's capability to 615 MW (net), or roughly 645 MW (gross), and replacement of the low pressure turbine would add another 12-15 MW. *Id*. at AM-02660307-08; Koppe Test., Tr. Vol. 3-B, 25:3-26:11; Williamson Test., Tr. Vol. 9-B, 40:10-41:2, 41:7-42:1.

275. Later in 2008, Mr. Williamson's prediction that Unit 2 would be able to achieve 625 MW (net) after the work was incorporated into Ameren's 10-Year System Plan, and represented an increase of 44 MW over the capability of Unit 2 at the time. This was the only increase in capability across the entire Ameren system noted in the 10-Year Plan. 10 Year Plan Spreadsheet (Pl. Ex. 251), at "UE" tab (hidden comment to row 20, col. F: "Rush Island unit 2 net output is increased from 581 to 625 (44 MW increase) provided by Steve Schoolcraft"), and "UE Changes" tab (row 54: "Rush Island 2's net output were changed to 625 MW per the plant's request …"); Koppe Test., Tr. Vol. 3-B, 26:16-27:6.

276. As described above, in 2009, Ameren completed an updated financial analysis for the Unit 2 outage. In addition to improvements in equivalent availability, Ameren's updated analysis included a 22.5 MW "projected annual increase … in plant capacity" as a result of the replacement of the reheater, economizer, and air preheater. Financial Analysis for Unit 2 (Pl. Ex. 48), at "Data Entry" Sheet, row 147, col. B & E; Koppe Test., Tr. Vol. 3-B, 28:2-12, 30:4-32:23.

277. The capacity increase input in the financial analysis was based on Ameren's estimate that replacing the economizer, reheater, and air preheater would allow Unit 2 to produce

30 more MW of capacity during the summer and 20 more MW for the rest of the year. The capability benefits were based on the combined effect of all three component replacements, and represented an increase over what Unit 2 was able to achieve during the pre-project period. Koppe Test., Tr. Vol. 3-B, at 27:7-32:23; Pl. Ex. 48, at "Data Entry" Sheet, row 147, col. B & E (formula bar: 0.25*30 + 0.75*20); July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465690 ("30MW gain in summer (3 mos), 20MW gain balance of year from Reheater, Economizer and APH investment"), Pl. Ex. 347, at AM-02637758 (same), June 15, 2009 CPOC Email (Pl. Ex. 895), at AM-02632842 (same).

278. In the Fall of 2009, Ameren also completed updated Full Work Order Authorizations for the replacement of the reheater, economizer, and air preheater. Consistent with previous projections, Ameren engineers described that a "gain of 30 MW in the summer and 20 MW in the winter will be obtained with the combined reheater, economizer, and air preheater replacements." October 15, 2009 Memo (Pl. Ex. 23), at AM-00926323; September 18, 2009 Memo (Pl. Ex. 26), at AM-00954160. Similar statements were made in other Ameren documents. *See, e.g.,* Pl. Ex. 893, at AM-02229417 ("Approximately 30 megawatts of unit capacity will be recovered during the hottest months because of lower gas flow pressure drops through the new economizer and air preheaters.").

279. Based on his review of Ameren's documents and data, Mr. Koppe confirmed that Ameren should have expected, and did expect, an increase in Unit 2's capability of at least 22 MW (gross) as a result of replacing the economizer, reheater, and air preheater. That additional capability would result from eliminating the effects of pluggage and allow Unit 2 to burn more coal per hour. Koppe Test., Vol. 3-B, 33:14-34:1; *see also* Vol. 3-A, 27:18-25, 29:2-8, Vol. 4-A, 46:23-47:18.

280. Ameren should not have expected any sustainable change in gross efficiency as a result of the reheater, economizer, and air preheater replacements. There was no expected efficiency benefits used as an input in the original Unit 2 project justification. The updated project justification included a 0.5% reduction in auxiliary load for the economizer and air preheater replacements, which equates to about 3 MW of net capability. The 3 MW reduction in auxiliary load would improve net efficiency, not gross efficiency, and would not be expected to change the full load heat input of Unit 2. FOF 117. Ameren did not project any decrease in fuel usage as a result of any efficiency changes associated with the component replacements. Koppe Test., Vol. 3-A, 5:13-20, Vol. 3-B, 28:13-29:8, Ex. 110, at AM-02465690 Pl. Ex. 48, at "Data Entry" sheet, at rows 149-152 (no decrease in fuel usage input for auxiliary load reductions).

281. Ameren's best expectation for the effect of the LP turbine on unit efficiency is that it would increase Unit 2's capability by 12 MW, which is the amount that was guaranteed by the vendor. Sind Test., Vol. 9-B, 20:3-12, 26:23-28:3. Ameren's updated financial analysis for the Unit 2 outage estimated that the efficiency improvements associated with the LP turbine would allow Unit 2 to produce 15 more MW of capability. The analysis was based on the assumption that the turbine-related efficiency improvements would allow Unit 2 to produce more megawatts but would not result in the unit burning less coal. Pl. Ex. 48, at "Data Entry" sheet, rows 149-152 (no "decrease in fuel usage" input for turbine replacement) Pl. Ex. 110, at AM-02465690; Koppe Test., Vol. 3-B, at 29:9-32:9.

2. Actual increases in Unit 2's capability

282. Consistent with the results achieved after the Unit 1 project, there was a big improvement in Unit 2 in the air preheater differential as a result of the air preheater replacements, where the differential pressure went from about 15 inches of water to about 5

inches. Koppe Test., Tr. Vol. 3-A, 25:22-27:17; Sind Test., Tr. Vol. 9-B, 25:6-26:2 (Mr. Sind's capacity analysis showed a big decrease in air preheater differential pressure from 13-14 inches to less than 6 inches); Williamson Test., Tr. Vol. 9-B, 44:7-14 (differential pressure of 15 inches indicates "high pluggage").

283. The improvement in the air preheater differential pressure, along with improvements in the other limitations (economizer differential pressure and ID fan suction pressure), meant that Unit 2's capability and ability to burn coal was no longer limited by pluggage after the Unit 2 boiler upgrade. Koppe Test., Tr. Vol. 3-A, 27:18-25, 28:7-14, 29:2-8. During the PSD baseline period, when the unit was experiencing extensive pluggage, the average full load capability of Rush Island Unit 2 was only 620 gross megawatts. FOF 120; Koppe Test., Tr. Vol. 3-B, 35:17-36:4, 45:12-46:5; PX 928 (Rule 1006 summary of full load tests for Unit 2).

284. The increase in capability at Unit 2 was evident as soon as the unit returned to service after the 2010 outage. For example, on May 29, 2010, Ameren conducted a Full Load Test in which Unit 2's gross capability was measured to be 655 MW, exactly as Mr. Williamson had predicted in 2008. Compare May 29, 2010 Full Load Test (Pl. Ex. 236) (655.13 gross megawatts), with June 2008 Email (Pl. Ex. 267), at AM-02660307-08 (predicting 625 net megawatt); Williamson Test., Tr. Vol. 9-B 41:14-16 (confirming that 625 net megawatts equates to 655 gross megawatts); *see also* Sind Test., Tr. Vol. 9-B, 29:19-30:16. A full load test conducted in October 2010, after the unit had been in service for several months following the boiler upgrade, showed even higher capability. The gross capability measured during that test was 664 MW. October 19, 2020 Full Load Test (Pl. Ex. 913). No capability limitations were noted by plant engineers in either test report.

285. Similarly, in October 2010, Ameren performed a test to verify that the new reheater, economizer, and air preheater had satisfied their performance guarantees. Unit 2's capability during the performance test was recorded as about 659 MW (gross). Boiler Performance Test Report (Pl. Ex. 81), at AM-00482381.

286. Ever greater capability was noted among the "Bottom-Line Results" of the Unit 2 outage during the 2010 State of the System Meeting: "679 Gross MWs!" 2010 State of the System (Pl. Ex. 41), at AM-02493751.

287. After the 2010 outage, Ameren also reported a substantial increase in Unit 2's capability to its system operator, MISO, to NERC, and to the Missouri Public Service Commission. Specifically, in September 2010, Ameren reported to NERC that Unit 2's <u>summertime</u> peak capability had increased to 648 MW (gross), 617 MW (net), "due to work completed in the 2010 major boiler outage (replacement low pressure turbines and ***numerous boiler modifications***)." October 27, 2010 MISO Verification Test Data (Pl. Ex. 139), at AM-02663830 (emphasis added). Ameren provided the same information to NERC in September 2010. September 15, 2010 Capability Validation (Pl. Ex. 133), at AM-02645178; *see also* Koppe Test., Tr. Vol. 3-B, 46:6-47:22.

288. Later in December 2010, Ameren responded to a request from the Missouri Public Service Commission to identify any plant upgrades that it expected to result in an increase in the amount of electricity the plant would produce in the future. MPSC Data Request 0257 (Pl. Ex. 222); Koppe Test., Vol. 3-B, 50:22-51:11.

289. Ameren told the Missouri Public Service Commission that the 2010 outage, including the component replacements at issue, would result in a 34 MW increase in Unit 2's capability, which it characterized as having been based on a "significant capacity restoration[]"

of 22 MW and a "true capacity increase[]" of 12 MW. Ameren Resp. to DR 0257 (Pl. Ex. 223); Koppe Test., Vol. 3-B, 51:12-52:22. Joe Sind, the Ameren engineer who performed the analysis supporting Ameren's statements to the Missouri Public Service Commission, confirmed that the reported 12 MW "true capacity increase" was based on the company's best expectation of the impact of the LP turbine replacement on the capability of the unit. Sind Test., Tr. Vol. 9-B, 20:3-12, 27:12-28:3. Mr. Sind's work papers show that his capacity analysis only looked at changes in unit capability and air preheater differential pressures and that he reported increases in capability for other Ameren units where work had been done on air preheaters but no turbine work had occurred. Sind Test., Tr. Vol. 9-B, 22:3-23:17, 25:6-26:2.

290. Mr. Koppe confirmed the increase in capability reported by Ameren to the Public Service Commission was consistent with his review of "thousands of hours of operation at full power." Koppe Test, Tr. Vol. 4-A, at 49:16-23.

291. In its response to the Missouri Public Service Commission, Ameren also reported that a 2.4% efficiency improvement had occurred as a result of the 2010 overhaul, of which 1.9% was due to the LP turbine replacement and 0.5% was due to the reduction in auxiliary load caused by the air preheater and economizer replacements. Dec. 6, 2010 Email re: "Updated DR 0257 Spreadsheet" (Pl. Ex. 216), AM-02757946; Ameren Resp. to DR 0257 (Pl. Ex. 223), at AM-02762954; Sind Test., Tr. Vol. 9-B 26:23-28:3; Finnel Test., Tr. Vol. 10-A, 12:16-13:18. As a result, the increase in capability Ameren reported to the Missouri Public Service Commission was greater than the reported efficiency improvement, which means that Unit 2 would be capable of burning more coal as a result of the 2010 work. Sind Test., Vol. 9-B, 28:6-18; Koppe Test., Vol. 3-B, 52:3-22.

292. Ameren takes its obligation to provide truthful information to the Missouri Public Service Commission seriously. Meiners Rule 30(b)(6) Dep., Oct. 15, 2014, Tr. 19:5-13.

293. Outside of this litigation, Ameren has attributed only 12 MW of the megawatt capacity increase at Unit 2 to the replacement of the LP turbine. Even as recently as a January 2011 email, Mr. Shelton reconfirmed that the 1.9% improvement in efficiency that Ameren reported to the Missouri Public Service Commission equated to 12 MW. Mr. Shelton further stated that while there might be a little more increase, he could not quantify or estimate any such benefit because it would be too uncertain. Shelton Test., Tr. Vol. 10-A, 100:13-101:1, 102:11-103:20; January 21, 2011 Email (Pl. Ex. 935), at AM-02248224.

294. Ameren further raised the capability of Unit 2 after the 2010 boiler upgrade. In December 2010, the gross capacity of Rush Island Unit 2 was further increased to "better reflect the increase in output following the spring 2010 outage in which two new LP turbines were installed and several boiler components were replaced." The July 2011 gross capacity was listed as 641 MW, which was 26 MW greater than the July 2008 capacity, while the December 2011 gross capacity was listed as 653 MW. December 14, 2010 Capability Table (Pl. Ex. 257), at AM-00067232, 67235; Shelton Test., Tr. Vol. 10-A, 92:22-93:15.

295. Mr. Koppe also conducted an analysis of the company's operating data and found a very substantial increase in Unit 2's capability after the 2010 boiler upgrade. Koppe Test., Tr. Vol. 3-B, 5:25-6:3; *id*. at 19:14-19 ("comparing the baseline period to the post-project period, the capability of Unit 2 increased by a large amount"). Mr. Koppe's findings are consistent with Ameren's documents.

296. Mr. Koppe's analysis of the Plant Information ("PI") data focused on those hours in which Unit 2 was operated at "full load," as indicated by the fact that the turbine valves were

wide open, and accepting as much steam as the boiler could produce. Mr. Koppe's approach is consistent with the approach Ameren uses for its full load tests, which are weekly tests done by plant engineers to determine the capability of the units. Koppe Test., Tr. Vol. 3-B, 6:9-7:16, 8:20-9:8; Sind Test., Vol. 9-B, 30:1-7 (during a full load test, the plant is trying to generate as much output as it can).

297. The pre-project period in Mr. Koppe's analysis of the PI data was January 2006 through December 2007, which is the period of time closest to the PSD baseline for which Ameren produced a complete set of data. The capability of Unit 2 during that time was 615 MW. Koppe Test., Tr. Vol. 3-B, 34:2-35:13.

298. The post-project period in Mr. Koppe's analysis of the PI data was October 2010 to August 2011, because that period provided the "best measure … of how much the unit's actual capability had increased" as a result of the project. The post-project capability of Unit 2 was 653 MW (gross). Koppe Test., Tr. Vol. 3-B, 34:16-35:8.

299. Based on the Plant Information data, the overall increase in capability was 38 MW. This is a 6.2% increase in Unit 2's capability. Koppe Test., Vol. 3-B, 49:9-15.

300. Based on his analysis of the PI data, Mr. Koppe determined that 23.3 MW (3.8%) of the increase were related to the component replacements at issue, and 14.7 MW (2.4%) were related to efficiency improvements. The 23.3 MW related to the project at issue resulted in Unit 2 being able to burn more coal per hour. Koppe Test., Vol. 3-B, 34:2-35:13, 49:1-50:18.

301. A similar increase in capability is shown by looking at all of Ameren's full load tests conducted during the PSD baseline period and comparing them to the post-project period. Based on the full load tests, the average capability of Rush Island Unit 2 increased from 620 MW (gross) during the baseline period to 657 MW (gross) during the post-project period, for an

overall increase of 37 MW. Koppe Test., Tr. Vol. 3-B, 35:17-36:4, 45:12-46:5; see also Pl. Ex. 928 (1006 summary of full load tests for Unit 2).

3. Dr. Sahu's emission calculations based on Unit 2's capacity increase

302. As noted above, Dr. Sahu determined that a capability increase of only 1.7 MW at Rush Island Unit 2 will cause a 40 ton per year increase in SO_2 emissions. Sahu Test., Vol. 5, 41:11-14, 46:5-11.

303. Dr. Sahu calculated the emissions associated with an 18-MW increase in capability and determined that Ameren should have expected such an increase to result in an emissions increase of 416.8 tons per year of SO_2. Sahu Test., Vol. 5, 84:5-87:25.

304. The company's project justification documents indicate that it expected Unit 2's capability to increase as a result of the project by more than ten times the amount that would result in 40 additional tons of SO_2 per year. Because the actual and expected increase in capability far exceeded 1.7 MW, and exceeded the 18 MW used in Dr. Sahu's calculations, at least 40 tons of the overall increase in SO_2 emissions are related to the capability increase caused by the replacement of the economizer, reheater, and air preheater at Unit 2. Sahu Test., Tr. Vol. 5, 87:22-25, 97:3-98:16.

4. Nothing in Mr. Caudill's opinions negates Mr. Koppe's calculations of capability increases

305. In contrast with Mr. Koppe, Ameren's capability expert, Mr. Caudill, ignored Ameren's full load tests. He failed to even analyze the performance test that specifically assessed the post-project performance of the boiler upgrades. Although Mr. Caudill reviewed many Ameren performance test reports for turbines, including turbines at plants that are not at issue in this case, he did not review the performance test report for the new reheater, economizer,

and air preheaters that are actually at issue in this case. Caudill Test., Tr. Vol. 10-B, 53:7-54:6; Boiler Performance Test Report (Pl. Ex. 81).

306. Instead, Mr. Caudill simply applied "filters" to the pre- and post-project data that excluded more than 99% of the data in the periods he chose. For instance, the pre-project period he chose included 7,473 hours of data, but he filtered out all but 28 of those hours. Similarly, the post-project period he chose included 14,304 hours, but he filtered out all but 111 hours. Caudill Test., Tr. Vol. 10-B, 67:11-22. The effect of Mr. Caudill's decision to filter out 99% of the operating data was that he only included hours in his capability analysis when the unit was not load limited. Caudill Test., Tr. Vol. 11-A, 4:16-6:4. Rather than assess the actual capability of the Unit 2 boiler, Mr. Caudill excluded all of the effects of pluggage on the boiler's actual capability, including the thousands of hours of data that demonstrated the actual effects of pluggage when the boiler could not produce enough. Koppe Test., Vol. 3-B, 7:17-8:19.

307. Removing Mr. Caudill's filters drastically changes the results of his pre-and post-project comparisons. For instance, at Unit 2, the unfiltered data show that average hourly gross heat input actually increased by over 300 mmBTU per hour and that the maximum hourly gross heat input similarly increased by more than 300 mmBTU per hour. Caudill Test., Tr. Vol. 11-A, 7:10-8:2. Similarly, Mr. Caudill's unfiltered data show that average hourly MW increased by approximately 50 MW and that the maximum hourly megawatts increased by 29 MW. Caudill Test., Tr. Vol. 11-A, 8:3-15 (Caudill Cross Test.).

308. In addition to confirming that Unit 2 was actually operating at higher average hourly heat inputs after the 2010 outage, Mr. Caudill's unfiltered data also confirm that Unit 2 spent significantly more time operating at higher loads following the 2010 outage. For instance, during the pre-project period when Unit 2 was experiencing load limitations due to pluggage, it

spent only 10% of its operating hours at the highest load range identified by Mr. Caudill, with the largest fraction of the operating hours (40%) spent at the second highest load range. By contrast, after the 2010 outage the load range at which Unit 2 operated the most had shifted up to the highest load range identified by Mr. Caudill, with Unit 2 spending 40% of its operating hours at the highest load range after the 2010 outage as compared to 10% before the outage. Caudill Test., Tr. Vol. 11-A, 11:8-13:16. This is exactly what would be expected when a plugged boiler is no longer load limited following an upgrade.

309. Mr. Caudill also expressed an opinion on efficiency. However, his efficiency analysis suffered from at least two fundamental flaws that render it of little to no relevance here. First, Mr. Caudill conceded that his opinions do not address whether the projects were expected to, or did, cause increases in the total annual amount of generation or fuel burned at Rush Island. By analogy, Mr. Caudill explained that his analysis looked at the equivalent of miles-per-gallon rather than looking at the total gallons of fuel used in a year. Caudill Test., Tr. Vol 10-B, 11:20-12:12.

310. Second, Mr. Caudill did not analyze the required NSR pre-and post-project periods. Ameren itself has chosen specific two-year pre-project baseline periods to present in this case for purposes of determining whether its projects violated New Source Review. Vol. 10-B, 30:19-31:12 (Caudill Cross Test.). Yet Mr. Caudill only used approximately one year of pre-project data. And at Unit 2 there was not a single month in the pre-project period that Mr. Caudill used that actually overlapped with the two-year NSR baseline period that is at issue in this case. Caudill Test., Tr. Vol. 10-B, 32:4-33:17.

311. In addition, the time periods Mr. Caudill examined skew his results. For instance, he relied on pre-project periods when efficiency was significantly worse than it was during the

applicable NSR baseline period, effectively making the unit less efficient for purposes of his comparison. Ameren's Exhibit TW demonstrates that during the pre-project period selected by Mr. Caudill, Rush Island Unit 2 had the worst efficiency (i.e., the highest heat rate) in any of the five years leading up to the 2010 outage. Yet Mr. Caudill did not even look at data from those other years. Exhibit TW; Caudill Test., Tr. Vol. 10-B, 42:25-43:19.

D. PROSYM-BASED EMISSIONS CALCULATIONS

312. In addition to Dr. Sahu's translation of the performance improvements calculated by Mr. Koppe into calculations of emissions increases, the United States also presented emissions analyses performed by Dr. Ezra Hausman using Ameren's production cost modeling program.

313. Ameren's experts agree that using results from a production cost modeling run is an appropriate way to forecast future emissions for a New Source Review analysis. King Test., Tr. Vol. 6-B, 66:3-15; Chupka Test., Tr. Vol. 8-B, 80:14-17. In fact, Ameren expert Michael King admitted that he used production cost modeling runs in his New Source Review analyses in prior enforcement cases. King Test., Tr. Vol. 6-B, 66:16-19.

1. Production cost modeling at Ameren

314. "A production cost model is a computer application used to simulate an electric utility's generation system and load obligations." Finnell MPSC Test. (Pl. Ex. 439), at 3:10–11.

315. Ameren regularly uses a production cost model called ProSym to forecast its unit operations for a variety of business purposes, including fuel budgeting and rate case justifications before the Missouri Public Service Commission. Finnell MPSC Test. (Pl. Ex. 439), at 3:11–14; Ringelstetter Test., Vol. 11-B, 12:15–17.

316. Ameren's ProSym model is calibrated with actual load information to check its accuracy as a forecasting tool. Finnell Rule 30(b)(6) Dep., Nov. 22, 2013, Tr. 28:6-20. The calibration shows that the projection runs "come within a fairly high degree of accuracy." Finnell Rule 30(b)(6) Dep., Nov. 22, 2013, Tr. 28:6-29:13. According to Ameren, ProSym "does a good job of modeling the electric system and how it's operated." Finnell Rule 30(b)(6) Dep., Nov. 22, 2013, Tr. 29:2-13.

317. This computer simulation software uses a complex algorithm, but is basically a "supply and demand" model that predicts how the system operator, MISO, will dispatch Ameren's units hour-by-hour for a given period after taking into account various inputs like unit performance projections and load forecasts that Ameren develops as inputs into the program. Finnell Test., Tr. Vol. 9-B, 67:10–11; Hausman Test., Tr. Vol. 4-B, 41:17–23, 44:7–15.

318. As Ameren's witness Mr. Finnell explained, at Ameren, "[t]he fuel budget process involves collecting information from various work groups or [expert] areas in the company for items that are used in the ProSym model. The ProSym model is then executed, and the results are prepared and issued to various groups within the company." Finnell Test., Tr. Vol. 9-B, 66:22–67:1.

319. The fuel budgeting process typically involves forecasting unit operations for five years. Finnell Test., Tr. Vol. 9-B, 70:20- 21.

320. Ameren's modeling runs show how unit performance improvements interact with rising system loads or other market factors to affect unit operations. Hausman Test., Tr. Vol. 4-B, 40:7–12; Ringelstetter Test., Tr. Vol. 11-B, 56:10-21.

321. Jaime Haro, Ameren's manager in charge of load forecasting and risk management, testified at trial he had worked with the company's modeling department, and

confirmed that Ameren's modeling resources could be used to perform sensitivity analyses and investigate how different scenarios might impact operations at Ameren's units. Haro Test., Tr. Vol. 9-A, 133:1–14.

322. The inputs used by ProSym in simulating dispatch and operations can be divided into two types: market factors and unit characteristics. Hausman Test., Tr. Vol. 4-B, 42:13–17.

323. Market considerations that are input into ProSym include things like hourly load data—e.g., load forecasts for the market Ameren serves—as well as fuel costs, off-system market data, and system requirements. Finnell MPSC Test. (Pl. Ex. 439), at 3:3–5; Hausman Test., Tr. Vol. 4-B, 42:21–43:15.

324. Unit characteristics that are supplied for the model include measures of the unit's efficiency (also called its "heat rate" as it describes how much heat or fuel it takes for the unit to produce each unit of electricity), the unit's maximum capacity, the unit's projected availability, and other physical constraints such as how long it takes the unit to ramp up to full load if it is taken offline for any reason (its "ramping constraints"). Hausman Test., Tr. Vol. 4-B, 43:21–44:3.

325. As used by Ameren, the model takes into account two measures of unit availability when it projects unit operations: a unit's "forced outage rate," and its "partial outage rate." Hausman Test., Tr. Vol. 4-B, 52:25–53:20.

326. The forced outage rate is a measure of time that the unit was able to run at any level. So, in a non-leap year, it would be the number of hours the unit could run divided by 8,760, the number of hours in a year. Hausman Test., Tr. Vol. 4-B, 53:2–6.

327. The partial outage rate is the model's input for deratings. It is the percentage of actual available generation divided by the total available generation from the unit assuming

every available hour could have been loaded at full power. Hausman Test., Tr. Vol. 4-B, 53:9–15.

328. Adding the forced and partial outage rates of a unit together gives you the "effective unit outage rate." To determine a unit's equivalent availability factor, one subtracts the effective unit outage rate from 1. Hausman Test., Tr. Vol. 4-B, 53:16–54:9.

2. Dr. Hausman's sensitivity analyses

329. After investigating Ameren's modeling files, Dr. Hausman identified several performance improvements that Ameren modeled at its Rush Island plants concurrent with the boiler upgrade work at issue in this case. Hausman Test., Tr. Vol. 4-B, 47:19–48:2.

330. Dr. Hausman executed "sensitivity analyses" using Ameren's production cost modeling files to determine how the performance improvements at the Rush Island Units were impacting the modeling projections for those units' operations. Hausman Test., Tr. Vol. 4-B, 47:19–48:2.

331. A sensitivity test is a standard modeling technique whereby a modeler runs a computer simulation multiple times, varying only one input or parameter a little bit each time in order to investigate how that single element interacts with the rest of the system being modeled. Hausman Test., Tr. Vol. 4-B 46:24–47:8.

332. Dr. Hausman's sensitivity analyses revealed straightforward, linear relationships between unit capacity or unit availability and the unit's projected fuel use—and, accordingly, pollution levels. Hausman Test., Tr. Vol. 4-B, 55:20-56:19, 63:20-64:20, 65:22-66:7, 71:7-25, 72:12-21.

333. As shown below, any one of the performance improvements that Ameren modeled at the Rush Island units following the boiler upgrades would result in a concomitant

increase in fuel use that would translate into a pollution increase well above the 40 tons-per-year threshold for SO_2 to trigger New Source Review. Hausman Test., Tr. Vol. 4-B, 73:11–21.

a. Unit 1 sensitivity analysis

334. For Unit 1, Dr. Hausman reviewed a credible fuel budgeting modeling run performed in 2006 in order to evaluate how performance improvements following the 2007 projects at Unit 1 would be projected to affect operations and pollution. The model run he used was contemporaneously performed by the company when Ameren was planning the Unit 1 work, the modeling files were complete (allowing for replication and verification of the results), and the inputs presented credible, long-term forecasts without "red flags" such as artificial constraints or other indications that would suggest the model run was used for a different purpose or did not reasonably reflect company expectations. Hausman Test., Tr. Vol. 4-B, 68:4-16 & 97:15–98:1; *see also* Finnell Test., Tr. Vol. 10-A, 5:23–8:23 (discussing Plaintiff's Exhibit 892 and updates to Ameren's 2006 fuel budget modeling).

335. Comparing the year before the work was performed to the year after it was completed, Ameren modeled a 4% increase in equivalent availability following the boiler upgrades—a 2.2% improvement in the unit's forced outage rate and a 1.8% improvement in the unit's partial outage rate. Hausman Test., Tr. Vol. 4-B, 69:16–22.

336. Dr. Hausman determined that a one percentage point improvement in Unit 1's forced outage rate would translate into an additional 481 billion BTUs of fuel consumption per year and an additional 162 tons of SO_2 per year. Hausman Test., Tr. Vol. 4-B, 71:19-23.

337. Dr. Hausman also found that reducing Unit 1's partial outage rate (deratings) by one percentage point would result in an additional 408 billion BTUs of fuel consumption per year and an additional 138 tons of SO_2 per year. Hausman Test., Tr. Vol. 4-B, 72:12–21.

b. Unit 2 sensitivity analysis

338. For Unit 2, Dr. Hausman reviewed Ameren's "Original" 2010 Fuel Budget modeling run performed in early 2010 in order to evaluate how performance improvements following the 2010 projects at Unit 2 would be projected to affect operations and pollution following that work. That model run was used by Ameren's environmental services department to perform its "reasonable possibility analysis" for that work. Hausman Test., Tr. Vol. 4B, 49:6–10; Hutcheson Test., Vol. 11-A, 38:22-39:1.

339. Dr. Hausman determined that each additional megawatt of increased unit capacity at Unit 2 will result in that unit burning an additional 69 billion BTUs per year and an additional 23 tons of SO_2 per year. Hausman Test., Tr. Vol. 4-B, 59:24–60:2.

340. Dr. Hausman also found that a one percentage point improvement in the unit's forced outage rate would translate into an additional 566 billion BTUs per year and, as a result, an additional 189 tons of SO_2 per year. Hausman Test., Tr. Vol. 4-B, 64:15–20.

341. A one percentage point improvement in Unit 2's partial outage rate would translate into an additional 466 billion BTUs per year and, as a result, an additional 156 tons of SO_2 per year. Hausman Test., Tr. Vol. 4-B, 64:15–20.

3. Dr. Hausman's "with and without" analyses

342. In addition to his sensitivity analyses, Dr. Hausman also performed a "with and without" analysis using Ameren's ProSym model. A "with and without" analysis is a standard modeling technique used throughout the industry and in many fields that employ computer modeling. It compares two scenarios—one in which the performance improvements Ameren expected were realized (the scenario Ameren itself modeled), and another scenario in which the

units simply continued operating as they had in the past, without realizing any performance improvements as a result of the modifications. Hausman Test., Tr. Vol. 4-B, 25:12–18, 74:5–7.

343. This technique allows the modeler to look at the impact of one change (or set of changes) in the system while holding all else constant. Hausman Test., Tr. Vol. 4-B, 25:16–19 & 74:7–12.

344. Ameren's experts conceded that utilities often run a production cost model twice, changing just one variable, in order to see how changing that variable would impact the output of the model. King Test., Tr. Vol. 6-B, 67:14-19; Chupka Test., Vol. 8-B, 79:18-81:2. As Ameren expert Marc Chupka testified, the type of with-and-without modeling analysis that Dr. Hausman did in this case is a "standard tool" in utility modeling practice. Chupka Test., Tr. Vol. 8-B, 80:18-22.

345. Ameren expert Michael King agreed that the difference between two estimates of future emissions – one of which accounted for the project and one of which did not – would show the impact of the project. King Test. Tr. Vol. 6-B 69:7-71:23.

346. In his testimony in a prior NSR enforcement case, Ameren expert Michael King performed two modeling runs to identify the emissions that he testified were unrelated to the project and should be excluded from an NSR calculation under the demand growth exclusion. King Test. Tr. Vol. 6-B 65:17-21. In other words, Mr. King used the same technique in that case that Dr. Hausman did here (except Mr. King set out to identify the emissions that were *unrelated* to the project, while Dr. Hausman identified the emissions *related* to the project).

347. Similarly, Ameren expert Marc Chupka testified that one way to perform an NSR emissions analysis would be to (1) start with a contemporaneous emissions projection that

incorporates the effect of the project; (2) compare that projection to the baseline period; and then (3) address any unrelated factors. Chupka Test., Tr. Vol. 8-B, 81:3-24.

a. Unit 1 analysis

348. For Unit 1, Dr. Hausman's with-and-without analysis compared the ProSym modeling forecasts performed by Ameren in 2006 to another version in which the unit did not increase its availability by 4% following the work.

349. The comparison revealed that, but for the performance improvements modeled at the unit, Rush Island Unit 1 would have operated 192 fewer hours, the unit would have burned over 1,600 billion BTUs less coal, and it would have emitted 562 fewer tons in the year he examined. Hausman Test., Tr. Vol. 4-B, 79:23–80:7.

350. Based on Ameren's updated 2006 fuel budget modeling, the company projected that it would emit as much as 15,561 tons per year of SO_2 in the five years after the project, a 687-ton increase above baseline levels. Of that projected increase in emissions, 562 tons would not have been projected were it not for the availability improvements modeled at Unit 1. Hausman Test., Tr. Vol. 4-B, 80:10–21.

351. Dr. Hausman also used Ameren's Plant Information data to develop inputs based on the putative performance improvements in the company's Plant Information data. Dr. Hausman accepted the data at face value and gave Ameren credit for a 3.0% efficiency improvement (more than Ameren reasonably should have or did expect) and also incorporated a 20-MW increase in Unit 1's capacity. Hausman Test., Tr. Vol. 4-B, 81:1–3.

352. Using these inputs from the company's Plant Information data and re-running his with-and-without analysis, Dr. Hausman found that Ameren would have projected a 716-ton

increase above baseline pollution levels, of which 591 tons would not have been projected but for the performance improvements at the unit. Hausman Test., Tr. Vol. 4-B, 81:3–6.

b. Unit 2 analysis

353. For Unit 2, Dr. Hausman compared the ProSym modeling forecasts performed by Ameren to another version in which the unit did not increase its capacity by 18 MW and improve its availability by 2% following the work. The performance improvements represented by Ameren in this model are consistent with the performance improvements that Mr. Koppe independently determined the company should have expected to result from the boiler work. Hausman Test., Tr. Vol. 4-B, 82:21–24. The comparison revealed that, without the performance improvements modeled at the unit, Rush Island Unit 2 would have operated 96 fewer hours, the unit would have burned nearly 1,600 billion BTUs less in coal, and it would have emitted 746 fewer tons of SO_2 in the year he examined. Hausman Test., Tr. Vol. 4-B, 75:18–76:5.

354. Based on Ameren's "original" 2010 fuel budget modeling, the company projected as much as 16,816 tons per year of SO_2 in the five years after the project, a 2,528-ton increase above baseline levels. Of that projected increase in emissions, 746 tons would not have been projected were it not for the performance enhancements modeled at Unit 2. Hausman Test., Tr. Vol. 4-B, 76:22–77:6.

355. As with Unit 1, Dr. Hausman reviewed Ameren's Plant Information data to develop inputs based on the putative performance improvements contained in the company's data. Once again, Dr. Hausman accepted the Plant Information data at face value. Thus, Dr. Hausman gave Ameren credit for an efficiency improvement (4.2%) that exceeded what it reasonably should have or did expect, and also incorporated a 34 MW increase in capacity (a 5.75% increase). Hausman Test., Vol. 4-B, 79:6–8.

356. Using these PI-inputs and re-running his with-and-without analysis, Dr. Hausman concluded that Ameren still would have projected a 1,905-ton per year increase above baseline pollution levels, of which 696 tons would not have been projected but for the performance improvements at the unit. Hausman Test., Tr. Vol. 4-B, 78:21–79:2.

IV. AMEREN HAS FAILED TO MEET ITS BURDEN TO ESTABLISH THE APPLICABILITY OF THE DEMAND GROWTH EXCLUSION

357. Ameren pled as its Twenty-Sixth Affirmative Defense that any emissions increases following the 2007 and 2010 outages at Rush Island Unit 1 or Unit 2 were the result of increased demand and not the projects at issue. Answer (ECF No. 250), at 31.

A. Background about the Market for Rush Island's Generation

358. The Midcontinent Independent System Operator ("MISO") serves as the dispatch operator for Ameren's Rush Island units. Hausman Test., Tr. Vol. 4-B, 33:24–34:1.

359. As a dispatch operator, MISO aims to meet system demand with the lowest-cost—though still reliable—portfolio of electricity generation it can. "[G]eneration owners tell the dispatch operator what's available and at what price. And then the dispatch operator uses a computer algorithm to find the lowest cost way of meeting load." Hausman Test., Tr. Vol. 4-B, 33:19–23, 34:2–9.

360. "MISO's job is to find the lowest cost way of meeting that demand. And the way they do that is they start by turning on the lowest cost sources of energy first. Those are often nuclear or coal units like the Rush Island units. And then they progressively turn on more and more costly generators to run until at every moment the energy being generated is balanced with the load required by the system." Hausman Test., Tr. Vol. 4-B, 31:14–21.

361. As a general matter, electricity cannot be stored, so—at least when considering the system as a whole—electricity production and demand must be constantly balanced. Hamal Test., Tr. Vol. 9-A, 98:11–13. That does not mean, though, that electricity production and demand are the same thing. As with every market, the electricity market has a demand side and a supply side—and just because demand for electricity may be rising does not mean that any specific generating unit will be used to serve that rising demand. Hamal Test., Tr. Vol. 9-A 41:24–42:8.

362. The Rush Island units cannot generate—and so cannot serve demand—if they are unavailable. And Ameren cannot offer generation it does not have to the market: if a Rush Island unit was forced offline because of some mechanical failure, Ameren would not be able to offer Rush Island generation into the MISO market. Similarly, when Rush Island units are load limited or derated for some reason, Ameren cannot offer the unavailable portion of its generating capacity to the MISO market. Hamal Test., Tr. Vol. 9-A, 40:21–41:7; Naslund Test., Tr. Vol. 6-B, 13:24-14:5; King Test., Tr. Vol. 6-B, 52:24-53:6 (demand and availability are both necessary in order for a unit to operate).

363. Furthermore, in general, MISO cannot call on Ameren's units to provide more electricity than Ameren has offered into the market. Hamal Test., Tr. Vol. 9-A, 41:10–14; Hausman Test., Tr. Vol. 4-B, 35:6–9.

364. Ameren does not need MISO's permission to bring a unit offline if it has experienced a tube leak or other failure at the unit. Hamal Test., Tr. Vol. 9-A, 41:17–20; Hausman Test., Tr. Vol. 4-B, 35:10–12.

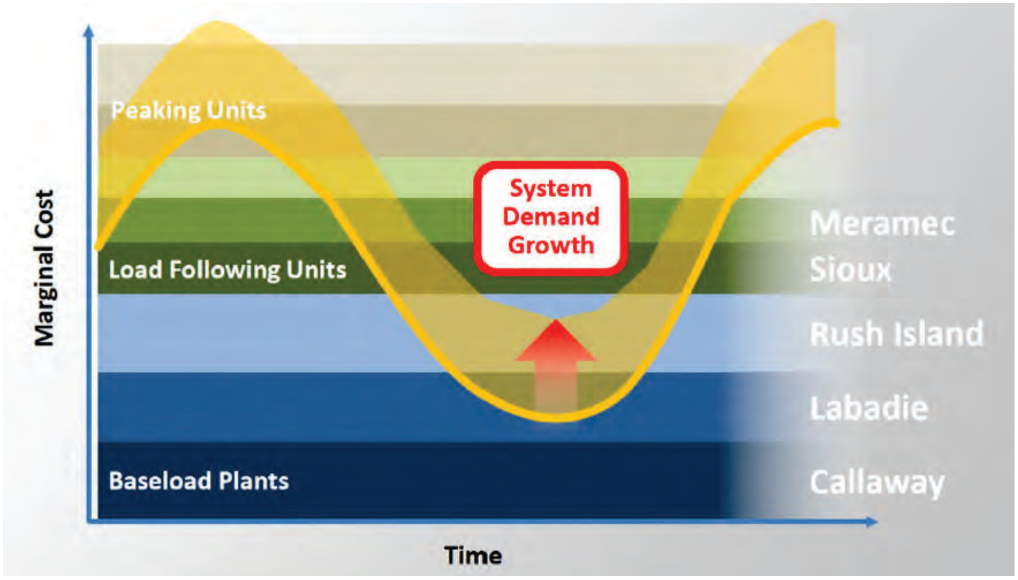
365. MISO does not tell generation owners like Ameren how to spend their capital improvement budgets or how to improve their generation services. Hamal Test., Tr. Vol. 9-A,

41:21–23; Hausman, Tr. Vol. 4-B, 35:13–19; Meiners Test., Tr. Vol. 7-B, 57:17-58:13. Ameren controls the engineering of its units and decides what maintenance work needs to be performed and when to perform that work. Hausman Test., Tr. Vol. 4-B, 36:3–6; Meiners Test., Tr. Vol. 7-B, 57:17-58:13. By controlling the maintenance of and investment in the Rush Island generating units, Ameren manages those supply assets to ensure that they can serve as much market demand as they can. Hausman Test., Vol. 4-B, 35:23–36:21.

366. MISO does not pay bonuses to generation owners when their units perform well or reliably. Hausman Test., Tr. Vol. 4-B, 35:20–22.

367. "Rush Island has low operating cost[s]. MISO's job is to run the system as efficiently as possible, and that translates into MISO doing what it can to get Rush Island to run more." Hamal Test., Tr. Vol. 9-A, 37:20–23. As a natural corollary, if Ameren is able to make the Rush Island units able to operate more hours or at higher loads, then MISO would call on them to make use of that new-found capability. Hamal Test., Tr. Vol. 9-A, 51:22–52:17.

368. Jaime Haro, Senior Director of the Ameren's Enterprise and Commodity Risk Management Department, described how the Rush Island units compare to other units in Ameren's generating portfolio by providing a generalized schematic of the "merit order" or "dispatch order" of its various plants. Haro Test., Tr. Vol. 9-A, 130:14 – 132:9; Hausman Test., Tr. Vol. 4-B, 31:14–32:22. At the bottom of the schematic are units that cannot shut down and are the cheapest to run, such as Ameren's Callaway nuclear plant. Next up to be dispatched are other baseload coal units such as the Rush Island generating units that run basically whenever they are available. Haro Test, Vol. 9-A, 65:1–66:1; Tr. Vol. 6-A, 55:4-7.



[Ameren Demonstrative WC_2]

369. Coal units like Rush Island are expensive to shut down, and it takes hours—sometimes as much as a day—to start them back up. Hamal Test., Tr. Vol. 9-A, 45:10–15. As such, the Rush Island units may ramp down their generation through the night or during other periods of low system load, but they generally do not turn off. Hamal Test., Tr. Vol. 9-A, 46:7–23; Haro Test., Tr. Vol. 9-A, 131:7–12.

370. As illustrated by Ameren's schematic, the general impact of an increase in system demand is that the Rush Island units might ramp down a little later at night than they otherwise would, or ramp up to high loads a little earlier in the mornings than they otherwise would. Haro Test., Tr. Vol. 132:2–9.

371. As Mr. Haro testified, though, when load is up, as it often is during the "on peak" hours shown with relatively high prices at the left and right hand side of the graphic, the Rush Island units are typically generating as much as they can. Haro Test., Tr. Vol. 9-A, 131:1–15.

Obviously, if the unit is already fully loaded, it cannot increase its output in order to serve more of the market's demand for electricity. Hamal Test., Vol. 9-A, 58:16–17.

372. In general, the Rush Island units are more likely to be running fully-loaded during "on peak" hours than "off peak" hours. Hamal Test., Tr. Vol. 9-A, 59:3–5, 59:17–19. Even according to Ameren's expert's analysis, only a third of the hours the Rush Island Unit 2 operated with some available capacity to spare were "on peak" hours. Thus, according to Ameren's expert, Unit 2 was at maximum capacity for more than half of all hours in the baseline period—and more than two-thirds of all "on peak" hours in the baseline period. Ringelstetter Test., Vol. 11-B, 40:10 – 15; Def. Demonstrative TK-15.[3]

373. This relationship is borne out in Ameren's modeling files. For example, as is evident in Ameren's modeling efforts performed in 2006, even when the company forecast system load to increase each year, the Rush Island units were projected to generate at essentially flat levels throughout the forecast period. As Dr. Hausman explained, this clearly indicates the Rush Island Units are baseload units, and they are more or less insensitive to variations in system load. Hausman Test., Tr. Vol. 4-B, 45:20–22.

B. Ameren's Failure of Proof Regarding Demand Growth as a Cause of Increased Emissions

374. In the company's 2011 Corporate Social Responsibility Report, Ameren characterized the projects at issue in this case as "necessary to respond" to increased demand. Naslund Test., Tr. Vol. 6-B, 16:12-15, 18:3-5; Corporate Social Responsibility Report (Pl. Ex.

---

[3] Even this number appears to understate how often the units were run at their "available capacity." Ms. Ringelstetter's analysis does not accurately reflect those hours when the unit was ramping up after coming offline. She counted those hours as having "available capacity" even though the units would have been physically incapable of generating more during that time. Ringelstetter Test., Vol. 11-B, 69:3–70:15.

431) at AM-00510618. In other words, Rush Island could not have served at least some of the increasing system demand *without* the Rush Island upgrade projects.

375. To the extent that system demand was growing, as of 2008, Ameren expected that its purchase of three combustion turbines (natural gas units), would satisfy that demand growth until at least 2018. Naslund Test., Tr. Vol. 6-B, 15:14-16:11.

376. To the extent that system demand was growing, Ameren did not offer any evidence at trial to show how changes in system demand, if any, would or did specifically impact the operation of and emissions from the Rush Island units. For example, Ameren utility market expert Cliff Hamal admitted that he did not quantify "how demand would change Rush Island's operations in any way." Hamal Test., Tr. Vol. 9-A, 39:23–40:5.

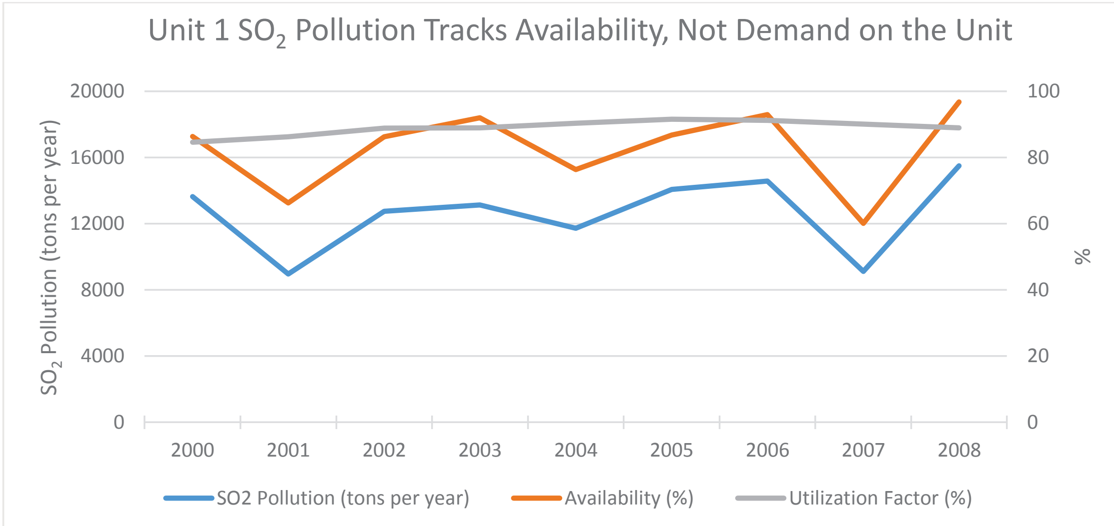
377. The industry does have a standard measure that isolates demand for the output of individual generating units. That metric is known as the "utilization factor," and Ameren itself uses it during the course of its business. Sahu Test., Tr. Vol. 5, 56:18-57:3, 76:15-22; Ringelstetter Test., Tr. Vol. 11-B, 80:18-81:6; Economic Evaluation of Plant-upgrading Investments (Pl. Ex. 241), at AME_RHK000011-12 ("loading order [is] reflected in the utilization factor") (EPRI Report, Vol. 1); Availability Worksheet (Pl. Ex. 250), at Spreadsheet Tab "Instructions" (utilization factor is the "percent of mwhrs used after outages and derates").

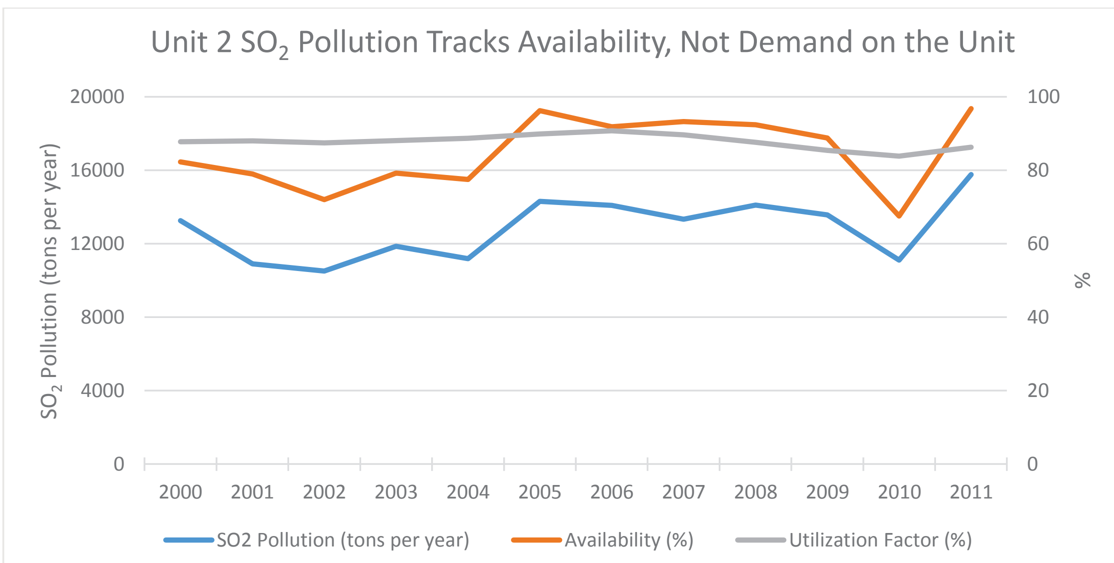
378. Ameren expert Michael King testified that demand for the generation of coal units had been decreasing since 2007 due to falling natural gas prices. King Test., Tr. Vol. 6-B, 34:20-35:3, 35:8-16. Mr. King also testified that the utilization factors for the Rush Island units have been declining since around 2007. King Test., Tr. Vol. 6-B, 87:13-24. Mr. King further explained that if the utilization factor is decreasing, any emissions increases during that time period cannot be the result of increased demand. King Test., Tr. Vol. 6-B, 88:3-6, 89:9-12.

379. Ameren expert Sandra Ringelstetter calculated utilization factors in this case and found that the utilization factor for Unit 1 was projected to remain basically constant and in fact decreased from 91.18% in the baseline period to 89.66% in the applicable post-project period. Ringelstetter Test., Tr. Vol. 11-B, 83:4–15; Def. Ex. NE, at "RI U1 2007 Summary" tab. As a result, any increase in generation that was projected to occur and was in fact realized at Unit 1 following the 2007 outage cannot be attributed to increased demand.

380. For Unit 2, Ms. Ringelstetter calculated that Unit 2's utilization was projected to increase slightly (about 2%), but that it in fact decreased from 91.45 in the baseline period to 89.37 in the relevant post-project period. Ringelstetter Test., Tr. Vol. 11-B 81:7-83:3; Def. Ex. NE, at "RI U2 2010 Summary" tab. As a result, the more than 15% increase in emissions that was projected to occur and that was in fact realized at Unit 2 following the 2010 boiler upgrades cannot be attributed to increased demand.

381. At Rush Island, emissions of SO_2 track availability of the units more closely than demand. Sahu Test., Tr. Vol. 5, 103:5-107:19; *see also* King Test., Tr. Vol. 6-B, 86:2-23 (Ameren expert conceding the relationship between availability and SO_2 pollution at Rush Island).





382. Ameren did not offer any evidence to explain how an increase in emissions associated with an increase in capacity at Rush Island can be caused by demand growth.

V. AMEREN'S NSR EMISSION ANALYSES

383. Ameren called two witnesses at trial from its Environmental Services Department: Steven Whitworth and Michael Hutcheson. Mr. Whitworth was the Supervisor of the Air

Quality section within Ameren's Environmental Services Department from 2002 to 2007. In 2007, Mr. Whitworth became Department manager, which meant that he has ultimate responsibility over the entire Environmental Services group. Whitworth Test., Tr. Vol. 11-A, 90:4-9. Mr. Hutcheson works for Mr. Whitworth and was the Ameren employee responsible for performing the NSR emissions calculations that Ameren presented at trial. Hutcheson Test., Tr. Vol. 11-A, 34:2-35:2, 54:20-55:11, 63:9-15.

384. Ameren does not have any internal guidelines for performing a New Source Review analysis. Hutcheson Test, Tr. Vol. 11-A, 65:21-24.

385. The Environmental Services Department at Ameren is responsible for determining New Source Review applicability. Environmental Services does not have any role in Ameren's capital project justification process. Naslund Test., Tr. Vol. 6-B, 19:20-23, 20:7-18.

386. Project justification packages include a document called the Project Risk Management Plan. Schweppe Dep., May 20, 2014, Tr. 112:2-7.

387. Robert Schweppe was Director and later Managing Supervisor of the Project Engineering group at Ameren. Prefatory Statement to Depo Designation, Vol. 6-A, 19:9-11; Project Approval Package (Pl. Ex. 1), at AM-0072586. Mr. Schweppe signed off on the Project Risk Management Plan for the major component replacements at issue for both Unit 1 and Unit 2. Project Approval Package (Pl. Ex. 1), at AM-00072606 (Unit 1 boiler components); Project Approval Package (Pl. Ex. 3), at AM-00072841 (Unit 2 boiler components); Project Approval Package (Pl. Ex. 4), at AM-00072864 (Unit 1 air preheater); Project Approval Package (Pl. Ex. 6), at AM-00072923 (Unit 2 air preheater).

388. Each Project Risk Management Plan lists whether certain risk factors have been addressed, followed by a series of check boxes. One of the check boxes is for

"Legal/Environmental." For each of the projects at issue, the Legal/Environmental box was not checked. Pl. Ex. 1 at AM-00072606; Pl. Ex. 3 at AM-00072841; Pl. Ex. 4 at AM-00072864; Pl. Ex. 6 at AM-00072923.

389. Mr. Schweppe testified that he did not know why the Legal/Environmental box was not checked, and that he did not "recall that box ever being checked" for "any project risk plan." Mr. Schweppe continued that he did not know what the box meant and that he had never asked anyone to understand what it meant. Schweppe Dep., May 20, 2014 Tr., 112:14-114:5.

A. Ameren Performed No Pre-Project NSR Analysis for Either Project

1. Rush Island Unit 1

390. Ameren has admitted that it performed no emission calculations for purposes of determining PSD applicability prior to undertaking the 2007 project at Unit 1. Whitworth Test., Tr. Vol. 11-A, 94:23-25; Boll Test., Tr. Vol. 8-B, 38:3-5; Birk Dep., Sept. 24, 2013, Tr. 220:14-21; *see also* Knodel Test., Tr. Vol. 1-A, 88:10-12; Ameren Closing Arg., Vol. 12, 51:18-20.

391. Mr. Whitworth, the Head of Ameren's Environmental Services department, testified at trial that the only pre-project emission evaluation he did for Unit 1 was a non-numerical analysis that considered only whether the Unit 1 project would increase the unit's potential to emit. Mr. Whitworth also admitted that he relied on an inapplicable provision of the Missouri regulations. Whitworth Test., Tr. Vol. 11-A, 88:16-25, 90:12-15, 90:20-92:19; *see also* Boll Test., Tr. Vol. 8-B, 9:7-13:25 (company relied on non-numerical evaluation of whether project would have an impact on maximum continuous rating), 38:3-14.

392. Ameren's Environmental Services Department did not communicate with project engineer David Boll at any time prior to the Unit 1 project completion in 2007. Boll Test., Vol. 8-B, 39:17-21, 40:6-9.

393. The Rush Island Plant Manager at the time of the 2007 outage was Robert Meiners. As plant manager, he was accountable for making sure the plant complied with environmental regulations. Meiners Test., Tr. Vol. 7-B, 64:2-5. However, Mr. Meiners had no communications with anyone about whether to seek a New Source Review permit for the Unit 1 project. When asked whether he understands that PSD requires utilit[ies] to make a prediction of future emissions in order to do [] emissions analys[es], Mr. Meiners replied "That's not – not my responsibility. I'm not involved with it." Meiners Dep., April 8, 2014, Tr. 342:11-17. In fact, Mr. Meiners testified that throughout his more than 40-year career at Ameren, he never had a single discussion with anyone about whether or not to seek an NSR permit for any capital project at all. Meiners Test., Tr. Vol. 7-A, 68:2-18 and Vol. 7-B, 64:2-20. Similarly, Mr. Strubberg testified that he was not involved in any assessment of whether the projects triggered PSD. Strubberg Test., Tr. Vol. 8-A, 73:17-74:5.

394. Prior to undertaking the Unit 1 project, Ameren did not communicate with permitting authorities about whether a New Source Review permit would be required. Whitworth Test., Tr. Vol. 11-A, 106:3-7.

2. Rush Island Unit 2

395. The Head of Ameren's Environmental Services department, Mr. Whitworth, testified at trial that the only pre-project emission evaluation he did for Unit 2 was a non-numerical analysis that considered only whether the Unit 2 project would increase the unit's potential to emit. Mr. Whitworth also admitted that he relied on an inapplicable provision of the Missouri regulations. Whitworth Test., Tr. Vol. 11-A, 88:16-25, 90:12-15, 90:20-92:19.

396. The Ameren employee who was responsible for doing NSR calculations for Unit 2 was Michael Hutcheson. Mr. Hutcheson testified that he did not review any EPA or

Missouri Department of Natural Resources guidance specifically as part of his work for the project at issue. Hutcheson Test., Tr. Vol. 11-A, 65:25-66:2.

397. Mr. Hutcheson admitted he had no personal knowledge of the project or whether the effects of the project were included in the projections he relied upon.

a. Mr. Hutcheson testified that in performing the company's NSR analysis, he did not speak to any of the engineers who planned and developed the project. He received information from his superiors in the Environmental Services Department, but he did not know the source of that information. Hutcheson Test., Tr. Vol. 11-A, 63:5-19.

b. Mr. Hutcheson also testified that he did not review any of the project justification documents for the work. Hutcheson Test., Tr. Vol. 11-A 63:20-25.

c. Mr. Hutcheson did not know whether the modeling runs that he relied on for his analysis included any projected improvements in capacity or availability. Mr. Hutcheson did nothing to check the validity of the modeling runs he received, but simply "took them on their face." Hutcheson Test., Tr. Vol. 11-A, 65:4-20; Hutcheson Dep., April 24, 2014, Tr. 118:20-119:5.

d. Mr. Hutcheson testified that he did not consider whether availability was expected to improve as a result of the projects because he did not think that information was "relevant" or "necessary." Hutcheson Test., Tr. Vol. 11-A, 82:16-25.

398. Mr. Hutcheson performed two purported NSR analyses for the Rush Island Unit 2 project – the "Original" Reasonable Possibility Analysis and the "Amended" Reasonable Possibility Analysis. Neither analysis was completed before the project work started. Knodel Test., Tr. Vol. 1-A, 88:13-18; Whitworth Test., Tr. Vol. 11-A, 96:12-23, 97:2-15; Hutcheson

Test., Tr. Vol. 11-A, 84:15-17, 85:3-8. Mr. Hutcheson's analysis relied on a ProSym model run the company performed that had been completed in January 2010, after the outage had begun. Hutcheson Test., Vol. 11-A, 38:22-24. The Original Reasonable Possibility analysis was not completed until after the project had begun. Mr. Hutcheson admitted that the analysis *should* be completed before beginning construction. Hutcheson Test., Tr. Vol. 11-A, 56:1-7; 84:15-85:2; *see also* Knodel Test., Tr. Vol. 1-A, 88:24-89:3.

399. Mr. Hutcheson began working on the Original Reasonable Possibility Analysis only after Ameren's legal department requested analyses of about 20 projects, including the Rush Island Unit 2 project. Some of the projects he was asked to analyze had already occurred and some were planned for the future. Hutcheson Test., Tr. Vol. 11-A, 34:2-23.

400. Although the Unit 2 project was originally approved in 2005 and re-approved by Ameren's Board of Directors and CEO on August 14, 2009 (FOF 136, 137), Mr. Hutcheson did not even begin collecting information relevant to his NSR analysis until November or December 2009. Hutcheson Test., Tr. Vol. 11-A, 84:11-14.

401. Ameren's "Original" ProSym modeling run was not completed until January 2010, after the 2010 outage had begun. The original case was used to develop the corporate budget for 2010. Finnell Dep., Nov. 22, 2013, Tr. 79:2-8. After the 2010 outage was complete, Ameren ran two other modeling cases, including the "EDF" case. Finnell Test., Tr. Vol. 10-A, 9:25-10:5. The EDF case was completed in early 2011. Finnell Test., Tr. Vol. 10-A, 10:3-5. The EDF case was the same as the "Original" case, but was modified to include efficiency improvements. Finnell Dep., Nov. 22, 2013, Tr. 77:12-20. The EDF case was used by environmental services to perform the Amended Reasonable Possibility Analysis. Finnell Dep., Nov. 22, 2013, Tr. 76:4-79:8; Hausman Test., Tr. Vol. 4-B, 87:11-14.

402. Ameren's Original Reasonable Possibility analysis "projected" that Unit 2's emissions of SO_2 would increase by 2,531.15 tons per year, from 14,287.73 in the baseline period to 16,818.88 tons per year in the highest projected post-project period. Hutcheson Test., Tr. Vol. 11-A, 40:22-41:2; Knodel Test., Tr. Vol. 1-A, 91:10-17; Def. Ex. C at Tab Net Emissions Change; *see also* Pl. Ex. 493, at AM-02231873, at "projected Emissions" tab (showing even higher projected SO_2 emissions of 17,018 for Unit 2 in 2012).

403. Ameren excluded every ton of the projected emissions increase on the basis that Unit 2 was capable of accommodating all of the increases in the baseline. Ameren provided no other reason for excluding the projected emissions increases in its Original Reasonable Possibility Analysis. Knodel Test., Tr. Vol. 1-A, 91:10-17. Mr. Hutcheson stated that there was no mechanism in his spreadsheet (Def. Ex. C and D) to account for whether the projected increase was related to the project. He testified that the relatedness question was a "qualitative" one not a "quantitative" one. Hutcheson Test., Tr. Vol. 11-A, 80:22-81:3.

404. Ameren did not rely on any guidance or applicability determinations in making their capable of accommodating determination. Whitworth Test., Tr. Vol. 11-A, 102:3-8, 103:24-104:3.

405. In late 2010, well after Ameren had completed the Unit 2 boiler upgrade, Mr. Hutcheson was asked by Ameren's in-house counsel, Susan Knowles, to revise his analysis. Hutcheson Test., Tr. Vol. 11-A, 85:3-11; Naslund Test., Tr. Vol. 6-B, 18:14-19; Hutcheson Dep., April 24, 2014, Tr. 115:2-12. Mr. Hutcheson used the EDF case to perform the Amended Reasonable Possibility Analysis. Hutcheson Dep., April 24, 2014, Tr. 117:10-20; Hausman Test., Tr. Vol. 4-B, 87:11-14.

406. Mr. Hutcheson completed the Amended Reasonable Possibility Analysis in early 2011, almost a year after the Unit 2 project had begun, and then only after EPA had issued a Notice of Violation to Ameren and after this lawsuit had been filed. Knodel Test., Tr. Vol. 1-A, 92:14-24, 93:15-19; Hutcheson Test., Tr. Vol. 11-A, 55:2-56:9, Def. Ex. D; RFA No. 7.

407. Mr. Hutcheson was asked to perform the Amended Reasonable Possibility analysis in order to incorporate a 2.4% efficiency improvement expected from the 2010 outage. No efficiency improvement had been incorporated into the Original Analysis. Mr. Hutcheson was not asked to make any other changes to the inputs into the analysis, such as changes that reflected the full extent of the capacity or availability improvements at Unit 2. Hutcheson Dep., April 24, 2014, Tr. 115:13-23; 117:10-20.

408. Ameren's expert, Mr. King, testified that he would not perform an NSR analysis based on a modeling run that was created just for NSR purposes. Mr. King agreed that in using such a run, a source runs the risk of looking like it is "cooking the forecast" to project no emissions increase. King Test., Tr. Vol. 6-B, 67:20-68:13.

409. Even with the changes made to the efficiency input, Ameren's Amended Reasonable Possibility Analysis still "projected" an increase of SO_2 emissions of 2,059.30 tons per year. Knodel Test., Tr. Vol. 1-A, 93:3-5; Def. Ex. D. As with its original analysis, Ameren excluded every ton of the projected emissions increase on the basis that the unit was capable of accommodating those emissions in the baseline period. Ameren provided no other basis for excluding those emissions increases. Knodel Test., Tr. Vol. 1-A, 93:6-14.

B. Ameren's Post Hoc Reasonable Possibility Analysis is Substantively Flawed

1. Ameren's calculations fail to model all of the performance improvements expected from the boiler upgrades

410. Ameren's Reasonable Possibility Analysis was based on its computer simulations performed for fuel budgeting purposes in January 2010. Those simulations include an 18 MW increase in Unit 2 capacity and a 2% improvement in unit availability—resulting in a 95% EAF—for the unit following the boiler work at issue in this case. *See* FOF 338, 353.

411. But project justification documents developed in 2009 projected significantly better performance at Unit 2 following the work. The CPOC report relied on a 22.5 MW increase in unit capacity as a result of the boiler work, as well as a 4.2% improvement in availability—resulting in a nearly 97% EAF—for the unit following the upgrades. *See* FOF 157, 158, 253.

2. Ameren's capable of accommodating approach

412. Ameren calculated the emissions the unit was capable of accommodating before the project by using the amount of time the unit was available to operate and multiplying that by the 95th percentile emissions rate (in pounds per hour). Hutcheson Test., Tr. Vol. 11-A, 41:3-17, 47:20-48:6, 68:16-24. Mr. Hutcheson calculated the 95th percentile emissions rate in Def. Ex. C, Tab Sheet1 and the results are shown in columns X and Y of the tab. Hutcheson Test., Vol. 11-A, 46:18-47:1.

413. Mr. Hutcheson's use of the 95 percentile emissions rate was not based on anything in the New Source Review rules. Hutcheson Test., Tr. Vol. 11-A, 69:13-70:5. Nor was it a standardized practice within Ameren. In fact, he used a 97th percentile emissions rate for nitrogen oxides for the same project. Hutcheson Test., Tr. Vol. 11-A, 78:3-22; Def. Ex. C at Tab RI U2 W2010 Detail.

414. In selecting the emissions rate for the capable of accommodating analysis, Mr. Hutcheson wanted to pick a rate that was "representative of what the unit could accommodate in

the baseline." The value he picked was in the top five percent of emissions rates that the unit achieved during the baseline period and that the median value would have been the 50^{th} percentile. He also testified that he "would have no doubt" that there could be a big difference between the 95^{th} percentile value and the 50^{th} percentile value. Hutcheson Test., Tr. Vol. 11-A, 70:12-71:11.

415. Mr. Hutcheson did not look to see whether Unit 2 actually ran at the 95^{th} percentile value for even 24 hours. Hutcheson Test., Tr. Vol. 11-A, 73:8-11.

416. The 95^{th} percentile calculation that Mr. Hutcheson said was a representative emissions rate for Unit 2 actually included several hours in which Unit 2 was emitting at a rate well over what is allowed by its permit. Def. Ex. C at Tab Sheet1 (Column L, Rows 4563-4574 and 4590-4591); Hutcheson Test., Tr. Vol. 11-A, 73:12-21.

417. By using the 95^{th} percentile emissions rate, Ameren calculated it would have accommodated about 17,550 tons of SO_2. Hutcheson Test., Tr. Vol. 11-A, 67:5-16. That much annual pollution would be more than Unit 2 had emitted since 1995, when the units were required to make reductions under the Acid Rain program. Declaration of Steven Whitworth (Pl. Ex. 926), at p. 10; Hutcheson Test., Tr. Vol. 11-A, 67:20-68:6; Knodel Test., Tr. Vol. 1-A, 56:1-4.

418. Mr. Hutcheson testified that had he used an average SO_2 emissions rate rather than the 95^{th} percentile rate, it would "essentially be recalculating the baseline." Hutcheson Test., Vol. 11-A, 47:12-14. This is incorrect. Ameren's capable-of-accommodating calculation is based on the unit's *availability*, not on the actual operation. It calculates the additional emissions impact from running every hour the unit was available.

419. Had Mr. Hutcheson used the 50th percentile value for the SO_2 rate, even Ameren's flawed analysis would show the project triggered New Source Review. This can be seen from Def. Ex. C. Column Y on Sheet1, which has the results of the 95th percentile calculation. The calculation is linked to the ultimate emissions calculation set forth in Tab Net Emissions Change. Hutcheson Test., Vol. 11-A, 76:8-24; Def. Ex. C.

420. When clicking on the interactive formula bar for Cell Y8 in Tab Sheet1, the user can change .95 to .5 and thus run the calculation using the 50th percentile. After doing so, the Net Emissions Change tab automatically changes: the capable-of-accommodating number becomes 197 tons, the net change (the emissions increase) becomes 2,334 tons, and the spreadsheet indicates that the project triggers New Source Review. Def. Ex. C at Tab Net Emissions Change (Columns E, G, and I).

3. No analysis of relatedness

421. Mr. Hutcheson testified that to assess whether the increase was related to the project he talked to several people including his boss, Ken Anderson, and Steven Whitworth, the

head of the Environmental Services Department. None of the engineers who planned the outage were involved. Hutcheson Test., Tr. Vol. 11-A, 81:4-16.

422. Mr. Hutcheson testified that they discussed the heat rate, maximum design rate of the boiler, and SO_2 emissions rate. They concluded that those characteristics would not change due to the projects and thus any increase was not related to the projects. Hutcheson Test., Vol. 11-A, 49:17-50:21.

423. In performing the New Source Review analysis for Unit 2, Mr. Hutcheson did not look at whether availability was expected to increase as a result of the project. He testified that if the unit was capable of accommodating additional demand, "the availability is not necessarily relevant" and that it "wasn't necessary" to look at availability for his analysis. Hutcheson Test., Vol. 11-A, 82:16-25.

424. In contrast to Mr. Hutcheon's trial testimony, Ameren in fact uses availability predictions as part of its process to determine how much coal to buy. The company does so because the more available a unit like Rush Island is, the more it will generate and the more coal it will need. Naslund Test., Tr. Vol. 6-B, 11:6-16.

425. Ameren also used availability in the *baseline* as the basis for its capable of accommodating calculations. As Mr. Hutcheson explained, the company looked to availability to determine what the unit was capable of generating before the project. Hutcheson Test., Tr. Vol. 11-A, 44:9-14, 87:4-12.

426. In Rule 30(b)(6) testimony, Steven Whitworth, the head of Ameren's Environmental Services Department, testified as Ameren's corporate representative. Mr. Whitworth testified that he believed emissions that a unit was capable of accommodating are per se unrelated. In the Rule 30(b)(6) deposition, Whitworth testified that, "The emissions that the

unit was capable of accommodating prior to the outage would be totally unrelated to . . . any activities that occurred on the outage. So just by the nature of the scope, the emissions are unrelated." Whitworth Rule 30(b)(6) Dep., Dec. 4, 2013, Tr. 38:4-12; Whitworth Test., Tr. Vol. 11-A, 101:19 – 102:2.

C. Nothing in Ms. Ringelstetter's Analyses Excuses Ameren's Failure to Perform Appropriate NSR Projections

1. Ms. Ringelstetter failed to address relatedness for either unit

427. Changes in availability would affect how much the unit was projected to generate. Ringelstetter Test., Tr. Vol. 11-B, 78:3–9.

428. Changes in unit capacity would affect how much the unit was projected to generate. Finnell Test., Tr. Vol. 10-A, 9:7–10.

429. Ms. Ringelstetter examined selected ProSym modeling files and observed that Ameren projected changes in the Rush Island units' availability and capacity following the boiler work at issue in this case, but testified that those changes had nothing to do with the boiler work. *See*, *e.g.*, Ringelstetter Test., Vol. 11-B, 56:10–15.

430. Ms. Ringelstetter noted that the maximum capacity at Rush Island Unit 2 was projected to be 11 MW above baseline levels following the boiler upgrades, but she attributes the capacity increase entirely to the LP turbine work performed in 2010. Ringelstetter, Vol. 11-B, 17:20–24 & Ameren's Summary Exhibit XF_2 (indicating 11 megawatt increase).

431. However, her baseline capacity number is not a measure of the unit's actual performance based on operating data; rather it is a reported number that tracks Ameren's Capability Tables. Ringelstetter Test., Tr. Vol. 11-B, 73:12–74:9.

432. Ameren's documents and witnesses stated that the company's 2005 Capability Tables were "unrealistically high" and were later adjusted downward significantly in February, 2006. Finnell Test., Tr. Vol. 10-A, 5:23–8:23 (discussing Plaintiff's Exhibit 892 and updates to Ameren's 2006 fuel budget modeling which show adjustments from the "unrealistically high" 610 MW to values between 581-596 MW). Since Ameren's selected baselines for both units include substantial amounts of 2005, Ms. Ringelstetter's 11 MW number significantly understates the projected capacity increase at Unit 2 compared to Ameren's documents and data. FOF 157, 289, 299, 300, 301.

433. Ms. Ringelstetter further testified that Ameren's ProSym models projected an increase in availability at each unit following the boiler upgrades, but stated that the increase is not substantial enough to appear to be a meaningful difference, and so discounts it entirely for her emissions assessment. Ringelstetter Test., TR. Vol. 11-B, 17:4–12.

434. Ms. Ringelstetter discounted these increases even though the availability forecast for Ameren's economic justification of the work at Unit 2 was fine-tuned to the tenth of a percent, and even that tiny variation meant hundreds of thousands of dollars dropped out of the analysis. June 15, 2009 Email (Pl. Ex. 895), Meiners Test., Tr. Vol. 7-B, 34:9-35:25.

435. Ms. Ringelstetter offered no opinion on how—if at all—the projects at issue in this case would have been expected to change the operations of the Rush Island units. Ringelstetter Test., Tr. Vol. 11-B, 59:23–60:3.

436. Nor did Ms. Ringelstetter offer any independent opinion on whether or to what extent the low pressure turbine replacement that occurred at Rush Island Unit 2 alongside the boiler modifications had any impact on unit operations or performance. Ringelstetter Test., Tr. Vol. 11-B, 60:4–9.

437. As such, all of her emissions analyses—and all of the emissions she concludes should be excluded from the emissions projection—rest on the assumption that *none* of the projected emissions increases were caused or enabled by the projects at issue in this case. Ringelstetter, Tr. Vol. 11-B, 18:9–11 & 22:2–9.

438. When she developed her calculations for her expert report, Ms. Ringelstetter believed it was *irrelevant* whether the projects at issue in this case resulted in performance improvements. Rather, by her calculations, the only thing that mattered for the demand growth exclusion was whether the unit "could have accommodated" the projected emissions levels during the baseline. Ringelstetter Test., Tr. Vol. 11-B, 77:2–17.

2. Ms. Ringelstetter's Unit 1 analysis relies on faulty assumptions

a. Background regarding ancillary services

439. Ancillary services are things other than simple electric generation that utilities provide to keep the electric grid operating reliably. Generally they involve promises that certain amounts of generation will be held in reserve or would be dedicated to real-time adjustments in response to market fluctuations. When a unit was providing some ancillary services, it would typically not be operating at its full capabilities. Hamal Test., Tr. Vol. 9-A, 23:4–6; Haro Test., Tr. Vol. 9-A, 99:21–100:13.

440. On January 1, 2007, Ameren Missouri entered into a short term contract to provide ancillary services to its Illinois affiliates. Def. Ex. HX. That contract was to last "from January 1, 2007 until the earlier of (i) December 31, 2007, or (ii) the date during calendar year 2007 on which the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") ancillary services market for Ancillary Services is operational." Def. Ex. HX at 1.

441. The short-term contract was later renewed when the launch of MISO's ancillary service market was further delayed. Haro Test., Tr. Vol. 9-A, 133:24–134:7.

442. The contract did not specify how much of the ancillary services described in the contract would be provided by Rush Island units or how often the units would be assigned to provide those services. Def. Ex. HX at Article 3, § 3.1.1 and Schedule A.

443. As of January 2009, ancillary services such as regulation hours and spinning reserves were offered into—and cleared through—MISO's ancillary services market. Hamal Test., Tr. Vol. 9-A, 43:10–12; Ringelstetter Test., Tr. Vol. 11-B, 95:10–14.

444. As Mr. Hamal explained: "In order to provide [ancillary services], you can't be at full load. You have to back off. You have to be at partial load. And so when prices are really high, I'd rather have a high-cost unit at partial load than a low-cost unit." Hamal Test., Vol. 9-A, 24:11–15.

445. The Rush Island units would not be expected to provide ancillary services once MISO's ancillary service market was implemented. Ameren's contract for ancillary services was never intended to extend beyond when MISO's ancillary services market started up in 2009. Haro Test., Vol. 9-A, 102:1-14, 134:4-7.

446. The MISO ancillary services market helped optimize the provision of ancillary services like regulation and spinning reserves: "it allow[ed] MISO to look at the fact that not only is that unit providing regulations, but it's not providing energy. So if that's a low-cost unit providing regulation, there may be a high-cost unit that could provide that regulation and save the system money overall." Hamal Test., Tr. Vol. 9-A, 24:5–10.

447. Since the Rush Island units are relatively-low cost units that run all the time, (Hamal, Tr. Vol. 9-A, 26:16–17), the implementation of the MISO ancillary services market

meant they would be "held back" little if any to provide ancillary services once those services were cleared through the market system. Hamal Test., Tr. Vol. 9-A, 24:20–24.

448. Ameren's chief modeler, Mr. Timothy Finnell, explained that in order to model ancillary services like regulation hours or spinning reserves in ProSym, Ameren would inflate a unit's partial outage rate, thereby depressing the unit's availability in the model. That would, in effect, lower the output of the units that were assigned to regulation in the model. Finnell Test., Tr. Vol. 9-B, 99:3–7; *see also* Ringelstetter Test., Tr. Vol. 11-B, 62:4–63:17.

449. Mr. Finnell admitted that assigning units regulation hours or ancillary services in the model would affect how much generation they were expected to produce and how much coal they were expected to burn in the forecast years. Ameren modeled ancillary services by increasing a unit's partial forced outage rate. Increasing the forced outage rate results in reduced generation and coal burned in the model. Finnell Test., Tr. Vol. 9-B, 99:3–100:19.

450. In 2008, Mr. Finnell, then head of Operations Analysis in Ameren's Corporate Planning Department and in charge of the company's ProSym modeling, testified before the Missouri Public Service Commission about how the sale of ancillary services impacted the company's business forecasts:

> Q. Is AmerenUE selling ancillary services to the utility operating subsidiaries owned by Ameren Corporation in Illinois?
>
> A. Yes, for 2008, AmerenUE is selling 39 MW of spinning reserves and 68 MW of supplemental reserves to Illinois affiliates.
>
> Q. Does the PROSYM model include the sales of ancillary services to these Illinois utilities?
>
> A. No. The sales of these ancillary services were not included because they are based on a short-term contract that will end when the MISO ancillary service market begins.

Finnell MPSC Test. (Pl. Ex. 439), at 12:16–23.

451. Neither of Ameren's two experts hired to discuss dispatch and market issues quantified how the provision of ancillary services influenced Rush Island operations before the projects were performed or once the modifications were completed. Mr. Hamal "didn't get into the details and quantify how much regulation Rush Island did," focusing instead on the general market structure. Hamal Test., Tr. Vol. 9-A, 44:3-5. Ms. Ringelstetter, despite offering an opinion that Ameren's modeling of ancillary services was "entirely appropriate," (Ringelstetter Test., Tr. Vol. 11-B, 66:4–6), did not mention ancillary services, regulation hours, or spinning reserves in her expert report, nor was she aware of any "specifics" regarding Ameren's short-term ancillary service agreements. Ringelstetter Test., Tr. Vol. 11-B, 66:10–67:10.

b. Ms. Ringelstetter's modeling choice

452. For the analysis in which she concludes that projected emissions would not increase following the Unit 1 modification work, Ms. Ringelstetter uses a ProSym modeling effort that includes two artificial adjustments.

453. First, the ProSym modeling run that Ms. Ringelstetter used when assessing the 2007 project at Rush Island 1 included an input for that unit which was intended to reflect its provision of ancillary services. Despite the short-term nature of the services as described above, she used a run where Unit 1 was modeled as holding back 15 MW for regulation hours for *every year* of the model forecast, 2007 through 2012. Ringelstetter Test., Tr. Vol. 11-B, 63:18–64:2; *see* Hausman Test., Tr. Vol 4-B, 97:3-9.

454. Second, Ms. Ringelstetter claims the modeling effort suffered from what she calls a bias in the inputs which requires a downward adjustment to the model's projections. However,

Ameren never performed such an adjustment when it did its own analyses, and in fact other modeling efforts did not suffer from this bias. Hausman Test., Tr. Vol. 4-B, 98:9–99:12.

455. Without either of these adjustments, Ms. Ringelstetter's analysis would show a significant projected increase in Rush Island 1 operations and pollution above baseline levels. Hausman Test., Tr. Vol. 4-B, 99:13–23.

VI. THE 2007 AND 2010 BOILER UPGRADES TRIGGERED TITLE V REQUIREMENTS

456. The Clean Air Act Title V permit for the Rush Island Plant contains a condition restating the requirement that Ameren was prohibited from performing any unpermitted major modifications of Rush Island Units 1 or 2. Declaration of Steven Whitworth (Pl. Ex. 926), at attached Title V Permit, AM-02511339-2511393, at 2511362.

457. Ameren has not obtained a permit for its major modifications, and the Rush Island Title V permit does not incorporate PSD requirements for its major modifications. Pl. Ex. 926, at attached Title V Permit, AM-02511339-2511393, at 2511348-350 (Listing no Unit Specific Emission Limitations for SO_2).

CONCLUSIONS OF LAW

I. OVERVIEW

Under the Clean Air Act's PSD program, an existing source of pollution must obtain a permit and install state-of-the-art emissions controls when the source makes a "major modification." *Ameren SJ Decision*, 2016 WL 728234, at *4. The United States claims Ameren violated the PSD program's requirements by making major modifications to Units 1 and 2 at Rush Island without obtaining applicable permits or installing required emissions controls. The only disputed element of proof is whether the projects performed on Units 1 and 2 were "major modifications" under the law. *See* Subsection II.A (other elements of proof undisputed). To prove a major modification, the United States must show the work at issue was (1) "a physical change or change in method of operation that (2) would result in a significant net emissions increase." *Ameren SJ Decision*, 2016 WL 728234, at *2 (citing 40 C.F.R. §52.21(b)(2)).

For the purposes of the first prong of the test, the term "physical change" is extremely broad, and there is no dispute that the projects were physical changes. *Id.* at *4. But not all physical changes trigger PSD permitting requirements. Routine maintenance, repair, and replacement projects are excluded from the definition of "major modification." *Id.* Ameren argues the challenged Rush Island projects were routine maintenance projects and as a result exempt from being considered "physical changes." Subsection III.A below explains why the challenged projects are not routine maintenance.

For the purposes of analyzing the second prong of the test, Subsection II.B below explains that the projects would be expected to result in—and did result in—a significant net emissions increase. Because the projects were physical changes that would result and did result in a significant net emissions increase, they were major modifications under PSD.

Because the United States has proved the Rush Island projects were major modifications, Ameren violated the PSD provisions of the Clean Air Act because it did not obtain the required permits or meet other PSD requirements before beginning construction. In addition, as explained in Subsection II.C below, Ameren also violated the Title V provisions of the Clean Air Act.

II. THE UNITED STATES PROVED THAT AMEREN VIOLATED THE PREVENTION OF SIGNIFICANT DETERIORATION AND TITLE V PROVISIONS OF THE CLEAN AIR ACT

A. Undisputed Elements of Proof

The only disputed element of proof is whether the projects were major modifications under the law.

There is no dispute that:

- Ameren is a "person" under the applicable law and the owner and operator of the Rush Island facility. 42 U.S.C. 7602(e) and 10 C.S.R. 10-6.020(2); FOF 2.
- Rush Island Units 1 and 2 are each a "major emitting facility," a "major stationary source," and an "electric steam generating unit" under the applicable PSD and Title V provisions. 42 U.S.C. § 7479(1), 40 C.F.R. § 52.21(b)(1) and (b)(31); FOF 13.
- EPA provided sufficient pre-filing notice of the violations to Ameren and the State of Missouri and provided notice of the filing of this case to the State. 42 U.S.C. § 7413(a), (b); FOF 18-21.
- At the time of the projects, Rush Island was in an area designated as attainment for SO_2. 42 U.S.C. § 7471; FOF 11. Therefore the PSD program applies.

B. The Projects Should Have Been Expected to Cause—and Did Cause—Emissions Increases

1. Legal standard

There are two ways to establish PSD liability. The United States can satisfy its burden by proving either that: (1) the source should have expected an emissions increase related to the project (the expectations approach); or (2) an emissions increase related to the project actually occurred (the actual emissions approach). *Ameren SJ Decision*, 2016 WL 728234, at *16; *see also* 40 C.F.R. § 52.21(a)(2)(iv)(*b*), (*c*).

Regulations establish how to compare pre- and post-project emissions. The pre-project "baseline" is any 24 consecutive months in the 5 years before the project. 40 C.F.R. §52.21(b)(48)(i). The post-project period is the maximum annual emissions in any one of the five years after the project. 40 C.F.R. §52.21(b)(41)(i). The difference between the baseline and post-project high emissions year is the emissions increase for PSD purposes. An increase of 40 tons or more of SO_2 per year is "significant" under the regulations. 40 C.F.R. §52.21(b)(23)(i). In this case, there is no evidence of any creditable emissions decreases, so any emissions increase proven is the same as the net emissions increase. *See* 40 C.F.R. § 52.21(b)(3).

Under the expectations approach, courts must determine what a source should have expected at the time of the project. To prevail, the United States "must show that at the time of the projects [defendant] expected, or should have expected, that its modifications would result in a significant net emissions increase." *Ameren SJ Decision*, 2016 WL 728234, at *13 (citing cases and quoting *United States v. Ala. Power Co.*, 730 F.3d 1278, 1282 (11th Cir. 2013) (internal quotations omitted)).

Ameren's internal documents are relevant to what the company expected or should have expected. *See*, *e.g.*, *Ala. Power*, 730 F.3d. at 1286-87; *United States v. La. Generating LLC*, 929 F. Supp. 2d 591, 593-594 (M.D. La. 2012) ("The documents clearly show outages were a problem and the company planned to work on the reheaters in order to fix those problems."); *Ohio Edison*, 276 F. Supp. 2d at 834 ("The documents prepared to justify the expenditures described the various purposes of the projects to include replacement of major components to increase the life and the reliability of the units.").

Under the actual emissions approach, the question is simply whether SO_2 emissions actually increased by more than 40 tons per year as a result of the project.

Under either approach, additional operations made possible by a project must be attributed to that project. As EPA has explained, "where the proposed change will increase reliability, lower operating costs, or improve other operational characteristics of the unit, increases in utilization that are projected to follow can and should be attributable to the change." 61 Fed. Reg. 38,250, 38,268 (1996). A series of court decisions have echoed this requirement.

"If an increase in hours of operation is caused or enabled by a physical change, the increased hours must be included" in the projection. *Duke Energy 2010*, 2010 WL 3023517, at *5; *see also Duke Energy 2007*, 549 U.S. at 577-78 (noting regulatory provision that requires assessing number of hours the unit is or probably will be running); *Ala. Power*, 730 F.3d at 1281; *United States v. Cinergy Corp.*, 458 F.3d 705, 710 (7th Cir. 2006) (revitalizing a plant to operate more hours may trigger PSD obligations); *Ohio Edison*, 276 F. Supp. 2d at 834-35 (finding PSD liability for projects that were "intended to result in increased hours of operation as a result of a reduction in . . . forced outages").

Even when there is evidence that emissions will or did increase after a project, a source may demonstrate that the increased emissions should be excluded from PSD review under the "demand growth exclusion." Under the demand growth exclusion, a source must exclude from its calculations:

> any emissions increases that "an existing unit could have accommodated during the consecutive 24–month period used to establish the baseline actual emissions . . . and that are also unrelated to the particular project, including any increased utilization due to product demand growth." 67 Fed.Reg. at 80,277 (codified at 40 C.F.R. § 52.21(b)(41)(ii)(c)).

New York v. U.S. E.P.A., 413 F.3d 3, 31 (D.C. Cir. 2005) ("*New York I*"). After substantial argument about the application of the demand growth exclusion at summary judgment, I explained its application as follows:

> if emissions increase because a project enables the unit to meet previously unmet demand during peak hours, for example, those emissions increases are likely related to the project and therefore do not qualify for the demand growth exemption. . . if the unit undergoes modifications that allow it to run more during the daytime hours tha[n] it could before, it cannot be said that the increased emissions were merely a coincidence or unrelated to the modification.

Ameren SJ Decision, 2016 WL 728234, at *10.

Finally, Congress intended for the PSD rules to "have broad application." *Id*. (citing *Ala. Power Co. v. Costle*, 636 F.2d 323, 399-400 (D.C. Cir. 1979)).

2. **The evidence shows that Ameren should have expected an emissions increase related to each project, and such an emissions increase occurred**

The core facts of this case show that before Ameren performed the challenged projects, problems with the components at issue were limiting the units' performance. Replacing those components would improve performance and result in additional use and pollution. That was what Ameren should have expected before the work began. The evidence shows that is what Ameren *did* expect. The evidence also shows that is exactly what happened.

Two key—and undisputed—characteristics of the Rush Island units underlie the entire discussion of emissions increases. First, the Rush Island units are big sources of pollution. That means even small performance improvements can enable a 40-ton increase in SO_2. For example, there is no dispute that it only takes an additional 21 hours of operations at full power for a Rush Island unit to emit more than 40 tons of SO_2. FOF 190.

Second, the Rush Island units are "baseload" units. FOF 6. They are relatively cheap sources of electricity. FOF 50. The market for electricity, which puts a premium on price, drives these baseload units to operate as much as they can. *Id*. That means the Rush Island units run every hour they are available—and at high or even maximum levels during hours of "peak" demand. FOF 6, 371-372. Moreover, Rush Island's baseload status means that if the units improve their performance in any way that allows them to generate more electricity, the market will call on the units to generate more electricity. FOF 50, 215. As Ameren's retired executive Charles Naslund explained at trial, Ameren plans its coal purchases based in part on availability projections because the company knows that the more available the Rush Island units are, the more they will run. FOF 424. That additional generation requires additional coal—and means additional pollution. FOF 205.

These two facts lead to a logical conclusion: if the Rush Island units are upgraded so they *can* generate more electricity, they *will*. Performance improvements have a direct impact on annual generation and pollution levels. Ameren's witnesses and documents recognize this simple relationship. FOF 424, 427-428, 448. And using Ameren's computer modeling software, United States' expert Ezra Hausman illustrated that a mere one-megawatt improvement in unit capacity would lead to an additional 23 tons per year of SO_2 pollution and that a one percent improvement in unit availability would result in about 150 extra tons of SO_2 per year. FOF 336-337, 339-41. Ameren should have expected the Rush Island boiler upgrades to result in at least an additional 40 tons of SO_2 pollution—and that is exactly what happened.

a. The Koppe-Sahu emissions calculations show a predicted increase at Unit 1 and were confirmed by an actual increase

Before the projects, the components at issue were causing outages and deratings at Unit 1. FOF 47-88. Ameren's availability data showed that the economizer, reheater, lower slope tubes, and air preheater were the predominant cause of availability losses at the unit, so Ameren decided to replace them with redesigned components. FOF 136, 138-139, 222-223. The decision to replace these components was the result of a lengthy and deliberate process and was ultimately approved by a series of managers and executives, culminating with the Ameren parent company CEO. FOF 136, 177. One of the bases of that approval was the expectation that the replaced components would cause *no* outage time for *20 years* following the projects. FOF 38, 145-149. Looking at the unit as a whole, Ameren expected that Unit 1's long-term availability would increase to 95% after the work was done, about a 3% increase compared to the PSD baseline. FOF 228.

The United States' expert Robert Koppe did his own analysis of how the project would affect Unit 1's performance. Mr. Koppe is a power plant engineer who has spent much of his career analyzing the performance of generating units on behalf of utilities and public service commissions using methodologies that courts have consistently found to be reliable. FOF 90-91; *see, e.g., United States v. Cinergy Corp.*, 623 F.3d 455, 459 (7th Cir. 2010); *United States v. Ohio Edison Co.*, 276 F. Supp. 2d 829, 877 (S.D. Ohio 2003). Mr. Koppe analyzed the problems affecting Rush Island during the baseline period and determined what Ameren should have expected to result from the work it did in the 2007 and 2010 outages. FOF 195.

Mr. Koppe started by identifying all the outage hours and deratings attributed to the components at issue during the baseline. He found that the equivalent availability losses due to the four components at issue totaled 336 hours in the baseline period, about half the unit's total outage time.[4] FOF 197, 222. Importantly, Mr. Koppe also looked at the condition of the unit as a whole and the other work performed during the 2007 outage. FOF 197-198. As Mr. Naslund explained at trial, Ameren was working hard to address any potential future problems during the outage. FOF 199. Mr. Koppe concluded that the other work performed during the 2007 outage would prevent availability from declining due to other potential issues. FOF 255. He also

[4] Ameren claims that Mr. Koppe and Dr. Sahu should have accounted for derates differently. This portion of Ameren's criticism has to do with what is known in the industry as a "utilization factor" and whether Mr. Koppe and Dr. Sahu should have used a different utilization factor for deratings than they did for outages, as Ameren's expert Marc Chupka testified he would have done. But Mr. Chupka is an economist, not a power plant engineer, and Dr. Sahu's use of a single utilization factor for both outages and deratings is exactly what the Electric Power Research Institute ("EPRI") has recommended since the 1980s. FOF 210. In fact, except for the purposes of this litigation, Ameren instructs its engineers to do the very same thing. FOF 210.

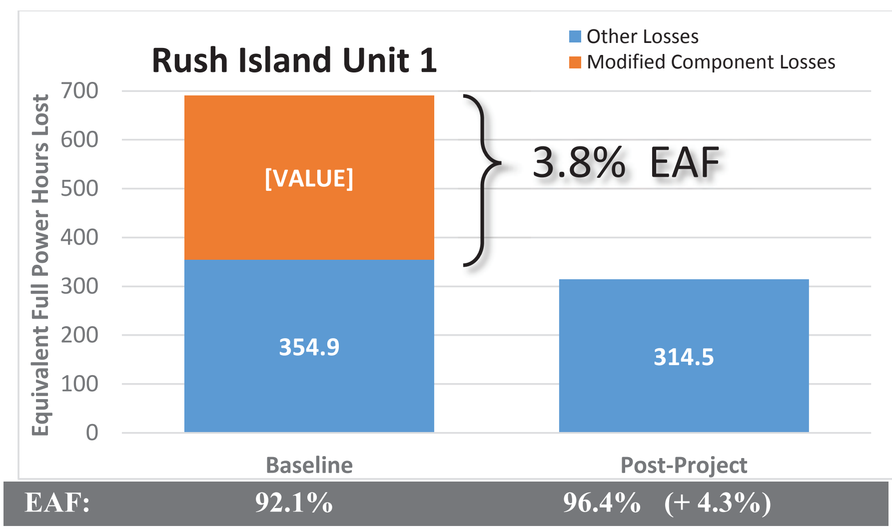
concluded that the project would completely eliminate availability losses from the components at issue and result in an availability improvement of 3.8% from the baseline, bringing Unit 1's availability to about 96% post-project.[5] FOF 224-225, 227. Mr. Koppe concluded—and Ameren witnesses and documents confirm—that availability would not have increased at all if these problematic components had not been replaced. Rather, it would have gotten worse. FOF 227, 231, 239, 255.

Dr. Ranajit Sahu, a permitting engineer and expert for the United States, took Mr. Koppe's findings on expected improved availability and used them to calculate the expected additional pollution that would result from the improvements, using a methodology that has been recognized as industry-standard by several courts. *See, e.g.*, *Ala. Power*, 730 F.3d at 1284-85; *La. Generating*, 929 F. Supp. 2d at 596. Dr. Sahu concluded, as Ameren did, that the company would utilize the regained hours at the same proportion as it had in the past. FOF 206, 208. Based on his and Mr. Koppe's analyses, Dr. Sahu calculated an expected increase in emissions of 608 tons of SO_2 post-project for Unit 1. FOF 232. Because Dr. Sahu's calculation was based on

[5] Ameren argues in its post-trial brief that Mr. Koppe testified that it would not be reasonable to expect the units could achieve over 95% availability post-project because "things happen" and "other components can fail." Ameren then argues that an increase to 95% at Unit 1 is no significant increase at all because Unit 1 had a baseline availability of 94.7%. There are two major flaws with this argument. First, Mr. Koppe did not testify that the units would not be expected to achieve over 95% availability; in fact, he testified that Ameren should have expected "the fairly long-term average equivalent availability" to reach about 95%, but "the best performance post-project" (which is the relevant measure) "would be more like 97 or 98 percent." Koppe Test., Tr. Vol. 3-A, 79:7-14. Second, Ameren's argument that there was no expected significant availability increase only works if its suggested baseline availability figure of 94.7% is accepted. That figure is at odds with Mr. Koppe's well-supported calculation that Unit 1's baseline availability was actually 92.1%. Ameren's calculations appear to be based on the exclusion of certain GADS events from its performance data, but Ameren offered no testimony at trial to support that approach.

the additional operation allowed by the project, the entire predicted increase is related to the work. *Id.*

Post-project results confirm Mr. Koppe and Dr. Sahu's calculations. In 2008, Unit 1 set its record availability with the best availability in the entire Ameren system. FOF 234; *see also* FOF 236. As Mr. Koppe and Ameren both expected, all the outages and deratings due to the replaced components were eliminated. FOF 237. Availability during the highest post-project emissions year reached 96.4%, which is 4.3% higher than the baseline. FOF 238. The entire expected improvement related to the project (3.8%) was realized. That improvement was an order of magnitude more than the 0.3% increase needed to result in 40 additional tons of SO_2. FOF 191. The chart below shows the baseline availability losses caused by the components at issue (orange) and caused by all other factors (blue). After the work was completed, Unit 1's actual availability climbed to 96.4% and it did not experience any losses due to the new components and actual availability. FOF 237–38.



With the availability improvement came an actual increase in emissions of 665 tons of SO_2. FOF 664. Those additional tons were made possible by the availability improvement and are related to the project. FOF 239.

At trial, Ameren sought to exclude any testimony from Mr. Koppe and Dr. Sahu on the cause of the actual increase. As discussed below (*see* Subsection I.A on Evidentiary Issues), I am denying Ameren's motions to strike this testimony because I find that the challenged opinions were properly disclosed. But even without the challenged testimony, the evidence shows an actual and significant net increase of emissions related to the project for both units. Ameren has *not* challenged the admissibility of the testimony by Mr. Koppe and Dr. Sahu that:

- An availability improvement of just 0.3% or an additional 21 hours of operation would cause a more than 40 ton-increase in pollution.
- The work would eliminate all availability losses due to the components, increase overall availability by far more than 0.3%, and increase pollution.[6]
- Post-project data shows those predictions came true: there were no component losses of any kind in the post-project year, availability improved by much more than 0.3%, the unit operated hundreds of hours more, and pollution increased.

FOF 267. Mr. Koppe and Dr. Sahu made a prediction based on improved unit performance, and the actual data confirmed those predictions. As Mr. Koppe explained at trial:

> [If] half of all the outage time that's occurring is eliminated by the projects and the effect of all the other equipment in the unit stays the same . . . then the availability of the unit as a whole increases, and it increases specifically because the projects have eliminated boiler tube leaks in these sections and have eliminated the effects of pluggage.
>
> ***
>
> The causation of what actually happened is obvious from the—from the data.

Koppe Test., Tr. Vol. 4-A, 115:18-25, 4-B, 18:1-4.

---

[6] Ameren concedes that Unit 1 availability was projected to increase by 1.3%. Ameren Br. at 5 (Doc. 835).

Here, based on the substantial and credible evidence presented showing how the project would cause improvements in availability and, as a result, increase emissions, I am able to find, even without explicit expert testimony, that the predicted cause of the increase was the cause of the actual emissions increases. *See, e.g.*, *United States v. Crenshaw*, 359 F.3d 977, 988 (8th Cir. 2004) (citing *Jackson v. Virginia*, 443 U.S. 307, 319 (1979) (noting court authority "to draw reasonable inferences from basic facts to ultimate facts").

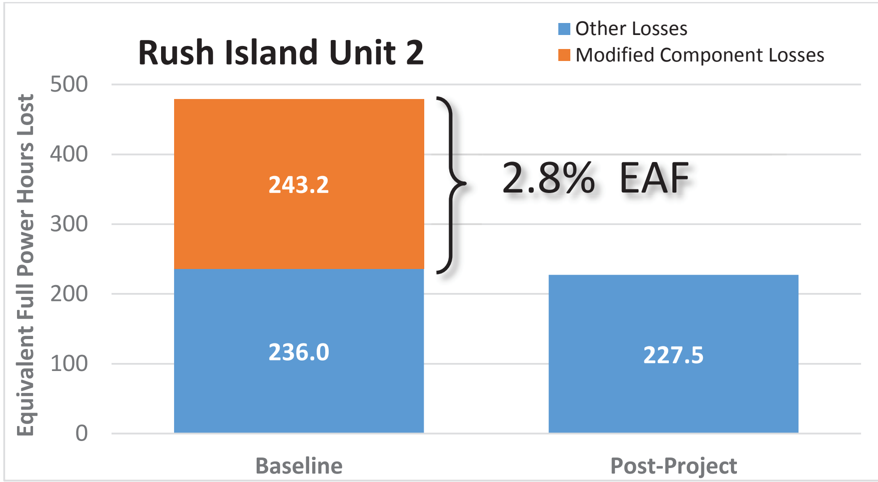
b. The Koppe-Sahu emissions calculations show a predicted increase at Unit 2 and were confirmed by an actual increase

The background story of Unit 2 is the same as Unit 1. Unit 2 had the same problems with the components at issue limiting the unit's availability in the time leading up to the outage. As with Unit 1, Mr. Koppe analyzed the expected impact of the 2010 project on Unit 2's availability. FOF 47–88, 145–47, 197–98. Mr. Koppe found that the outages and deratings at Unit 2 caused by the economizer, reheater, and air preheater resulted in about 245 equivalent lost hours during the baseline, slightly more than half the total lost operating time. FOF 247. As with Unit 1, Mr. Koppe examined the overall condition of Unit 2 and found that other work performed during the outage would prevent availability from getting worse and that the component replacements would result in an availability improvement. FOF 251. For Unit 2, he predicted that the project would completely eliminate all of the losses due to the three components at issue and, by itself, would improve Unit 2's availability by 2.8%. FOF 248, 251. None of these improvements would be possible if Ameren had not replaced the reheater, economizer, and air preheater. Rather, without the project, availability at Unit 2 would have decreased, not increased. FOF 255.

Ameren argued at trial that availability could *never* increase beyond 95%. But former plant manager Robert Meiners agreed with Mr. Koppe and Dr. Hausman that the long-term availability forecast of 95% meant individual years would be as high as 97% or 98%. FOF 257. As noted above, the relevant PSD inquiry compares the baseline emissions to the year with the highest amount of projected emissions in the five-year post-project period. Tellingly, Ameren already knew that Unit 1 set an availability record after the 2007 project of nearly 97% in 2008. FOF 254. When seeking re-approval of the Unit 2 project in 2009, Ameren's engineers explicitly stated they expected Unit 2 to perform "at least equal to, if not better than," Unit 1 and expected a 3–4% availability improvement. FOF 256. Mr. Meiners confirmed this at trial, testifying that the availability input used in financially justifying the Unit 2 outage to senior company executives was almost 97%. FOF 253.

The post-project data shows that Unit 2's availability actually reached 97.4% in the highest year after the project. FOF 260. As Ameren's trial witness Scott Anderson testified after reviewing Unit 2's historic availability statistics, the difference between the pre- and post-project performance was "night and day." FOF 261. Comparing the baseline to the post-project year, Mr. Koppe predicted an availability improvement of 2.8% due to the project alone, and Ameren actually got an improvement of 2.9%. FOF 259. The components at issue caused no availability losses after the project, as Mr. Koppe predicted. *Id.* As with Unit 1, the availability improvements far exceeded the small changes that would cause Unit 2 to emit 40 additional tons of SO_2.

The chart below shows the baseline availability losses caused by the components at issue (orange) and caused by all other factors (blue). After the work, there were no losses due to the new components and actual availability climbed to 97.4%. FOF 259–60.



EAF: 94.5% 97.4% (+ 2.9%)

Based on Mr. Koppe's prediction of regained availability, and using the method described above, Dr. Sahu calculated an expected increase of 415 tons per year of SO_2 in Unit 2 that would result from the availability improvement alone. FOF 258.

Separate from the expected increase in emissions based on availability improvements, Ameren also should have expected an emissions increase at Unit 2 based on capacity improvements. After the Unit 1 outage, Ameren saw a significant *capacity* gain as a result of the project. FOF 269. Ameren and Mr. Koppe both analyzed how a similar capacity gain would affect Unit 2's post-project operation.[7] [8]

There is no dispute that Ameren realized a gain in capacity, measured in megawatts ("MW"), at Unit 1. FOF 269–70, 274. Ameren expected similar improvement at Unit 2. *Id.* In

[7] In addition, Ameren replaced the low pressure turbine during the 2010 outage, which would also be expected to affect performance.

[8] Ameren argues that Mr. Koppe and Dr. Sahu's analyses double count the effect of deratings already accounted for in its availability analysis in its capacity analysis, but Dr. Sahu clearly presented separate emissions calculations for the availability and capacity increases. FOF 258, 302-303. *See also* US Br. at 26 n.16 (Doc. 838).

a series of company documents from Fall 2007 until the time of the overhaul, Ameren engineers repeatedly stated that significant capacity increases (of up to 30 MW) would result from the boiler work. FOF 269–78. That expectation was included in the documents presented to corporate executives seeking approval of the Unit 2 project. That expectation was even used to calculate how the project would impact Ameren's shareholders and ratepayers. FOF 158, 276. For instance, in the justification for the outage work that was presented to Ameren's executives, the company's engineers explained exactly what benefits they assessed in determining the projected value of the project. The first benefit listed is "30 MW gain in summer (3 mos), 20 MW gain balance of year *from reheater, economizer and APH [air preheater] investment*." Pl. Ex. 110 at AM-02465690 (emphasis added); FOF 277.

As he did for availability, Mr. Koppe independently studied the data and information produced by Ameren and reached a conclusion similar to what Ameren's engineers found before the Unit 2 outage. Mr. Koppe confirmed that pluggage had limited Unit 2's capability during the pre-project period and that Ameren should have expected at least 22 MW of increased capability due to the boiler work. FOF 279. Another 12-15 MW of capability would result from the new LP turbine. FOF 280. Dr. Sahu calculated that an 18 MW capacity increase due to the boiler project alone would increase emissions by 417 tons of SO_2. FOF 303.

The post-project data confirmed the results of Mr. Koppe's analysis. In fact, Ameren reported its improved capacity to MISO, the North American Electric Reliability Council, and the Missouri Public Service Commission, among other outside entities, each time attributing a major portion of the unit's capacity increase to the boiler work at issue. For example, Ameren responded to an inquiry from the Missouri Public Service Commission in a rate case related to the Unit 2 2010 outage. In defending its requested rate increase, Ameren stated that unit capability improved by 34 MW, of which 22 MW were restored capacity. FOF 288–89. Similarly, Ameren reported that Unit 2's *summertime* peak capability had increased to nearly 650 MW gross "due to work completed during the 2010 major outage (replacement of lower pressure turbines and *numerous boiler modifications*)." FOF 287 (emphasis added).

Ameren's post-project reports are quite similar to what Mr. Koppe found in reviewing the post-project data. Mr. Koppe first analyzed Ameren's "Plant Information" database and determined that Unit 2's capability had increased by 38 MW, from 615 MW during the pre-project period[9] to 653 MW afterwards. FOF 296–99. An almost identical increase is observed by comparing Ameren's "full load" test reports. The average capability reported by Ameren in those reports increased by 37 MW, when comparing baseline (620 MW) and post-project (657 MW) periods. FOF 295, 301.

Of the overall increase in capability, Mr. Koppe determined that about 23 MW of the increase were due solely to the component replacements and would require more coal to be burned. FOF 300. Ameren's documents show that it had reached the same conclusion. The predicted and actual capability increases Mr. Koppe reports are right in line with what Ameren used in its financial justification for Unit 2 (22.5 MW) and far more than the 1.7 MW that would result in 40 additional tons of SO_2.

Based on the performance improvements predicted by Mr. Koppe, Dr. Sahu calculated increases of more than 400 tons of SO_2 due to either the availability increase or the capacity increase alone. FOF 258, 303. Both the availability and capacity improvements Mr. Koppe predicted were borne out by actual data. FOF 237–38, 259–60. After the 2010 project, overall

[9] Because Ameren did not produce complete Plant Information data from before 2006, Mr. Koppe used January 2006-December 2007 for the pre-project period, since that was closest in time to Ameren's baseline.

emissions of SO_2 from Unit 2 increased by 2,171 tons per year. FOF 266. As a result, the actual emissions increase includes increases resulting from the availability increase and the capacity increase. Each is an order of magnitude larger than the PSD significance threshold.[10]

3. Dr. Hausman used Ameren's modeling to quantify the emissions impact from the projects

The conclusions of Mr. Koppe and Dr. Sahu are further supported by Dr. Hausman's analysis of Ameren's computer modeling efforts. Dr. Hausman is a modeler and market consultant with nearly 20 years of experience focused on the electric industry.

Ameren uses a sophisticated computer modeling program called ProSym to predict the operations of its generating fleet—including the Rush Island units—so it can plan accordingly. FOF 314–15. Ameren uses ProSym modeling for a number of things, including rate recovery proceedings before the Missouri Public Service Commission, fuel purchasing and planning, and informing capital investment decisions. FOF 315. Ameren has testified to the public service commission that its use of ProSym is "very well calibrated" and gives reliable projections of future unit performance. Plaintiff's Exhibit 439.

In the lead-up to the Rush Island overhaul projects—and in the normal course of its business—Ameren used ProSym to model and predict the Rush Island units' fuel needs ("heat input" in the industry parlance) for the years after the 2007 and 2010 major boiler outages. FOF 318–19, 329. Dr. Hausman performed two types of analysis based on Ameren's modeling. First, Dr. Hausman examined how varying specific inputs, such as the units' availability parameters or

[10] As noted in the discussion of Unit 1, even if I were to exclude testimony on actual emissions causation from Mr. Koppe and Dr. Sahu, which I will not, I can connect the dots myself to find the predicted—and realized—improvements caused the predicted—and realized—emissions increase.

maximum capacity values, would affect the model's projections for that unit's future performance. FOF 330–31. In effect, he investigated whether, and to what extent, the Rush Island units would actually use extra operating hours or extra capacity if the units were improved. The model that Ameren used routinely to simulate its units' operations showed that if Ameren increased the number of hours its Rush Island units were able to run, or if the company enabled the units to operate at higher output levels during those hours, then the units would take advantage of those performance enhancements, burning more coal and, as a result, emitting more pollution. FOF 332. In fact, the models showed that both a unit's capacity level and its availability are linearly related to the unit's projected coal consumption. *Id*.

The results of the ProSym runs confirm the admissions by Ameren's witnesses: performance improvements like capacity increases or availability gains would lead to additional operations and additional pollution. FOF 427–28. Dr. Hausman's sensitivity analyses quantify those relationships.

The following chart provides the results of Dr. Hausman's sensitivity analyses. Dr. Hausman ran several iterations of Ameren's ProSym model to identify what changes in forced outage rates, partial outage rates, and capacity would mean for coal consumption and pollution. FOF 334–41.

	Performance Measure	**Δ Coal Consumption (Billion BTU)**	**Δ SO_2 Pollution (tons per year)**
Rush 1	Forced Outage Rate (per 1%)	481	162
	Partial Outage Rate (per 1%)	408	138
Rush 2	Maximum Capacity (per 1 MW)	69	23
	Forced Outage Rate (per 1%)	566	189
	Partial Outage Rate (per 1%)	466	156

The demonstrated relationship between availability and capacity and emissions mean that a mere 0.3% improvement in availability[11] or a 1.7 MW increase in capacity is enough to cause the Rush Island units—modeled by Ameren in its regular business—to emit 40 additional tons of SO_2 pollution. FOF 333.

Dr. Hausman's second set of analyses compared the results of Ameren's modeling efforts, which included assumptions about improved unit availability and capacity beginning the year after the projects were performed, to model runs in which the Rush Island Units were not improved—that is, a scenario in which the outages that included the projects at issue in this case were never undertaken. FOF 342. These "with and without" analyses served to isolate the amount of the projected increase in unit operations and air pollution that was caused or enabled by Ameren's 2007 and 2010 outage work. FOF 343, 345. In other words, even though other factors contributed to unit operations and pollution, the comparison reveals how much of those emissions would not have been emitted "but for" the Rush Island performance improvements. Ameren—not Dr. Hausman—performed the engineering assessments of their outage work and folded those expected operational benefits into the company's modeling.[12] Dr. Hausman simply examined the result of those operational benefits on the units' projected operations. The

[11] These figures were based on Unit 1's partial outage rate results. Looking at Unit 2 or the forced outage rates would yield a smaller percentage triggering 40 tons of $S0_2$.

[12] Ameren argues that Dr. Hausman's with-and-without analyses are irrelevant because they do not compare baseline performance to projected performance. Rather, his analyses compare two future scenarios: the projected performance with the project to projected performance without the project. Although the comparison Dr. Hausman did is not the same as what is required of sources doing PSD calculations, Dr. Hausman's comparisons are relevant to this case, which requires a determination about causation. The purpose of Dr. Hausman's analysis was to examine the relationship between capacity and availability and that of generation and emissions. Conducting a with-and-without analysis provides useful causation information and is a standard industry method.

performance improvements Dr. Hausman identified in Ameren's ProSym input files are consistent with the performance improvements Mr. Koppe expected the Rush Island units would see over baseline levels based on his engineering analysis. The results of Dr. Hausman's analyses are summarized in the table below:

	Baseline Emissions	Modeled Performance Improvements	Projected Emissions	Total Increase	Result of Improvements
Rush 1	14,874 tpy	4.0% EAF	15,561 tpy	687 tons	562 tons
Rush 2	14,288 tpy	18 MW and 2.0% EAF	16,816 tpy	2,528 tons	746 tons

FOF 348–50, 353–54. These results show that Ameren's modeling would predict significant emissions increases at the Rush Island units as a result of the projects.

Ameren's expert witnesses confirmed at trial that the technique Dr. Hausman used is commonly used in the industry. FOF 344. Ameren's experts Michael King and Marc Chupka testified that they had done or recommended similar analyses in prior PSD enforcement cases—but did not do them here. *Id*.

4. **The evidence shows that efficiency improvements would not prevent emissions from increasing as a result of the projects**

Ameren argued that it expected unit efficiency to improve at Unit 2[13] and that this efficiency improvement would offset any overall increase in emissions. Before this litigation, however, Ameren made clear that it expected the improved efficiency to result in *more*

[13] Ameren has also argued that efficiency was expected to prevent an emissions increase at Unit 1. However, the project was not justified based on any efficiency improvements. It was justified based on outages and load limitations. FOF 145–47, 212. Moreover, while Ameren has now claimed some improvements in the unit's *net* efficiency, such an improvement means more of the unit's generation can be sent to the grid (as opposed to be used to run the plant itself) but does not reduce the amount of coal burned. FOF 117, 213, 351.

generation (greater total capacity) rather than less coal burned. In justifying the projects to management, Ameren's engineers predicted a small improvement (0.5%) in auxiliary load due to the boiler component replacements and a 15 MW increase in capacity due to the low pressure turbine. FOF 280. The 15 MW Ameren attributed to the turbine was *separate* from the 22.5 MW improvement attributed to the boiler components. Pl. Ex. 110; FOF 281. Similar improvements were reported by Ameren to the Missouri Public Service Commission—a 0.5% improvement due to the boiler component replacements and a 1.9% (12 MW) improvement due to the turbine replacement. FOF 291. Both types of improvements would result in producing more generation, but *not* in burning less coal. FOF 117, 213, 214, 280. Consistent with these reported expectations, Ameren did not incorporate *any* efficiency change in the 2010 fuel budget model run that it used as the projection for its NSR emissions calculation. FOF 401, 407. While Ameren later revised that run to reflect changed efficiency at Unit 2, it only did so *after* the project was long complete and the United States had filed this lawsuit. FOF 401. These revisions, which were made after the completion of the project and even after this lawsuit was filed, lack credibility. And even the revised projection showed an emissions increase that would trigger NSR after the analysis is adjusted to disregard Ameren's inappropriate application of the demand growth exclusion. *See* Subsection III.C.

The United States' experts took these potential efficiency improvements into consideration in performing their analyses. FOF 213–15, 279, 280, 300. Mr. Koppe explained that auxiliary load reductions would not impact gross efficiency, which is what matters for purposes of determining how much sulfur dioxide a unit will emit. FOF 117, 213. In his analysis of the turbine replacement at Unit 2, Mr. Koppe concluded that because the capacity increase at Unit 2 exceeded the efficiency improvement, the unit would ultimately still burn more coal even with the turbine replacement. FOF 214, 215, 280, 281, 300. Separately, Dr. Hausman did a variant of his with-and-without analysis that incorporated an efficiency increase that was even greater than the 2.4% improvement Ameren reported to the Missouri Public Service Commission. Dr. Hausman's analysis found improving efficiency had only a small effect on the projected increase related to the project, which was 696 tons of SO_2—still more than 15 times the threshold requirement. FOF 356.

Ameren concedes that efficiency actually got *worse* after the project compared to the baseline. Ameren blames a portion of the actual increase in pollution on the realized decrease in efficiency. Regardless of the cause for the unit's decline in efficiency, each hour of operations or each extra MW that is generated at the plant requires that much more coal—and results in that much more pollution. Ameren's argument has no impact on the United States' actual emissions theory because blaming increased emissions on unexpectedly declining unit efficiency does not change the fact that the units burned more coal and emitted more pollution than they otherwise would have without the boiler upgrades—and some of the emissions increase would never have occurred had Ameren decided not to perform those overhauls. Ameren did not claim that the efficiency decrease accounts for the entire post-project emissions increase. So even if some of the post-project actual increase was due to worsening efficiency, there was still an increase of emissions due to the projects.

Ameren argues that efficiency was *expected* to improve, so it was reasonable to expect less pollution, and then it argues that efficiency *actually* got worse, so the increase in pollution is unrelated to the projects. The evidence shows that the efficiency increase that Ameren claims to have expected would result in more MW, not less fuel burned. FOF 214, 215, 280, 281, 291, 300. And while the efficiency decrease that came after the project could explain part of the actual increase, it does not alter the fact that a substantial portion of the increase (far more than 40 tons) was related to the increased availability and capacity caused by the project. FOF 216.

5. **Conclusion: The emissions evidence shows an increase related to the projects should have been expected and actually occurred**

Ameren expected the projects to cause its highest period of post-project availability to rise well above the baseline availability for both units. The projects caused substantial availability increases. Ameren also expected and realized a post-project increase in capacity at Unit 2 from the challenged boiler work. Those expected and actual performance improvements were significantly larger than the small changes (an additional 21 full power hours or 1.7 MW) needed to cause a 40-ton increase in emissions.

The United States' experts approached the question of estimating the projected increases from different perspectives. Mr. Koppe and Dr. Sahu first focused on the expected incremental availability (and, for Unit 2, capacity) improvement, determined whether those improvements would be realized for the unit as a whole, and then directly calculated the tons of emissions associated just with those project-related improvements. Dr. Hausman took another approach. Using Ameren's modeling, he began with a projection that accounted for *everything* that Ameren expected at the units in the future, and then he isolated the amount of generation and pollution related to the project. Ameren criticized both approaches but never did its own calculation to show which of the additional tons of emissions were related to the projects.

Using these different approaches, Mr. Koppe and Dr. Sahu reached very similar conclusions to Dr. Hausman. Additionally, these experts' calculations were confirmed by the actual results, as shown in the two charts below:

UNIT 1	Koppe/Sahu	Hausman	Ameren's Documents	Actual Emissions
Δ EAF	3.8%	4.0%	4.0%	4.3%
Δ SO_2	608 tons	562 tons	[No PSD Analysis]	665 tons
FOF	227, 232	348 – 350	228 – 231	238, 243

UNIT 2	Koppe/Sahu	Hausman	Ameren's Documents	Actual Emissions
Δ EAF	2.8%	2.0%	3-4%	2.9%
Δ Capacity	18.1 MW	18 MW	22.5 MW	23 MW
Δ SO_2	415 (EAF) 417 (MW)	746 tons	2,531	2,170 tons
FOFs	251, 258, 303	353, 354	256, 276, 277, 402	260, 266, 300

The Koppe-Sahu results, Dr. Hausman's analyses, and the actual post-project data all establish that there is a significant net SO_2 increase of more than 40 tons that was caused by the projects. Based on the known facts that the Rush Island units are low-cost, baseload units, common sense compels the same conclusion: improving availability or capacity at baseload units like Rush Island will result in additional operations and pollution. Ameren's model confirms that relationship, as Dr. Hausman showed and Ameren's chief modeler confirmed in his testimony. FOF 329–41, 448. Other courts have recognized this relationship. *See* Subsection II.B.1 above (citing cases). Ameren should have expected a significant net emissions increase and should have obtained a permit before beginning work.

C. Ameren Also Violated Title V

Because I conclude the projects were major modifications, I also find that Ameren has violated Title V of the Clean Air Act.

Title V creates an operating permit program designed to collect all of a source's applicable requirements under the Clean Air Act in a single place. 42 U.S.C. § 7661c(a); *Ameren SJ Decision*, 2016 WL 728234, at *3 (quoting *Sierra Club v. Otter Tail Power Co.*, 615 F.3d. 1008, 1012 (8th Cir. 2010)).

Missouri's Title V program requires sources to obtain a permit with "all applicable requirements." 10 C.S.R. § 10-6.065(6)(C)1.A; *see also* 42 U.S.C. §§ 7661 - 7661c(a). By definition, applicable requirements include requirements under the New Source Review program. 10 C.S.R. § 10-6.020(2)(A)23; *see also Ameren SJ Decision*, 2016 WL 728234, at *24. In addition, Ameren's Title V permit prohibits major modifications without Ameren first obtaining a permit. FOF 456.

By performing major modifications without obtaining an NSR permit (and satisfying the associated requirements, including the requirement to operate best availability control technology to reduce emissions), Ameren violated both the requirement to obtain a permit with all applicable requirements and the permit prohibition against unpermitted major modifications.

III. AMEREN'S DEFENSES AND CRITIQUES OF THE UNITED STATES' EVIDENCE FAIL

A. The Projects were not Routine Maintenance

Ameren has asserted the routine maintenance, repair, and replacement defense. The routine maintenance exemption provides that projects do not constitute "major modifications" if they merely consist of routine maintenance, repair, or replacement activities. *See* 40 C.F.R. § 52.21(b)(2)(iii)(a); 10 C.S.R. 10-6.060(8).

Based on the evidence presented at trial, I conclude that the projects cannot be considered routine maintenance under the law. The Rush Island boiler refurbishments at issue were the most expensive boiler projects ever performed on an Ameren boiler. FOF 182, 183. They involved the redesign and replacement of major boiler components that were intended to improve the performance of the units and enable them to burn coal they were not originally intended to burn. FOF 47, 53, 62, 134, 138–47. They were the first such replacements in the history of each unit, are rarely done at any unit in the industry, and the combination of boiler replacements has rarely, if ever, been done in the industry. FOF 172, 174–76. Under the appropriate legal standards, every factor of the routine maintenance test weighs heavily against classifying the work as routine maintenance, repair, and replacement. Even Ameren's designated expert on routine maintenance, Jerry Golden, acknowledged at trial that these projects were not *de minimis*. FOF 164.

1. Legal standard

The standard for the routine maintenance, repair and replacement exemption in the NSR rules "is a narrow one and is generally limited to *de minimis* circumstances." *Ameren SJ Decision*, 2016 WL 728234, at *5. Ameren has the burden of proving the routine maintenance exemption applies. *Id.*

As I explained at summary judgment, to determine whether a defendant has met its burden of proving the routine maintenance exemption, courts examine the projects, taking into account the 1) nature and extent, 2) purpose, 3) frequency, and 4) cost of the activity to arrive at a common-sense finding. *Id.* at *4, *5 (citing *Wisconsin Elec. Power Co. v. Reilly*, 893 F.2d 901, 910-11 (7th Cir. 1990)). "Frequency [is] evaluated by considering the work conducted at the particular unit, work conducted by others in the industry, and work conducted at other individual units within the industry. In evaluating frequency, the most relevant inquiry is how often similar projects have been undertaken at particular units in the industry, not how many similar projects have been implemented industry wide." *Id*. at *5.

EPA has consistently interpreted the routine maintenance exemption as requiring review based on the "principle that a non-routine collection of activities, considered 'as a whole,' is not exempt under routine exclusion, even if individual activities could be characterized as routine." *Id.* at *8. For these reasons, as I stated at summary judgment:

> separate equipment or component replacements should be taken as a whole, i.e., multiple component replacements may constitute one 'project,' for purposes of the RMRR analysis, if . . . it appears that the work was done as part of one project. Under this common sense framework, I agree with EPA that whether the challenged work was planned for together, budgeted together, performed together, and undertaken for the same purpose are relevant to the inquiry.

Id.

2. The boiler refurbishments at each Rush Island unit constitute one project for routine maintenance purposes

All of the boiler component replacements were related in that they were planned together, budgeted together as capital projects, performed at the same time, and undertaken for the same purpose. As a result, I find that the work should be viewed together in determining whether it qualifies for the routine maintenance exemption.[14]

<u>The work was planned together.</u> There is no question that Ameren planned the component replacements together. When Ameren issued the contract documents to qualified bidders for the project, it consolidated all of the work in its contract specifications. FOF 133, 134. Ameren noted that the projects were combined to "gain efficiencies in procurement, design and installation" and described the air preheater replacement as "part of a Major Mechanical

[14] Even if I were to consider each major component replacement separately, I would still conclude that the projects were not routine maintenance under the weight of the evidence.

Work Package to include the Economizer, Reheater and Lower Slope portion of the boiler." FOF 132. Ameren described the "major boiler modifications for Rush Island 1 and 2" as follows:

> For several years we have been planning major refurbishment of the Rush Island 1 and 2 boilers, which have operated for nearly 30 years without replacing any of the major components. The major scope elements include the following major components which are experiencing an increase in tube leaks and fatigue issues, and have been redesigned to improve future operation and maintenance:
>
> - Reheater—redesigned for PRB coal
> - Economizer—redesigned for PRB coal
> - Lower Slope—ruggedized design to better withstand slag falls
> - Air Preheater—redesigned for ease of future basket replacement.

P. Ex. 6; FOF 139.

<u>The work was budgeted together.</u> As of December 2004, Ameren had created a preliminary capital budget for the replacement of the Unit 1 economizer, reheater, lower slopes, and air preheater as part of a single project. FOF 126. Even though Ameren prepared separate work orders for the two air preheater replacements, all the work was from Ameren's capital budget—not the operations and maintenance budget—and was budgeted for the same outage to be performed at the same time. FOF 130, 131, 181. Likewise, at Unit 2, Ameren consolidated the replacement of the challenged components when it sought bids from outside engineering firms to design, fabricate, and install those components. FOF 133.

<u>The work was performed at the same time.</u> It is undisputed that the components at issue were performed together during the same outages at Unit 1 and Unit 2. FOF 25, 169, 170.

<u>The work was undertaken for the same purpose.</u> Ameren's routine maintenance expert, Mr. Golden, agreed that the purpose of the work at each unit was the same. FOF 150–51. Mr. Golden confirmed Mr. Stevens' testimony that the purpose of the work at each unit was to eliminate pluggage and fouling of the economizers and reheaters and to eliminate future forced

and maintenance outages caused by tube leaks.[15] FOF 56–69, 145–47, 149. The United States' expert Mr. Koppe also explained that Ameren could completely resolve the capability restraints caused by pluggage only by replacing each of the components at issue during the same outage. FOF 53, 63, 196. Ameren's Jeff Shelton agreed. FOF 64.

3. The projects do not qualify for the routine maintenance exemption

a. Nature and extent

The 2007 and 2010 projects involved the replacement of major boiler components that are integral to the operation of the Rush Island Unit 1 and 2 boilers. The 2007 and 2010 projects took years to design and plan and required the special fabrication of components that were not otherwise available at the Rush Island plant. FOF 139, 164. The projects were far more extensive than the type of maintenance, repair, and replacement routinely performed at Rush Island and other coal-fired power plants. FOF 165–72. And it is clear from Ameren's documents that the company itself never considered these projects to be just "routine maintenance," as that term is understood in the industry; it considered them to be "major boiler modifications" or "major boiler refurbishments." FOF 50, 130, 139, 171.

Each of the boiler components was redesigned to eliminate the recurring problems associated with Ameren's switch to PRB coal. FOF 53, 134, 138–49. These design changes were intended to upgrade and improve the performance of the boilers. FOF 145–60.

Given the complexity of the replacements, the components were designed, engineered, and constructed by outside contractors, such as Alstom Power, the original manufacturer of the boilers. The work was well beyond the capacity of Ameren's own staff. FOF 128, 166.

[15] On Unit 1, the lower slopes were replaced to eliminate tube leaks and repair damage resulting from slag falls and erosion following the switch to PRB coal. FOF 52, 53, 56–59.

In contrast with routine maintenance, repairs, and replacements undertaken at utility plants, the projects required approvals of executives at the very highest level of the company, including Ameren's CEO. FOF 135–37.

The economizers, reheaters, and air preheaters each weigh hundreds of thousands of pounds and required construction of heavy equipment such as monorails and cranes. FOF 162, 167–68.

The 2007 outage for Unit 1 lasted 100 days and required more than 1,000 workers and 448,539 total hours of labor, of which 402,109 hours were performed by contractors. FOF 169. Ninety-one percent of the work done during the Unit 1 outage was performed by contractors. *Id*.

The 2010 outage at Unit 2 lasted approximately 100 days and required more than 350,000 hours of labor, of which 290,953 hours were performed by contractors. FOF 170. An average of 360 contractor staff worked two 10-hour shifts six days a week during the outage. *Id*.

The 2007 and 2010 overhauls were considered capital projects and were funded out of Ameren's capital budget rather than the operations and maintenance budget. FOF 181. As capital projects, these component replacements improved the value of the generating unit. FOF 180.

As a result, the nature and extent of these projects weighs heavily against a finding that these projects qualify for the narrow routine maintenance exemption.

b. Purpose

As noted above, the consistent purpose of the projects was to eliminate pluggage, fouling, and tube leaks. Ameren expected that tube leaks in the economizers and reheaters would be eliminated for at least 20 years. FOF 38, 145–47. By contrast, routine maintenance, repair, and replacement is performed to allow a unit or plant to continue to operate in its present condition.

See Doc. 227-2, Memorandum from Don Clay, Acting EPA Ass't Admin. (Sept. 9, 1988), at 3-4; Doc. 227-3, 2000 DTE Applicability Determination Detailed Analysis, at 11.

The replacement of these major boiler components allowed the units to operate hundreds more hours than they could in the baseline period at a higher capacity by eliminating tube leaks, load limitations, and operational constraints. The purpose of these projects indicates that the work was far from routine.

c. Frequency

Even though the most relevant inquiry is how often similar projects have been undertaken at particular units in the industry, for each of the three inquiries under the frequency factor, the inquiry weighs heavily against a finding of routineness.

Frequency at the unit. None of the components at issue had been replaced at these units before. FOF 173. The components were replaced after 31 years of service at Unit 1 and 33 years of service at Unit 2. FOF 4, 174.

Frequency at individual units within the industry. The components at issue are very rarely replaced at any plant. FOF 174–76. Ameren's expert confirmed this point. Mr. Golden agreed that the typical life of a reheater is about 30 years, the typical life of a primary economizer is about 35 years, and the typical life of the lower furnace is about 40 years. FOF 174. Mr. Golden also testified that complete air heater replacements (including the rotor and all baskets), like the ones done at Rush Island, are not done frequently at any unit. *Id*. This evidence, coming from Ameren's expert, demonstrates that replacing the components at issue is rarely done at individual units within the industry.

Work conducted by others in the industry. Mr. Golden testified about a list he has complied of 18,300 projects undertaken at coal-fired power plants. The list includes projects that

Mr. Golden identifies as capital projects costing more than $100,000. *Id*. As an initial matter, the relevance of Mr. Golden's list to this case is weak because Mr. Golden has been unable to identify *any* coal-fired unit in the electric utility industry that has replaced the economizer, the reheater, the lower slopes, and the air preheater together. *Id*. Boiler refurbishments like the ones at Rush Island are not common in the industry.

Regarding air preheater replacements, Mr. Golden identified 35 replacements of regenerative air preheaters going back to the 1970s.[16] FOF 176. By his count, that is less than 2 percent of the coal-fired units in the country. However, Mr. Golden was unable to say whether those 35 instances were complete replacements or similar to those at Rush Island. *Id*. Even if they were, a replacement that takes place at less than 2 percent of the units going back to the 1970s is not common in the industry.

As a result, the frequency factor weighs heavily against these projects being routine.

d. Cost

The projects at issue were the most expensive capital projects ever done at Rush Island. Each project cost substantially more than the entire operations and maintenance budget for the plant for an entire year. FOF 177, 178, 182. Grouping the replacements at each unit together, the two projects were among the most expensive boiler projects ever undertaken at any of Ameren's plants. FOF 183.

Based on the undisputed facts regarding the costs of these projects, the cost factor also weighs heavily against these projects being routine.

4. Conclusion: the projects cannot be considered routine

[16] Even for the claimed 35 air preheater replacements, Mr. Golden was unable to testify that all were complete replacements or that all the replacements were comparable to the air preheater replacements at Rush Island. FOF 177.

Ameren has not satisfied its burden of proving that the Rush Island projects fall within the narrow routine maintenance exemption. The 2007 and 2010 major boiler outages were unprecedented events for Rush Island Units 1 and 2—they were the centerpieces of the "most significant" outages in plant history. FOF 172. A common sense finding weighing the nature and extent, purpose, frequency and cost of the projects reveal them to be far from *de minimis* activities contemplated by the exemption. Ameren's expert agreed and testified at trial that these projects were not *de minimis* activities. As a result, Ameren's routine maintenance defense fails.

B. The Emissions Increases Cannot Be Set Aside Based on the Demand Growth Exclusion

Ameren also asserts the "demand growth exclusion," set forth at 40 C.F.R. § 52.21(b)(41)(ii)(c), as a defense to liability. As the United States Court of Appeals for the District of Columbia explained in *New York v. EPA*, "the regulation establishes two criteria a source must meet before excluding emissions from its projection: (1) the unit could have achieved the necessary level of utilization during the [baseline period]; and (2) the increase is not related to the physical or operational change(s) made to the unit." 413 F.3d at 33 (quotations omitted). "The two prongs are distinct. Satisfying the 'could have accommodated' prong is necessary but not sufficient to justify application of the exclusion, and emissions that 'could have been accommodated' at baseline are not per se 'unrelated.'" *Ameren SJ Decision*, 2016 WL 728234, at *21.

Additionally, as stated at summary judgment, "the burden is Ameren's to prove that the demand growth exclusion applies." *Id*.

1. Ameren's experts confirm that demand was not projected to—and did not—cause the pollution increases at Rush Island

Fundamental to an invocation of the demand growth exemption is that demand *on the unit* increases. But in this case just the opposite happened, as the data shows—and Ameren's expert witnesses conceded.

A unit's "utilization" is a measure of how much of its available capacity the unit is called on to use. The measure serves to reflect market demand on a specific unit. FOF 377. As Mr. King explained, a declining utilization factor means demand on the unit is decreasing. FOF 378. As a result, when the utilization factor is declining, an increase in pollution *cannot* be the result of demand. *Id.*

As far as the actual emissions case is concerned, Mr. King and Ms. Ringelstetter both testified that the utilization factor for the Rush Island units actually *decreased* after the projects. FOF 378–80. The declining demand that the units actually experienced after the projects prevents Ameren from asserting a successful demand growth argument for the actual emissions increase shown in the data.

Ameren's application of the demand growth exclusion also fails for the expectations case. Ameren's testifying expert Marc Chupka looked at the utilization factor data leading up to each project and concluded that "[i]t would be reasonable to assume a constant utilization factor for projecting future emissions" following the boiler upgrades at issue in this case. FOF 208. Ms. Ringelstetter agreed. She testified that the utilization of Unit 1 was projected to remain basically constant, and, though utilization of Unit 2 was projected to increase somewhat (about 2%), the increase paled in comparison to the projected increase in emissions (over 15%). FOF 380. A constant utilization factor means static demand on the units. If that demand is constant, it cannot be the cause of an emissions increase. Regardless, even the marginal projected increase in Unit 2's utilization factor cannot account for the substantial emissions increase that Ameren's modeling and calculations projected. *Id*.

2. Ameren's evidence does not address what portion of the units' projected or actual emissions increases were "unrelated" to the projects

The evidence Ameren presented in support of the demand growth defense generally falls into two categories: (1) evidence that regional demand for electricity was generally going up during the years surrounding the Rush Island projects, and (2) calculations regarding how much generation (and pollution) the units "could have accommodated" during the baseline periods. The central problem for Ameren's defense is that these showings, while necessary to the company's proof, are insufficient to establish that the demand growth exclusion applies to any specific "portion" of its projected emissions increases, as required by the rule. *Cf.* 40 C.F.R. § 52.21(b)(41)(ii)(*c*); *see also* 40 C.F.R. § 52.21(r)(6)(i)(*c*) (requiring operators to document and describe certain PSD analyses, including "the amount of emissions excluded under [the demand growth exclusion] and an explanation for why such amount was excluded"). Ameren has failed to establish a correlation between rising regional demand and any specific impact on unit performance in order to show what portion of its projected emissions increases are "unrelated" to the projects at issue in this case.[17]

[17] Ameren's theory on demand growth appears to be that, if it can prove emissions were related to demand, then the emissions cannot be related to the projects. This rests on the false assumption that an effect can only have one cause. Because pollution, like any effect, can have more than one "but for" cause, it is not enough for Ameren to simply point out that some of its projected and actual increases in emissions are related to the presence of sufficient market demand for Rush Island power. Ameren disputes the relevance of the restaurant analogy argued by the United States and used by the Court at summary judgment. *See Ameren SJ Decision,* 2016 WL 728234 at *10 n.17. But the restaurant analogy remains useful. To be sure, a meal

The first category of Ameren's evidence—its various system load forecasts—fails to connect meaningfully to projections of unit operations because increases in system demand do not necessarily translate into increases in unit operations. As Ameren's witnesses testified, during the baseline period, the units operated as baseload units and operated whenever they were available. As a result, they were usually fully-loaded during "on peak" hours when system demand was at its highest. FOF 371–72. If the units were generally maxed out anyway, increases in system demand would have little effect on unit operations.[18] That is reflected in Ameren's expert testimony on unit utilization, discussed above. Moreover, as Dr. Hausman testified, Ameren's ProSym modeling efforts showed just how disconnected unit operations were from system level demand. Ameren's load forecasts were inputs into its modeling runs, and they reflected the company's expectation that system load was growing on the order of 1% a year. But the output files from those very same runs reveal Ameren's computer simulations projected that generation from the Rush Island units would increase immediately following the outage and then remain relatively flat. FOF 373. Ameren seems to suggest that rising regional demand for electricity—like a rising tide—would lift operating levels at its units. The evidence clearly establishes otherwise.

served to a restaurant customer is "related" to the customer's decision to order it (customer demand); but that does not mean that the meal is "unrelated" to the restaurant having an open table or the chef's preparation of the food.

[18] Ameren witness Jaime Haro noted that, for baseload units like Rush Island, increases in system demand would mean the units still ran at high levels most of the day, but they might ramp down a little later each day or turn up to full load a little earlier each morning. FOF 370. The marginal increases in demand on the "shoulder" hours may have been attributable to system level demand, but Ameren made no attempt to quantify just what portion of its emissions projections were made up of these marginal shifts. As a result, Ameren cannot meet its burden of proof on this defense.

Ameren's second category of evidence, presented through its expert Sandra Ringelstetter, is a series of calculations describing how much SO_2 pollution the Rush Island units "could have accommodated" during their respective baseline periods. This, too, fails to address how any specific portion of its projected emissions increases is unrelated to the projects at issue. It does not address any portion of the units' projected emissions *at all*. While varying somewhat in the details, all of these calculations involve picking a pollution rate the units achieved at some limited point during the baseline period (sometimes a month, sometimes a week, sometimes a discontinuous set of hours taken from across the 24-month baseline period), and then multiplying that emissions rate by the unit's baseline equivalent availability levels. Since EAF is a measure of available hours, and since its emissions rate is related to a unit's load levels,[19] these calculations essentially assume that the unit would run flat out, at some very high level of operations, through day and night, for nearly two continuous years. Ameren then concludes that, since demand was going up and its "could have accommodated" calculations result in more emissions than any projected increase in this case, *all* projected emissions increases can and should be excluded from the NSR liability calculation.

Ameren's "could have accommodated" calculations are fundamentally flawed. For example, they employ unreasonably-high emissions rates and rely on applicability determinations divorced from the operational realities of electric utilities. But even if Ameren's "could have accommodated" calculations were reliable, the calculations cannot—as a structural matter—say anything about whether the projected emissions from the units are *related* to the projects at hand. Ameren's "could have accommodated" calculations consider neither the

[19] Despite Ms. Ringelstetter's testimony to the contrary, hourly emissions are directly related to hourly heat input in her own analysis, Ringelstetter Test., Vol. 11-B, 85:15–86:3, and the relationship between heat input and unit load level is "more or less linear." *Id.* at 85:9 – 11.

projects at issue nor the projected emissions in any way. At best, the calculations have something to say about only one prong of the demand growth exclusion, which is not sufficient to establish the exclusion applies.

3. Ameren's other demand growth arguments fail

Ameren made two additional arguments at trial in support of its demand growth defense. First, Ameren argued that "unit-level demand" is not the focus of the test, and that instead, the demand growth exclusion focuses directly on "systemwide demand." In other words, Ameren argues that the problem of translating system demand into demand on the unit and changes in unit operations is not required by the rule itself. For that proposition, Ameren cites the 1992 WEPCO Rule Preamble where the demand growth exclusion was first introduced. The passage does not support Ameren's argument; in fact, just the opposite:

> [W]here increased operations are in response to independent factors, such as system-wide demand growth, which would have occurred and *affected the unit's operations* even in the absence of the physical or operational change, such increases do not result from the change and shall be excluded from the projection of future actual emissions.

57 Fed Reg. 32,314, 32,326 (1992). As a result, the regulations themselves establish that EPA has always required an operator to show whether—and to what extent—demand would "affect the unit's operations" before the demand growth exclusion could be applied.[20]

---

[20] Ameren cites various other authorities in its post-trial brief to support its argument that evidence of increasing systemwide demand is sufficient to establish the demand growth exclusion. Ameren misreads each of these authorities, ignoring paired language clarifying that the relevant inquiry requires consideration of how demand affects the units at issue. The demand growth standard is clear. In situations like these, "where [a] proposed change will increase reliability, lower operating costs, or improve other operational characteristics of the unit, increases in utilization that are projected to follow can and should be attributable to the change." 61 Fed. Reg. 38,250, 38,268 (1996).

Ameren's second argument was presented through the testimony of Ms. Ringelstetter. Specifically, Ameren argued that any performance changes or any emissions increases following the Rush Island modifications would be unrelated to those boiler modifications. This conclusion is unsupported and was offered for the first time at trial.

Until the summary judgment ruling, Ameren and its experts declared that it did not really matter *what* the project was so long as the unit, during the baseline, "could have accommodated" the projected emissions. As the head of Ameren's Environmental Services Department testified in Rule 30(b)(6) deposition testimony, "The emissions that the unit was capable of accommodating prior to the outage would be totally unrelated to . . . any activities that occurred on the outage. So just by the nature of the scope, the emissions are unrelated." Whitworth Rule 30(b)(6) Depo. Test. 38:4-12; *see also Ameren SJ Decision*, 2016 WL 728234, at 9 (describing Ameren's argument that "'unrelated' means any emissions increases a unit could have accommodated at baseline"). And when Ms. Ringelstetter originally performed her "could have accommodated" calculations, she declared that was the only step necessary to establish that the exclusion applied. She testified at her deposition that even assuming the performance improvements she recognized in Ameren's modeling files were the result of the boiler upgrades, it would not have changed her analysis, her calculations, her considerations, or her conclusions in any way. FOF 438.

Ameren's theory is inconsistent with the plain language of the regulations, the case law, and my summary judgment decision holding that the two prongs of the exclusion are distinct. *See Ameren SJ Decision*, 2016 WL 728234, at *11. After my summary judgment ruling, Ameren adjusted its theory and attempted to show that neither the capacity increase experienced at Unit 2 nor the availability increase experienced at either unit was related to the boiler upgrade work at issue in this case. Not only is such a conclusion contrary to the Ameren's internal engineering and economic documents, the pre- and post-project analyses provided by Ms. Ringelstetter, on which Ameren bases its relatedness arguments, are flawed.

Ms. Ringelstetter's capacity analysis begins by relying on inapplicable pre-project values. Instead of comparing projected future operations to actual, past operations, she looks at modeling inputs from previous years. Though those earlier modeling efforts might generally be expected to reflect the unit's actual operations around that time, the capacity values used here present a particular problem: Ameren uses its capability tables to develop unit capacity inputs, and for half of the baseline at each unit, the capacity tables were "unrealistically high."[21] FOF 431–32. That means the capacity increase Ameren expected to see and did see following the Unit 2 work was about twice what Ms. Ringelstetter saw. That increase cannot be attributable to turbine work alone, as Ms. Ringelstetter claims. FOF 431–32; *cf.*, *e.g.*, FOF 304.

Ms. Ringelstetter's analysis also discounts the observed availability increases post-project as being too small to be meaningful. Essentially, Ms. Ringelstetter argues that the increases are "in the noise," so there is no increase at all. But the evidence shows that just a 0.3% availability improvement could result in 40 additional tons of SO_2 at Rush Island. FOF 191. Ameren's

[21] In January and February of 2006—and in middle of the baseline periods—Ameren decided to update its capability tables to come up with more accurate predictions. Pl. Ex. 157 at AM-02743289. For the Rush Island units, that meant substantially reducing the projected unit capabilities as operating data showed that the units were struggling to perform as expected for many months of the year. U.S. FOF 119. Recognizing this, and using "historical operating data along with design criteria," Ameren updated its capability tables and substantially reduced the Rush Island numbers in order to "generate more realistic capability ratings for all of [the company's] fossil units." Pl. Ex. 260 at AM-00091465. The new numbers dropped the average annual capability ratings for the units by about 12 MW. Compare Pl. Ex. 157 with Pl. Ex. 260. So Ms. Ringelstetter's baseline capability number is substantially inflated since almost half of the numbers there were "unrealistically high." U.S. FOF 432.

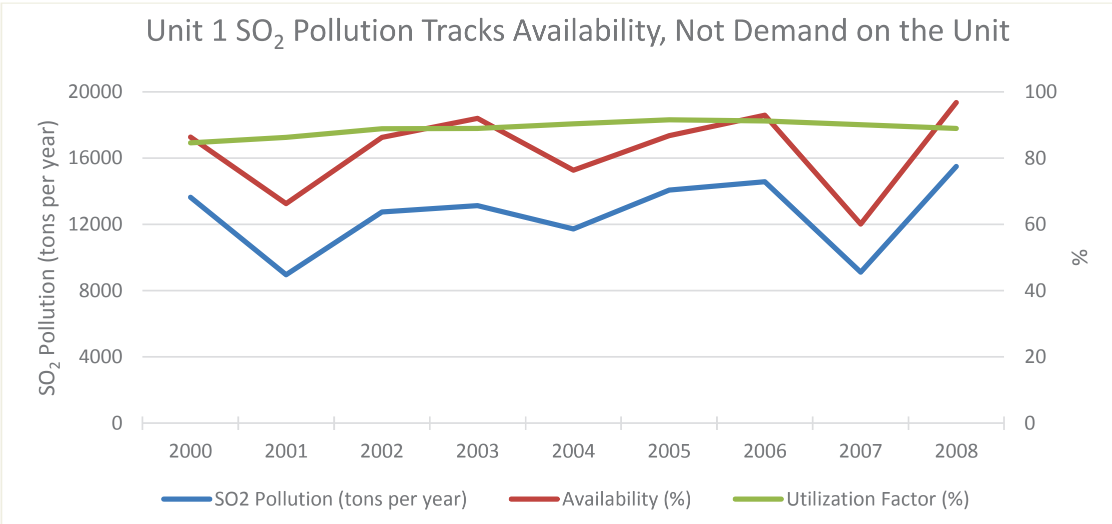
economic justifications were calculated to a tenth of a percent. FOF 104, 148. Ms. Ringelstetter's opinion also disregards the fact that Ameren projected long-term averages in its computer modeling and that specific years, as is relevant under the PSD analysis, might be as much as 2% or 3% higher than the inputs presented in the ProSym inputs. FOF 257. The important inquiry here is the size of the availability gain, which the evidence noted in Subsection II.B has shown to be about 3–4%. As Dr. Hausman testified, that kind of gain would lead to additional operations and pollution. To the extent Ms. Ringelstetter's testimony disregards these gains, her testimony is simply not credible.

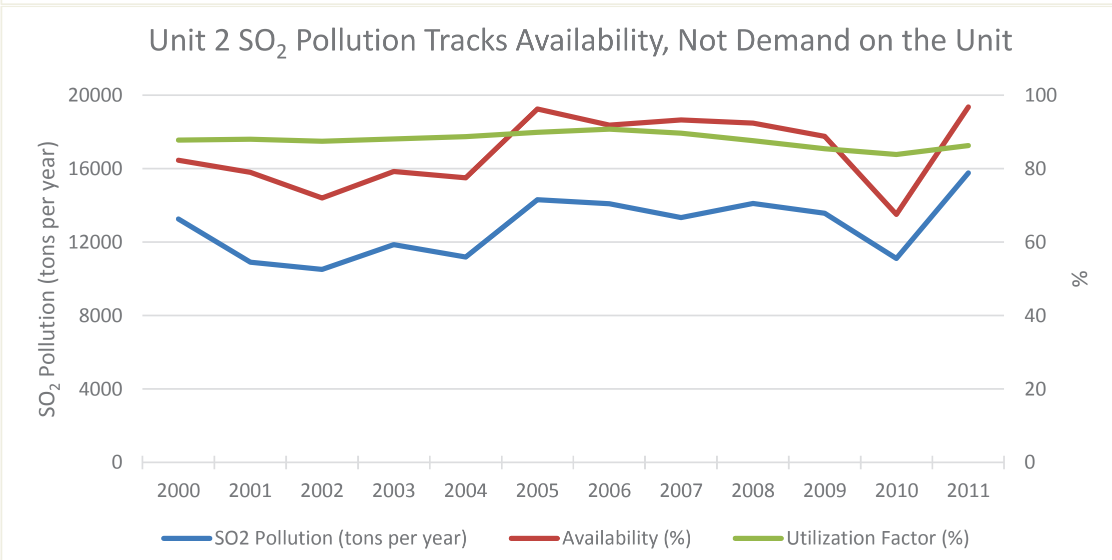
4. Emissions resulting from operations that would not have been possible but for the boiler upgrades cannot be considered "unrelated" to those boiler upgrades

Ameren's demand growth defense fails to address whether projected emission increases are related to the projects at issue. No matter how Ameren calculates the quantity of emissions it could have emitted had demand for electricity stayed high through the night, it does not address the reality that the units' real opportunities to sell more (and emit more) came by expanding their ability to operate when the demand is high—and when their units are generally maxed out—during the day. FOF 370–71. If there were baseline hours where the unit could not operate because of outages caused by the components at issue, any post-project recovery of those hours would be related to the project. Mr. Koppe found there were 246 outage hours for Unit 1 and 146 outage hours for Unit 2 caused by the projects in the baseline. FOF 240, 263. As described in Subsection II.B of my Conclusions of Law, both Mr. Koppe and Ameren concluded that those hours would be recovered and used in the post-project period. For those hours, the units went from unable to operate to able to operate. Demand did not cause that change; the units already operated every hour they could. That change resulted from $70 million of capital work. As I explained at summary judgment, when a unit "undergoes modifications that allow it to run more during the daytime hours tha[n] it could before, it cannot be said that the increased emissions were merely a coincidence or unrelated to the modification." *Ameren SJ Decision*, 2016 WL 728234, at *10.

Ameren's witness admitted that changes in unit capacity or availability would lead to changes in operations and pollution, FOF 427–28, and the company justified the cost of the projects on precisely those kinds of performance improvements. FOF 146, 277. Dr. Hausman specifically examined how performance improvements at the units translate into coal consumption and pollution, and the result is predictable: when the units are better able to supply electricity, they do so, and they burn more coal in the process, emitting more pollution. *See* Subsection II.B.2.c.

Moreover, the company's data reflects the straightforward relationship between the Rush Island units' performance abilities and their pollution levels. As discussed earlier, "[u]tilization is a variable that describes how much of the [unit's] available capacity the unit utilizes," and that in turn reflects the influence of all of the "market considerations" like system demand and market price that can impact unit operations. FOF 377. A unit's equivalent availability factor, on the other hand, reflects the engineering condition of the unit—how well it has been maintained and whether it stands ready to generate whenever needed. FOF 94. The graphs below show that Ameren's historical emissions data reflects the reality that Rush Island operations were driven by its engineering condition (measured by its availability) more than any market fluctuations (measured in its utilization). These graphs show SO_2 emissions, availability, and utilization factor at Units 1 and 2, respectively. They were the subject of testimony by Dr. Sahu and Mr. King and are based on data compiled by Dr. Sahu and Ms. Ringelstetter.[22]





[22] Ameren moved to exclude the graphs as not properly disclosed. For reasons I discuss below (*see* Section on Evidentiary Issues), I will deny Ameren's motion as it relates to these graphs. Notably, the charts were also used in the United States' summary judgment briefing, Doc. 609 at p. 20, and Ameren's David Strubberg presented a similar chart, comparing availability and generation, at the 2008 State of the System Meeting. FOF 202.

Reviewing these charts at trial, Ameren's testifying expert Michael King conceded that there was a relationship between availability and pollution. FOF 381.

Ameren argued that being forced to translate system level demand into an effect on unit operations would turn the analysis from an annual emissions focus to an hour-by-hour assessment, which is not contemplated by the regulations. That argument fails for two reasons.

First, just as a restaurant owner knows the ebb and flow of customers throughout the lunch and dinner rushes, Ameren knew that Rush Island generally ran hard throughout the day and ramped down somewhat at night. In this context, Ameren's employees noted that derates resulting from pluggage in the units' boiler components were costing the company as much as $25,000 a day. FOF 112. A company does not lose earnings when it has available capacity that it could dip into at a moment's notice; it loses earnings when it cannot provide the generation it would otherwise be able to sell for a profit. *See, e.g.*, FOF 112, 274 (Williamson email). And when Ameren justified the substantial expense of the boiler overhauls at the Rush Island units, the company quantified the benefit of recovering availability and capacity. Again, those benefits can only be considered "benefits" of the projects if the units would not have otherwise been able to operate that often or at those levels. *See*, *e.g.*, FOF 146. Documents like these reflect the general truth—without necessitating an hour-by-hour data review—that the units were limited, the problems were expected to be fixed, and the units would operate more as a result.

Ameren's argument that NSR cannot require sources to perform an hour-by-hour look at operations is disingenuous when its own ProSym software—which it uses regularly in the course of its business and runs hundreds if not thousands of times each year—solves the dispatch problem on an hour-by-hour basis for every year it is told to do so. FOF 317. That model makes it easy to isolate how performance improvements would interact with other market constraints to determine unit operations on an hour-by-hour basis and further determine how those hourly operations translate into annual generation and pollution numbers. Dr. Hausman did just that, and the results showed a straightforward relationship: more capacity or more availability led to more generation and more pollution. PSD requires sources to consider "all relevant information" in analyzing whether emissions will increase; it does not contemplate sources ignoring known, relevant information just because it might be unfavorable. Section 52.21(b)(41)(ii)(a). Ameren had the relevant information, and that information showed that the Rush Island units' performance would improve, resulting in increased generation and emissions.

As I have previously ruled, increases made possible by performance improvements must be attributed to the project and cannot be covered by the demand growth exclusion. *See* Subsection II.B.1.

C. Ameren's New Source Review Analyses Are Fatally Flawed and Cannot Provide Safe Harbor from Liability

Ameren's emissions calculations are not reasonable analyses under the PSD rules and therefore do not show that Ameren should not have expected an emissions increase.

1. Ameren does not have a legitimate process for assessing PSD applicability

First, Ameren's position relies on a fundamental misunderstanding of the PSD program. Ameren offered the testimony of Mr. Boll and Mr. Whitworth at trial to describe how Ameren determined whether a project might cause an emissions increase. Both witnesses testified that the company looked to whether the unit's *potential* emissions were expected to increase.[23] FOF 391. The company employee actually charged with performing the PSD analysis for Unit 2

[23] Mr. Boll used the term maximum continuous rating. FOF 391. As Ameren explained in its earlier briefing, that term is a measure of a unit's potential emissions. Doc. 542 at 5-6.

confirmed Ameren's reliance on the wrong metrics when he testified that any improvements in availability were "irrelevant." FOF 396, 397(d).

Ameren's method of assessing PSD does not comply with the rules, EPA's instructions, or case law. The rules explicitly direct a source to compare projected emissions to baseline emissions, both measured in tons per year. 40 C.F.R. § 52.21(b)(41), (48). As noted above, both EPA and the courts that have interpreted the PSD program have explained that "[i]f an increase in hours of operation is caused or enabled by a physical change, the increased hours must be included" in the projection. *Duke Energy 2010*, 2010 WL 3023517, at *5. EPA has brought enforcement actions since 1999 based on improvements in availability that lead to increases in annual pollution. Ameren's testifying expert conceded that EPA's enforcement approach has been "well-known in the industry" since 1999. FOF 219.

By focusing on potential emissions, Ameren ignores my ruling on Ameren's first motion for summary judgment. In motions practice, Ameren argued that the United States had to show a "modification" under the Missouri SIP before turning to the issue of whether the projects were "major modifications." Doc. 542 at 1-2. Ameren argued that modification status was controlled by *potential* emissions. *Id*. I rejected that argument. Doc. 711. As Ameren argued at summary judgment, "'modification' and 'major modification' are distinct terms with separate characteristics under the SIP." Doc. 542 at 5. At trial, however, Ameren described its internal analysis as focused solely on the first test, not the major modification test actually before the Court.

For the reasons described in Subsection II.B.2 of my Conclusions of Law, if Ameren had considered how the actual performance changes would affect generation, it would have expected and found emissions increases related to the project.

Second, Ameren failed to coordinate between the engineers who planned and performed the projects and the environmental services employees charged with assessing NSR applicability. Michael Hutcheson, who performed the NSR analysis for the Unit 2 project, reported that he learned about the project from his boss and his boss's boss but never talked to the engineers working on the project. FOF 397(a).

On the other side of this divide, engineering leaders at Ameren like Robert Meiners and David Strubberg testified that they had no involvement in assessing whether the projects triggered PSD. FOF 393. Mr. Meiners testified that as plant manager, he was "accountable" for ensuring that Rush Island complied with environmental regulations. *Id*. Despite that accountability, Mr. Meiners testified that he had never been involved in a single discussion about whether to seek a New Source Review permit for any project:

> Q. Even though you were plant manager, though, you had no involvement at all in the decision of whether to seek a New Source Review permit for either of the projects at issue in this case, right?
>
> A. I was not involved with that. We had an environmental department that took care of those kind of items. I was not involved.
>
> Q. And by "not involved," I mean, you didn't have a single discussion with anyone about the decision of whether to seek a New Source Review permit?
>
> A. No, I did not.
>
> Q. And, in fact, throughout your career at Ameren you've never had a single discussion with anybody about whether to seek a New Source Review permit for any project, right?
>
> A. No, I have not.

Tr. Vol. 7-B, 64:6-20.

The project justification packages that Ameren regularly put together as part of the work approval process included a checkbox asking whether the proponent had assessed

"Legal/Environmental" risks. FOF 388. But as one engineering manager testified, he could not "recall that box ever being checked" and had no idea what it meant. FOF 389. Each project had to be approved by a series of managers and executives, even the company CEO and board of directors. FOF 135–37. But the Environmental Services Department, charged with assessing NSR applicability, was not asked to approve the projects.

As a result, Ameren's PSD process suffered from two major flaws: the employees charged with assessing applicability started with an incorrect understanding of the law and lacked a meaningful understanding of the facts of the projects. In addition to these procedural flaws, for the reasons that follow, the actual analyses Ameren did "conduct" (for Unit 2 only) provide no basis for finding that Ameren could have reasonably expected the project would not significantly increase net emissions.

2. Unit 1

Ameren concedes that it performed no numerical calculation for the Unit 1 project.[24] FOF 391. Whatever qualitative analysis may have been done at the time cannot shield Ameren from liability now. Nor can the post-hoc analysis offered at trial by testifying expert Sandra

[24] Ameren argued for the first time in its post-trial brief that it was not required to perform a numerical calculation at Unit 1 because the provision of the 2002 Reform Rules requiring such calculations be performed was on remand at the relevant time. Ameren's argument fails. Even though a portion of the rule was on remand at the time, the Missouri SIP and EPA still required sources to maintain these records. *See* 71 Fed. Reg. 36,486, 36,487-88 (June 27, 2006); *see also* US Resp. Br. (Doc. 838) at 47-48. Moreover, as Ameren itself points out, the United States has not brought a record-keeping case and is not seeking judgment that Ameren failed to maintain the necessary records. Rather, the relevant issue is whether Ameren reasonably should have expected emissions to increase because of the projects. Whether Ameren performed a numerical calculation at all is certainly relevant to that inquiry and will, accordingly, be considered.

Ringelstetter, who used an inapt modeling run and incorrect application of the demand growth exclusion.

As an initial matter, there is no contemporaneous evidence that Ameren performed any assessment of the Unit 1 project. Mr. Boll testified that Ameren performed a qualitative emissions analysis for the projects in 2005. FOF 390, 391. But this analysis did not even rise to the back-of-an-envelope level—there is no written record of any such analysis. Moreover, because Mr. Boll and Mr. Whitworth made clear they only considered the maximum continuous rating of the unit, any qualitative analysis they did "conduct" did not comply with NSR requirements and therefore was not reasonable under the law. *Id.*

The post-hoc analysis performed by Ms. Ringelstetter does nothing to support Ameren's belief that emissions would not increase at Unit 1. Despite presumably having access to scores of ProSym modeling runs that projected Unit 1's post-project operations, Ms. Ringelstetter selected a run with two key flaws. First, according to her trial testimony, the run actually overstated emissions, so she adjusted it downward. FOF 454. Notably, other runs had no such issue, and Ameren itself never saw the need to adjust the run. FOF 454. Second, the run intentionally depressed output from Unit 1 for the full five years following the project based on the potential for the unit to provide ancillary services.[25] FOF 448, 449, 453. Ameren did not provide any evidence to support this assumption other than the testimony of Ms. Ringelstetter herself. Ms. Ringelstetter testified the modeling assumption was "entirely appropriate" and yet did not offer any document or specific fact to support that conclusion. She never even

[25] Ancillary services are services other than simple electric generation that utilities provide to keep the electric grid operating reliability. FOF 439.

mentioned ancillary services, spinning reserves, or regulation hours in her expert report. FOF 451. Moreover, the limited evidence in the record contradicts her opinion:

1. The only evidence that Ameren may have expected to provide some ancillary services with the Rush Island units around the time the boiler upgrades were performed is a short-term contract between Ameren Missouri and its Illinois affiliates. But that contract does not require anything specific of the Rush Island units in particular; in fact, it gave Ameren Missouri flexibility to provide the services from a number of different units. FOF 442.

2. Whatever effect the contract may have had on operations of the Rush Island units, the effect was never expected to last. The contract was never intended to extend beyond the inauguration of MISO's regional ancillary services market (originally scheduled in 2008 and then delayed to January 2009). FOF 440. Ameren's witnesses all agreed that once MISO implemented its ancillary services market the Rush Island units would not be providing such services at it does not make economic sense to hold back such cheap, reliable sources of generation. In fact, Ameren's head modeler told the Missouri Public Service Commission in that it did not make sense to model those services because they were based on a "short-term contract that will end when the MISO ancillary service market begins." FOF 445.

Selecting a run which depressed output for five years by modeling ancillary services at the Rush Island Unit 1 that—if ever they had an impact on operations—would last no more than two years after the project runs afoul of the regulations' requirement to "consider all relevant information" and use the highest year of post-project emissions. 40 C.F.R. § 52.21(b)(41)(ii)(*a*).[26]

3. Unit 2

While Ameren did at least perform numerical analyses for Unit 2, these analyses are no more compelling than its qualitative analysis for Unit 1.

As an initial matter, even though PSD analyses should be completed before beginning construction, Ameren did not complete any numerical analysis for Unit 2 until after the project work started. FOF 398-401. Ameren began its "Original" analysis at the end of 2009, which

[26] After using an inappropriate modeling run to obtain projected emissions, Ms. Ringelstetter misapplied the demand growth exclusion, as described in Subsection III.B of my Conclusions of Law.

relied on a January 2010 modeling run. By the time that analysis was done, the project was underway and it was too late for Ameren to comply with the law if a permit was required. Moreover, the work had been *approved* for four years at that point. The work was first approved in 2005 and then reassessed in a process that culminated with the final approval from the Board of Directors in August 2009. FOF 400.

Mr. Hutcheson testified at trial that the Original Unit 2 emissions calculation was one of about two dozen requested at the same time by Ameren's legal department. FOF 399. The projects to be assessed were a mix of past and future projects. *Id.* For Unit 2, the request came well after the project had been fully approved. FOF 400. This type of afterthought analysis (even if it had been finished just before the start of construction instead of just after) does not serve as a reasonable emissions calculation or prevent a finding of liability, particularly where the analysis fails to account for the company's actual expectations of performance improvements, as discussed below.

Ameren's "Amended" Unit 2 analysis is not helpful because it was not performed until even later and was only performed well after the project was completed, after Ameren received the Notice of Violation from EPA, after this lawsuit was filed, and only upon the request of Ameren's in-house counsel. FOF 401, 405-406. Ameren's in-house counsel asked the Environmental Services Department to perform this post-project amended "expectations" analysis to include the results of the amended EDF case that counsel had previously asked Mr. Hutcheson to run. That case was modeled to include additional efficiency improvements that had been left off from the Original run. FOF 401-407. Because the Amended analysis was performed under these circumstances and presumably for the purpose of this litigation, any credibility the analysis might otherwise have is severely diminished. Ameren's expert, Mr.

King, testified that he would not perform an NSR analysis based on a modeling run that was created just for NSR purposes, agreeing that in using such a run, a source runs the risk of looking like it was "cooking the forecast" to project no emissions increase. FOF 408.

In addition to these procedural flaws, the analyses Ameren actually did conduct suffered from considerable substantive flaws. Ameren's Original analysis failed to fully incorporate the improved availability the company expected after the project. The modeling run used for the projection assumed 95% availability for Unit 2 after the project. FOF 257, 410. But, as discussed in Subsection II.B.2 above, Ameren expected that the best years after the project would be 2–3% higher than that, based on its experience with Unit 1's record availability in 2008. The justification seeking ultimate approval for the project was based on an availability of nearly 97%. The regulations require Ameren to consider the highest year of emissions. 40 C.F.R. § 52.21(b)(41)(i). By limiting availability to 95%, Ameren failed to perform a reasonable analysis under the PSD rules.

Even without fully accounting for the project's effects, Ameren's analysis would have shown an NSR-triggering increase except for what Ameren excluded based on its capable of accommodating analysis. In calculating the capable of accommodating number, however, Ameren posited that the unit could have run all available hours *and* that it could have polluted at its 95th percentile emissions rate. FOF 412. The effect was that the total capable of accommodating number was more SO_2 per year than Ameren had emitted since 1995 (when Acid Rain rules were taking effect). FOF 417. Had Ameren used a more realistic emissions rate, its own analysis would have shown that it was *not* capable of accommodating the projected increase. FOF 413–16, 419, 420.

The post-hoc analysis by Ms. Ringelstetter begins with the same flaw as Mr. Hutcheson's calculation. Ms. Ringelstetter also failed to properly account for the project. She used the same modeling run as Mr. Hutcheson and as a result did not account for Ameren's actual, expected highest year of availability and "business activity." In addition, she attributed the entire capacity gain modeled in that run to the turbine, despite the fact that Ameren expected increased capacity resulting from the boiler work as well, as described in Subsection II.B.2 above. FOF 430.

Finally, Ms. Ringelstetter did not do her own analysis of whether the increased emissions projected by the model were related to the project.[27] FOF 437. She simply assumed they were not. FOF 437–38. Because her assumptions are incorrect, Ms. Ringelstetter's analysis is not persuasive.

EVIDENTIARY ISSUES FROM TRIAL

At trial and in post-trial briefing, both parties moved to exclude, strike, or deem irrelevant certain testimony or exhibits. For the reasons stated below, to the extent I have relied on evidence and testimony challenged by either party in my findings of fact and conclusions of law set out above, the parties' motions are denied. To the extent I have not relied on the challenged evidence and testimony, the parties' motions are denied as moot.

I. AMEREN'S MOTIONS TO STRIKE TESTIMONY AND EVIDENCE

A. Ameren's Motions to Strike Mr. Koppe and Dr. Sahu's Testimony and Evidence Concerning the Causation of Actual Emissions Increases

In two motions filed during trial (Doc. 787 and 793), and in a motion filed along with its post-trial briefs (Doc. 832), Ameren moved to exclude certain testimony of Mr. Koppe and Dr. Sahu, along with related exhibits that were admitted into evidence during trial concerning

[27] Ms. Ringelstetter's analysis of the emissions that unit was capable of accommodating is also flawed, for the reasons described in Subsection III.B of my Conclusions of Law.

causation of the actual emissions increases. Ameren argues the testimony concerning the causation of the actual emissions increases are new, undisclosed opinions.

While Ameren argues that Mr. Koppe and Dr. Sahu's opinions are new, there is no dispute that both Mr. Koppe and Dr. Sahu (1) analyzed the actual post-project data in their reports, the attachments, and their work papers, and (2) stated that the projected increases actually materialized. Both Mr. Koppe and Dr. Sahu disclosed in their reports that they analyzed post-project actual data. Likewise, their opinions about how the projects enable increased availability and contribute to increases in emissions were discussed in their reports and at their depositions. Ameren argues that because neither expert's report states their opinions in the precise words that Ameren thinks they should have used, the reports did not give notice that the projects at issue actually caused increases in emissions. But the notice required of expert opinions is not so formulaic. While undisclosed expert opinions are inadmissible, Rule 26(a)(2)(B) "contemplates that the expert will supplement, elaborate upon, explain and subject himself to cross-examination upon his report." *Thompson v. Doane Pet Care Co.*, 470 F.3d 1201, 1202-1203 (6th Cir. 2006) (holding the district court erred in excluding the testimony of an expert accounting witness because he failed to recite in his report that his opinion was based on "generally accepted accounting principles," the phrase used in the contract at issue in the case; further holding there was no authority for the "mechanical and formalistic ruling" that an expert's opinion must state such "magic words"); *see also Wood v. Robert Bosch Tool Corp.*, No. 4:13 CV 01888 TCM, 2015 WL 5638040, at *8 (E.D. Mo. 2015) (denying in part a motion to strike new expert opinion statements because the offered statement "clarifies [the expert witness's] earlier information, does not contradict it, and should not be surprising to Defendant or its experts"). For these reasons, and those set out in the United States' post-trial brief (*see*

Doc. 831 at 50-56) and its opposition to Ameren's motion to strike (*see* Doc. 836), Mr. Koppe and Dr. Sahu's challenged opinions are not "new opinions." Ameren had sufficient notice of both the United States' actual emissions case and of Mr. Koppe and Dr. Sahu's opinions.

Moreover, Ameren cannot show that it was prejudiced by the challenged testimony or the admission of the exhibits. The evidence the United States presented to show that the actual emissions increases were caused by the projects was also presented in the context of its expectations case regarding the expected causes of projected emissions increases, so the challenged testimony is in part cumulative evidence. Additionally, Ameren had the opportunity both during pre-trial discovery and during cross-examination at trial to test those opinions. *See* Doc. 831 at 50-56. Finally, Mr. Koppe's testimony regarding Ameren's full load tests and related exhibit 928 do not prejudice Ameren. Exhibit 928 is merely a summary exhibit of Ameren's own capability data. Ameren itself argued at summary judgment that such summary evidence containing simple mathematic calculations (averaging pre-project and post-project data and comparing them) is admissible. Moreover, Mr. Koppe considered the full load tests along with numerous other materials to reach his conclusion that the capacity increase was due to the projects, making the exhibit cumulative evidence.

Accordingly, I find that the opinions were sufficiently disclosed and that Ameren has not suffered any prejudice from the admission of that testimony because it had notice and opportunity to test it and because it is in part cumulative evidence. As a result, I will not strike Mr. Koppe and Dr. Sahu's testimony on the causation of the actual emissions, Mr. Koppe's testimony concerning the increased MW capability at Unit 2, or the related challenged exhibits.

B. Ameren's Motion to Strike Dr. Hausman's Testimony Criticizing Ms. Ringelstetter's Opinions

Ameren has also moved to strike certain testimony of Dr. Hausman, arguing that he offered new opinion testimony at trial when he criticized Ms. Ringelstetter's analysis. Ameren asks me to strike Dr. Hausman's testimony from the record per Fed. R. Civ. P. 26. In the challenged testimony, Dr. Hausman testified about the different ProSym runs he and Ms. Ringelstetter analyzed, which included a discussion of why he chose the particular run selected. This testimony is not a new opinion that should be stricken under Rule 26. Rather, as Rule 26 contemplates, Dr. Hausman's testimony merely clarified his previously disclosed opinion, explaining why he chose the ProSym run he used and how the different runs he and Ms. Ringelstetter used factored into the different conclusions each expert drew. *Thompson*, 470 F.3d at 1202-1203. Moreover, Ameren has not shown it was prejudiced by this testimony, as it had always had the opportunity to test the basis of Dr. Hausman's analysis. *See also* Doc. 836 at 17 (discussing the lack of prejudice to Ameren).

As a result, I will not strike Dr. Hausman's testimony concerning the differences between his and Ms. Ringelstetter's analyses because it is not undisclosed testimony and Ameren cannot show it was prejudiced by the testimony.

II. THE UNITED STATES' MOTION TO CURTAIL RE-LITIGATION OF THE LAW OF THE CASE

In its post-trial brief, the United States also raised an evidentiary issue, renewing its motion in limine to curtail Ameren's re-litigation of the law of the case. *See* Doc. 757; Doc. 758 at Section IV.B. The United States argues that three categories of evidence Ameren presented at trial are irrelevant and should be excluded:[28] (1) applicability analyses or permitting documents that were generated after the projects at issue in this case and involving different facilities operating under separate state implementation plans at different types of sources, (2) testimony from EPA or state agency staff regarding the operation and application of regulatory provisions, and (3) PowerPoint presentations and other pamphlets discussing NSR regulations.

Ameren argues that these categories of evidence are relevant, not to establish the reasonableness of any legal interpretation, but to establish the reasonableness of its engineering judgments, emissions analyses, and predictions of the future.

To the extent I rely on the challenged evidence in my findings and conclusions above, I will deny the United States' motion. To the extent I have not relied on the challenged evidence, the motion is denied is moot.

CONCLUSION

For the reasons set out above, I find that the United States has established by a preponderance of the evidence that Ameren violated the PSD and Title V provisions of the Clean Air Act. The 2007 project at Rush Island Unit 1 and the 2010 project at Rush Island Unit 2 were each major modifications under the PSD provisions of the Clean Air Act. Ameren violated the requirements of the PSD program by failing to obtain a preconstruction permit and install best available pollution control technology, among other requirements. Ameren also violated Title V of the Clean Air Act and its operating permit by performing a major modification without obtaining the required permit and by not including applicable requirements in its operating

[28] The United States seeks to exclude the following exhibits and testimony: Ameren exhibits BQ, PQ, PV, QJ, QS, RB, RC, RD, RE, RG, RH, RN, OY, OZ, PA, PF, and deposition testimony from David Campbell, Trial Tr. Vol. 12, 9:10-11:8; Gregg Worley, Trial Tr. Vol. 12, 4:2-5:22; and James Stewart, Trial Tr. Vol. 12, 11:4-13:2.

permit applications. As a result, I will enter a finding of liability against Ameren. A status conference will be set to address remedies.

Accordingly,

IT IS HEREBY ORDERED that Defendant Ameren Missouri is found liable under the Clean Air Act, 42 U.S.C. § 7401 *et seq*.

IT IS FURTHER ORDERED that a status conference to address remedies is set for **Wednesday, February 15, 2017 at 11:00 a.m.** in courtroom 16-South.

IT IS FURTHER ORDERED that the United States' Motion in Limine to Curtail Ameren's Re-Litigation of the Law of the Case #[757] is **DENIED** per my rulings above.

IT IS FURTHER ORDERED that Ameren's Motion to Treat Certain KDHE Produced Documents as Highly Confidential During Trial #[778] is **DENIED** as moot.

IT IS FURTHER ORDERED that Ameren's Motion to Bar Robert Koppe's New Causation Opinions #[787] is **DENIED** as moot.

IT IS FURTHER ORDERED that Ameren's Motion to Bar Dr. Ranajit Sahu's New Opinions #[793] is **DENIED** as moot.

IT IS FURTHER ORDERED that Ameren's Motion to Strike EPA's New Expert Opinion Evidence and Related Trial Exhibits #[832] is **DENIED** per my rulings above.

IT IS FURTHER ORDERED that the Parties' Joint Motion to Correct Clerk's Exhibit List #[829] is **GRANTED**.

RODNEY W. SIPPEL
UNITED STATES DISTRICT JUDGE

Dated this 23rd day of January, 2017.

United States Court of Appeals
For the Eighth Circuit

No. 19-3220

United States of America

Plaintiff - Appellee

Sierra Club

Intervenor - Appellee

v.

Ameren Missouri

Defendant - Appellant

Chamber of Commerce of the United States of America; American Chemistry Council; America's Power; Missouri Chamber of Commerce and Industry; National Association of Manufacturers; National Mining Association

Amici on Behalf of Appellant(s)

Appeal from United States District Court for the Eastern District of Missouri - St. Louis

Submitted: December 16, 2020
Filed: August 20, 2021

Case No. EF-2024-0021
Schedule KM-r3

Before SMITH, Chief Judge, LOKEN and MELLOY, Circuit Judges.

SMITH, Chief Judge.

Ameren Missouri ("Ameren") appeals an adverse judgment of the district court in a Clean Air Act (CAA) enforcement action brought by the United States of America, acting at the request of the Administrator of the United States Environmental Protection Agency (EPA) (hereinafter, EPA or "government"). Ameren argues that the district court erroneously found it liable for not obtaining permits for projects at its Rush Island Energy Center ("Rush Island") and, as a result, assessed liability under the applicable federal regulations. In addition, Ameren maintains that the district court ordered legally flawed injunctions at both Rush Island and at a different plant, Labadie Energy Center ("Labadie"). We affirm the district court's liability determination, but we reverse in part the remedial portion of its order concerning the Labadie plant and remand for further proceedings consistent with this opinion.

I. *Background*

A. *Statutory and Regulatory Background of the CAA*

"Congress enacted the Clean Air Act Amendments of 1970 seeking to guarantee the prompt attainment and maintenance of specified air quality standards." *Sierra Club v. Otter Tail Power Co.*, 615 F.3d 1008, 1011 (8th Cir. 2010) (quotations omitted). In enacting the CAA amendments, Congress "directed EPA to devise National Ambient Air Quality Standards (NAAQS) limiting various pollutants, which the States were obliged to implement and enforce." *Id.* (quotation omitted). The New Source Performance Standards (NSPS) program was a key part of the CAA's regulatory scheme. *Id.* The NSPS program "required EPA to develop technology-based performance standards designed to limit emissions from major new sources of pollution." *Id.* (quotation omitted). Both newly constructed facilities and modified facilities with increased emissions constitute "[n]ew sources." *Id.* "It is 'unlawful for any owner or operator of any new source to operate such source in violation of' applicable performance standards." *Id.* (quoting 42 U.S.C. § 7411(e)).

The NSPS program, however, "did too little to 'achieve the ambitious goals of the 1970 amendments.'" *Id.* (quoting *Env't Def. v. Duke Energy Corp.*, 549 U.S. 561, 567 (2007)). "Merely setting emissions limits failed to improve air quality in those areas that had already attained the minimum standards of the NAAQS because polluters had no incentive to diminish emissions below the established limits." *Id.* As a result, in 1977, Congress amended the CAA "to add the 'Prevention of Significant Deterioration' (PSD) program, which seeks to ensure that the 'air quality floor' established by the NAAQS does not 'in effect become a ceiling.'" *Id.* (quoting *Sierra Club v. Thomas*, 828 F.2d 783, 785 (D.C. Cir. 1987)).

The PSD program limited construction of major emitting facilities with specified preconditions. 42 U.S.C. § 7475(a). "The term 'construction' when used in connection with any source or facility, includes the *modification* . . . of any source or facility." *Id.* § 7479(2)(C) (emphasis added). "The term 'modification' means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." *Id.* § 7411(a)(4).

The PSD program prohibits the construction of a major emitting facility unless preconditions are satisfied. One precondition is that the proposed facility obtain a permit setting forth applicable emission limitations. *Id.* § 7475(a)(1). Another precondition is that "the owner or operator of such facility demonstrates . . . that emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of" prescribed air quality standards. *Id.* § 7475(a)(3). The PSD program also requires the owner or operator to install "the best available control technology for each pollutant subject to regulation . . . emitted from, or which results from, [the proposed] facility." *Id.* § 7475(a)(4). The "'best available control technology' (BACT) . . . . is not a particular type of technology." *Otter Tail*, 615 F.3d at 1011 (quoting 42 U.S.C. § 7475(a)(4)). Instead, the BACT "is an 'emission limitation based on the maximum degree of reduction of each pollutant subject to regulation . . . which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable' for the facility in question." *Id.* (alteration in original) (quoting 42 U.S.C. § 7479(3)).

Only *major* modifications to emitting sources are subject to PSD review. *Ala. Power Co. v. Costle*, 636 F.2d 323, 399 (D.C. Cir. 1979). "Major modification means any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase . . . of a regulated NSR [New Source Review] pollutant . . . ; and a significant net emissions increase of that pollutant from the major stationary source." 40 C.F.R. § 52.21(b)(2)(i).

For projects that only involve "existing emissions units," the EPA applies what it calls the actual-to-projected-actual applicability test. *Id.* § 52.21(a)(2)(iv)(c).[1] To apply this test, the "baseline actual emissions" must first be calculated. "Baseline actual emissions means the rate of emissions, in tons per year, of a regulated NSR pollutant . . . ." *Id.* § 52.21(b)(48).

---

[1]This test provides: "A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions . . . and the baseline actual emissions . . . , for each existing emissions unit, equals or exceeds the significant amount for that pollutant . . . ." *Id.*

> Next, the "projected actual emissions" must be calculated by determining the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12–month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source.

Id. § 52.21(b)(41)(i). An "owner or operator of the major stationary source . . . [must] consider all relevant information" to calculate "the projected actual emissions." *Id.* § 52.21(b)(41)(ii)(a). "[A]ll relevant information . . . include[s] . . . historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans under the approved State Implementation Plan . . . ." *Id.* But the owner or operator "[s]hall exclude" from the projected actual emissions "that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions . . . and that are also unrelated to the particular project, including any increased utilization due to product demand growth." *Id.* § 52.21(b)(41)(ii)(c). The "exclu[sion] [of] increases stemming from unrelated demand growth" is referred to as "the 'demand growth exclusion.'" *New York v. EPA*, 413 F.3d 3, 16 (D.C. Cir. 2005).

Finally, the baseline actual emissions calculation is subtracted from the projected actual emissions calculation to determine if the difference between the numbers is "significant." 40 C.F.R. § 52.21(a)(2)(iv)(c). A table in the regulations sets forth the numeric thresholds that are considered "significant" for each regulated pollutant. *Id.* § 52.21(b)(23)(i). If the difference in the projected actual emissions and the baseline actual emissions is significant, *see id.*, then a permit is required before beginning construction on the project. *Id.* § 52.21(a)(2)(iii).

The actual-to-projected-actual test is distinguishable from "a potential-to-potential test," which "compare[s] past potential emissions with future potential emissions." *New York*, 413 F.3d at 17. "[T]he plain language of the CAA indicates that Congress intended to apply NSR to changes that increase actual emissions instead of potential or allowable emissions . . . ." *Id.* at 40.

B. *Missouri's State Implementation Plan*

"The PSD program is primarily implemented by the states through 'state implementation plans' (SIPs)." *Otter Tail*, 615 F.3d at 1011 (citing 42 U.S.C. § 7471). While "[s]tates have broad discretion in designing their SIPs," their "plans must include certain federal standards." *Id.* The EPA reviews and approves States' SIPs. *Id.* at 1011–12.

Missouri expressly incorporated the EPA's PSD regulations into its SIP ("Missouri SIP"). *See* Mo. Code Regs. Ann. tit. 10, § 6.060(8)(A) (2007) ("All of the subsections of 40 CFR 52.21, other than [certain subsections], are hereby incorporated by reference."). The EPA approved Missouri's SIP, explaining that "the provisions of § 52.21 supersede the state provisions for purposes of the PSD program." Approval and Promulgation of Implementation Plans; State of Missouri, 71 Fed. Reg. 36,486-02, 36,487 (June 27, 2006); *see also id.* at 36,489 ("This revision also incorporates by reference the other provisions of 40 CFR 52.21 as in effect on July 1, 2003, which supersedes any conflicting provisions in the Missouri rule. Section 9, pertaining to hazardous air pollutants, is not SIP approved.").

C. *Title V Program*

In addition to the CAA's PSD program, "the CAA . . . require[s] each covered facility to obtain a comprehensive operating permit setting forth all CAA standards applicable to that facility." *Otter Tail*, 615 F.3d at 1012 (citing 42 U.S.C. § 7661a(a)). The operating permits "incorporate into a single document all of the CAA requirements governing a facility. Similar to other CAA programs, Title V is implemented primarily by the states under EPA oversight. In states with EPA approved programs," the state permitting authority issues the Title V permits. *Id.* (citations omitted). These permits "are subject to EPA review and veto." *Id.* The EPA has approved Missouri's operating permit program under Title V of the CAA. This program is incorporated into the Missouri SIP. *See* Mo. Code. Regs. Ann. tit. 10, § 6.065 (2007).

D. *Factual Background and Procedural History*

This case involves Ameren's Rush Island power plant, which includes two coal-fired electric generating units, Units 1 and 2. These units began service in 1976 and 1977. They were grandfathered into the PSD program. They do not have air pollution control devices for sulfur dioxide. Rush Island currently emits approximately 18,000 tons of sulfur dioxide per year. Small performance improvements or increases in unit availability can result in a 40-ton increase in sulfur dioxide. For the Rush Island units to emit more than 40 tons of sulfur dioxide, it takes only an availability of 0.3 percent or an additional 21 hours of operation at full power.

By 2005, problems with Units 1's and 2's major boiler components forced Ameren to frequently take the units out of service. This made the units underperform and reduced the amount of electricity Ameren could generate and sell from the units. Ameren decided to replace the problem components with new, redesigned components. Ameren, however, did not do any quantitative PSD review for Unit 1's project and belatedly performed PSD review for Unit 2's project. Ameren proceeded with the projects without reporting its planned modifications to the EPA, obtaining the necessary permits, or installing pollution controls. To replace the major boiler components, Ameren took Unit 1 offline in 2007 and Unit 2 offline in 2010. Each unit was completely offline for three to four months to complete the projects. Ameren spent more than $20 million per project.

By replacing the failing components with new, redesigned components, Ameren expected unit availability to improve by much more than 0.3 percent, allowing the units to operate hundreds of hours more per year after the projects. Ameren expected to use that increased availability (and increased capacity for Unit 2) to burn more coal and generate more electricity. Unavoidably, the units would also emit more sulfur dioxide pollution.

As Ameren expected, its replacement of the failing components resulted in increased availability at Units 1 and 2 by eliminating hundreds of outage hours per year. And, Unit 2's capacity increased. The units ran more, burned more coal, and consequently emitted hundreds of tons more sulfur dioxide per year because of the operational increases.

The government filed suit against Ameren in response to the projects. It alleged that Ameren violated the CAA, the Missouri SIP, and Ameren's Rush Island Plant Title V Permit by performing major modifications on Units 1 and 2 without obtaining the necessary permits, installing pollution control technology, or otherwise complying with all applicable requirements.

1. *Liability Phase*

a. *Summary Judgment*

The district court bifurcated the proceedings into a liability phase and a remedy phase. During the liability phase, the district court issued two summary-judgment orders. In the first summary-judgment order, the district court rejected Ameren's argument that the major-modification test set forth in the federal regulations did not provide the relevant PSD liability test because the Missouri SIP elsewhere separately defined *modification* to mean that "the source's *potential* emissions would significantly increase." *United States v. Missouri (Ameren I)*, 158 F. Supp. 3d 802, 808 (E.D. Mo. 2016) (emphasis added). According to Ameren, the government could not establish liability because it never alleged that "the [Rush Island] projects increased the units' *potential* emissions." *Id.* (emphasis added). In rejecting this argument, the court first explained that "the PSD rules impose their own independent, stand-alone applicability provisions in Section (8) of the Missouri SIP (incorporating EPA's PSD rules set out at 40 C.F.R. 52.21)." *Id.* at 809. The court reasoned that "the PSD-specific applicability language should trump the general applicability language in Section (1) of the [Missouri] SIP." *Id.*

The court next cited the "well-established" "regulatory and statutory history of the PSD rules" as leaving "no doubt that the federal PSD rules are focused on 'major modifications' which are based on actual emissions determinations," not potential emissions. *Id.* at 810. The court found "most persuasive[] [that the] EPA's approval of the SIP provided that the CAA and the program requirements as set out in 40 C.F.R. § 52.21 would supersede any conflicting provisions in the state SIP." *Id.* (citing Approval and Promulgation of Implementation Plans; State of Missouri, 71 Fed. Reg. at 36,489).

Finally, the district court concluded that Ameren urged an interpretation of the SIP that would conflict with the PSD rules and, in the court's view, "render a portion of the PSD rules superfluous." *Id.*

In its second summary-judgment order, the district court addressed causation and "the PSD program's demand growth exclusion." *United States v. Ameren Mo. (Ameren II)*, No. 4:11-cv-77-RWS, 2016 WL 728234, at *9 (E.D. Mo. Feb. 24, 2016). According to the district court, "two main criteria . . . determine whether a major source of pollution must obtain a PSD permit. First, there must be a physical change, and second, that change would be expected to cause a significant net increase in actual emissions." *Id.* The demand growth exclusion is relevant to the second criteria—"how to determine whether the physical changes would have caused a significant net emissions increase, and if so, whether any of the increased emissions may be excluded from review under the 'demand growth exclusion.'" *Id.* The district court rejected Ameren's proposed interpretation of the exclusion as applying to "any emissions increases a unit could have accommodated at baseline." *Id.* Instead, the court held "that the demand growth exclusion requires a showing that the unit 'could have accommodated' the emissions at baseline *and* that . . . those increases were unrelated to the project." *Id.* at *11. The court also held that "while it remains the EPA's burden to prove that Ameren should have expected the projects to cause an increase in emissions, the burden is Ameren's to prove that the demand growth exclusion applies." *Id.*

Also in the second summary-judgment order, the district court addressed Ameren's argument that "because EPA brought suit *after* the challenged projects' completion," it was "limited to an 'actual increase' theory." *Id.* at *13. Under Ameren's actual-increase theory, the EPA would have to show that "the Projects actually caused emissions to increase" to establish Ameren's liability. *Id.* By contrast, under "an 'expectations' theory," the EPA could establish liability by showing "that Ameren 'should have expected' the Projects to increase emissions." *Id.* The court held that the government could proceed on the expectations theory. *Id.* at *13–16.

Additionally, the court considered Ameren's argument that the government had to "come forward with admissible evidence of what a reasonable power plant operator or owner would expect, and its failure to do so [was] fatal to EPA's expectations theory case." *Id.* at *18. But the court agreed with the government "that no special standard of care evidence is required for the factfinder to be able to determine whether a reasonable power plant operator or owner would have expected the projects to cause a significant emissions increase"; instead, "the PSD regulations themselves . . . guide the factfinder's determination." *Id.*

Finally, the court rejected Ameren's argument that the court "lack[ed] subject matter jurisdiction to hear EPA's [Title V] claim that Ameren [was] operating under an inadequate or deficient permit." *Id.* at *24.

b. *Trial*

Subsequently, the district court held a trial on the merits. After trial, the district court entered an order setting forth its factual findings and legal conclusions. *See United States v. Ameren Mo. (Ameren III)*, 229 F. Supp. 3d 906 (E.D. Mo. 2017). The court concluded that Ameren's Rush Island overhauls were major modifications that triggered PSD pollution-control requirements. The district court found that "[t]he emissions evidence show[ed] [that] an increase related to the projects should have been expected and actually occurred." *Id.* at 997 (emphasis omitted). The court identified categories of evidence that "all establish that there is a significant net [sulfur dioxide] increase of more than 40 tons that was caused by the projects." *Id.* at 998.

First, the court identified "[t]wo key—and undisputed—characteristics of the Rush Island units." *Id.* at 988. The first characteristic was that "the Rush Island units are big sources of pollution." *Id.* The second characteristic was that "the Rush Island units are 'baseload' units" that are "cheap sources of electricity" and "operate as much as they can." *Id.* According to the court, "[t]hese two facts lead to a logical conclusion [that] if the Rush Island units are upgraded so they *can* generate more electricity, they *will*. Performance improvements have a direct impact on annual generation and pollution levels." *Id.*

Second, Robert Koppe, a power plant performance expert, opined that the Rush Island's plant availability increased because it replaced "these problematic components." *Id.* at 989. Thereafter, "Dr. Ranajit Sahu, a permitting engineer and expert for the United States, took Mr. Koppe's findings on expected improved availability and used them to calculate the expected additional pollution that would result from the improvements." *Id.* at 990. He "calculated an expected increase in emissions of 608 tons of [sulfur dioxide] post-project for Unit 1." *Id.* And, "[b]ased on Mr. Koppe's prediction of regained availability, . . . Dr. Sahu calculated an expected increase of 415 tons per year of [sulfur dioxide] in Unit 2 that would result from the availability improvement alone." *Id.* at 992.

Third, Dr. Ezra Hausman, a modeler and market consultant with 20 years' experience in the electric industry, explained that the "sophisticated computer modeling program" that Ameren used "to model and predict the Rush Island units' fuel needs . . . for the years after the 2007 and 2010 major boiler outages" "showed that both a unit's capacity level and its availability are linearly related to the unit's projected coal consumption." *Id.* at 994, 995. Thus, "if Ameren increased the number of hours its Rush Island units were able to run, or if the company enabled the units to operate at higher output levels during those hours, then the units would . . . burn[] more coal and, as a result, emit[] more pollution." *Id.* at 994–95. Dr. Hausman's "results show[ed] that Ameren's modeling would predict significant emissions increases at the Rush Island units as a result of the projects." *Id.* at 996.

Finally, "the actual post-project data" showed "a significant net [sulfur dioxide] increase of more than 40 tons that was caused by the projects." *Id.* at 998. Both units were available more and operated every hour that they were available. Both units also increased their maximum generating levels. This resulted in both units increasing their sulfur dioxide pollution.

In summary, the court determined that "[b]ased on the known facts that the Rush Island units are low-cost, baseload units, common sense compels the same conclusion: improving availability or capacity at baseload units like Rush Island will result in additional operations and pollution." *Id.*

Regarding liability, the district court also rejected Ameren's defenses. First, the district court concluded that Ameren failed to satisfy "its burden of proving that the Rush Island projects fall within the narrow routine maintenance exemption." *Id.* at 1003. The court characterized "[t]he 2007 and 2010 major boiler outages [as] unprecedented events for Rush Island Units 1 and 2—they were the centerpieces of the 'most significant' outages in plant history." *Id.* (citation omitted).

Second, the court rejected Ameren's argument that any increases in production and pollution were merely the result of demand growth that should be excluded from the liability assessment. According to the court, the "relevant information" that Ameren had "showed that the Rush Island units' performance would improve, resulting in increased generation and emissions." *Id.* at 1010.

In summary, the district court "enter[ed] a finding of liability against Ameren," concluding that the Rush Island Unit 1 and 2 projects described above were major modifications under the CAA, Ameren violated the PSD program's requirements "by failing to obtain a preconstruction permit and install best available pollution control technology," and Ameren violated Title V of the CAA. *Id.* at 1017.

2. *Remedy Phase*

a. *Summary Judgment*

After entering its post-trial order on liability, the district court proceeded to the remedy phase. The court addressed the parties' summary-judgment motions. First, the court rejected Ameren's argument "that the Clean Air Act does not authorize injunctions as a remedy for past violations." *United States v. Ameren Mo. (Ameren IV)*, 372 F. Supp. 3d 868, 871 (E.D. Mo. 2019). According to the court, "[t]he plain language of § 7413(b) gives the EPA authority to 'commence a civil action' for injunctive relief or civil penalties, 'or both,' whenever a person '*has* violated or is in violation of any requirement or prohibition of' EPA air quality control programs." *Id.* (quoting 42 U.S.C. § 7413(b)). The court reasoned that § 7413(b)'s plain "language places no restriction on injunctive relief for past violations" and instead "authorizes the EPA to seek injunctive relief whenever a person *has violated* the Clean Air Act." *Id.*

In addition, the district court rejected Ameren's argument that the court could not "order injunctive relief that includes emissions reductions or control technology at the Labadie Energy Center (Labadie) coal-fired power plant." *Id.* at 874.

b. *Trial*

The district court subsequently held a remedy trial. Following the trial, the court issued an order imposing a two-pronged remedy with the purpose of "[(1)] bring[ing] Ameren's Rush Island facility into compliance with the law and [(2)] . . . remediat[ing] the harm from the more than 162,000 tons—and counting—in excess [sulfur dioxide] that Rush Island emitted after Ameren failed to obtain a PSD permit there." *United States v. Ameren Mo. (Ameren V)*, 421 F. Supp. 3d 729, 802 (E.D. Mo. 2019).

As to compliance, the district court concluded that "Ameren must make Rush Island compliant by obtaining a PSD permit with emissions limitations based on wet FGD [flue gas desulfurization technology]" used as the BACT. *Id.* at 806 (emphasis omitted). The court determined that FGD technology is technically and economically feasible and "can remove 95% or more of [sulfur dioxide] emissions." *Id.* at 812.

As to remediation, the district court concluded that "Rush Island's excess pollution is best remediated by decreasing emissions at the nearby Labadie Energy Center." *Id.* at 789 (emphasis omitted). Labadie consists of four coal-burning units and is located 35 miles west of St. Louis. Ameren argued that imposition of the remedy was "extreme" and "constitute[d] a penalty" "because Labadie is 'totally innocent,' and Ameren has not violated the Clean Air Act there." *Id.* at 820. The district court rejected Ameren's argument, reasoning that its "remedy is based on straightforward equitable principles and the authority [it] ha[s] under the Clean Air Act 'to restrain' violations, 'to require compliance,' and 'to award any other appropriate relief.'" *Id.* (quoting 42 U.S.C. § 7413(b)). According to the court, its remedy was "narrowly tailored" because "a tight geographic nexus [exists] between the harms Rush Island caused and the benefits gained through reducing Labadie's emissions. Pollution from Labadie affects the same communities as those affected by Rush Island, and to the same degree." *Id.* at 820–21. The court reasoned that its remedy "achieve[d] the maximum possible environmental benefit": "When Ameren reduces emissions at Labadie commensurate with the excess emissions from Rush Island, Ameren will have put the public in the place it would have been absent Ameren's Clear Air Act violation." *Id.* at 821. The court explained that "Ameren's ton-for-ton reductions at Labadie will lower the risks of premature mortality and disease in the same communities impacted by Ameren's Rush Island violations." *Id.*

The court rejected Ameren's argument "that any injunction against its Labadie plant would constitute a penalty." *Id.* While the court acknowledged it could not "issue injunctive relief that would constitute a penalty," it concluded that "[b]y ordering emissions reductions up to, but not surpassing, the excess emissions from Rush Island, [the court was] ordering relief that goes exactly to 'remedying the damage caused to the harmed parties by the defendant's action.'" *Id.* (quoting *United States v. Ameren Mo.*, No. 4:11-cv-77-RWS, 2016 WL 468557, at *1 (E.D. Mo. Feb. 8, 2016)). The court "order[ed] Ameren to base its relief at Labadie on DSI [dry sorbent injection] control technology" "[t]o . . . ensure that any relief at Labadie does not surpass the damage caused by Rush Island." *Id.* Installation of DSI technology on Labadie's units would allow Ameren to "operate DSI for as many years as necessary to remediate Rush Island's excess emissions[] and terminate its use of DSI without suffering significant lost capital assets." *Id.* The court "order[ed] Ameren to begin operating Labadie with DSI, or a more effective pollution control, beginning no later than three years after [its] order." *Id.* at 822.

3. *Summary*

In summary, the district court found Ameren in violation of the CAA for "mak[ing] major modifications to expand Rush Island's capacity" without "apply[ing] for a PSD permit and meet[ing] reduced emissions requirements." *Id.* at 824. By failing to "apply for the required PSD permit," Ameren "skirted PSD's requirement to install the best available technology to control the pollution Rush Island emits." *Id.*

"To remedy [Ameren's] violation of the Clean Air Act," the district court ordered Ameren to "apply for a PSD permit for Rush Island within ninety days, propose wet FGD as BACT in its permit application, and implement BACT no later than four and one-half years from [the] order." *Id.* "In addition to the relief [the court] order[ed] at Rush Island, [it] also order[ed] Ameren to reduce its pollution at Labadie in an amount equal to Ameren's excess emissions at Rush Island." *Id.* It left Ameren the option whether to "install[] DSI or some other more effective pollution control at Labadie." *Id.*

II. *Discussion*

Ameren appeals the district court's orders. It raises five arguments: (1) the Rush Island projects did not require permits under the Missouri SIP; (2) the Rush Island projects did not constitute major modifications; (3) the district court lacked jurisdiction under Article III and statutory authority under the CAA to enter the injunctions; (4) the injunctive relief ordered at Labadie is punitive, not remedial, and therefore prohibited; and (5) the district court lacked jurisdiction over the Title V claims. We address each in turn.

A. *Missouri SIP*

Ameren first argues that "under the plain language of Missouri's SIP, permits are required only for increases in potential emissions" and "it [is] undisputed that the [Rush Island] Projects would not, and did not, increase potential emissions." Appellant's Br. at 30. According to Ameren, the district court erroneously "substituted the federal regulations' applicability standard," which "nullified the SIP Permit Rule's Applicability Provision." *Id.* at 30–31.

The Missouri SIP identifies which construction or modification projects at emission sources require prior construction permits. Mo. Code Regs. Ann. tit. 10, § 6.060 (2007). Ameren cites to § 6.060(1) of the Missouri SIP, entitled "Applicability" ("Applicability Section"). This section governs Missouri's air quality construction permit programs. The Applicability Section provides, in relevant part, that

> [n]o owner or operator shall commence construction[2] or *modification* of any installation subject to this rule, begin operation after that construction or *modification*, or begin operation of any installation which has been shut down longer than five (5) years without first obtaining a permit from the permitting authority under this rule.

Mo. Code Regs. Ann. tit. 10, § 6.060(1)(C) (2007) (emphases added).

In turn, the Missouri SIP offers two definitions of *modification*. First, it generally defines "[m]odification" as "[a]ny physical change, or change in method of operation of, a source operation or attendant air pollution control equipment which would cause an increase in *potential emissions* of any air pollutant emitted by the source operation." *Id.* § 6.020(2)(M)(10) (emphasis added). "Potential to emit" means

[2]"It is undisputed that the projects at issue were not 'construction' as defined by the Missouri SIP or the PSD rules." *Ameren I*, 158 F. Supp. 3d at 809 n.5.

the unit's ability to emit at full design capacity "assuming continuous year-round operation." *Id.* at § 6.020(2)(P)(19).

Second, the Missouri SIP separately defines "Title I modification." *Id.* § 6.020(2)(M)(11). A "Title I modification" is "[a]ny modification that requires a permit under *10 CSR 10-6.060 section (7) or (8)*, or that is subject to any requirement under 10 CSR 10-6.070 or 10 CSR 10-6.080." *Id.* § 6.020(2)(T)(3) (emphasis added).[3]

Ameren maintains that the Missouri SIP limits PSD applicability to only projects increasing both actual *and* potential emissions. According to Ameren, the Missouri SIP's Applicability Section and definitional sections mean that "[i]f a project would *not* increase a unit's potential emissions, it is *not* a modification and does *not* trigger permitting under the Applicability Provision." Appellant's Br. at 35. Because the government "never alleged that the projects increased the units' potential emissions, Ameren argues that it [was] entitled to full summary judgment." *Ameren I*, 158 F. Supp. 3d at 808–09.

Ameren, however, overlooks that, in contrast to the general definition of *modification* in § 6.020(2)(M)(10), § 6.060(8)(A) of the Missouri SIP contains "*PSD-specific* applicability language." *Id.* at 809 (emphasis added) (citing *RadLAX Gateway Hotel, LLC v. Amalgamated Bank*, 566 U.S. 639, 645 (2012)). That section—expressly referenced in the Missouri SIP's definition of "Title I modification"—provides, in relevant part:

---

[3]In addition to defining *modification*, the Missouri SIP independently defines "[m]ajor modification" as "[a]ny physical change or change in the method of operation at an installation or in the attendant air pollution control equipment that would result in a significant net emissions increase of any pollutant." *Id.* § 6.020(2)(M)(3). The Missouri SIP uses the term *major modification* in a section concerning BACT. *See id.* § 6.020(2)(B)(5).

> (8) Attainment and Unclassified Area Permits.
>
> (A) *All of the subsections of 40 CFR 52.21* other than (a) Plan disapproval, (q) Public participation, (s) Environmental impact statements and (u) Delegation of authority *are incorporated by reference*. 40 CFR 52.21 as used in this rule refers to 40 CFR 52.21 promulgated as of July 1, 2003 as published by the Office of the Federal Register, U.S. National Archives and Records, 700 Pennsylvania Avenue NW, Washington, D.C. 20408. This rule does not incorporate any subsequent amendments or additions.

Mo. Code Regs. Ann. tit. 10, § 6.060(8)(A) (2007) (emphases added).

In turn, the federal regulation referenced in § 6.060(8)(A) of the Missouri SIP provides that the PSD's "[a]pplicability procedures" "apply to the construction of any new major stationary source or the *major modification of* any existing major stationary source" located in a PSD area. 40 C.F.R. § 52.21(a)(2)(ii) (emphasis added). The regulations explicitly define major modification. "*Major modification* means any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase . . . of a regulated NSR pollutant . . . ; and a significant net emissions increase of that pollutant from the major stationary source." *Id.* § 52.21(b)(2)(i) (emphasis added). "A . . . major modification shall meet each applicable emissions limitation under the [SIP] and each applicable emissions standard and standard of performance under 40 CFR parts 60 and 61." *Id.* § 52.21(j)(1).

The federal regulation establishes that a *major modification* triggers the PSD requirements. According to the regulation, "[n]o . . . major modification . . . shall begin actual construction without a permit that states that the . . . major modification will meet those requirements." *Id.* § 52.21(a)(2)(iii). To assess whether a major modification occurred, the federal regulation states that an "*[a]ctual-to-projected-actual applicability test* [applies] for projects that only involve existing emissions units." *Id.* § 52.21(a)(2)(iv)(c) (emphasis added). Under that test,

> [a] significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions . . . and the baseline actual emissions . . . , for each existing emissions unit, equals or exceeds the significant amount for that pollutant . . . .

Id.

As the district court observed, "EPA's approval of the [Missouri] SIP illustrates why the specific PSD rules control." *Ameren I*, 158 F. Supp. 3d at 810. In approving the Missouri SIP, the EPA stated, "[W]e are approving most of the revisions to the Construction Permits Required rule because the revisions incorporate, by reference, the Federal New Source Review reforms . . . . " Approval and Promulgation of Implementation Plans; State of Missouri, 71 Fed. Reg. at 36,486. More specifically, it stated that it was "approving revisions to Missouri rule, 10 CSR 10-6.060, Construction Permits Required, into the SIP. This rule incorporates by reference the . . . PSD . . . program in 40 CFR 52.21 . . . ." *Id.* at 36,487.

Importantly, the "EPA's approval of the SIP provided that the CAA and the program requirements as set out in 40 C.F.R. 52.21 would supersede any conflicting provisions in the state SIP." *Ameren I*, 158 F. Supp. 3d at 810 (quoting 71 Fed. Reg. at 36,486 ("This revision incorporates by reference the other provisions of 40 C.F.R. 52.21 as in effect on July 1, 2003, *which supersedes any conflicting provisions in the Missouri rule.*" (emphasis added in *Ameren I*))).

Furthermore, as the district court pointed out, Ameren's argument that "the [Missouri] SIP first requires . . . that a threshold determination be made that a project is a 'modification'" under § 6.020(2)(M)(1), "would render a portion of the PSD rules superfluous." *Id.* at 810. The Supreme Court rejected a similar argument in *Duke Energy*. In that case, the Court held that the EPA is not required "to conform its PSD regulations on 'modification' to their NSPS counterparts." 549 U.S. at 565. According to the Court, aligning the PSD regulations with the NSPS regulations "was inconsistent with their terms and effectively invalidated them." *Id.* Relevant to the present case, the Court rejected the defendant power company's argument that, "before a project can become a 'major modification' under the PSD regulations, it must meet the definition of 'modification' under the NSPS regulations." *Id.* at 581 n.8 (citations omitted). According to the Court, "the language of the regulations [did] not support" such a reading because it would render portions of the PSD regulations superfluous. *Id.* ("[I]t would be superfluous for PSD regulations to require a 'major modification' to be a 'physical change in or change in the method of operation,' if they presupposed that the NSPS definition of 'modification,' which contains the same prerequisite, had already been satisfied." (citations omitted)).

Finally, *United States v. Cinergy Corp.*, 623 F.3d 455 (7th Cir. 2010), upon which Ameren relies, is distinguishable. There, the EPA brought an enforcement action against several coal-fired power plants. *Id.* at 456. As in the present case, the EPA alleged that the plants' projects were major modifications requiring a PSD permit. *Id.* The plants argued that no permit was required because the projects did not increase the units' potential emissions under the Indiana SIP, which based applicability on increases in potential emissions instead of actual emissions. *Id.* at 458. On appeal, the Seventh Circuit held that "[t]he Clean Air Act does not authorize the imposition of sanctions for conduct that complies with a [SIP] that the EPA has approved." *Id.* (citing 42 U.S.C. § 7413(a)(1)).

Like the power plants in *Cinergy*, Ameren maintains that it lacked notice "that EPA would treat its approval of Sections 10–6.060(1)(C) (Applicability) and 10–6.020(2)(M)(10) (definition of 'modification') as a rejection of them"; furthermore, it asserts that "allowing EPA to impose liability when it is undisputed no modification has occurred would violate basic principles of due process and fair notice." *Ameren I*, 158 F. Supp. 3d at 812. But *Cinergy* is distinguishable from the present case because (1) the Indiana SIP did not incorporate the PSD rules into the State's plan; (2) the "EPA's approval of the Indiana SIP did not expressly provide that the PSD rules as set out in the Code of Federal Regulations supersede any conflicting provisions in the state SIP"; and (3) the power plants in *Cinergy* had "actual notice" of the Indiana SIP provision, whereas "it is not clear that Ameren had actual notice of the SIP provision." *Id.* Furthermore, *Cinergy* is merely persuasive authority and not binding on this court. *See Duluth, Winnipeg & Pac. Ry. Co. v. City of Orr*, 529 F.3d 794, 798 (8th Cir. 2008).

Accordingly, we hold that the district court did not err in holding that the Rush Island projects required permits through application of the actual-to-projected-actual applicability test under 40 C.F.R. § 52.21(a)(2)(iv)(c), incorporated by reference in § 6.060(8)(A) of the Missouri SIP.

B. *Major Modification*

Alternatively, Ameren argues that "even if federal regulations governed applicability, Ameren was held liable under the wrong legal standards, independently requiring reversal." Appellant's Br. at 45. Ameren maintains that the district court erred in concluding the Rush Island projects constituted *major modifications*. Specifically, Ameren contends that the district court erroneously (1) shifted the burden of proof on causation; (2) "applied new interpretations of the federal regulations' causation provision"; and (3) applied a "'reasonable power plant operator' standard the regulations do not require." *Id.* at 45–46. In addition, Ameren asserts that the district court erred by permitting the government to use expert opinions on actual post-project emissions that were not disclosed. *Id.* at 56.

A "[m]ajor modification" at emission sources occurs when a physical change in the facility would result in "a significant emissions increase." 40 C.F.R.

§ 52.21(b)(2)(i). "To satisfy its burden under the [CAA], the government ha[s] to show that at the time of the projects [Ameren] expected, or should have expected, that its modifications would result in a 'significant net emissions increase' . . . ." *United States v. Ala. Power Co.*, 730 F.3d 1278, 1282 (11th Cir. 2013).

1. *Burden of Proof*

One feature of the federal regulation's "projected-actual-emissions methodology [is] the exclusion from the emissions projection of any emissions due to increased demand." *New York*, 413 F.3d at 31. This demand-growth exclusion functions as a type of defense for the source to avoid triggering PSD requirements. The federal regulation "allow[s] exclusion of emissions that could have been accommodated during the baseline period and 'that are also unrelated to the particular project.'" *Id.* at 33 (quoting 40 C.F.R. § 52.21(b)(41)(ii)(c)). Emissions "unrelated to the particular project . . . include[] any increased utilization due to product demand growth." *Id.* (quoting 40 C.F.R. § 52.21(b)(41)(ii)(c)).

Thus, under the regulation, "a source must"

> establish[] two criteria . . . before excluding emissions from its projection: "(1) [t]he unit could have achieved the necessary level of utilization during the consecutive 24-month period [the source] selected to establish the baseline actual emissions; and (2) the increase is not related to the physical or operational change(s) made to the unit."

Id. (alterations in original) (emphasis added) (quoting Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Baseline Emissions Determination, Actual-to-Future-Actual Methodology, Plantwide Applicability Limitations, Clean Units, Pollution Control Projects, 67 Fed. Reg. 80,186-01, 80,203 (Dec. 31, 2002)); *see also United States v. DTE Energy Co.*, 845 F.3d 735, 737 (6th Cir. 2017).

Ameren argues that "the [d]istrict [c]ourt improperly shifted the burden of proving causation to Ameren." Appellant's Br. at 46. Before the district court, the parties disputed who bore the burden of proving "that any increases in emissions were caused by demand growth." *Ameren II*, 2016 WL 728234, at *11. Ameren argued that the EPA bore the burden of proving demand growth "because under the definition of 'projected actual emissions,' the regulations require that unrelated emissions be exempted from the calculation." *Id.* By contrast, the EPA maintained that Ameren bore the burden of proof on demand growth as "the party seeking to benefit from an exemption." *Id.* The district court held that "*while it remains EPA's burden to prove that Ameren should have expected the projects to cause an increase in emissions*, the burden is Ameren's to prove that the demand growth exclusion applies." *Id.* (emphasis added).

The district court is correct. As recognized in *New York* and *DTE Energy*, it is the source's burden to prove the applicability of the demand-growth exclusion. This is in accordance with the Supreme Court precedent that the party asserting the exception bears the burden of proving its applicability. *NLRB v. Ky. River Cmty. Care, Inc.*, 532 U.S. 706, 711 (2001) ("The burden of proving the applicability of the supervisory exception . . . should thus fall on the party asserting it."); *FTC v. Morton Salt Co.*, 334 U.S. 37, 44–45 (1948) ("[T]he general rule of statutory construction that the burden of proving justification or exemption under a special exception to the prohibitions of a statute generally rests on one who claims its benefits . . . .").

As a result, we hold that the district court did not impermissibly shift the burden of proof to Ameren in proving the applicability of the demand-growth exclusion.

2. *Causation*

According to Ameren, in post-trial briefing, the government switched theories on how the district court should analyze increased demand to satisfy the demand-growth exclusion. Ameren also asserts that the government, in effect, promulgated a new causation standard without following notice-and-comment rulemaking. Specifically, Ameren contends, the government persuaded the district court that Ameren had to show "demand growth for a specific unit's generation." Appellant's Br. at 47. Ameren argues that this causation standard is "the exact opposite of EPA's prior statements [that] '[d]emand growth refers to what the utility expects to be required to produce in the way of energy system wide, *not for a single unit*, but system wide.'" *Id.* (citation omitted).

We hold that the district court did not apply an improper causation standard. Citing *New York*, the district court expressly acknowledged that Ameren had to satisfy "two criteria . . . before excluding emissions from its projection." *Ameren III*, 229 F. Supp. 3d at 1003 (quoting *New York*, 413 F.3d at 33). The first requirement is that "*the unit* could have achieved the necessary level of utilization during the [baseline period]." *Id.* (emphasis added) (alteration in original) (quoting *New York*, 413 F.3d at 33). The second requirement is that "the increase is not related to the physical or operational change(s) made to *the unit*." *Id.* (emphasis added) (quoting *New York*, 413 F.3d at 33). This accurately states the appropriate causation standard. As a result, the district court did not err in holding that to prove the applicability of the demand-growth exclusion, Ameren had to establish "that demand *on the unit* increases." *Id.* at 1003.

3. *Reasonable Power Plant Operator*

"In order to be deemed a major modification, [the government] . . . [must] show (1) a physical change to the plant; (2) a significant net emissions increase; and (3) a causal link between the two." *United States v. La. Generating, LLC*, 929 F. Supp. 2d 591, 593 (M.D. La. 2012). As explained *supra*, "the government had to show that at the time of the projects [Ameren] expected, or should have expected, that its modifications would result in a 'significant net emissions increase' . . . ." *Ala. Power Co.*, 730 F.3d at 1282.[4]

"[T]he [federal] regulations do not require a utility to be prescient, rather they require the company to undertake a *reasonable estimate* of what post-project emissions would be." *United States v. Duke Energy Corp.*, No. 1:00-cv-1262, 2010 WL 3023517, at *6 (M.D.N.C. July 28, 2010) (emphasis added) (citing *United States v. Cinergy Corp.*, 458 F.3d 705, 709 (7th Cir. 2006)). "[T]he question [is] whether the owner of the facility at the time of the work . . . expected or *reasonably should have expected*, the work to increase emissions . . . ." *La. Generating*, 929 F. Supp. 2d at 593 (emphasis added).

In its motion for summary judgment at the liability phase, Ameren argued that "under an expectations theory," the EPA had to "come forward with admissible evidence of what a reasonable power plant operator or owner would expect, and its failure to do so is fatal to EPA's expectations theory case, warranting a grant of partial summary judgment." *Ameren II*, 2016 WL 728234, at *18. While "Ameren acknowledge[d] that the determination of whether a party acted reasonably is generally a question for the factfinder," it maintained that "when the touchstone for objective reasonableness requires a technical understanding of the subject matter that is beyond a layperson's normal understanding, the factfinder must have guidance to make that determination." *Id.*

The district court, however, determined "that no special standard of care evidence is required for the factfinder to be able to determine whether a reasonable power plant operator or owner would have expected the projects to cause a significant emissions increase." *Id.* The court reasoned that (1) "[t]he legal standards supplied

[4]Alternatively, the government can prove a project actually resulted in a significant increase in emissions. *See* 40 C.F.R. § 52.21(a)(2)(iv)(b).

by the PSD rules are sufficient to guide the analysis," and (2) "the parties . . . submitted mountains of evidence regarding what they believe a reasonable power plant operator or owner would have concluded." *Id.* Specifically, the parties' experts would "testify about what Ameren did to make its projections, what information Ameren considered or did not consider, and why, and what the projections showed." *Id.* The court noted that other "courts that have considered expectations theory enforcement actions" have applied "[t]his method." *Id.* (first citing *United States v. Duke Energy Corp.*, 981 F. Supp. 2d 435, 439 (M.D.N.C. 2013); then citing *Cinergy*, 623 F.3d at 459; and then citing *La. Generating*, 929 F. Supp. 2d at 593).

On appeal, Ameren now asserts that the district court erroneously denied "[s]tandard-of-care evidence [in] defining the specific boundaries of reasonableness." Appellant's Br. at 50. According to Ameren, "the written requirements of the regulations," as opposed to the "expert witnesses' subjective views," "should have governed liability." *Id.* Ameren maintains that "[b]y superimposing a[] [reasonable power plant operator] standard, the [d]istrict [c]ourt allowed EPA's experts to second-guess Ameren's conclusions even though Ameren followed the regulations' written requirements." *Id.* at 51.

We conclude that the district court did not err in holding that "no special standard of care evidence is required for the factfinder to be able to determine whether a reasonable power plant operator or owner would have expected the projects to cause a significant emissions increase." *Ameren II*, 2016 WL 728234, at *18. Instead, the district court, as the factfinder, was entitled to "consider all relevant information available to [Ameren] at the time of the project, including prior operating data and [Ameren's] own statements and documents" in determining whether Ameren "should have predicted that a project would have caused a [significant] net increase." *Id.* at *19 (quoting Jury Instr. No. 23, *United States v. Cinergy*, 1:99-cv-1693-LJM-JMS (S.D. Ind. 2008), ECF No. 1335).

4. *Expert Testimony*

Ameren argues that the district court abused its discretion in admitting and relying on undisclosed expert opinions. *See Ryan v. Bd. of Police Comm'rs of St. Louis*, 96 F.3d 1076, 1081 (8th Cir. 1996) ("We review the district court's decision to admit evidence over a party's objection for abuse of discretion.").

In two motions filed during the trial on the liability phase and in post-trial briefs, Ameren moved to exclude the expert testimony of Koppe and Dr. Sahu "concerning causation of the actual emissions increases." *Ameren III*, 229 F. Supp. 3d at 1015. Ameren argued to the district court that "the testimony concerning the causation of the actual emissions increases are new, undisclosed opinions." *Id.*

The district court denied Ameren's motions to exclude Koppe's and Dr. Sahu's testimony. First, it rejected Ameren's argument that the experts' opinions were "new" and concluded that Ameren had "sufficient notice of both the United States' actual emissions case and of Mr. Koppe and Dr. Sahu's opinions." *Id.* at 1016. The court highlighted that the experts "(1) analyzed the actual post-project data in their reports, the attachments, and their work papers, and (2) stated that the projected increases actually materialized." *Id.* at 1015. Additionally, the court noted that the experts discussed in their reports and depositions "how the projects enable increased availability and contribute to increases in emissions." *Id.* The court explained that the experts were not required to "state[] their opinions in the precise words that Ameren thinks they should have used" because the "notice required of expert opinions is not so formulaic." *Id.*; *see also Thompson v. Doane Pet Care Co.*, 470 F.3d 1201, 1202–03 (6th Cir. 2006) (explaining that Federal Rule of Evidence 26(a)(2)(B) "contemplates that the expert will supplement, elaborate upon, explain and subject himself to cross-examination upon his report")).

Second, the district court concluded that even if it erroneously admitted the expert testimony, Ameren was unable to "show that it was prejudiced by the challenged testimony or the admission of the exhibits." *Ameren III*, 229 F. Supp. 3d at 1016. This was because "[t]he evidence the United States presented to show that the actual emissions increases were caused by the projects was also presented in the context of its expectations case regarding the expected causes of projected emissions increases, so the challenged testimony is in part cumulative evidence." *Id.* The court also noted Ameren's "opportunity both during pre-trial discovery and during cross-examination at trial to test those opinions." *Id.*

Here, even assuming that the district court abused its discretion by admitting the expert testimony, "any error would be harmless." *Smith v. Tenet Healthsystem SL, Inc.*, 436 F.3d 879, 889 (8th Cir. 2006). Harmless error applies here because the district court, as the factfinder, expressly stated that had the expert testimony on actual emissions not been admitted, the result would not be different.

C. *Injunctive Relief*

Ameren argues generally that the district court lacked Article III jurisdiction and statutory jurisdiction to issue injunctive relief "based on Rush Island's *operation*." Appellant's Br. at 66. According to Ameren, the district court found during the liability phase "that the Rush Island Projects were major modifications requiring permits before Ameren could commence construction." *Id.* at 67. But, during the remedy phase, the government "did not seek to prove any injury from the violation it proved" and "[i]nstead . . . sought to obtain relief based on the harm from Rush Island's operation without a PSD permit." *Id.* Ameren maintains that "[o]perations do not cause an injury that the PSD program recognizes." *Id.* Ameren further argues that the district court lacked jurisdiction to impose injunctive relief redressing "excess emissions." *Id.* at 69. Ameren asserts that the government waived "penal relief, including civil penalties; an injunction to prevent construction; an injunction to obtain information about future planned projects; and declaratory relief." *Id.* at 71 (citations omitted). Finally, Ameren argues that the CAA "does not authorize injunctions for wholly past violations" and that "[o]nly past violations are at issue here." *Id.* at 72.

"We review a district court's grant of a permanent injunction for abuse of discretion." *Kittle-Aikeley v. Strong*, 844 F.3d 727, 735 (8th Cir. 2016). An abuse of discretion occurs when a district court "reaches its conclusion by applying erroneous legal principles or relying on clearly erroneous factual findings." *Id.* (citation omitted). "Where the determinative question is purely legal, our review is more accurately characterized as *de novo*." *Id.* (quotation omitted).

"Whenever . . . the [government] finds that any person *has violated* or is in violation of any requirement . . . of an applicable implementation plan or permit, [the government] [must] notify the person . . . of such finding." 42 U.S.C. § 7413(a)(1) (emphasis added). Only after the "expiration of 30 days following the date on which such notice of a violation [was] issued" may the government "bring a civil [enforcement] action." *Id.* § 7413(a)(1)(C). The government is authorized to "commence a civil action for a permanent or temporary injunction, or to assess and recover a civil penalty . . . , or both," "[w]henever such person *has violated*, or is in violation of" a requirement of Title I of the CAA. *Id.* § 7413(b)(1) (emphasis added). A civil enforcement action

> may be brought in the district court of the United States for the district in which the *violation* is alleged to have occurred, or is occurring, or in which the defendant resides, or where the defendant's principal place of business is located, and such *court shall have jurisdiction to restrain such violation, to require compliance, to assess such civil penalty, to collect any fees owed* the United States under this chapter (other than subchapter II) *and any noncompliance assessment and nonpayment penalty owed* under section 7420 of this title, *and to award any other appropriate relief.*

Id. § 7413(b) (emphases added).

In summary,

> [t]he Clean Air Act authorizes the EPA to bring a civil enforcement action when any person *has violated* a permit or SIP, *has violated* any requirement in certain subchapters of the Clean Air Act (including the PSD program), or "attempts to construct or modify a major stationary source" in any state that the EPA Administrator has found out of compliance with the New Source Review program.

United States v. EME Homer City Generation, L.P., 727 F.3d 274, 291–92 (3d Cir. 2013) (emphases added).

Section 7413(b) "limits a district court's jurisdiction to awarding certain kinds of relief." *Id.* at 292. "Each type of relief in [§ 7413(b)] (except for civil penalties) is necessarily forward-looking." *Id.* (footnote omitted). The remaining term —"[a]ny other appropriate relief"—is merely a "catch-all" provision that "follows 'a list of specific items separated by commas.'" *Id.* at 293 (quoting *Ali v. Fed. Bureau of Prisons*, 552 U.S. 214, 225 (2008)). "As the word 'other' demonstrates, this general phrase is a residual category of the same type as the preceding items (namely, kinds of relief)." *Id.* "[T]he canon of *ejusdem generis* requires us to interpret this catch-all as permitting forward-looking relief, consistent with the preceding types of relief in the list." *Id.* at 295.

In *Homer City*, the Third Circuit held that "[t]he text of the Clean Air Act does not authorize an injunction against *former* owners and operators for a *wholly past PSD violation*, even if that violation causes *ongoing harm*." *Id.* at 291 (emphases added). But the court "express[ed] no opinion" on whether injunctions are "available in general to remedy *ongoing harm* from *wholly past violations*." *Id.* at 291 n.19 (emphases added). Indeed, as against the current owners, the court explained that the government could, after "*completion* of a facility's modification, . . . still obtain an *injunction* requiring the owner or operator to comply with the PSD requirements." *Id.*

at 289 (emphases added); *see also United States v. U.S. Steel Corp.*, 16 F. Supp. 3d 944, 950 (N.D. Ind. 2014) ("Requiring a company to do 'a further round of modifications to get the permit' could only be done through injunctive relief." (quoting *United States v. Midwest Generation, LLC*, 720 F.3d 644, 646 (7th Cir. 2013)).

Homer City is distinguishable from the present case because it concerned injunctive relief against a facility's *former* owners. *United States v. Luminant Generation Co., L.L.C.*, 905 F.3d 874, 888 (5th Cir. 2018), *reh'g en banc granted*, 929 F.3d 316 (5th Cir. 2019).[5] It does not detract from the plain language of § 7413(b), which "plainly gives district courts jurisdiction to restrain a violation, require compliance, and award any other appropriate relief whenever a person has committed a . . . violation" *Id.*

Here, however, Ameren also specifically challenges the district court's injunction against its Labadie plant, which committed no violations of the CAA. According to Ameren, neither the CAA nor the regulations authorize such relief.

Under § 7413, a district court "has the authority to order [a defendant] to take appropriate actions that remedy, mitigate and offset harms to the public and the environment *caused by the [defendant's] proven violations* of the CAA." *United States v. Cinergy Corp.*, 582 F. Supp. 2d 1055, 1060 (S.D. Ind. 2008) (emphasis added); *see also United States v. Oliver*, No. 3:06-CV-196-JWS, 2009 WL 10671371, at *13 (D. Alaska June 25, 2009) ("Section 113(b) of the Clean Air Act, 42 U.S.C. § 7413(b), expressly provides for injunctive relief to *redress violations* of the Act." (emphasis added)), *aff'd*, 394 F. App'x 376 (9th Cir. 2010).

---

[5]The Fifth Circuit ultimately dismissed the appeal in *Luminant* on the parties' motion.

Here, the government never provided notice of or alleged that the Ameren's Labadie plant committed a *violation* of the CAA. The plain language of § 7413(b) and caselaw make clear that the injunctive relief a district court may award must redress a *violation* of the CAA. *See* 42 U.S.C. § 7413(b)(1)–(3) (permitting civil enforcement actions "[w]henever such person has violated, or is in violation of" certain requirements and noting that the district "court shall have jurisdiction to restrain such violation"). Because Ameren committed no violation of the CAA at its Labadie plant, the district court lacked authority to authorize injunctive relief as to it. *Cf. United States v. Cinergy Corp.*, 618 F. Supp. 2d 942, 967 (S.D. Ind. 2009) (denying government's requested relief because the remedy would be punitive as the government proved no violation at the non-source unit against which it was sought.), *rev'd on other grounds*, 623 F.3d 455 (7th Cir. 2010); *United States v. Westvaco Corp.*, No. MJG-00-2602, 2015 WL 10323214, at *12 & n.27 (D. Md. Feb. 26, 2015) (rejecting government's request for the district court to order the defendant "to install control technology on a totally 'innocent' boiler" that the government never alleged "violated PSD regulations" (footnote omitted)).

Accordingly, we reverse the Labadie injunction and remand for further proceedings consistent with this opinion.

E. *Jurisdiction over Title V Claims*

Finally, Ameren challenges the district court's jurisdiction over the Title V claims.

Ameren operates Rush Island under a Title V permit issued by the Missouri Department of Natural Resources. This permit "restat[ed] the requirement that Ameren was prohibited from performing any unpermitted major modifications of Rush Island Units 1 or 2." *Ameren III*, 229 F. Supp. 3d at 985.

The government brought Title V claims against Ameren, and Ameren challenged the district court's subject matter jurisdiction to hear those claims. It argued—as it does here—that the Title V violation "is reviewable exclusively by the courts of appeals, not collaterally in civil . . . enforcement actions in the district courts." Appellant's Br. at 73 (alteration in original) (quoting *Homer City*, 727 F.3d at 296–97).

Ameren's jurisdictional argument lacks merit. "The EPA has authority to bring a civil enforcement action against a person who, among other things, 'has violated, or is in violation of, any other requirement or prohibition of [various subchapters, including Title V].'" *Homer City*, 727 F.3d at 298 (alteration in original) (quoting 42 U.S.C. § 7413(b)(2)). In turn, Title V's plain text "lists only two ways in which it can be violated: operating without a Title V permit or *violating the terms of a Title V permit while operating a source*." *Id.* (emphasis added) (citing 42 U.S.C.§ 7661a(a)).

The district court expressly found that Ameren violated an express permit term prohibiting it from performing unpermitted major modifications. *Cf. Otter Tail*, 615 F.3d at 1020. Under § 7413(b), the district court had jurisdiction to consider whether Ameren violated the express terms of its Title V permit.

III. *Conclusion*

Accordingly, we affirm the judgment of the district court in all respects *except* as to the injunctive relief entered against Ameren's Labadie plant. We remand for further proceedings consistent with this opinion.

____

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

UNITED STATES OF AMERICA,	)	
	)	
Plaintiff,	)	
	)	
and	)	
	)	
SIERRA CLUB,	)	No. 4:11 CV 77 RWS
	)	
Plaintiff-Intervenor,	)	
	)	
vs.	)	
	)	
AMEREN MISSOURI,	)	
	)	
Defendant.	)	

MEMORANDUM OPINION & ORDER

TABLE OF CONTENTS

INTRODUCTION

I. Summary

In 1970, Congress enacted the modern Clean Air Act to protect the nation's air resources and "promote the public health and welfare and the productive capacity" of the people. 42 U.S.C. § 7401(b)(1). Not satisfied with the results achieved under the 1970 statute, Congress amended the Clean Air Act in 1977 to add protections for areas meeting existing federal air quality standards. The 1977 amendments require newly-constructed power plants to install pollution controls. These pollution controls decreased the pollution coming from new plants. Acknowledging the cost of retrofitting old facilities, the 1977 amendments allowed existing plants to continue operating for their natural lifespan without pollution controls. Existing plants retained this "grandfathered" status until they were modified in any way beyond routine maintenance that increased emissions.

Ameren Missouri's (Ameren) Rush Island Energy Center (Rush Island) started operating in 1976, one year before the Clean Air Act Amendments. In the mid-2000's, as Rush Island was reaching the end of its natural lifespan, Ameren decided to conduct the most significant outage in Rush Island history to redesign and rebuild essential parts of Rush Island's boilers. To increase Rush Island's capacity and lengthen its life, Ameren reconstructed Rush Island's Unit 1 in 2007 and Unit 2 in 2010. Collectively, these construction outages lasted about 200 days and required more than 1,360 workers and almost 800,000 hours of labor. Rush Island's generating capacity and pollution emissions both increased as a result of these major modifications.

Before making these major modifications, Ameren should have obtained a Clean Air Act permit and installed the best pollution controls available, which were required after 1977 for all new and rebuilt power plants. Ameren did not apply for a permit. Forty-three years after it first came on-line, Rush Island is still operating without any pollution controls. It is now the tenth-highest source of sulfur dioxide pollution in the United States. More than two and a half years ago, I determined that Ameren had violated the Clean Air Act. During the last two and a half years, the parties have prepared and presented evidence to determine how to bring Ameren into compliance with the 1977 Clean Air Act. I held a trial in April 2019 on this issue.

In this memorandum order and opinion, I provide my findings of fact and conclusions of law from that trial. As a remedy, I will order Rush Island to come into compliance with the Clean Air Act by obtaining a permit under the Prevention of Significant Deterioration (PSD) program. I will also order Ameren to remedy Rush Island's excess pollution with ton-for-ton reductions at its nearby Labadie Energy Center. This remedy will satisfy the purpose of the Clean Air Act to "promote the public health and welfare and the productive capacity" of the people, and it is narrowly tailored to address the harms created by Ameren's violations.

II. Case History

In this Clean Air Act case, Plaintiff United States of America claims that Defendant Ameren increased the risk of negative health impacts and premature deaths by releasing excess pollution from Rush Island. Plaintiff is acting at the request of the United States Environmental Protection Agency (EPA). According to the EPA, Rush Island has released more than 162,000 excess tons of sulfur dioxide into the air because Ameren failed to apply for a permit that would require it to install pollution control technology when it redesigned and rebuilt its boilers at Rush Island. That sulfur dioxide transformed into fine particulate matter ($PM_{2.5}$) that can cause heart attacks, asthma attacks, strokes, and premature death. Had Ameren installed the required pollution control technology, it would have reduced its Rush Island pollution by 95% or more. To remedy these harms, the EPA seeks an order requiring Ameren to (1) obtain the required

Clean Air Act permit (2) install sulfur dioxide "scrubbers" at Rush Island, and (3) install pollution control technology at a second coal-fired power plant to account for the excess emissions Rush Island continues to release while it operates without pollution controls.

I separated the liability and remedies phases of this case to more orderly conduct discovery and presentation of arguments. In August and September 2016, the liability phase concluded with a 12-day bench trial. On January 23, 2017, I issued my memorandum opinion and order on the liability phase. I found that Ameren violated the Clean Air Act, 42 U.S.C. § 7470 et seq., by overhauling its coal-fired boilers at Rush Island without obtaining the required permits. On February 16, 2017, I granted the Sierra Club's motion to intervene in this suit as a matter of right. [ECF No. 863].[1]

In April 2019, I held a six-day bench trial to determine the appropriate remedy in this case. In this memorandum order and opinion, I set forth findings of fact and conclusions of law from the remedies phase trial. These findings and conclusions depend in significant part on the evidence presented and conclusions made during the liability phase. Accordingly, I will summarize aspects of the liability phase trial as follows.

III. Liability Phase Findings of Fact and Conclusions of Law

Rush Island is a pulverized coal-fired power plant in Jefferson County, Missouri, directly adjacent to the Mississippi River. Rush Island's two units went into service in 1976 and 1977, immediately before the 1977 Clean Air Act Amendments. Because of this timing, Rush Island is one of many power plants that were grandfathered into the Clean Air Act's permitting scheme.

[1] Throughout this memorandum opinion and order, I sometimes refer to the Plaintiffs jointly. Frequently, I refer to the EPA's arguments, experts, and evidence without mentioning Sierra Club. These references reflect that the EPA presented much of the evidence at trial. Sierra Club was also present for the entire remedies trial, and independently has standing to seek the injunctive relief I order in this case.

The Rush Island plant currently emits about 18,000 tons of SO_2 per year. Neither of Rush Island's units has air pollution control devices for SO_2.

Under the Clean Air Act, every new or modified major pollution source must obtain one of two permits: a Non-Attainment Area permit when they are built in areas more polluted than the National Ambient Air Quality Standards (NAAQS), or a Prevention of Significant Deterioration (PSD) permit when they are built in attainment areas, which are less polluted than the NAAQS. 42 U.S.C. § 7470 et seq. The EPA sets NAAQS for six criteria pollutants at levels "requisite to protect the public health." 42 U.S.C. § 7409(b). However, NAAQS alone are insufficient to meet the goals of the Clean Air Act: Congress determined that even in attainment areas, air pollution control was necessary "to ensure that the air quality in . . . areas that are already 'clean' will not degrade." Alaska Dep't of Envtl. Conservation v. E.P.A., 540 U.S. 461, 470 (2004) (quoting R. Belden, Clean Air Act 6 (2001) at 43).

Congress has made some exceptions to blunt the impact of the Clean Air Act. Specifically, the Act does not require existing facilities to immediately install pollution controls. Instead, the Act allows these facilities to continue operating through their normal lifespans. This grandfathering only lasts until these plants cease operating or undergo major modifications. Any plant that is retired but reactivated loses its grandfathered status and must obtain a permit. A plant that is rebuilt in any significant way must obtain a permit as well.

Accordingly, the Clean Air Act represents a compromise: by limiting the duration of grandfathering to facilities' natural life, Congress prevented existing polluters from maintaining in perpetuity their *advantage* over new plants.

> [O]ld plants [are treated] more leniently than new ones because of the expense of retrofitting pollution-control equipment. But there is an expectation that old plants will wear out and be replaced by new ones that will be subject to the more stringent pollution controls that the Clean Air Act imposes on new plants. One

> thing that stimulates replacement of an old plant is that aging produces more frequent breakdowns and so reduces a plant's hours of operation and hence its output.

United States v. Cinergy Corp., 458 F.3d 705, 709 (7th Cir. 2006). Through the "major modification" exception to grandfathering, Congress memorialized this compromise as a matter of law.

Major modifications occur when there is a "physical change" or change in the method of operation of a major stationary source that would significantly increase net emissions. See United States v. Ameren Missouri, 2016 WL 728234, at *4 (citing 40 C.F.R. § 52.21(b)(2)(i)). An increase of 40 tons or more per year of sulfur dioxide ("SO_2"), the pollutant discussed in this case, is "significant" under the regulations. 40 C.F.R. § 52.21(b)(23)(i).

Under the Clean Air Act, if a grandfathered polluter ever modifies its facilities, it must do four things: (1) calculate the impact of those modifications, (2) report the planned modifications to the EPA, (3) obtain the requisite permits, and (4) install the required pollution control technologies at that time. This process ensures that any "major modifications" are identified, reported, and permitted. Ameren made major modifications to Rush Island without reporting those modifications and obtaining a permit.

The natural life of many of Rush Island's component parts is 30 to 40 years. Consistent with those lifespans, by 2005, major boiler components at Rush Island were experiencing performance problems including leaks, slagging, fouling, plugging, gas flow resistance, erosion, and mechanical failure. These problems forced Ameren to take the units offline with increasing frequency so that they could be unplugged, repaired, and otherwise serviced. These aging problems also reduced the capacity of the Rush Island boilers by slowing gas flow and reducing the gas volume moving through each boiler. See United States v. Ameren Missouri, 229 F. Supp.

3d 906, 922-936 (E.D. Mo. 2017).

Ameren sought to increase its plant capacity by redesigning and replacing essential components of both boilers, specifically the economizer, reheater, air preheater, and the "lower slope" panels surrounding the boiler. Ameren overhauled Unit 1 and Unit 2 in this manner in 2007 and 2010, respectively. After Ameren replaced these components at each unit, that unit's electric generating capacity increased immediately to levels that had not been seen in years. To achieve this improved capacity, Ameren employed more than 1,000 workers over several years. For example, "[t]he 2010 major boiler outage at Rush Island Unit 2 lasted approximately 100 days and required more than 350,000 hours of labor, of which 290,953 hours were performed by contractors. An average of 360 contractor staff worked two 10-hour shifts six days a week during the outage." United States v. Ameren Missouri, 229 F. Supp. 3d 906, 943 (E.D. Mo. 2017). The outage at Unit 1 was similar in scope and length, and both units' projects required years of planning.

Additional evidence presented at trial established that Ameren's work at both units did not constitute "routine maintenance." The new components in each boiler were designed, engineered, and constructed by outside contractors, and the complexity of the replacements was beyond the capacity of Ameren's in-house staff. Id. at 1001. The replaced equipment was so large and heavy that monorails had to be built to transport it at the construction site. Id. Ameren budgeted and paid for these projects out of its capital budget instead of its operations and maintenance budget. Id. at 1002. The Rush Island modifications required approval from high-level Ameren executives, which is unnecessary for routine maintenance. Id. at 1001. Ameren's Vice President called the 2007 modifications the "most significant outage in Rush Island history" and referred to the replacement of the economizer, reheater, air preheater, and lower slopes as distinct from other "routine maintenance that had to be performed" during the outage. Id. at 943.

Ameren's own internal metrics demonstrated an actual increase in emissions at Rush Island. Specifically, Ameren recorded outages and "derate" events, where Rush Island's maximum output was reduced. Ameren recorded these events contemporaneously in its Generating Availability Data System (GADS), and based staff bonuses in part on availability data. Id. at 931-933. Between 1997 and 2007, Unit 1's availability fluctuated between 70% and 90%. Id. at 949. Following its upgrade, Unit 1's availability increased to 96.77% in 2008. Id. at 954. This value was higher than any 12-month period at Unit 1 since 1990. Id. Unit 2's availability increased from 94.5% during a five-year baseline to 97.4% after the modifications. Id. at 958. This value was higher than any 12-month period at Unit 2 since 1987. Id. Ameren's employees have admitted that those availability increases would not have happened but for the projects.

Courts recognize these availability improvements as leading to emissions increases. "A significant decrease in outages results in a significant increase in both production and emissions." United States v. Ohio Edison Co., 276 F. Supp. 2d 829, 834-35 (S.D. Ohio 2003). "If the repair or replacement of a problematic component renders a plant more reliable and less susceptible to future shut-downs, the plant will be able to run consistently for a longer period of time," emitting more pollution as the plant is operated. United States v. Ala. Power Co., 730 F.3d 1278, 1281 (11th Cir. 2013).

With the facts presented at trial, the preponderance of evidence demonstrated that (1) Ameren conducted a "major modification" when it used more than 1,000 workers to design and replace essential components of Rush Islands boiler units in 2007 and 2010; (2) Ameren should have expected those modifications to increase emissions by more than forty tons of sulfur dioxide per year; (3) those modifications actually increased emissions by reducing future stoppages, increasing plant capacity, and extending the life of the plant; and (4) those modifications were, in Ameren's expert's words, not de minimis or routine modifications, nor did emissions increase because of demand alone.

Ameren should have obtained a Clean Air Act permit before beginning its major boiler modification. Ameren did not seek that permit. As a part of the permitting process, major pollution sources like Rush Island are required to have the Best Available Control Technology (BACT) when they undergo major modifications. Rush Island did not have any pollution control technology. Twelve and nine years since Ameren overhauled Unit 1 and Unit 2, respectively, Rush Island still does not have any pollution control technology. Through the end of 2016, Rush Island emitted 162,000 tons of sulfur dioxide more than it would have had Ameren complied with its obligations under the Clean Air Act.

Now, in the remedy phase of the trial, Ameren and the EPA dispute whether I should order injunctive relief in this case and what injunctive relief is appropriate. In September 2018, the parties filed five separate motions for summary judgment, three from Ameren, one from the EPA, and one from Plaintiff-Intervenor Sierra Club on the subject of standing. I granted the Sierra Club's motion for summary judgment on standing with respect to relief requested at Rush Island. [ECF No. 1055] There was no dispute of material fact that Sierra Club's members were injured in fact, their injuries were traceable to Ameren's excess emissions, and pollution reductions at Rush Island would redress their injuries.

I denied the parties' other motions for summary judgment. Neither the EPA nor Ameren demonstrated that there was no dispute of material fact concerning the appropriate remedy. I must evaluate injunctive relief relying on the "well-established principles of equity" the Supreme

Court articulated in eBay Inc. v. MercExchange, L.L.C., 547 U.S. 388, 391 (2006).[2] Based on the parties' filings, I could not say as a matter of law what injunctive relief was required pursuant to the eBay factors.

In April 2019, the EPA and Ameren presented their arguments concerning remedies over six days of trial. The EPA requests an order requiring Ameren to obtain a PSD permit for Rush Island, (2) propose Flue Gas Desulfurization (FGD) scrubbers as the appropriate permit technology, (3) meet an emissions limitation based on FGD scrubbers, and (4) address ton-for-ton excess emissions from Rush Island by installing pollution control technology on Ameren's Labadie Energy Center. Based on the extensive testimony provided by its experts, the EPA argues that the eBay factors support this relief.

Ameren argues that it did not have fair notice of the EPA's legal interpretations, that there is no evidence of harm created by its SO_2 emissions, that Ameren has already decreased its emissions, that it should have had the opportunity to apply for a much less stringent "minor permit," and that the expense of installing scrubbers is unduly burdensome.

In addressing these arguments, I note that by making major modifications without satisfying the requirements of the Clean Air Act, Ameren reaped significant financial benefits. According to Ameren's 2011 estimates, installing wet FGDs at Rush Island would cost between $650 million and $960 million. September 19, 2011 Project Plan (Pl. Ex. 1102), at AM-REM-00294509. Ameren deferred these costs for more than ten years at the expense of downwind communities that it will never have to fully repay. Instead, I may only order remediation enough to account for the total amount of excess emission released by Ameren, a remedy that is more

[2] Though the eBay case did not establish the governing standard for a permanent injunction, I will rely on the eBay Court's presentation of the "familiar principles" as a four-factor test. eBay, 547 U.S. at 391. In this memorandum opinion and order, I refer to the factors as the "eBay factors" or "eBay standard."

than a decade late, but which is closely tailored to the harm suffered by these communities.

Accordingly, and based on the evidence presented at trial, I conclude that the following injunctive relief is necessary to remedy the harm created by the more than 162,000 tons of excess pollution Ameren released from Rush Island: Ameren must (1) apply for and obtain the applicable Clean Air Act permit from the Missouri Department of Natural Resources (MDNR) for its Rush Island Plant, (2) propose wet flue gas desulfurization (FGD) as the required control technology for Rush Island, (3) meet an emissions limitation of 0.05 lb/mmBTU at Rush Island and (4) install and use dry sorbent injection (DSI) technology, or another more effective control technology, at its Labadie Energy Center (Labadie), until it reduces pollution from Labadie in an amount equal to the excess emissions from Rush Island.

This remedy results from the following findings of fact and conclusions of law. In summary, I find that the EPA's experts convincingly and credibly testified that wet FGD is the most effective control technology that could be used at Rush Island. Additionally, when considering the energy, environmental, and economic impacts, wet FGD is achievable at Rush Island. As a result, wet FGD is the Best Available Control Technology (BACT) for Rush Island. The EPA's experts also convincingly and credibly testified that Ameren's failure to install BACT at Rush Island has led to more than 162,000 tons of excess SO_2 emissions and increased the risk of health problems and premature mortality in the exposed population. Considering this evidence, I conclude that ordering commensurate reductions at Labadie is a remedy that is closely tailored to the harm suffered, addresses irreparable injury that could not be compensated through legal remedies, serves the public interest, and is warranted when considering the balance of hardships in this case.

FINDINGS OF FACT

I. BACKGROUND: RUSH ISLAND'S MAJOR MODIFICATIONS

a. Ameren Redesigned and Rebuilt Units 1 and 2 Near the End of Their Design Life

1. Rush Island Units 1 and 2 began operating in 1976 and 1977. They were originally grandfathered into compliance with the Clean Air Act without needing to install BACT emission limitations imposed by the Prevention of Significant Deterioration (PSD) program. Ameren Missouri, 229 F.Supp.3d at 915.

2. Neither Rush Island Unit 1 nor Rush Island Unit 2 has installed any air pollution control devices for SO_2 emissions. Id.; see also id. at 917 (Liability Findings ¶ 8).

3. Rush Island Units 1 and 2 were originally designed to have an approximately 30-year life, with components typically lasting 30 to 40 years. Id. at 917 (Liability Findings ¶ 5). By 2007 and 2010, when Ameren modified Rush Island Units 1 and 2, they had already been operating for 30 years. Ameren has already run the Rush Island plant ten years longer than it expected at the time the plant was constructed.

4. The 2007 and 2010 modifications ended Rush Island's grandfathered status under the PSD program. The modifications were made during the most significant outage in Rush Island plant history and were justified based on increasing plant operations and revenue. Id. at 915; see also id. at 940 (Liability Findings ¶¶ 155-160), 943 (Liability Findings ¶ 172).

b. Modifications at Rush Island Led to Actual Emissions Increases

5. At trial, Ameren argued that it had reduced both its fleetwide SO_2 emissions and its emissions from Rush Island. In 2010, Ameren began operating pollution control equipment, specifically Flue Gas Desulfurization (FGD) scrubbers, at its Sioux pulverized coal-fired power plant northeast of Rush Island. Knodel, Tr. Vol. 1-A, 88:16-89:2. Ameren also converted two of

its four units at the Meramec Energy Center to natural gas combustion. Michels, Tr. Vol. 5-B at 5:22-6:7. These changes decreased emissions from the Sioux and Meramec plants. (Ex. UU).

6. Ameren did not install pollution control equipment at Rush Island or its Labadie Energy Center, although it began using lower sulfur coal at these two plants. Michels, Tr. Vol. 5-B, 5:22-6:7.

7. Ameren has not submitted evidence demonstrating that Rush Island's emissions have decreased or stayed the same after its major modifications. At the remedies phase trial, and in its proposed findings of fact, Ameren did not present any data demonstrating Rush Island's emission rate before 2007. Without that information, Ameren cannot demonstrate that its emissions decreased or stayed the same after its major modifications.

8. After the liability trial, I found that Ameren's modifications at Rush Island had increased emissions from Unit 1 by about 665 tons per year and from Unit 2 by about 2,171 tons per year. Ameren Missouri, 229 F. Supp. 3d 906, 955, 959.

c. Rush Island Is One of a Small Minority of Similar Plants That Continue to Operate Without SO_2 Scrubbers

i. SO_2 Scrubbers Are Widely Used in the Electric Utility Industry

9. There are two ways to reduce the amount of SO_2 emitted from a pulverized coal-fired electric generating unit: (1) reduce the sulfur content of the source coal, and (2) use a control system to capture SO_2 before it is released to the atmosphere. The main types of control technology used to capture SO_2 are FGD scrubbers and dry sorbent injection (DSI) technology. Staudt Test., Tr. Vol. 1-B, 12:20-13:14; Callahan Dep., Nov. 8, 2017, Tr. 44:3-10 (testimony of Ameren supervisor of environmental projects).

10. FGD scrubbers have been widely used to reduce SO_2 from coal-fired electricity generating units for decades. Staudt Test., Tr. Vol. 1-B, 15:2-4; Mar. 2009 Rush Island FGD

Project Technology Selection Report (Pl. Ex. 1029), at AM-02638262 and AM-02638283; Missouri Department of Natural Resources (MDNR) Rule 30(b)(6) Dep., Aug. 10, 2018, Tr. 141:23-142:3.

11. Scrubbers can either be "wet" or "dry," depending on the amount of moisture introduced into the gas stream. Wet FGD systems introduce more moisture, reducing the temperature of the gas stream and keeping some water in the form of droplets, rather than vapor. Water droplets create a more reactive environment, increasing the amount of SO_2 "scrubbed" from the exhaust. Additionally, the lower temperatures in a wet FGD system are compatible with using limestone as the "scrubbing reagent." Limestone is cheap and readily available in Missouri. Staudt Test., Tr. Vol. 1-B, 13:4-14:12; see also Mar. 2009 Rush Island FGD Project Technology Selection Report (Pl. Ex. 1029), at AM-02638262 and AM-02638283.

12. Dry FGD systems cool the gas stream less than wet FGD systems do. They use hydrated lime as a reagent, remove less SO_2 than dry systems do, and produce a dry waste product that must be disposed of at cost. Staudt Test., Tr. Vol. 1-B, 13:4-14:12; see also Mar. 2009 Rush Island FGD Project Technology Selection Report (Pl. Ex. 1029), at AM-02638262 and AM-02638283.

13. Wet FGD scrubbers are the most effective SO_2 control technology. They can remove more than 99% of a plant's SO_2 emissions. Dry FGD scrubbers are slightly less effective, but they can still remove more than 95% of a plant's SO_2 emissions, depending on the type of coal being burned. Staudt Test., Tr. Vol. 1-B, 14:13-15:1; Snell Test., Tr. Vol. 4-B, 50:8-22; Harley Dep., Apr. 11, 2018, Tr. 100:17-101:6 (testimony of Ameren Director of Project Engineering); see also March 2008 EPRI Report: Flue Gas Desulfurization Performance Capability (Pl. Ex. 1045), at AM-02699777 ("plants designed for 99% removal are scheduled to

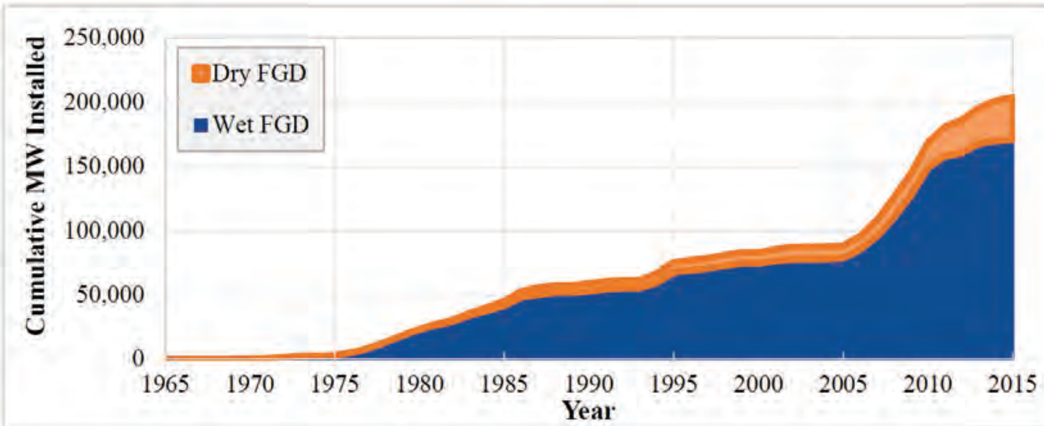
be operating in late 2008 or early 2009").[3]

14. As illustrated by Figure 1, scrubbers have been used at pulverized coal-fired power plants dating back to the early 1970s. As of 2016, most of the coal-fired generating capacity operating in the United States was produced by power plants with scrubbers. Specifically, 200,000 megawatts of capacity was available at scrubbed coal-fired units out of 250,000 megawatts of capacity at all coal-fired electric generating units. Staudt Test., Tr. Vol. 1-B, 15:2-25; Black & Veatch Rush Island FGD Technology Selection Report (Pl. Ex. 1029), at AM-02638262.

15. Of that 200,000 megawatts, wet scrubbers account for about 170,000 megawatts, while dry scrubbers account for the other 30,000 megawatts. Staudt Test., Tr. Vol. 1-B, 15:2-25, 19:9-21:15; see also Black & Veatch Rush Island FGD Technology Selection Report (Pl. Ex. 1029), at AM-02638262. Wet scrubbers are by far the dominant SO_2 control technology for power plants.

[3] The Electric Power Research Institute (EPRI) is a research arm of the electric utility industry. Ameren and other utilities fund EPRI to research and provide reports on the best practices on a variety of issues, including the performance and cost of pollution controls. Callahan Dep., Nov. 8, 2017, Tr. 58:15-21, 59:8-18; Harley Dep., Apr. 11, 2018, Tr. 38:22-40:3.

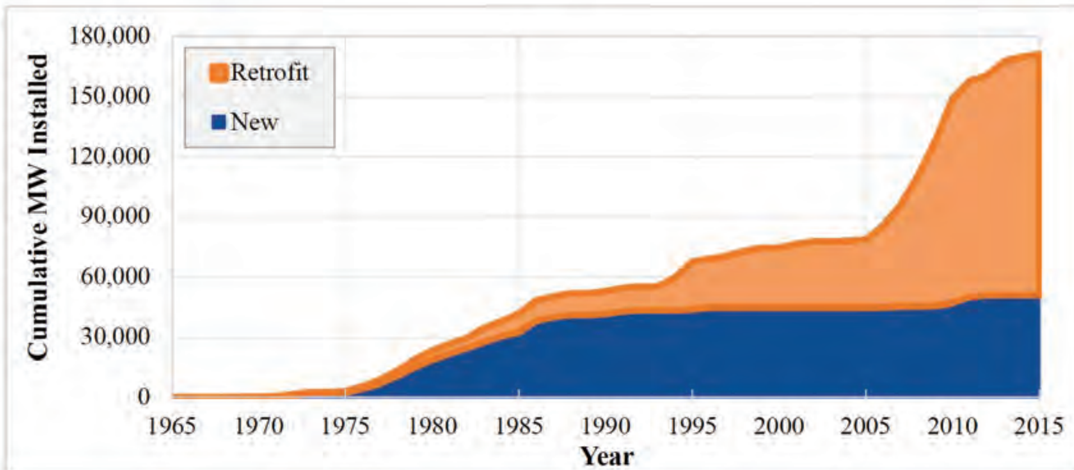
Figure 1



16. Scrubbers are currently installed on hundreds of coal-fired electric generating units, including approximately 84% of coal-fired power plants in the United States, weighted by generating capacity. Knodel Test., Tr. Vol. 1-A, 77:6-9; Staudt Test., Tr. Vol. 1-B, 15:17-16:10; see also Stumpf Dep., Mar. 27, 2018, Tr. 48:18-25 (Ameren project manager testifying that FGDs have become prevalent in the utility industry); Harley Dep., 51:1-52:25 (Ameren senior director testifying about scrubber "boom" in the utility industry); Mitchell Dep., May 30, 2018, Tr. 39:14-18 (Ameren project engineer testifying that scrubbers were well-established at the time of the FGD engineering studies for Rush Island).

17. The vast majority of wet scrubbers operating at power plants today were installed on existing plants, as illustrated by Figure 2. About 120,000 megawatts of the total 170,000 megawatts of wet scrubber capacity operating in 2015 was installed on existing plants. Most of that scrubbed capacity was installed between 2005 and 2015. Staudt Test., Tr. Vol. 1-B, 65:13-66:16.

Figure 2



18. Rush Island's continued operation without pollution controls has made it one of the largest sources of SO_2 pollution in the United States. Between 1997 and 2017, Rush Island moved from being the 154th to the 10th highest man-made source of SO_2 emissions in the country. Knodel Test., Tr. Vol. 1-A, 73:6-74:5.[4]

ii. DSI Controls Are Not Commonly Installed on Units of Rush Island's Size

19. Unlike FGD control technology, dry sorbent injection does not require a reaction vessel or added moisture. Instead DSI involves blowing reagent directly into the duct work downstream of the coal-fired boiler. A fabric filter or baghouse (hereinafter referred to as DSI-FF) can be added to remove particulate matter and increase overall removal efficiency of sulfate and other pollutants. Without a baghouse, an ordinary DSI system can remove 50% of SO_2 emissions. With a baghouse, a DSI-FF can remove 70% SO_2 reductions. Staudt Test., Tr. Vol. 1-B, 16:11-17:22; Snell Test., Tr. Vol. 4-B, 10:18-11:9; Harley Dep., Apr. 11, 2018, Tr. 163:2-19

[4] In that same year, Ameren's Labadie plant ranked as the fourth highest SO_2 emitter in the United States, and Missouri as a whole had become the second highest SO_2 emitting state in the country, behind only Texas. Knodel Test., Tr. Vol. 1-A, 74:6-15.

(testifying that DSI typically can achieve 40 to 50% reductions).

20. There are only a handful of units the size of Rush Island that currently use DSI for SO_2 control. None of those systems were in operation prior to 2007 when Ameren undertook the major modifications at issue in this case. Neither party presented testimony identifying the source category to which those large units with DSI belong. Staudt Test., Tr. Vol. 1-B, 52:10-17; Tr. Vol. 2-A, 33:1-11.

21. Ameren's expert Colin Campbell admitted that Rush Island would be the first power plant to have BACT determined based on the use of DSI, Test., Tr. Vol. 4-A, 98:3-7.

d. Ameren Evaluated FGD Installation at Rush Island

22. Although Ameren did not install control technology at Rush Island, Ameren spent about $8 million between 2008 and 2011 evaluating what control technology it should install. Staudt Test., Tr. Vol. 1-B, 17:23-19:7; Campbell Test., Tr. Vol. 4-A, 93:12-17; September 19, 2011 Project Plan (Pl. Ex. 1102), at AM-REM-00294508.

23. Ameren completed two phases of its evaluation. "[T]he first phase evaluated the various . . . technologies and the second phase utilized the selected technology (Wet FGD system) to develop a design basis, scope and detailed cost estimate." June 2, 2010 Request for Preliminary Work Order Authorization (Pl. Ex. 1095), at AM-REM-00288486.

24. The consulting firms Black & Veatch and Shaw prepared independent feasibility studies during these phases. Staudt Test., Tr. Vol. 1-B, 17:23-20:22; AmerenUE Rush Island Power Plant Technology Selection Report (Pl. Ex. 1029); Shaw Technology Evaluation (Pl. Ex. 1069); Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 134:13-135:2, 135:22-136:11, 138:16-138:20, 138:25-139:6 (identifying Pl. Exs. 1029 and 1069 as the final Phase 1 reports, which were the best estimates available at the time concerning the feasibility of using wet scrubbers at

Rush Island); Callahan Dep., Nov. 8, 2017, Tr. 119:17-120:9 (supervisor of the Phase 1 and 2 studies testifying Ameren hired multiple independent engineering firms to get a "better handle on potential cost as well as schedule").

25. Ameren's internal presentations indicate that these studies were designed to evaluate business planning and compliance options for a number of regulations, including the Cross-State Air Pollution Rule, rules for Hazardous Air Pollutants, and the New Source Review Program, the regulatory program at issue in this case. See June 1, 2010 CPOC Presentation, Scrubber Technology Assessment, Rush Island Plant (Pl. Ex. 1099), at AM-REM-00288980.

26. In Phase 1, Shaw solicited bids from six vendors with extensive experience installing FGDs. Shaw Technology Evaluation (Pl. Ex. 1069), at AM-REM-00191161; Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 138:25-139:12. After reviewing this and other information, Shaw recommended wet FGD for further review and eventual installation at Rush Island. This decision was "[b]ased on the overall evaluation of experience, performance, arrangement, operating flexibility, constructability, modularization, site impacts, capital costs, operating costs, maintenance and repair costs, and other attributes such as permitting, social-economic costs and public relations." Shaw Technology Evaluation (Pl. Ex. 1069), at AM-REM-00191196; Staudt Test., Tr. Vol. 1-B, 20:9-22:9.

27. Black & Veatch also recommended wet FGD for further review in Phase 1.

28. Ameren accepted the consulting firms' recommendations, selecting wet FGD for further evaluation in Phase 2. In Phase 2, Ameren requested more detailed cost estimates, engineering designs, and project execution plans for Rush Island. The Phase 2 reports were thousands of pages long, included bid information from FGD suppliers, and laid out a detailed schedule for installing FGD at Rush Island. Staudt Test., Tr. Vol. 1-B, 33:17-36:7; Callahan

Dep., Nov. 7, 2017, Tr. 165:16-166:20; May 2010 Shaw Final Report (Pl. Ex. 1071); August 2010 Black & Veatch Execution Plan and Report (Pl. Ex. 1115).

i. Ameren's Studies Recommended Wet FGD at Rush Island

29. As part of its efforts, Ameren evaluated the technical and economic feasibility of installing FGDs at Rush Island. These evaluations were summarized in several presentations given to Ameren management. February 5, 2010 Project Review Board Presentation-Rush Island FGD (Pl. Ex. 1100), at AM-REM-00288998 to 289000; June 1, 2010 Corporate Project Oversight Committee (CPOC) Presentation, Scrubber Technology Assessment, Rush Island Plant (Pl. Ex. 1099), at AM-REM-00288981 to 288987; March 2, 2009 Economic Value Analysis for Rush Island FGD Project Plan (Pl. Ex. 1023), at AM-02634859 to 2634860.

30. Based on its evaluations, Ameren's corporate project oversight committee agreed that wet FGD technology (1) was technically and economically feasible at Rush Island, (2) was the right choice for complying with, among other things, New Source Review, and (3) should be pursued further in contract development. Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 58:24-59:12, 59:25-60:22, 82:3-83:17.

31. Ameren explained in one of its management presentations that wet FGD was its "technology choice for SO_2 removal at Rush Island" because of its "advantages in cost, capability and flexibility" over other options. June 1, 2010 CPOC Presentation, Scrubber Technology Assessment, Rush Island Plant (Pl. Ex. 1099), at AM-REM-00288987.

32. For coal-fired power plants, the emission limitation is typically stated in terms of pounds of pollutant per million BTU of heat input (lb/mmBTU). This unit represents the amount of pollution emitted per unit of fuel put into the boiler. Knodel Test., Tr. Vol. 1-A, 39:1-6. The emission limitation is always accompanied by an averaging time; for coal-fired power plants,

typically the averaging time used is a 30-day rolling average to help address variability on a day-to-day basis. Knodel Test., Tr. Vol. 1-A, 39:7-11.

33. Ameren concluded that the wet FGD systems have the advantage of "[d]emonstrated performance" to meet an SO_2 emission rate guarantee of 0.06 lb/mmBTU. June 1, 2010 CPOC Presentation (Pl. Ex. 1099), at AM-REM-00288984; Callahan Dep., Nov. 8, 2017, Tr. 201:13-21 (agreeing that 0.06 pounds per million BTU was a demonstrated number that could be achieved).

34. Ameren rejected the less-effective DSI technology because it was "[n]ot commercially demonstrated" and "not proven to meet low emissions requirements." June 1, 2010 CPOC Presentation (Pl. Ex. 1099), at AM-REM-00288984.

35. Ameren concluded that wet FGD also had advantages with respect to other environmental impacts, including the removal of Hazardous Air Pollutants (HAPs). Staudt Test., Tr. Vol. 1-B, 40:12-41:7. For example, wet FGD helps remove other acid gases. June 1, 2010 CPOC Presentation, Scrubber Technology Assessment, Rush Island Plant (Pl. Ex. 1099), at AM-REM-00288985. Wet FGD also helps remove organic HAPs, in part due to lower flue gas temperatures. Id. Specifically, wet FGD helps remove oxidized mercury, sulfur trioxide, particulate matter, hydrogen chloride, and hydrogen fluoride. Direct Testimony of Mark Birk, Missouri Public Service Commission Case No. ER-2011-0028 ("Birk PSC Testimony"), Sept. 3, 2010 Tr. 3:20-4:2 (Pl. Ex. 1003); see also Callahan Dep., Nov. 8, 2017, Tr. 25:14-23. Wet FGD also eliminates landfill impacts because the gypsum byproduct can be sold to nearby cement plants. Id. at AM-REM-00288986.

36. Ameren concluded that wet FGD was an economically viable option as well. In Ameren's words "[e]conomic evaluation supported" the use of wet FGD at Rush Island. March

2, 2009 Economic Value Analysis for Rush Island FGD Project Plan (Pl. Ex. 1023), at AM-02634859; February 5, 2010 Project Review Board Presentation-Rush Island FGD (Pl. Ex. 1100), at AM-REM-00288999; June 1, 2010 CPOC Presentation: Scrubber Technology Assessment Rush Island Plant (Pl. Ex. 1099), at AM-REM-00288984 to 288986; August 20, 2010 Rush Island Progress Overview (Pl. Ex. 1101), at AM-REM-00289177; Staudt Test., Tr. Vol. 1-B, 23:2-7; Callahan Dep., Nov. 8, 2017, Tr. 186:7-10.

37. Wet FGD has a less expensive reagent than dry FGD or DSI. The wet FGD limestone reagent costs $28/ton; the dry FGD lime reagent costs $75/ton; and the DSI trona reagent costs $150/ton. Shaw Technology Evaluation (Pl. Ex. 1069), at AM-REM-00191180.

38. Ameren also determined that wet FGDs would not require the new induced draft booster fans that dry FGD would require. Instead, the existing fans would only need to be upgraded. Foregoing the new fans would reduce capital costs at Rush island by $37 to $50 million and would result in lower plant energy consumption. An additional $20 million could be saved by using limestone milling equipment at Ameren's Sioux power plant. June 1, 2010 CPOC Presentation, Scrubber Technology Assessment, Rush Island Plant (Pl. Ex. 1099), at AM-REM-00288983; Staudt Test., Tr. Vol. 1-B, 36:20-38:7, 55:5-15.

39. Wet FGD also provides greater fuel flexibility for Rush Island. Because wet FGD removes more SO_2 per ton of coal, Ameren could use higher sulfur coal in some circumstances while still meeting emissions limitations. Staudt Test., Tr. Vol. 1-B, 21:16-22:9; Callahan Dep., Nov. 8, 2017, Tr. 203:13-204:3; see also Birk PSC Testimony (Pl. Ex. 1003) Tr. 4:8-15 (describing fuel flexibility as advantage for wet FGDs in Sioux rate case).

40. Ameren's final project plan estimated that the total cost of installing wet FGDs at Rush Island would range from $650 million to $960 million, based on estimates provided by

multiple engineering firms. September 19, 2011 Project Plan (Pl. Ex. 1102), at AM-REM-00294509; see also February 5, 2010 Project Review Board Presentation-Rush Island FGD (Pl. Ex. 1100), at AM-REM-00289005; Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 87:11-88:1 (identifying these costs as the best estimates available to Ameren at the time of the cost of scrubbing Rush Island).

41. As part of its economic evaluation, Ameren also compared the estimated costs of installing wet FGDs at Rush Island to the costs incurred by other electric utilities for wet FGD installations. Ameren concluded that the costs of installing FGDs at Rush Island would be consistent with the costs borne by the rest of the industry to install scrubbers. See February 5, 2010 Project Review Board Presentation-Rush Island FGD (Pl. Ex. 1100), at AM-REM-00289006; Staudt Test. Tr. Vol. 1-B, 23:10-25:16, 56:20-57:6; Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 90:6-91:3.

42. Ameren also told the Missouri Public Service Commission in a formal planning document that it planned to install scrubbers on Rush Island and Labadie. Michels Test., Tr. Vol. 5-B, 17:6-18:19.

43. Wet FGD is an economically and technically feasible control technology for Rush Island. Staudt Test., Tr. Vol. 1-B, 42:19-24, 48:22-49:11.

ii. Ameren's Studies Confirmed the SO_2 Emission Rates Achievable at Rush Island

44. To design an FGD system cost estimate, a study must define the emission rate requirements of the proposed system. Staudt Test., Tr. Vol. 1-B, 6:19-7:12, 25:19-26:4; Callahan Dep., Nov. 8, 2017, Tr. 92:12-93:3, 129:8-130:9.

45. During the first two phases of Ameren's FGD study efforts, Ameren's engineering firms based their design work and cost estimates on an SO_2 emission rate target of

0.06 lb/mmBTU. May 2010 Shaw Final Report (Pl. Ex. 1071), at AM-REM-00194954 to 194955; August 2010 Black & Veatch Execution Plan and Report (Pl. Ex. 1115), at AM-REM-00324205 to 324206; Staudt Test., Tr. Vol. 1-B, 26:5-27:4; Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 145:21-146:3, 147:21-147:24, 158:13-21, 161:2-21; Callahan Dep., Nov. 8, 2017, Tr. 51:9-15, 123:8-124:14.

46. Ameren initially transmitted this 0.06 lb/mmBTU design rate to its outside engineering firms on October 3, 2008. When it did so, Ameren requested that the engineers assess whether FGDs could be designed to achieve even greater SO_2 reductions. Oct. 3, 2008 Letter to Black & Veatch (Pl. Ex. 1086) (requesting an assessment of “maximum achievable design basis” for SO_2 removal, “even if greater than the design values”); Oct. 3, 2008 Letter to Stone & Webster (Shaw) (Pl. Ex. 1085) (same). Concurrently, Ameren instructed its engineering firms to use a slightly higher “operating” value of 0.08 lb/mmBTU, which would “represent permit requirements” for the FGDs. Id.; Callahan Dep., Nov. 8, 2017, Tr. 93:20-94:5, 123:8-124:14.

47. Depending on the fuel being burned, Ameren estimated that these emission rate targets would reflect removal efficiencies of up to 99%. If Rush Island continued to burn lower sulfur PRB coal, then a design emission rate of 0.06 lb/mmBTU would reflect a 95% SO_2 reduction, while an operating rate of 0.08 lb/mmBTU would reflect a 90% reduction. Mar. 2, 2009 Economic Value Analysis for Rush Island FGD Project Plan (Pl. Ex. 1023), at AM-02634848.

48. As part of its FGD study efforts, Ameren also obtained FGD proposals from all of the major FGD suppliers in the United States, all of whom indicated that they could supply an FGD system capable of meeting Ameren’s emission targets. Staudt Test., Tr. Vol. 1-B, 72:19-

73:24.

49. For example, the company Alstom submitted a wet FGD proposal to Ameren in May 2009. May 21, 2009 Alstom WFGD Indicative Submittal (Pl. Ex. 1068). At that time, Alstom had over 50,000 MW of wet FGD systems either operating or under contract. Id. at AM-REM-00191035. Alstom confirmed it could meet Ameren's emission requirements, id., and highlighted its experience with several relevant wet FGD projects for Rush Island:

- A wet FGD installed for a new 750-MW unit at the JK Spruce plant in 2009. The plant burns PRB coal and was provided an emission guarantee of 0.06 lb/mmBTU or 96% removal.
- Wet FGDs contracted to be installed on two existing 450-MW units at the Coronado plant. The plant burns PRB and was provided an emission guarantee of 0.04 lb/mmBTU or 97% removal.
- A wet FGD installed on an existing 720-MW unit at the Iatan plant in 2008. The Iatan plant is located in Missouri, burns PRB coal, and was provided an emission guarantee of 0.021 lb/mmBTU or 98% removal.

Id. at AM-REM-00191071-73; see also Staudt Test., Tr. Vol. 1-B, 74:4-76:9.

50. After the Phase 2 reports were finalized, Ameren began the specification development process for wet FGD at Rush Island. Aug. 5, 2010 Conference Mem. (Pl. Ex. 1088). The final specification was thousands of pages long and extremely detailed. Staudt Test., Tr. Vol. 1-B, 42:25-44:13; Construction Specification Section 1600—Design Basis (Pl. Ex. 1144).

51. As part of the specification development process, Ameren tasked a team of its engineers to confirm the emission rate targets for the FGDs and prepare the specification in coordination with Ameren's outside engineers. Stumpf Dep., Mar. 27, 2008, Tr. 63:21-64:15, 151:6-153:22, 154:11-17, 158:22-159:20.

52. As a result of the specification development process, on September 23, 2010, Ameren lowered its SO_2 emission rate requirements for the Rush Island FGDs to 0.04

lb/mmBTU. Sept. 23, 2010 Letter to Black & Veatch (Pl. Ex. 1076); Nov. 1, 2010 Conference Mem. (Pl. Ex. 1091), at AM-REM-00286756; Stumpf Dep., Mar. 27, 2008, Tr. 190:12-22, 198:2-8, 218:17-219:9, 238:11-19.

53. The 0.04 lb/mmBTU SO_2 emission rate was the same emission rate guarantee that Ameren obtained for the FGD installed in late 2010 at its Sioux plant. Staudt Test., Tr. Vol. 1-B, 71:13-20; Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 206:10-207:11, 208:6-9.

54. Based on the coal expected to be used at Rush Island, the 0.04 lb/mmBTU emission rate reflects SO_2 removal efficiencies of 95 to 97 percent. Nov. 17, 2010 Letter from BV to Ameren (Pl. Ex. 1174) at BV2_0204414-15; Staudt Test. Tr. Vol. 1-B, 44:14-46:4.

55. Ultimately, an emission rate of 0.04 lb/mmBTU was used as the design basis in the construction specification. Staudt Test., Tr. Vol. 1-B, 42:25-44:13; Construction Specification Section 1600—Design Basis (Pl. Ex. 1144), at AM-REM-00538825; see also Stumpf Dep., Mar. 27, 2008, Tr. 252:6-253:10, 254:9-23, 286:20-287:5. This rate was retained as the design basis until Ameren suspended the FGD project in September 2011. September 19, 2011 Project Plan (Pl. Ex. 1102), at AM-REM-00294511; Staudt Test., Tr. Vol. 1-B, 44:14-46:4; Stumpf Dep., Mar. 27, 2008, Tr. 286:20-287:5.

56. The pollution control experts in this case agree that an SO_2 emission rate of 0.04 lb/mmBTU would be an achievable design emission rate for a wet FGD at Rush Island. Staudt Test., Tr. Vol. 1-B, 46:5-8; Snell Test., Tr. Vol. 4-B, 51:13-52:16.

iii. Ameren's Studies Demonstrate How Quickly Wet FGD Can Be Installed

57. When Ameren suspended the Rush Island FGD project in September 2011, its engineers put into place a "reactivation plan" in case FGDs later became required. September 9, 2011 Project Plan (Pl. Ex. 1102) at AM-REM-00294510 ("The following link is to a document

that outlines instructions for reactivating the project including … an estimated schedule . . . [:] WFGD Specification Reactivation."); see also Staudt Test., Tr. Vol. 1-B, 46:9-47:23; Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 228:6-15.

58. Ameren's reactivation plan provided that the "Complete WFGD Specification turn-over from Shaw" should be "considered the starting point for picking up where the original [FGD] team left off." WFGD Specification Reactivation Instructions (Pl. Ex. 1141).

59. The reactivation plan also included a schedule for completing the project upon reactivation. The plan provided that, upon reactivation, engineers would need two weeks to verify the chosen SO_2 technology (wet FGD). If the technology selection changed, engineers would need an additional ten weeks to create a new specification. After management approval, Ameren could send the project to FGD suppliers for bid within six months from re-activation (which was May 2016, under the then-proposed schedule). September 19, 2011 Project Plan (Pl. Ex. 1102), at AM-REM-00294512, AM-REM-00294580. Based on that schedule, the FGD could have been "on-line" by the end of 2020, representing a four and one-half-year process from the time of reactivation. Id.

60. This reactivation plan allows Ameren to install FGD controls more quickly by taking advantage of all the resources already invested in engineering wet FGDs for Rush Island. Staudt Test., Tr. Vol. 1-B, 46:18-48:6. By the time the project was suspended, Ameren had invested 3 years of engineering work and approximately $8 million on the project. September 19, 2011 Project Plan (Pl. Ex. 1102), at AM-REM-00294508; see also Stumpf Dep., Mar. 27, 2008, Tr. 64:21-65:2, 291:18-292:19.

61. Company documents refer to the "[e]ngineering activities for Rush Island FGD" as "a significant risk mitigation strategy in terms of cost and schedule." 2010 Project Review

Board Presentation—Rush Island FGD (Pl. Ex. 1100), at AM-REM-00289019; see also, e.g., Ex. 1095, at AM-REM-00288487 ("Continuing with engineering activities for Rush Island FGD is a risk mitigation strategy for both cost and schedule."). The "risk" was the possibility that FGDs could be required by various drivers. Ameren's "response" was to "[g]et an early start on engineering in order to act as quickly as possible." Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 44:21-45:10, 47:24-48:13, 48:16-49:12, 101:18-103:1.

62. In light of the extensive amount of engineering work already completed, I find that Ameren would be able to install FGDs at Rush Island within four and one-half years from the date of the requirement to do so. September 19, 2011 Project Plan (Pl. Ex. 1102), at AM-REM-00294512, AM-REM-00294580 (May 2016 reactivation date and December 2020 online date).

II. RUSH ISLAND'S VIOLATIONS HAVE LED TO MORE THAN 162,000 TONS OF EXCESS SULFUR DIOXIDE POLLUTION

63. At the time Rush Island's boilers were modified, the surrounding airshed had attained the NAAQS for fine particulate matter, a key by-product of SO_2. Morris Test., Tr. Vol. 4-B, 69:4-24. Although part of Jefferson County is currently a non-attainment area for SO_2 itself, at the time of the modifications at Rush Island, it was in attainment of the SO_2 NAAQS. Therefore, the requirement to obtain a PSD permit and meet BACT emissions limitations applied to Rush Island. Ameren Missouri, 229 F.Supp.3d at 986; 42 U.S.C. §§ 7471, 7475.

64. Missouri is the PSD permitting authority for facilities in Missouri, pursuant to an EPA-approved State Implementation Plan, and is subject to EPA oversight. Knodel Test., Tr. Vol. 1-A, 45:2-23, 79:10-17; MDNR Rule 30(b)(6) Dep., Aug, 10, 2018, Tr. 101:13-15.

a. PSD Requires the Best Available Control Technology

i. BACT Determination Is a Five-Step Process

65. Missouri and the EPA use the same definition of BACT, which applies to both new and modified sources. Campbell Test., Tr. Vol. 4-A, 90:24-91:6.

66. BACT is "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation . . . which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility . . . ." 42 U.S.C. § 7479(3); Knodel Test., Tr. Vol. 1-A, 38:11-41:13.

67. An applicant for a PSD permit bears the responsibility when submitting its application of addressing all the steps in the BACT analysis. Knodel Test., Tr. Vol. 1-A, 51:19-23.

68. The permitting authority reviews each submission and determines if the analysis is correct. If the applicant's BACT analysis is incorrect, the permitting authority modifies the analysis to arrive at the appropriate BACT emissions limitation. In this case, Ameren should have prepared the initial BACT analysis, but the final BACT determination would have been made by MDNR with EPA oversight. Knodel Test., Tr. Vol. 1-A, 44:18-45:23, 53:11-54:18; Dec. 1, 1987 Memo on Improving NSR Implementation (Pl. Ex. 1320) at Campbell_EXP_0039928.

69. Because BACT requires "the maximum degree of reduction," BACT rates tend to get more stringent over time as pollution control technologies improve. Staudt Test., Tr. Vol. 1-B, 70:10-14, 80:23-81:3.

70. The EPA's Draft NSR Workshop Manual ("NSR Manual") outlines the BACT analysis process used by most permitting authorities, including MDNR. Knodel Test., Tr. Vol.

1-A, 48:12-20, 49:23-26, 50:2-6; MDNR Rule 30(b)(6) Dep., Aug. 10, 2018, Tr. 140:3-21.

71. The NSR Manual is the most commonly-referenced, commonly used guidance document for BACT analyses in the country. It is the most widely-distributed guidance relating to NSR that is not the regulations themselves. Campbell Test., Tr. Vol. 4-A, 90:4-10; see also id. at 88:17-89:19 (Ameren expert explaining that he provides a copy of the NSR Manual to participants in his BACT course, which focuses on the top-down method).

72. MDNR permit engineers rely on the NSR Manual in doing PSD reviews. MDNR Rule 30(b)(6) Dep., Aug. 10, 2018, Tr. 140:3-21.

73. Determining BACT involves a five-step, top-down process. Knodel Test., Tr. Vol. 1-A, 50:2-6; NSR Manual (Pl. Ex. 1190), at AM-REM-00544123-MDNR; MDNR Rule 30(b)(6) Dep., Aug. 10, 2018, Tr. 101:25-102:24, 106:4-7.

74. As part of the five-step process, the permit applicant

a. [Step One] Identifies all relevant control technologies for reducing the pollutant at issue, Knodel Test., Tr. Vol. 1-A, 50:7-16; NSR Manual (Pl. Ex. 1190), at AM-REM-00544123-MDNR.

b. [Step Two] Removes any technologies that are not technically feasible for the project in question, Knodel Test., Tr. Vol. 1-A, 50:17-24; NSR Manual (Pl. Ex. 1190), at AM-REM-00544123-MDNR,

c. [Step Three] Ranks the remaining technologies in order of control effectiveness, Knodel Test., Tr. Vol. 1-A, 50:25-51:10; NSR Manual (Pl. Ex. 1190), at AM-REM-00544123-MDNR,

d. [Step Four] Evaluates the technologies in sequence, from most effective to least effective, and selects the most effective technology that is achievable based on energy, environmental, and economic impacts and other costs, Knodel Test., Tr. Vol. 1-A, 51:11-13, 80:8-81:3; NSR Manual (Pl. Ex. 1190), at AM-REM-00544123-MDNR, and

e. [Step Five] Selects an emissions limitation rate based on the design and performance of other pollution sources that have already installed the control technology. Knodel Test., Tr. Vol. 1-A, 51:14-18; NSR Manual (Pl. Ex. 1190), at AM-REM-00544123-MDNR.

75. Step Four of the method gives the BACT determination a "top-down" character, because it starts with the top control option and moves in sequence to lesser options. If the energy, environmental, and economic impacts of the top option indicate that the technology is "achievable," then the analysis stops: the top control is the BACT technology. If the top control is not achievable, the next most-stringent control options are considered in sequence, until an achievable technology is settled on. Staudt Test., Tr. Vol. 1-B, 53:16-54:21; Campbell Test., Tr. Vol. 4-A, 92:20-25; NSR Manual (Pl. Ex. 1190), at AM-REM-00544119-MDNR. Again, as soon as an achievable technology is found in this sequence, the analysis stops, and that technology determines BACT.

76. The top-down approach applies regardless of whether a plant is new or is undergoing a modification. Knodel Test., Tr. Vol. 1-A, 106:20-25. Under the top-down approach, the burden of proof is on the applicant to justify why the proposed source is unable to apply the best technology available. Dec. 1, 1987 Memo on Improving NSR Implementation (Pl. Ex. 1320) at Campbell_EXP_0039928; Knodel Test., Tr. Vol. 1-A, 44:5-17.

77. Almost all Clean Air Act permitting agencies, including the Missouri Department of Natural Resources (MDNR), use the top-down method that is set forth in the

EPA's 1990 New Source Review Workshop Manual. Campbell Test., Tr. Vol. 4-A, 48:7-16, 90:20-23; Knodel Test., Tr. Vol. 1-A, 49:21-50:1, 79:22-80:2.

Cost-Effectiveness Calculations in a Top-Down BACT Analysis

78. Cost is one of several criteria considered in Step 4 of the BACT process, where applicants determine whether each control technology is achievable. Knodel Test., Tr. Vol. 1-A, 80:8-81:3.

79. However, step four of the BACT process is not a search for the most cost-effective controls; nor is it a cost-benefit analysis. Id.; Staudt Test., Tr. Vol. 1-B, 58:5-16. Rather, cost considerations are measured by what is achievable. 42 U.S.C. § 7479(3). "In the absence of unusual circumstance, the presumption is that sources within the same source category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category." NSR Manual (Pl. Ex. 1190), at AM-REM-00544146-MDNR; Staudt Test. Vol. 1-B, at 63:14-64:6.

80. Similar language is found elsewhere in the NSR Manual: "BACT is required by law. Its costs are integral to the overall cost of doing business . . . Thus, where a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant costs differences, if any, between the application of the control technology on those other sources and the particular source under review." NSR Manual (Pl. Ex. 1190) at AM-REM-00544148-MDNR.

81. MDNR specifically relies on the NSR Manual's guidance in considering the economic impacts of pollution controls under a BACT analysis. Staudt Test., Tr. Vol. 1-B, 64:7-10; Norborne PSD Permit (Pl. Ex. 1180), at AM-REM-00503313-MDNR (quoting NSR Manual); see also MDNR Rule 30(b)(6) Dep., at 138:20-139:6, 140:22-141:22) (MDNR witness

testifying that "when a permit writer looks at a permit application from, for example, a coal-fired utility, [] they would look towards other coal-fired utilities to determine the appropriate controls and what controls are already being used"). The focus is on other sources in the same source category, because they would face similar technical and economic circumstances. Staudt Test., Tr. Vol. 1-B, 64:11-19.

ii. Cost-Effectiveness Does Not Determine BACT

82. As one criterion under step four of the top-down method, applicants can also prepare calculations of cost-effectiveness. Average (or total) cost-effectiveness measures the cost of a control option in annualized costs per ton of pollution that it would reduce in a year. Staudt Test., Tr. Vol. 1-B, 57:19-58:4; NSR Manual (Pl. Ex. 1190), at AM-REM-00544153-MDNR to 544154-MDNR.

83. In contrast, incremental cost-effectiveness compares how much each additional ton of reduction costs as compared to another control option. Campbell Test., Tr. Vol. 4-A, 114:19-115:7. Staudt Test., Tr. Vol. 1-B, 92:1-14; NSR Manual (Pl. Ex. 1190), at AM-REM-00544158. Incremental cost-effectiveness is useful when comparing technologies "next" to each other in the effectiveness rankings, provided those controls result in similar emission rates. Staudt Test., Tr. Vol. 1-B, 92:15-23, NSR Manual (Pl. Ex. 1190), at AM-REM-00544158-MDNR ("The incremental cost effectiveness calculation compares the costs and emissions performance level of a control option to those of the next most stringent control option …") (emphasis added).

84. The NSR Manual cautions against over-reliance on incremental cost-effectiveness in eliminating a control under Step Four of the top-down method. Pl. Ex. 1190, at AM-REM-00544163-MDNR ("[U]ndue focus on incremental cost effectiveness can give an impression that

the cost of a control alternative is unreasonably high, when, in fact, the cost effectiveness, in terms of dollars per total ton removed, is well within the normal range of acceptable BACT costs."); see also In re General Motors, Inc., PSD Appeal No. 01-30, 10 E.A.D 360, 371 (E.A.B. Mar. 6, 2002) (the NSR Manual "places primary stress on the average cost measure").

iii. NSPS Do Not Fundamentally Alter the BACT Process

85. Alongside BACT requirements, all new major sources of pollution must meet "New Source Performance Standards" (NSPS). Pursuant to Section 111 of the Clean Air Act, the EPA establishes NSPS for different source categories. See 42 U.S.C. § 7411.

86. Ameren's expert admitted that the EPA sets the NSPS at rates that can be reasonably met by all new and modified sources in a source category, even though individual sources might be capable of lower emission rates. Campbell Test., Tr. Vol. 4-A, 98:14-18.

87. An applicable NSPS serves as a "floor" for the emission limit established as BACT. The BACT limit cannot be less stringent than the NSPS. 42 U.S.C. § 7479(3); In re Columbia Gulf Transm'n Co., PSD Appeal No. 88-11, 2 E.A.D. 824, 1989 WL 266361, at *4 (EPA 1989).

88. As the NSR Manual explains: "[T]he only reason for comparing control options to an NSPS is to determine whether the control option would result in an emission level less stringent than the NSPS. If so, the option is unacceptable." Ex. 1190, at AM-REM-00544129-MDNR (emphasis added).

89. "Simply meeting or exceeding the NSPS does not attest to the correctness of a BACT determination." Columbia Gulf, 1989 WL 266361, at *4. That NSPS sets "a 'floor' on emissions does not fundamentally change the BACT process of determining the 'best' available technology." United States v. Ameren Missouri, No. 4:11 CV 77 RWS, 2019 WL 1384631, at *3 (E.D. Mo. Mar. 27, 2019) (citing Columbia Gulf at *4).

90. The top-down method was originally developed in response to concerns that BACT analyses were inappropriately defaulting to the less-stringent and generally-applicable NSPS standards, without giving enough consideration to more stringent control options required for BACT. Knodel Test., Tr. Vol. 1-A, 47:14-48:9; June 13, 1989 Statement on Top Down BACT (Pl. Ex. 1321), at Campbell_EXP_0040089.

b. FGD Scrubbers Constitute BACT for the Vast Majority of Pulverized Coal-Fired Power Plants

i. The Electric Power Utility Industry Recognizes That FGD Constitutes BACT

91. BACT for a pulverized coal-fired power plant generally requires either wet or dry FGD scrubbers. Staudt Test., Tr. Vol. 1-B, 95:1-12. This trend results from the top-down process: scrubbers are the most-effective pollution controls. As the industry has progressed, an increasing number of plants have used scrubbers, demonstrating their achievability in different circumstances. See, e.g., supra Figure 1; ¶ 14.

92. As Ameren's Senior Director of Engineering and Project Management, Duane Harley, explained: "There's lots of different types of scrubbers in the market. Any one of those could be considered BACT. … Could be wet. Could be dry." According to Harley, dry scrubbers would be preferred in arid locations such as the West and wet scrubbers would typically be installed on plants that are larger than 300 MW. Harley Dep. Tr., Apr. 11, 2018, 97:5-98:8.

93. The electric power utility industry recognizes that FGD constitutes BACT for coal-fired units. In March 2008, the Electric Power Research Institute published a report on the performance capability of FGD systems. Staudt Test., Tr. Vol. 1-B, 85:7-86:19; see also supra Footnote 3. The report noted: "Many coal-fired units must comply with the Clean Air Act

(through New Source Review), consent decrees, or the Clean Air Visibility rules. Operators of these units have or will have to commit to installing FGD systems that meet the regulatory requirements of best available control technology (BACT) … .” 2008 EPRI Report (Pl. Ex. 1045), at AM-02699795.

94. Ameren itself has acknowledged that BACT may require FGD at Rush Island. Specifically, an Ameren presentation prepared in 2011 for the Missouri Public Service Commission indicates: “New Source Review lawsuit by EPA may require flue gas desulfurization (FGD) systems or scrubbers at Rush Island.” April 2011 Presentation: Ameren Missouri Long Term Low Sulfur Coal Supply (Pl. Ex. 1009), at AM-02225205. It is well-understood that BACT at Rush Island would likely require installing scrubbers.

ii. During The Past Twenty Years, Every BACT SO_2 Determination for a Pulverized Coal-Fired Power Plant Has Required FGD

95. The prevalence of FGD at other plants is demonstrated by databases maintained by EPA Headquarters and Region 7. EPA Headquarters maintains a RACT BACT LAER Clearinghouse (RBLC) with a searchable database of BACT permit decisions made throughout the United States. The RBLC catalogues permitted technology and emissions limitations for individual facilities. Knodel Test., Tr. Vol. 1-A, 52:5-53:7.

96. From about 2002 until about 2015, EPA Region 7 also maintained a New Source Review Electricity Generating Unit Coal-Fired Spreadsheet on its website. The spreadsheet was designed to include every NSR application that had been submitted across the United States. It included information such as unit size, type of controls, and BACT limits. Knodel Test., Tr. Vol. 1-A, 34:20-35:8, 52:24-53:10.

97. Every BACT determination for SO_2 emissions from pulverized coal-fired power plants during the past twenty years has required wet or dry FGD as the required pollution control

technology. Staudt Test., Tr. Vol. 1-B, 77:20-78:2.

98. During this period, MDNR determined that BACT at a coal-fired power plant in Southwest Missouri requires the use of FGD controls for SO_2. Chipperfield v. Mo. Air Conservation Comm'n, 229 S.W.3d 226, 240 (Mo. Ct. App. 2007). As noted by the Missouri Court of Appeals in a decision upholding MDNR's BACT determination: "In general, pulverized coal-fired boilers burning low-sulfur coal, such as Powder River Basin ('PRB') coal, may use dry FGD, while boilers burning high-sulfur coals, such as eastern bituminous coal, must use wet FGD." Id.

99. EPA expert Jon Knodel is an environmental engineer with EPA Region VII who reviews permits for coal-fired power plants in Missouri. Id. at 32:17-20, 54:3-55:3. Based on Knodel's count, between 1999 and 2008, MDNR issued four air permits for coal-fired power plants. Knodel Test., Tr. Vol. 1-A, 54:22-55:3. All of these required either wet or dry FGD as the SO_2 control technology. Id. at 57:23-58:2, 59:10-15, 59:18-60:21, 60:24-61:3.

100. In 1999, MDNR issued a PSD permit to Kansas City Power and Light's Hawthorn plant with a 30-day SO_2 BACT limit of 0.12 lb/mmBTU, based on the use of a dry FGD. Knodel Test., Tr. Vol. 1-A, 59:10-17.

101. In 2004, MDNR issued a PSD permit for City Utilities' proposed Southwest power plant with a 30-day SO_2 limit of 0.095 lb/mmBTU, based on the use of dry FGD. Knodel Test., Tr. Vol. 1-A, 55:4-58:2; Dec. 15, 2004 Permit to Construct (Pl. Ex. 1004), AM-00134223-EPA, AM-00134224-EPA; see also Chipperfield, 229 S.W.3d at 240 (describing determination of BACT rate). In doing so, MDNR explicitly found that the costs of both wet and dry FGD were reasonable. Staudt Test., Tr. Vol. 1-B, 67:3-68:13; In the Matter of Appeal of City Utilities PSD Permit, 10/11/05 Hr'g Tr. (Pl. Ex. 1177) at 16:18-17:16.

102. In 2006, MDNR issued a permit for Kansas City Power and Light's Iatan power plant with 30-day SO_2 limits of 0.1 lb/mmBTU for the existing unit (Unit 1) and 0.09 lb/mmBTU for the new unit (Unit 2), based on the use of wet FGD at both units. Knodel Test., Tr. Vol. 1-A, 59:18-60:9; Jan. 31, 2006 Permit to Construct (Pl. Ex. 1034), at AM-02693650-53. After these permit limits were challenged by a third party, an amended permit was issued in 2007 with lower SO_2 limits of 0.07 lb/mmBTU for Unit 1 and 0.06 lb/mmBTU for Unit 2. Knodel Test., Tr. Vol. 1-A, 60:10-21; July 13, 2007 Amendment to Permit (Pl. Ex. 1283), at AMEREM_JES0007121-25; Staudt Test., Tr. Vol. 1-B, 81:20-82:13.

103. In 2008, MDNR issued a PSD permit to Associated Electric Cooperative, Inc. (AECI) for the proposed Norborne plant with 30-day SO_2 limits of 0.07 to 0.08 lb/mmBTU, based on the use of dry FGD. Knodel Test., Tr. Vol. 1-A, 60:22-61:3; Feb. 22, 2008 Letter Enclosing Permit to Construct (Pl. Ex. 1180), at AM-REM-00503274-MDNR to 3275-MDNR.

104. These Missouri permit limits are consistent with those issued by other permitting authorities for coal-fired power plants during the same period, all of which also required the use of wet or dry FGD. Staudt Test., Tr. Vol. 1-B, 77:20-78:2.

105. For example, Ameren's expert Colin Campbell testified about a PSD permit issued for the following non-Missouri plants: (1) In 2005, Newmont's TS power plant was permitted for an SO_2 limit of 0.065 lb/mmBTU; (2) in 2007, LS Power's Longleaf power plant was permitted for the same emission rate (0.065 lb/mmBTU); and (3) also in 2007, Basin Electric's Dry Fork power plant in Wyoming was permitted for an SO_2 limit of 0.07 lb/mmBTU. <u>See</u> Campbell Test., Tr. Vol. 4-A, 107:13-108:4, 131:17-132:1.

c. The Parties' Competing BACT Analyses

106. During trial, the parties each presented expert testimony concerning what BACT

would have been at the time that Ameren modified Rush Island. Based on what BACT would have been, I can determine how much SO_2 Ameren would have emitted had it complied with the law. Then, I can subtract that lower pollution amount from the SO_2 emissions that were actually released to determine Rush Island's "excess emissions." For clarity, I refer to this determination as a "historic BACT analysis." According the correct historic BACT analysis, Ameren's failure to install scrubbers at Rush Island resulted in 162,000 tons of excess SO_2 emissions through the end of 2016. The excess emissions are a measure of the harm suffered by Plaintiffs because of Ameren's violation of the Clean Air Act.

107. In support of their proposed historic BACT analysis, Plaintiffs presented the expert testimony of Dr. James Staudt. Dr. Staudt has a bachelor's degree in mechanical engineering from the Naval Academy and a Ph.D in mechanical engineering from Massachusetts Institute of Technology. Staudt Test., Tr. Vol. 1-B, 4:25-5:6. Dr. Staudt has decades of experience in the air pollution control industry, first working for supply companies and then later as a consultant on control technology issues for government agencies and industry clients. Id. at 5:20-11:14. Because of his work, Dr. Staudt has been familiar with the BACT requirements for decades, and has previously been accepted as an expert on SO_2 BACT issues in United States v. Westvaco, No. MGJ-00-2602 Trial Transcript, ECF No. 985-4 at 8:19-9:23; id. at 10:12-11:14.

108. Dr. Staudt conducted two BACT analyses using the five-step process: one to determine historic BACT and a second to determine current BACT. Staudt Test., Tr. Vol. 1-B, 49:12-50:1.

109. In conducting his historic BACT analysis, Dr. Staudt considered (1) the engineering analyses and cost estimates prepared for Ameren's Rush Island FGD studies discussed above in Section I.d, (2) vendor proposals, (3) relevant BACT determinations reported

in the EPA Clearinghouse, (4) contemporaneous Missouri permits for coal-fired power plants, (5) industry performance data for scrubbers, and the (6) 0.04 lb/mmBTU SO_2 performance guarantee that Ameren obtained for the FGD system installed at its Sioux power plant. Staudt Test., Tr. Vol. 1-B, 35:23-36:6. 71:2-72:14, 76:10-77:19.

110. To challenge Dr. Staudt's testimony, Ameren presented the expert testimony of Colin Campbell. Campbell is a permit engineer with a bachelor's degree in mechanical engineering and economics from North Carolina State University. Campbell Test., Tr. Vol. 4-A, 39:12-16. Campbell teaches courses for agency employees and permit engineers on NSR issues, including a course on how to do a BACT analysis. Campbell Test., Tr. Vol. 4-A, 40:9-13, 40:24-41:25, 88:17-89:19.

111. Campbell performed an analysis of what BACT would be for Rush Island today. He did not conduct a historic BACT analysis. Instead, he assumed that historic BACT would have been the same as current day BACT. Campbell Test., Tr. Vol. 4-A, 94:12-95:5.

112. For both historic and current BACT, Campbell testified that Ameren could satisfy the law by installing DSI. According to Campbell, if Rush Island were permitted today, MDNR would set an emission rate of 0.275 lb/mmBTU, based on a DSI system with 50% SO_2 reduction. Campbell Test., Tr. Vol. 4-A, 69:10-22.

113. Campbell reached this determination by 1) ranking wet FGD, dry FGD, DSI with a fabric filter, and DSI without a fabric filter, in that order, 2) eliminating dry FGD and DSI with a fabric filter because they were too expensive, 3) calculating the incremental cost effectiveness between wet FGD with DSI without a fabric filter, 4) rejecting wet FGD because MDNR would find its incremental cost effectiveness too expensive, and 5) selecting the remaining option: DSI without a fabric filter.

114. I carefully observed and reviewed Campbell's and Dr. Staudt's conflicting testimony to determine their credibility. Based in part on the following credibility findings, I make factual findings concerning BACT for Rush Island in Section III.

d. Campbell's Testimony Rejecting Wet FGD and Choosing DSI Was Not Credible

115. Ameren primarily relies on Colin Campbell's expert testimony to argue that DSI constitutes BACT. Campbell testified that wet FGD's incremental cost effectiveness was too high for wet FGD to be BACT. Campbell Test., Tr. Vol. 4-A, at 97:21-98:7. Campbell further testified that Ameren should be able to come into compliance with the PSD program without obtaining a PSD permit. Id. at Tr. Vol. 4-A, 132:2-5.

116. Before trial, the EPA made a Daubert challenge to exclude these opinions. The EPA argued that Campbell's methods were unreliable because he did not follow the five-step process laid out in the NSR manual, among other arguments. I denied the EPA's motion because I could not say that Campbell's opinion was so unreliable as to be unhelpful to the trier of fact. United States v. Ameren Missouri, No. 4:11 CV 77 RWS, 2019 WL 1384580, at *3 (E.D. Mo. Mar. 27, 2019). However, I explained that Campbell's opinion would be more credible if he had completed and documented the five-step process used by permitting authorities across the country. Id. I noted that

> [Campbell's] methods depart significantly from the five-step process used in preparing a permit application or supporting documents. (Campbell deposition, filed under seal at ECF No. 968-5 at 196:11-18). Most importantly, Campbell eliminated the second-highest and third-highest ranking options before evaluating the first-highest ranking option. As a result, Campbell's incremental cost effectiveness compared the highest and lowest ranking options. This error violates Campbell's own advice to permit engineers. (BACT workshop presentation, filed under seal at ECF No. 970 at 3, 5-6). In his BACT workshop presentation, Campbell explained that incremental cost effectiveness should be performed between the "'dominant' control option [and] the next most stringent option." (Id. at 3). He cautioned that incremental cost is appropriate when "[D]ominant control

> options have similar average cost effectiveness numbers" or similar emission rate reductions. (Id. at 5).

Id. at *2.

117. Having now heard Campbell's testimony during trial, I will give little weight to his testimony because of flaws in his economic analysis, inconsistencies in his statements at trial, and his mischaracterization of how NSPS factors into the BACT process.

i. Campbell Overly Relied on Incremental Cost Effectiveness at Rush Island

118. Campbell's BACT determination hinges upon on his incremental cost effectiveness analysis. Campbell rejected wet FGD because it purportedly had an incremental cost effectiveness of $9,500/ton, well above the $6,800/ton limit he inferred from reviewing PSD permits issued by MDNR. Campbell Test., Tr. Vol. 4-A, 84:9-25.

119. Campbell did not reach any conclusions in this case about whether the average cost-effectiveness of wet FGD at Rush Island would represent unreasonable economic impacts for Ameren. Id. at 115:8-116:17.

120. As a general matter, Campbell's heavy reliance on incremental cost-effectiveness, without consideration of average cost-effectiveness, is inconsistent with BACT permitting practices. The NSR manual explains that "undue focus on incremental cost effectiveness can give an impression that the cost of a control alternative is unreasonably high, when, in fact, the cost effectiveness, in terms of dollars per total ton removed, is well within the normal range of acceptable BACT costs." NSR Manual (Pl. Ex. 1190), at AM-REM-00544163-MDNR.

121. Additionally, Campbell's testimony concerning incremental cost effectiveness was not credible for the following reasons: (1) he included non-comparable cost categories

when comparing wet FGD at Rush Island to MDNR's past permit decisions; (2) he compared the most effective with the least effective technology when calculating incremental cost effectiveness; (3) his cost thresholds are not supported by the MDNR permits he cites; and (4) he ignored the presumption that facilities in the same source category can bear the same costs.

122. Each of these flaws was necessary to Campbell's decision to reject wet FGD. Together they demonstrate that Campbell's cost analysis of wet FGD is not credible. Accordingly, I give little weight to Campbell's testimony rejecting wet FGD.

ii. Campbell's Cost Comparisons Include Cost Categories Not Included in Other Plants' BACT Determinations

123. To calculate incremental cost-effectiveness, Campbell relied on wet FGD cost estimates provided by Kenneth Snell, Ameren's control costs expert. Snell estimated that installing wet FGD at Rush Island would cost $896 million in 2016 dollars or $1 billion in 2025 dollars. Snell Test., Tr. Vol. 4-B, 28:1-9, 28:24-29:10.

124. In contrast, the EPA's expert Dr. Staudt estimated that installing wet FGDs at Rush Island would cost $582 million in 2016 dollars. Dr. Staudt based his estimate on costs included in Ameren's engineering studies, but he subtracted a set of variable costs normally excluded from comparative cost estimates. Under this "overnight" cost methodology, Dr. Staudt excluded the Allowance for Funds Used During Construction (or AFUDC), an inflation-like metric called escalation, overhead, and property taxes. Staudt Test., Tr. Vol. 1-B, 59:24-61:5; Tr. Vol. 2-A, 25:25-26:6, 28:18-30:18.

125. Snell's cost estimate differs from Dr. Staudt's estimate because Snell included $150 million for financing,[5] $64 million for escalation, $44 million for overhead, and $22 million for property taxes. Snell Test., Tr. Vol. 4-B, 57:19-59:25; Ex. HW, Ex. HX.

[5] Specifically, Snell calculated $150 million in AFUDC, the financing charge incurred over the time it takes to complete a project. Staudt Test., Tr. Vol. 1-B, 24:7-24; Vol. 2-A, 30:1-18.

126. Traditionally, these costs are excluded from cost comparisons across power plant and control technologies because they are extrinsic to the technologies themselves and vary dramatically. For example, different companies have different cost recovery rates and execute projects on different timelines. Excluding extrinsic costs allows for a more consistent way to compare costs across the industry. Staudt Test., Tr. Vol. 1-B, 24:7-24; Vol. 2-A, 30:1-18.

127. When Ameren conducted its own economic analysis comparing the costs of wet FGDs at Rush Island to others in the industry, it did not include AFUDC in its estimates. See February 5, 2010 Project Review Board Presentation—Rush Island FGD (Pl. Ex. 1100), at AM-REM-00289006.

128. Dr. Staudt's decision to remove the extrinsic expenses for the purpose of comparing project costs was not refuted by Snell or any of Ameren's other witnesses. Snell testified that he was "not offering an opinion as to whether or not it's appropriate to include [AFUDC or escalation] costs for the purposes of a BACT analysis." Snell Test., Tr. Vol. 4-B, 50:4-6. "[His] opinion is . . . the real costs that Ameren would incur if they were to install these technologies." Id. at 50:6-7.

129. Because Dr. Staudt's testimony concerning the appropriateness of excluding extrinsic expenses is uncontested, and I find Dr. Staudt's testimony to be credible, I also find that Dr. Staudt correctly excluded these extrinsic expenses from his BACT analysis.

130. In contrast, Snell used the total project costs, including the expenses Dr. Staudt excluded, to compare the cost of installing FGD at Rush Island to the costs at facilities featured in other permit determinations made by MDNR. In making this comparison, Snell should have instead relied on the cost calculating conventions normally used in BACT determinations.

131. When calculating incremental and average cost effectiveness between the various pollution control options for Rush Island, Campbell also should have excluded these variable costs.

132. Campbell did not ask Snell whether Snell's total cost estimates would be appropriate to use in conducting a BACT analysis. Snell Test., Tr. Vol. 4-B, 49:13-25.

133. I find that it was inappropriate for Campbell to rely on Snell's total cost estimates for purposes of doing a BACT analysis for Rush Island.

iii. Campbell's Incremental Cost Effectiveness Analysis Was Inconsistent With His Prior Trainings and Advice

134. To determine the incremental cost effectiveness at Rush Island, Campbell compared the per-ton cost of FGD with the per-ton cost of DSI.

135. Incremental cost effectiveness is appropriate for BACT determinations when the two compared technologies rank directly adjacent to each other in their effectiveness. See United States v. Ameren Missouri, No. 4:11 CV 77 RWS, 2019 WL 1384580, at *2 (E.D. Mo. Mar. 27, 2019), (citing In re General Motors, Inc., No. 27947, 10 E.A.D. 360, 2002 WL 373983 ,*9); see also Staudt Test., Tr. Vol. 1-B, 92:25-93:15; Campbell Test., Tr. Vol. 4-A, 119:16-18; NSR Manual (Pl. Ex. 1190), at AM-REM-00544158-MDNR ("The incremental cost effectiveness calculation compares the costs and emissions performance level of a control option to those of the next most stringent option") (emphasis added).

136. Additionally, the two compared technologies should have similar levels of effectiveness. Staudt Test, Tr. Vol. 1-B, 92:25-93:15. By following these rules, permit applicants can identify technologies that are unnecessarily expensive relative to similarly or equally effective technologies. Technologies with very different effectiveness should not be used for incremental cost effectiveness; the more effective technology is better. See id. at 92:15-23; NSR

Manual (Pl. Ex. 1190), at AM-REM-00544158-MDNR

137. Campbell ignored both of these conventions. First, he compared the most effective technology, wet FGD, with the least effective technology, DSI. The two are not ranked adjacent to each other. Second, wet FGD and DSI have do not have similar levels of effectiveness; the two have dramatically different levels of effectiveness. Staudt Test., Tr. Vol. 1-B, 92:25-93:15. Specifically, Campbell compared a wet FGD capable of achieving SO_2 reductions of more than 90% to a DSI system that can only achieve 50% reductions and an emission rate 5 ½ times higher than what could be achieved by the top controls. Campbell Test., Tr. Vol. 4-A, 118:24-119:15.

138. Campbell's comparison of wet FGD and DSI is inconsistent with his own guidelines used outside of litigation and the guidelines used by other practitioners. See Campbell Test., Tr. Vol. 4-A, 117:15-118:20 (discussing inconsistencies between Campbell's method in this case and his training materials).

139. Campbell now purportedly "vigorously" disagrees that incremental cost-effectiveness should be reserved for control technologies with similar reduction capabilities. Campbell Test., Tr. Vol. 4-A, 70:9-19.

140. Nonetheless, I find Campbell's testimony on the incremental cost comparison between wet FGD and DSI to be not credible, as it is inconsistent with established standards in the field and even his own past work.

iv. Campbell's Cost Threshold Opinion Is Unsupported

141. Campbell ultimately rejected wet FGD as BACT because its incremental cost effectiveness exceeded a threshold he inferred from MDNR and other permitting authorities' determinations. Campbell Test., Tr. Vol. 4-A, 119:19-120:3. Campbell's testimony on this point

was inconsistent, unsupported, and not credible.

142. Specifically, Campbell testified that permitting authorities across the country, and MDNR specifically, apply a "de facto line at $5,000" per ton for incremental cost-effectiveness. Campbell Test., Tr. Vol. 4-A, 61:8-9, 62:19-22, 67:4-12, 119:9-120:3, 121:14-17. Campbell testified on direct that permitting authorities will reject control technologies above this threshold.

143. On cross-examination, however, Campbell admitted that permitting authorities have accepted technologies with incremental cost-effectiveness values of $10,000/ton. Id. at 120:11-23.

144. Campbell also admitted he was only speculating when he said MDNR had a threshold at $5,000. He later testified that the limit in Missouri was actually $6,800/ton. Id. at 121:18-21.

145. According to Campbell, four Missouri permits supported his purported $6,800/ton threshold: Continental, Noranda, Norborne, and Southwest. Nothing in these permits actually establishes this limit. Staudt Test., Tr. Vol. 1-B, 93:16-22.

146. Two of these permits (Continental and Noranda) relate to, respectively, a cement plant and an aluminum smelter. Permits in these source categories are minimally relevant to a BACT determination at a pulverized coal-fired power plant. Campbell Test., Tr. Vol. 4-A, 111:5-113:9; Staudt Test., Tr. Vol. 1-B, 91:9-25; MDNR Rule 30(b)(6) Dep., Aug. 10, 2018, Tr. 137:24-142:3. Unlike power plants, it is "very unusual" for cement plants to use FGDs. Cement plants have "a great deal of intrinsic SO_2 capture" built into their process because SO_2 is a useful ingredient in their product. Staudt Test., Tr. Vol. 1-B, 91:9-25.

147. Additionally, the Noranda permit did not discuss incremental cost-effectiveness in its BACT analysis. Campbell admitted this fact on cross examination. Campbell Test., Tr. Vol.

4-A, 121:23-122:12. Therefore, the Noranda permit does not support Campbell's purported $6,800 threshold.

148. For the remaining two permits (Norborne and Southwest), Campbell admitted on cross-examination that the incremental cost-effectiveness values presented in those decisions "didn't much factor into the analysis." Campbell Test., Tr. Vol. 4-A, 122:14-123:12.

149. For the Norborne permit, Campbell admitted that MDNR's decision to select dry FGD over wet FGD was based largely on environmental and energy impacts and not costs. Campbell Test., Tr. Vol. 4-A, 123:25-125:20.

150. Even if the Norborne decision had been based on costs, it would not support a finding of a $6,800/ton threshold. The incremental cost effectiveness at Norborne was $20,218/ton, based on a 95% removal wet FGD with a 93% removal dry FGD. On cross-examination, Campbell admitted that Missouri's BACT determination at Norborne did not support the $6,800/ton threshold he claimed:

> Q. … So in terms of whether we can get a $6,800-per-ton incremental cost threshold out of the Norborne permit, we can't; right?
> A. That's right.

Id. at 125:23-126:1.

151. For the Southwest City Utilities permit, MDNR did not consider costs in its determination. MDNR Rule 30(b)(6) Dep., Aug. 10, 2018, Tr. 142:6-143:15, 144:18-24; Missouri Air Conservation 11/28/05 Decision (Pl. Ex. 1007) at AM-00151141 ("However, Hale agreed that dry FGD was BACT for this particular pulverized coal-fired boiler based on his review of the energy and environmental impacts of dry versus wet FGD. … Hale did not consider economic impacts of costs as part of his analysis of BACT for SO_2.").

152. Additionally, the applicant calculated an incremental cost-effectiveness of over

$10,000/ton when comparing wet and dry FGD, two adjacent technologies in the "top down" analysis. Staudt Test., Tr. Vol. 2-A, 7:1-9, 24:4-16. The Southwest City Utilities permit does not support the purported $6,800 threshold as Campbell applied it in this case.

153. Campbell pointed to only these four Missouri permits to support the purported $6,800/ton threshold. None of those permits actually support that threshold. I find that Campbell's testimony on this issue is not based on established criteria to evaluate cost-effectiveness and is not credible.

154. Ameren presents no credible evidence that MDNR or any permitting authority will reject technologies with incremental cost effectiveness above $6,800/ton.

v. Campbell Disregards MDNR Practice Concerning Sources in the Same Category

155. Campbell also undermines his credibility by contradicting the NSR's source category "cost presumption." This principal of NSR permitting holds that "in the absence of unusual circumstance, the presumption is that sources within the same category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category." NSR Manual (Pl. Ex. 1190), at AM-REM-00544146-MDNR.

156. MDNR included the same language in a PSD permit for the Norborne coal-fired power plant. In that permit, MDNR rejected an applicant's attempt to rely on incremental cost-effectiveness over the same source category cost presumption. MDNR stated the following:

> [A]s per the draft of NSR Workshop manual, "in the absence of unusual circumstance, the presumption is that sources within the same category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category." Since AECI has not provided any data which differentiates this project from previously permitted units which have limits of 0.05 lb/MMBTU on an annual basis, it is presumed that the costs these systems will

> incur can also be incurred by AECI. Therefore, the economic analysis provided by AECI was not considered in selecting the NO_x limit.

Norborne PSD Permit (Pl. Ex. 1180), at AM-REM-00503313-MDNR (quoting NSR Manual); see also MDNR Rule 30(b)(6) Dep., at 139:21-141:22) (testifying that "when a permit writer looks at a permit application from, for example, a coal-fired utility, [] they would look towards other coal-fired utilities to determine the appropriate controls and what controls are already being used").

157. Campbell claimed during his direct examination that "there is no such presumption" in the "real world." Campbell Test., Tr. Vol. 4-A, 58:8-59:4. But this testimony was not supported by any evidence.

158. Campbell's statement—that the same source category cost presumption does not apply in the real world—undermines his credibility.

vi. Campbell Incorrectly Rejects Information From Power Plants Subject to NSPS

159. Campbell testified that SO_2 BACT determinations for coal-fired power plants during the past couple decades are not informative for Rush Island in 2019 because they involved "new" plants subject to NSPS. Campbell Test., Tr. Vol. 4-A, 75:20-22, 100:5-102:11.

160. Campbell's decision to disregard new plants subject to NSPS is inconsistent with the design and function of NSPS and is unsupported by the evidence presented in this case. See FOF ¶ 85-90.

161. Despite these features, Campbell testified that sources subject to NSPS should not be compared to Rush Island, because the NSPS fundamentally altered the range of options available in a BACT determination. Campbell Test., Tr. Vol. 4-A, 75:20-22, 100:5-102:11.

162. There is no difference between the emissions rates that can be achieved through

use of FGDs at NSPS-subject new units and existing units. Campbell Test., Tr. Vol. 4-A, 105:9-13.

163. Instead of relying on recent BACT determinations, Campbell based his testimony on BACT determinations made in the late 1970s and early 1980s. He also considered a 1990 BACT determination for a CFB boiler in Hawaii to be relevant. Campbell Test., Tr. Vol. 4-A, 102:12-104:3.

164. Campbell's testimony on this point is inconsistent with the permit application he helped electric utility DTE prepare for its Monroe power plant. Campbell Test., Tr. Vol. 4-A, 104:4-19.

e. I Reject Campbell's Testimony That DSI Is BACT for Rush Island

165. In addition to the flaws in Campbell's testimony, the following facts contradict Campbell's claims that DSI is BACT for Rush Island.

166. In 2008, MDNR rejected DSI for a coal-fired power plant because it did not "represent the upper level of SO_2 controls" necessary to constitute BACT. Staudt Test., Tr. Vol. 1-B, 93:23-94:25; 2/22/08 Norborne PSD Permit (Pl. Ex. 1180) at AM-REM-00503315-MDNR to 3316-MDNR (rejecting control efficiencies of up to 85%).

167. No permitting authority anywhere in the country has ever determined SO_2 BACT for a pulverized coal-fired power plant based on DSI. If I were to accept Campbell's testimony, Rush Island would be the first pulverized coal-fired power plant to have BACT based on DSI. Staudt Test., Tr. Vol. 1-B, 89:7-9; Campbell Test., Tr. Vol. 4-A, 97:21-98:7; Knodel Test., Tr. Vol. 1-A, 63:22-25.

168. Under a top-down BACT analysis, to arrive at his BACT determination, Campbell would have had to evaluate and then eliminate wet FGD, dry FGD, and DSI-FF in that

order, before settling on the least effective control technology available for Rush Island. FOF ¶¶ 75, 113.

169. Campbell admitted he "gave dry FGD relatively little consideration in [his] analysis [and] didn't assess its impacts in any quantitative way in Step 4." Campbell Test., Tr. Vol. 4-A, 85:1-4. Similarly, he did not evaluate DSI with a fabric filter in "any quantitative way." Id. at 85:16-25.

170. Campbell then compared the very effective, more capital-intensive wet FGD with the least effective and least expensive option—DSI without a fabric filter. Id. at 119:7-11.

171. The flaws in Campbell's analysis affect the core of his testimony that DSI constitutes BACT at Rush Island. Campbell rejected wet FGD specifically because his calculated incremental cost effectiveness was higher than a threshold he allegedly derived from BACT permits. In doing so, Campbell (1) overly relied on incremental cost effectiveness, (2) considered extrinsic expenses not normally included in BACT cost comparisons, (3) inappropriately compared the most- and least-effective technology, (4) derived a cost threshold that is not supported by the evidence, and (5) disregarded consistency among pulverized coal-fired power plants installing FGD. Campbell also inappropriately disregarded BACT permits for power plants subject to NSPS. I reject Campbell's testimony that DSI is BACT for Rush island.

f. Dr. Staudt's Testimony Concerning BACT at Rush Island Was Credible

172. In contrast to Campbell, Dr. Staudt conducted the well-established five-step BACT determination as outlined in the NSR manual and as practiced by MDNR and other permitting authorities.

173. Specifically, Dr. Staudt started step four by analyzing the most effective control technology, wet FGD. Dr. Staudt evaluated the energy, environmental, and economic costs of

wet FGD and concluded that wet FGD was achievable.

174. In coming to these conclusions, Dr. Staudt relied on standards and practices outlined in the EPA's Draft NSR Manual, the EPA's Cost Control Manual, and in permits issued by MDNR. Dr. Staudt carefully explained his methods, provided consistent testimony, and supported his testimony with credible evidence.

175. Ameren attempted to challenge Dr. Staudt's credibility by arguing that Staudt 1) overly relied on plants that had to meet the NSPS, 2) evaluated natural gas conversion as a control technology throughout the five-step process, and 3) did not evaluate the incremental cost effectiveness of wet FGD.

176. These arguments do not demonstrate that Dr. Staudt's testimony is not credible. With respect to NSPS, Dr. Staudt convincingly testified that NSPS provides a floor that does not fundamentally alter the BACT determination. Staudt Test., Tr. Vol. 1-B, 89:21-91:8; Tr. Vol. 2-A, 7:10-8:1. With respect to the natural gas conversion, Dr. Staudt eliminated the natural gas option because it was a different kind of fuel, and its inclusion did not affect how wet FGD was analyzed in step four. Tr. Vol. 2-A, 21:6-17, 22:23-23:18.

177. Dr. Staudt's economic evaluation may have been more compelling if he had discussed incremental cost effectiveness, even if BACT determinations do not specifically require it.

178. Still, I find that Dr. Staudt's testimony is credible, helpful to the trier of fact, and instrumental to determining what BACT was at the time of Rush Island's modifications. I heavily rely on Dr. Staudt's testimony when discussing facts surrounding BACT determinations in this case.

g. BACT Requirements at Rush Island in 2007 and 2010

179. Staudt and Campbell—and ultimately the parties in this case—did not have any material disagreement over Steps 1 through 3 of BACT process. Campbell Test., Tr. Vol. 4-A, 97:9-20. The results of those analyses are identified below:

Step One: Identify Available Control Options

180. The available SO_2 control technologies for Rush Island Units 1 and 2 include wet FGD, dry FGD, DSI-FF, and ordinary DSI. Staudt Test., Tr. Vol. 1-B, 50:19-51:1; Campbell Test., Tr. Vol. 4-A, 50:16-51:13. I find that Dr. Staudt's and Campbell's testimony on this point is credible and that this is the appropriate ranking.

Step Two: Eliminate Technically Infeasible Options

181. None of these control technologies can be eliminated as technically infeasible for Rush Island. Staudt Test., Tr. Vol. 1-B, 51:24-52:5; Campbell Test., Tr. Vol. 4-A, 50:16-51:13, 93:1-8; Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 59:1-12.

Step Three: Rank Technically-Feasible Options by Effectiveness

182. Wet FGD is the most effective control technology (about 99% removal efficiency), followed by dry FGD (about 95%), DSI with a fabric filter (about 70%), and DSI without a fabric filter (about 50%). Staudt Test., Tr. Vol. 1-B, 14:13-15:1, 52:21-53:15, 16:11-17:14; Campbell Test., Tr. Vol. 4-A, 50:16-51:13; Snell Test., Tr. Vol. 4-B, 5:19-6:3, 18:19-19:7, 50:8-22.

Step Four: Evaluate Most Effective Controls

183. Dr. Staudt and Campbell disagreed about the results of the fourth and fifth steps.

184. Dr. Staudt concluded that wet FGD could not be eliminated because it was achievable, taking into account energy, environmental, and economic impacts and other costs. Staudt Test., Tr. Vol. 1-B, 54:22-55:4.

185. Campbell concluded that wet FGD could be eliminated because its incremental cost effectiveness was unacceptably costly when compared with DSI. As noted above, Campbell did not use the top-down method here. Instead Campbell eliminated the middle two options—because dry FGD and DSI-FF were not "dominant control options." Id. at 74:3-12.

186. Neither Campbell nor Ameren cites to any permitting authority, permitting applicant, permitting guide, or other authority supporting Campbell's method of excluding "non-dominant" control options before conducting the step four analysis.

187. In contrast, Dr. Staudt employed the top-down method, as practiced by MDNR and other permitting authorities. Dr. Staudt evaluated the energy, environmental, economic, and other costs associated with wet FGD.

188. Based on Dr. Staudt's credible, well-supported testimony, I find that the energy, environmental and economic impacts of wet FGD do not make wet FGD unachievable. Instead, these impacts are reasonable and comparable to the impacts experienced at other permitted pulverized coal-fired power plants.

Energy Impacts

189. The evidence does not show that wet FGD's energy impacts would be unreasonable for Rush Island. Staudt Test., Tr. Vol. 1-B, 54:22-55:4. Ameren's engineering studies determined that Ameren would not have to install power-intensive fans for wet FGD, but it would have to install them for dry FGD or DSI with a fabric filter. Staudt Test., Tr. Vol. 1-B, 55:5-19. These fans would decrease the overall power output of the plant.

190. Ameren presented evidence that wet FGD would reduce power output at Rush Island, due to the energy demands of the wet FGD controls. Snell Test., Tr. Vol. 4-B, 38:6-17. Ameren did not argue that this energy demand was different from the energy demand of

scrubbers at other pulverized coal-fired power plants. Additionally, Ameren did not present evidence that this energy demand would make wet FGD unachievable. As a result, the weight of the evidence demonstrates that the energy impacts of wet FGD do not make it unachievable for Rush Island.

Environmental Impacts

191. Relatedly, the evidence does not show that wet FGD would impose unreasonable environmental impacts at Rush Island. Instead, Ameren would have the environmental benefit of producing saleable gypsum instead of landfill waste. Staudt Test., Tr. Vol. 1-B, 40:12-41:24, 55:20-56:5; see FOF ¶¶ 35. Additionally, water limitations would not be an issue for Rush Island, because it is in close proximity to the Mississippi River. Staudt Test., Tr. Vol. 1-B, 56:6-14.

192. Ameren presented evidence at trial that wet FGD would require more wastewater treatment and new mercury controls, creating more costs for Ameren than DSI would impose. Snell Test., Tr. Vol. 4-B, 37:24-39:10. However, Ameren made no effort to explain how these environmental impacts made wet FGD unachievable. Nor did Ameren suggest that these environmental impacts are different from the kinds of impacts experienced at other pulverized coal-fired power plants. See NSR Manual (Pl. Ex. 1190), at AM-REM-00544146-MDNR; Staudt Test. Vol. 1-B, 63:14-64:6.

Economic Impacts

193. Finally, wet FGD would not impose unreasonable economic impacts at Rush Island. Staudt Test., Tr. Vol. 1-B, 56:15-19.

194. Ameren openly concedes that it can afford to install scrubbers at Rush Island. Ameren's contemporaneous studies confirmed that wet FGDs would be economically feasible.

The same studies show that, from a cost perspective, wet FGDs are preferable to dry FGDs at Rush Island. FOF ¶¶ 26, 31-33, 36, 38.

195. The large number of coal-fired electric generating units already equipped with wet FGDs provides strong evidence that the cost of wet FGD is achievable for a pulverized coal-fired power plant like Rush Island. Staudt Test., Tr. Vol. 1-B, at 62:8-21, 64:20-65:7, 66:17-67:2.

196. Ameren's engineering studies confirmed that the capital costs of installing wet scrubbers at Rush Island would be consistent with costs borne by other utilities. Staudt Test. Tr. Vol. 2-A, 56:20-57:6.

197. Rush Island does not have any unique characteristics that would make the typical costs of wet FGDs unreasonable in this context. Staudt Test., Tr. Vol. 1-B, 65:8-12; Snell Test., Tr. Vol. 4-B, 57:15-18. None of Ameren's experts have identified any circumstances at Rush Island that would make the costs to install wet FGDs at Rush Island unusual compared to other plants. Staudt Test., Tr. Vol. 1-B, 65:8-12; Snell Test., Tr. Vol. 4-B, 57:15-18.

198. On the contrary, Ameren's own engineers have admitted that there is nothing about Rush Island that makes it different from any of the other plants where FGDs have been installed. Mitchell Dep., May 30, 2018, Tr. 81:13-23, 192:2-10.

199. For purposes of historic BACT, Dr. Staudt calculated the average cost-effectiveness of wet FGD to be about $2800/ton for Rush Island Unit 1 and Unit 2. Staudt Test., Tr. Vol. 1-B, 57:7-58:22. Based on these figures, Dr. Staudt testified that wet FGD could not be eliminated as unachievable due to cost concerns. Id. at 62:3-7.[6]

[6] Dr. Staudt made conservative assumptions when calculating the average cost effectiveness for wet FGD. He based his baseline emission rate on low sulfur coal, leading to lower emissions reductions, a larger demoninator, and a higher per ton cost. Staudt Test., Tr. Vol. 1-B, 59:3-15, 61:16-62:2. Dr. Staudt also used a capacity factor of 80% rather than 100%. Staudt Test., Tr. Vol. 1-B, 61:16-62:2.

200. Wet FGD is achievable at Rush Island, taking into account the energy, environmental, economic impacts and other costs of this technology. I find no basis for eliminating the top control, wet FGD, at Step Four of the BACT analysis.

Step Five: Select BACT

201. In Step Five, the permit applicant and permitting authority determine what emissions limit can be achieved by installing the selected control technology.

202. For Rush Island Unit 1, Dr. Staudt testified that historic BACT would have been 0.08 lb/mmBTU, based on a 30-day rolling average. This corresponds to a design removal efficiency of 91.4%. Staudt Test., Tr. Vol. 1-B, 69:13-22.

203. For Rush Island Unit 2, Dr. Staudt testified that historic BACT would have been 0.06 lb/mmBTU, based on a 30-day rolling average. That would represent a 94% design removal efficiency. Staudt Test., Tr. Vol. 1-B, 69:23-70:2.

204. Dr. Staudt's historic BACT rates include a reasonable compliance margin and are consistent with the rates that Ameren's engineering studies confirmed would be achievable at Rush Island. FOF ¶ 30.

205. Dr. Staudt's historic BACT rates are consistent with permits issued by MDNR and other permitting authorities during the relevant period. Staudt Test., Tr. Vol. 1-B, 70:15-17, 79:6-18, 80:23-81:19. FOF ¶¶ 99-105.

206. Dr. Staudt's historic BACT rates are also consistent with the design specifications used for Ameren's engineering studies, and performance of FGDs at Ameren's other plants. By the time Rush Island Unit 2 was modified, Ameren already had a plant "perform[ing] at 0.06 pounds per million Btu, so [it] knew that number could be achieved." Callahan Dep., Nov. 8, 2017, Tr. 201:13-21; see also id. at 78:2-8, 84:8-23 (the FGDs at Ameren Illinois's Duck Creek

plant were achieving 99% removal or 0.06 lb/mmBTU).

207. Finally, Dr. Staudt's historic BACT rates are consistent with industry performance data. In 2008 and 2011, the years after each of the modifications at issue, the top 20% of performing scrubbers in the industry were achieving SO_2 rates, respectively, of 0.059 lb/mmBTU and 0.037 lb/mmBTU. Staudt Test., Tr. Vol. 1-B, 82:21-88:3.

208. For these reasons, I find that, at the time Ameren modified Rush Island, BACT required SO_2 emissions limitations at least as stringent as 0.08 lb/mmBTU for the 2007 modification of Rush Island Unit 1, and 0.06 lb/mmBTU for the 2010 modification of Rush Island Unit 2, based on 30-day rolling averages.

h. Rush Island's Excess Emissions Total More Than 162,000 Tons

209. Dr. Staudt calculated the excess emissions from Ameren's failure to install scrubbers in 2007 and 2010, based on Dr. Staudt's historic BACT determinations and Rush Island's actual emissions reported by Ameren to the EPA's Air Market Program. Staudt Test., Tr. Vol. 1-B, 99:17-101:4.

210. Based on Dr. Staudt's testimony and the evidence at trial, I find that Ameren's failure to install scrubbers at Rush Island resulted in 162,000 tons of excess SO_2 emissions through the end of 2016. These excess emissions continue at a rate of about 16,000 tons per year, and will be emitted each year that Rush Island operates without scrubbers. Staudt Test., Tr. Vol. 1-B, 101:5-9.

211. If Ameren finishes installation of wet FGD scrubbers at Rush Island in 2023, the excess emissions will total nearly 275,000 tons. Staudt Test., Tr. Vol. 1-B, 99:17-102:1. Obviously, the sooner Ameren installs scrubbers, the lower its excess emissions will be. Id. at 101:18-102:1.

III. CURRENT BACT ANALYSIS

212. While the historic BACT determination was necessary to calculate Rush Island's excess emissions between 2007 and the present day, a current BACT determination helps identify the appropriate relief in this case. The EPA has asked me to (1) determine what technology constitutes BACT for Rush Island and (2) order Ameren to propose that technology in its permit application. Without this relief, the EPA is concerned that Ameren will continue to delay and oppose the installation of the appropriate pollution control technology.

213. I find that wet FGD constitutes BACT for Rush Island today. I also find that BACT for Rush Island Units 1 and 2 is a 30-day rolling average of 0.05 lb SO_2/mmBTU. This emission limitation is lower than the historic BACT for Rush Island because BACT rates decrease over time due to the technology-forcing nature of the requirement.

a. Current BACT Requires Wet FGD

214. Ameren's and the EPA's expert testimony concerning current BACT is essentially identical to their expert testimony concerning historic BACT. On behalf of Ameren, Campbell conducted one BACT analysis used for historic and current BACT. On behalf of the EPA, Dr. Staudt conducted a current BACT analysis that had the same process and result as his historic BACT analysis, save an updated emissions limitation.

215. The parties agree on the results of steps one, two, and three. Additionally, Ameren's experts admitted that the rate the EPA determined in Step Five would be achievable with wet FGD. Campbell Test., Tr. Vol. 4-A, 93:18-94:3; <u>see also</u> Snell Test., Tr. Vol. 4-B, 51:13-52:16 (conceding that a design SO_2 emission rate of 0.04 lb/mmBTU is achievable at Rush Island).

216. For the same reasons as were applicable to the historic BACT analysis, I find that

wet FGD cannot be eliminated at Step Four of the top-down method based on unreasonable energy, environmental or economic impacts. FOF ¶ 189-200.

217. Between 2010 and the present day, scrubber technologies, including wet FGD, have become more prevalent at pulverized coal-fired power plants. Between 2005 and 2015, wet FGD technology was installed on nearly 100,000 megawatts of pulverized coal-fired electric generating capacity in the United States. FOF ¶ 17 and Figure 1. Almost all of that scrubbed generating capacity is at existing plants that installed scrubbers. FOF ¶ 17. Today, there are very few units the size of the Rush Island that continue to operate without any type of FGD controls. FOF ¶¶ 16, 18.

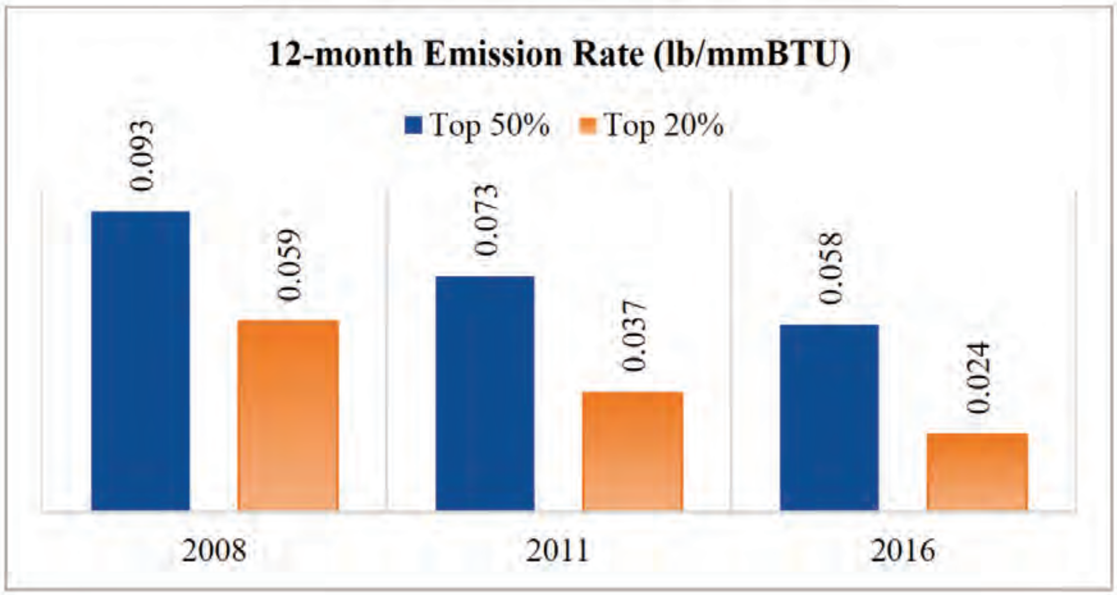
218. The more widespread use of FGD scrubbers at coal-fired power plants strengthens the argument that wet FGD is achievable today at Rush Island. As quoted by MDNR in its Norborne permit, "in the absence of unusual circumstance, the presumption is that sources within the same category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category." Norborne PSD Permit (Pl. Ex. 1180), at AM-REM-00503313-MDNR (quoting NSR Manual and emphasis added).

219. Ameren presented no evidence at trial to distinguish Rush Island from the other pulverized coal-fired power plants using scrubbers today. FOF ¶¶ 197-98. The only Ameren witness who attempted to do so was Campbell, who testified that the most unusual circumstance about Rush Island is that it is "not equipped with a scrubber and not otherwise required to install a scrubber . . ." Campbell Test., Tr. Vol. 4-A, 114:5-12.

220. The performance of scrubbers in the electric utility industry has continued to improve over the past decade, as illustrated in Figure 3. Figure 3 identifies the 12-month

averaged emission rate for the top performing 50% of plants and the top performing 20% of plants in 2008, 2011, and 2016.

Figure 3



221. As shown in Figure 3, the average emission rate achieved by the top 20% of units (57 units) in 2016 was 0.024 lb/mmBTU. In 2008 and 2011, the average emission rate being achieved by the top 20% of units was 0.059 and 0.037 lb/mmBTU, more than 100% and 50% higher than in 2016, respectively. These trends demonstrate a significant and sustained improvement in performance between 2008 and 2016. Staudt Test., Tr. Vol. 1-B, 82:21-83:20.

222. In Missouri, the Iatan plant reflects the low emissions rates that FGD can achieve today. Like Rush island, Iatan burns low-sulfur coal. Using wet FGDs since 2008, Iatan now achieves emission rates as low as 0.004 to 0.006 lb/mmBTU. Although similar in size to Rush Island, Iatan's total SO_2 emissions (250 tons) are a small fraction of Rush Island's (18,000 tons). Staudt Test., Tr. Vol. 1-B, 76:6-76:9, 84:10-84:25.

223. With respect to economic impacts, Ameren does not dispute that it can afford FGDs at Rush Island, and it presented no evidence that installing FGDs would otherwise impose an undue financial burden on the company. FOF ¶¶ 37-41, 194.

224. For his BACT analysis, Dr. Staudt estimated that the capital cost of installing wet FGDs at Rush Island would be about $582 million in 2016 dollars. This estimate was based on the costs calculated by Ameren's engineering studies, excluding AFUDC, escalation, corporate overhead, and property taxes consistent with the standard methodology for BACT cost calculations. Staudt Test., Tr. Vol. 1-B, 59:24-61:5; Tr. Vol. 2-A, 25:25-26:6, 28:18-30:18.

225. Based on those capital cost estimates, Dr. Staudt calculated the average cost-effectiveness of wet FGDs at Rush Island to be $3,854 per ton of SO_2 removed. Staudt Test., Tr. Vol. 1-B, 58:23:59-2. Dr. Staudt testified that wet FGD could not be eliminated based on these average cost-effectiveness figures, Staudt Test., Tr. Vol. 2-A, 26:17-27:5, and his testimony is unrebutted: Ameren's BACT expert reached no opinion on whether the average cost-effectiveness of wet FGDs at Rush Island would be considered unreasonable. Campbell Test., Tr. Vol. 4-A, 115:8-116:17.[7]

226. According to Ameren's engineering studies, this average cost effectiveness result is consistent with costs borne by other coal-fired power plants installing scrubbers. See February 5, 2010 Project Review Board Presentation-Rush Island FGD (Pl. Ex. 1100), at AM-REM-00289006; Staudt Test. Tr. Vol. 1-B, 23:10-25:16, 56:20-57:6; Ameren Rule 30(b)(6) Dep., Nov.

---

[7] On cross-examination, Campbell testified that permitting authorities generally use a $5000/ton threshold for average cost-effectiveness. Campbell Test., Tr. Vol. 4-A, at 115:8-14. While Campbell's testimony was inconsistent with his prior sworn deposition testimony that he knew of no "rule of thumb" limit for average cost-effectiveness, (id. at 115:8-116:17), I note that—if credited—Campbell's testimony would provide further support that $3,854/ton would be considered an acceptable average cost-effectiveness for purposes of BACT.

7, 2017, Tr. 90:6-91:3.

227. I find that the average cost-effectiveness of wet FGD at Rush Island is reasonable for a pulverized coal-fired power plant today. I also find that the economic costs of installing wet FGD at Rush Island do not make wet FGD unachievable.

228. Additionally, I find that neither the energy nor environmental costs of installing wet FGD at Rush Island make wet FGD unachievable. Ameren presents no evidence demonstrating, and I have no reason to find, that the energy and environmental costs for a current BACT determination at Rush Island are any greater or less reasonable than the energy and environmental costs for a historic BACT determination.

b. Current BACT Requires an Emissions Limitation of 0.05 lb/mmBTU

229. Dr. Staudt testified that, based on a selection of wet FGD, the appropriate emissions limitation for Rush Island is 0.05 lb/mmBTU. Staudt Test., Tr. Vol. 1-B, 70:3-17.

230. In 2011, Ameren accepted its consultants' recommendation that it solicit bids for a wet FGD system designed to meet an SO_2 emission rate of 0.04 lb/mmBTU, regardless of the type of coal burned. FOF ¶¶ 52-55.

231. Ameren's expert Campbell admitted that 0.05 lb/mmBTU would be an achievable emission rate at Rush Island and a good estimate of what MDNR would set as BACT if scrubbers were required. Campbell Test., Tr. Vol. 4-A, 93:18-94:3; see also Snell Test., Tr. Vol. 4-B, 51:13-52:16 (conceding that a design SO_2 emission rate of 0.04 lb/mmBTU is achievable at Rush Island).

232. An SO_2 emission rate of 0.05 lb/mmBTU could be achieved through use of either wet or dry scrubbers and does not represent the lowest achievable SO_2 emission rate at Rush Island. Staudt Test., Tr. Vol. 1-B, 70:18-25.

233. I find that wet FGD constitutes BACT today for Rush Island and the appropriate operating emissions limitation for this technology would be set at 0.05 lb/mmBTU, based on a 30-day rolling average.

IV. RUSH ISLAND'S EXCESS EMISSIONS CAUSED IRREPARABLE INJURY, INCLUDING INCREASED RISK OF PREMATURE MORTALITY

234. The EPA offered evidence to demonstrate that the excess SO_2 emissions resulting from Ameren's decision to ignore PSD requirements caused irreparable injury that could not be compensated through legal remedies. See eBay Inc. v. MercExchange, L.L.C., 547 U.S. 388, 391 (2006). The EPA also offered evidence to demonstrate that the balance of hardships and public interest favors injunctive relief. See id. Based on both parties' evidence, I make the following findings of fact concerning the result of Rush Island's excess pollution.

a. Rush Island's Excess Pollution Is Substantial

235. SO_2 is a regulated pollutant under the Clean Air Act. Any source that releases more than 100 tons of SO_2 yearly is considered a "major" source. 42 U.S.C. § 7479(1); see also 40 C.F.R. § 52.21(b)(1)(i) (same regulatory threshold).

236. Rush Island's annual SO_2 emissions and its excess emissions that should have been captured by BACT (16,000 tons per year) both far exceed this threshold. Compare Staudt Test., Tr. Vol. 1-B, 101:10-13 with 42 U.S.C. § 7479(1) and 40 C.F.R. § 52.21(b)(1)(i). The annual excess pollution from Rush Island alone is equivalent to the amount of pollution that would be emitted by more than 160 sources that each would be considered "major" sources of harmful air pollution under the Clean Air Act.

b. Rush Island's Excess SO_2 Emissions Created Harmful $PM_{2.5}$

237. SO_2 is directly emitted from Rush Island as a gas. However, SO_2 is not stable in the atmosphere. Over time, all the SO_2 released by Rush Island will convert to fine particulate

matter known as “$PM_{2.5}$.” $PM_{2.5}$ includes all particles that are 2.5 micrometers in diameter or smaller. Chinkin Test., Tr. Vol. 2-A, 97:6-19.

238. On average, about five percent of the SO_2 emitted by a facility will convert into $PM_{2.5}$ each hour, with a range of one to ten percent depending on meteorological variables. Chinkin Test., Tr. Vol. 2-A, 97:20-98:21. $PM_{2.5}$ pollution resulting from Rush Island’s excess SO_2 emissions travels hundreds of miles from Rush Island’s smokestack. Chinkin Test., Tr. Vol. 2-B, 22:15-19.

239. $PM_{2.5}$ derived from burning coal and other fossil fuels is known as combustion-related $PM_{2.5}$ or combustion particles. These combustion particles are generally less than one micrometer in diameter, about the same size as a virus. By contrast, most naturally-occurring particles in the atmosphere are greater than ten micrometers in diameter.

240. Because of their size, combustion-related $PM_{2.5}$ particles have a better chance of getting past the body’s natural defenses. $PM_{2.5}$ particles are more likely to get into deeper lung structures such as the alveoli, where they can do greater damage for more sustained periods of time. Schwartz Test., Tr. Vol. 3-A, 21:9-22:18, 59:5-11.

241. $PM_{2.5}$ is made up of different chemical constituents, which react with each other in the atmosphere. One of the constituents of combustion-related $PM_{2.5}$ is sulfate $PM_{2.5}$, which forms from SO_2 emissions. Sulfate $PM_{2.5}$ is one of the largest components of $PM_{2.5}$ in the atmosphere. Schwartz Test., Tr. Vol. 3-A, 22:19-23:10, 59:5-59:11.

242. Sulfate combustion particles are not pure, homogenous specimens. They chemically bind to other substances present in the outdoor air. Sulfate tends to combine with metals in the atmosphere, forming compounds that magnify the human health effects of $PM_{2.5}$. Schwartz Test., Tr. Vol. 3-A, 24:23-26:13, 27:5-28:24; see also Valberg Test., Tr. Vol. 5-A,

111:5-16 (conceding that the sulfate ion does not exist in the air by itself).

243. The available scientific evidence indicates that all constituents of $PM_{2.5}$ are toxic. Insufficient evidence exists to determine whether any particular constituent is more toxic than any other. Schwartz Test., Tr. Vol. 3-A, 23:11-13.

244. $PM_{2.5}$ is regulated in the United States and throughout the world on a mass basis, rather than on a constituent-by-constituent basis. Id. at 23:22-24:19, 58:23-59:24; see also Valberg Test., Tr. Vol. 5-A, 111:17-19, 113:2-5 (conceding that $PM_{2.5}$ is regulated on a mass basis, not a constituent basis).

i. Dr. Schwartz Presented Credible, Well-Supported, Expert Testimony Concerning the Health Impacts of $PM_{2.5}$

245. To demonstrate the health effects of $PM_{2.5}$, the EPA offered the expert testimony of Dr. Joel Schwartz. Dr. Schwartz is a tenured professor in the Department of Environmental Health and the Department of Epidemiology at the Harvard School of Public Health and is also a professor in the Department of Medicine at the Harvard Medical School. Schwartz Test., Tr. Vol. 3-A, 4:25-5:5, 8:17-20; see also Curriculum Vitae of Dr. Joel Schwartz (Pl. Ex. 1324).

246. Dr. Schwartz is one of the world's leading scientists on the health effects of air pollution. He has published about 790 peer-reviewed articles. Schwartz Test., Tr. Vol. 3-A, 12:8-11; Pl. 1324. His published research has been cited more than 60,000 times in the scientific literature. Id. at 12:18-19. Dr. Schwartz is not aware of any person who has published more articles than he has in the field of air pollution research. Id. at 13:1-4.

247. Dr. Schwartz performs extensive research on air pollution, teaches courses on epidemiology, and serves as the director of the Harvard Center for Risk Analysis. Schwartz Test., Tr. Vol. 3-A, 5:6-8, 7:13-10:10, 13:5-15:13. Dr. Schwartz's research has been cited by the EPA in its Integrated Science Assessments and has been relied upon by the World Health

Organization in setting standards for air pollution. Schwartz Test., Tr. Vol. 3-A, 15:14-16:1. Dr. Schwartz has also testified before Congress as to the health effects of air pollution, and recently provided a keynote presentation on $PM_{2.5}$ health effects to a World Health Organization conference of international public health ministers. Schwartz Test., Tr. Vol. 3-A, 16:2-25.

248. Dr. Schwartz has testified in federal court two times before this case. He was received as an expert in those cases. Id. at 18:2-5.

249. Dr. Schwartz's testimony is consistent with the scientific consensus that $PM_{2.5}$ harms public health and that there is no threshold below which $PM_{2.5}$ does not cause adverse health effects in exposed populations.

250. During his testimony and during cross-examination, Dr. Schwartz's answers were detailed, credible, and supported by an overwhelming amount of evidence. I find Dr. Schwartz's testimony concerning the health effects of $PM_{2.5}$ to be credible.

ii. $PM_{2.5}$ Causes Heart Attacks, Strokes, Asthma Attacks, and Premature Mortality

251. $PM_{2.5}$ is harmful to human health, causing numerous adverse health effects in exposed populations. Inhaling $PM_{2.5}$ leads to increased risk of high blood pressure, hardened arties, heart attacks, strokes, asthma attacks, and premature mortality. Schwartz Test., Tr. Vol. 3-A, 19:18-20:4, 49:6-50:13 (explaining the American Heart Association's official statement on health effects of $PM_{2.5}$ inhalation), 60:6-62:5 (explaining the EPA's Integrated Science Assessment on health effects of health effects of $PM_{2.5}$ inhalation).

252. The health effects from $PM_{2.5}$ are well-established, and the harmful mechanisms of $PM_{2.5}$ exposure have been demonstrated in many epidemiological, toxicology, and clinical studies. Schwartz Test., Tr. Vol. 3-A, 49:6-50:13, 60:6-62:5.

253. The effect of $PM_{2.5}$ exposure on life expectancy, heart attacks, and strokes is both

acute and chronic, based on short-term and long-term exposure, respectively. Schwartz Test., Tr. Vol. 3-A, 49:6-17, 60:18-61:11.

254. The harmful nature of $PM_{2.5}$ exposure is widely known and agreed upon. Schwartz Test., Tr. Vol. 3-A, 19:18-20:22, 47:6-24. Dr. Schwartz cited statements from the U.S. Centers for Disease Control, the U.S. Environmental Protection Agency, the American Heart Association, the American Thoracic Society, the American Medical Association, the National Academy of Sciences, the World Health Organization, the Royal College of Physicians of the United Kingdom, and the United Nations Environment Program to support his expert testimony on this point. Id.

255. The relationship between the concentration of $PM_{2.5}$ in the ambient air and resulting health effects is known as a concentration-response function. For premature mortality, the concentration-response function indicates the percent change in mortality that is expected from a given change in $PM_{2.5}$ exposure. Schwartz Test., Tr. Vol. 3-A, 36:4-38:2, 86:13-15.

256. The scientific consensus concerning ambient $PM_{2.5}$ concentrations is that there is no safe level below which $PM_{2.5}$ is not harmful. The $PM_{2.5}$ concentration-response relationship has been extensively analyzed in the scientific literature, and studies of both short- and long-term exposure to $PM_{2.5}$ have consistently found no evidence of a safe threshold. Schwartz Test., Tr. Vol. 3-A, 42:17-43:5, 43:22-45:17, 46:19-47:15, 57:16-58:10, 62:6-63:5, 64:11-24, 67:17-68:10.

257. The concentration-response relationship between $PM_{2.5}$ and mortality is linear. Researchers have *not* found a population threshold for ambient $PM_{2.5}$, including at the concentrations experienced in communities near Rush Island. Less data exists to determine the shape of the concentration-response relationship at annual ambient levels below 3 or 4 micrograms per cubic meter. However, the areas impacted by Rush Island's excess emissions are

all above those concentrations. Schwartz Test., Tr. Vol. 3-A, 38:6-39:16, 64:11-66:11, Schwartz Test., Tr. Vol. 3-B, 49:6-21.

258. Dr. Schwartz agrees with the World Health Organization that there is “no evidence of a safe level of exposure or a threshold below which no adverse health effects occur” from exposure to $PM_{2.5}$. Schwartz Test., Tr. Vol. 3-A, 57:16-58:10 (discussing statement on $PM_{2.5}$ health effects issued by World Health Organization).

259. Dr. Schwartz’s testimony about the scientific consensus concerning the $PM_{2.5}$ concentration-response relationship was in part based on a 2009 Integrated Science Assessment published by the EPA. Schwartz Test., Tr. Vol. 3-A, 60:4-63:5; see generally 2009 Integrated Science Assessment for Particulate Matter (Pl. Ex. 1209) at 2-8 to 2-17 (evaluating “evidence from toxicological, controlled human exposure, and epidemiologic studies” and concluding that $PM_{2.5}$ causes premature mortality and other health effects); id. at 6-75 (explaining that short- and long-term studies of concentration-response relationships have “consistently found no evidence for deviations from linearity or a safe threshold”); id. at 6-158 to 6-201 and 7-82 to 7-96 (further summarizing evidence for causal determinations for short- and long-term exposure).

260. The evidence demonstrating that there is no safe threshold for $PM_{2.5}$ has only increased since the EPA’s 2009 Integrated Science Assessment. Schwartz Test., Tr. Vol. 3-A, 64:11-66:11, 68:1-69:15; Schwartz Test., Tr. Vol. 3-B, 49:6-21.

261. Interpreting more recent studies, Dr. Schwartz testified that the linear concentration-response function between $PM_{2.5}$ and premature death has been demonstrated at lower concentrations than before. Schwartz Test., Tr. Vol. 3-A, 64:11-66:11, 68:1-69:15; Schwartz Test., Tr. Vol. 3-B, 49:6-21.

262. The concentration-response function cited by Dr. Schwartz is derived from

substantial sets of data that have been extensively analyzed in the peer-reviewed literature. In part, Dr. Schwartz relied on a recent study published in the New England Journal of Medicine that included approximately 500,000 unique $PM_{2.5}$ concentration data points at ambient levels between 6 and 16 micrograms per cubic meter, and 70,000 unique data points clustered between ambient $PM_{2.5}$ concentrations of 10 and 11 micrograms per cubic meter. The study found a linear relationship in these two ranges. Schwartz Test., Tr. Vol. 3-A, 36:10-37:12, 39:9-43:5.

263. Based on the no-threshold, linear concentration-response relationship for $PM_{2.5}$, any incremental increase in $PM_{2.5}$ exposure produces an incremental increased risk of mortality and other health effects in the population exposed to Rush Island's excess emissions. Similarly, any incremental decrease in exposure produces a positive impact on public health. Schwartz Test., Tr. Vol. 3-A, 39:9-16, 41:11-43:5, 46:19-47:5, 79:15-21.

264. Both of Ameren's toxicologists conceded that, if a substance is actually a no-threshold pollutant, any incremental increase in exposure produces an incremental increase in risk in the rate of mortality. Fraiser Test., Tr. Vol. 4-A, 28:9-15, Valberg Test., Tr. Vol. 5-A, 137:14-19.

265. Based on (1) the linear concentration-response function for $PM_{2.5}$, (2) the lack of a threshold for $PM_{2.5}$, (3) the conversion of 162,000 tons of excess SO_2 pollution into $PM_{2.5}$, and (4) the scientific consensus that $PM_{2.5}$ increases the risk of high blood pressure, heart attack, stroke, asthma attack, and premature mortality, I find that the pollution resulting from Ameren's failure to obtain a PSD permit has harmed—and continues to harm—public health. Schwartz Test., Tr. Vol. 3-A, 19:18-20:22, 42:17-43:5, 46:19-47:1, 65:17-66:11, 82:1-8.

iii. Dr. Fraiser's and Dr. Valberg's Testimonies Were Not Credible

266. In contrast with Dr. Schwartz, Defendants' testifying experts Dr. Lucy Fraiser and

Dr. Peter Valberg provided testimony that is inconsistent with and not supported by the scientific consensus on $PM_{2.5}$'s human health impacts.

Dr. Lucy Fraiser

267. Dr. Fraiser is a toxicological consultant who spends about 85% of her time on litigation support. Fraiser Test., Tr. Vol. 4-A, 23:3-7.

268. Dr. Frasier has not written any peer-reviewed publications or performed any original research on air pollution. Fraiser Test., Tr. Vol. 4-A, 22:21-23, 23:14-16. Dr. Fraiser has written five publications concerning the effects of cancer drugs based on her dissertation work, the last of which was published almost 25 years ago in 1995. Id. at 22:14-20.

269. At trial, Dr. Frasier testified that $PM_{2.5}$ concentrations below the NAAQS do not cause actual adverse health effects. Dr. Frasier's other opinions primarily flow from this assertion. This testimony contradicts the EPA statements and congressional reports regarding the NAAQS. Compare Fraiser Test., Tr. Vol. 4-A, 24:18-25:12 with, e.g., H.R. Rep. 95-294 at 112 (quoting National Academy of Sciences, Summary of Proceedings: Conference on Health Effects of Air Pollution (Nov. 1973); H.R. Rep. 95-294 at 111.

270. The House Report concerning the NAAQS states that "[i]n the absence of evidence to the contrary, for a population of various stages and initial states of health, no threshold should be stipulated below which exposure is harmless. Instead, the response to exposure should be assumed to be directly related to successively greater or lesser concentrations of the toxic materials and the level of resistance of those exposed." H.R. Rep. 95-294 at 111.

271. In the publication of the 2013 National Ambient Air Quality Standards, the EPA stated that "there is no discernible population-level threshold below which effects would not occur, such that it is reasonable to consider that health effects may occur over the full range of concentrations observed in the epidemiological studies, including the lower concentrations in the

latter years." 78 Fed. Reg. 3086, 3098, 3118-19, 3148 (Jan. 15, 2013).

272. Dr. Fraiser concedes that her opinions are contrary to the determinations of the World Health Organization, the American Heart Association, the EPA, and other mainstream scientific organizations that have concluded that $PM_{2.5}$ is a no-threshold pollutant that causes increased mortality. Fraiser Test., Tr. Vol. 4-A, 26:6-33:25.

273. Dr. Fraiser also admits that the NAAQS do not guarantee zero risk. Id. at 25:13-23. Instead, she argues that concentrations below the NAAQS "are not an unacceptable risk." Id.

274. Dr. Fraiser is not a statistician. Id. 21:18-22:6. Dr. Fraiser performs quantitative risk assessments, but she did not perform a quantitative risk assessment in this case. Id. at 24:6-9. Dr. Fraiser reviewed the EPA's health impacts modeling in this case, but her opinion is primarily based on her interpretation of the NAAQS. Id. at 24:10-22.

275. Dr. Fraiser's direct criticism of the EPA's health impacts testimony is outside of her area of expertise. For example, Dr. Fraiser criticized the epidemiological literature on health effects of $PM_{2.5}$, stating that confounding factors undermine these studies. However, Dr. Fraiser is not an epidemiologist and has never performed an epidemiological study. Fraiser Test., Tr. Vol. 4-A, 21:18-21. Dr. Fraiser's bare assertion that "innumerable potential confounding factors" mar these studies is not credible. Many $PM_{2.5}$ studies have analyzed the effects of confounders and found that they do not undermine the epidemiological results of these studies. Compare Fraiser Test., Tr. Vol. 3-B, 71:21-72:3 with Schwartz Test., Tr. Vol. 3-A, 69:16-76:15; see also 2009 Integrated Science Assessment for Particulate Matter (Pl. Ex. 1209) at 1-21 (explaining that that $PM_{2.5}$ "has been shown to result in health effects in studies in which chance, bias, and confounding could be ruled out with reasonable confidence"), 2-9 (summary of causal determinations for short-term $PM_{2.5}$ exposure), 2-11 (summary of causal determinations for long-

term $PM_{2.5}$ exposure).

276. Dr. Fraiser also testified that more recent epidemiological studies show uncertainty between $PM_{2.5}$ and mortality effects at levels below the NAAQS. Her testimony on this point is contradicted by the very studies she references. Explaining those studies, the EPA's 2018 draft Integrated Science Assessment states:

> A number of recent studies have conducted analyses to inform the shape of the concentration response relationship for the association between long-term exposure to $PM_{2.5}$ and mortality, and are summarized in Table 11-7. Generally, the results of these analyses continue to support a linear, no-threshold relationship for total, nonaccidental, mortality, especially at lower ambient concentrations of $PM_{2.5}$, i.e., less than or equal to 12 micrograms per meter cubed. Lepeule, et al. 2012; Di, et al. 2017 C; and Shi, et al. 2015 observed linear no-threshold concentration response relationships for total nonaccidental mortality with confidence in the relationship down to a concentration of 8, 5, and 6 micrograms respectively. Figure 1122.
>
> […]
>
> Similar linear no-threshold concentration response curves were observed for total nonaccidental mortality in other studies: Chen, et al. 2016; Hart, et al. 2015; Thurston, et al. 2015; Cesaroni, et al., 2013.

Fraiser Test., Tr. Vol. 4-A, 19:15-21:17 (quoting from the 2018 EPA Integrated Science Assessment for Particulate Matter (External Review Draft), Section 11.2.4, at 11-81). These contradictions make Dr. Fraiser's testimony less credible.

277. For all these reasons, I give little weight to Dr. Fraiser's testimony. Specifically, I find her testimony less credible because (1) she has no expertise in epidemiology and statistics, two areas on which she opines, (2) she has not published original research regarding the health impacts of air pollution, (3) her NAAQS opinion contradicts the scientific consensus about the lack of a human health population threshold for $PM_{2.5}$, and (4) she mischaracterizes the findings of recent epidemiological studies.

Dr. Peter Valberg

278. Dr. Valberg's opinions also conflict with the generally held scientific consensus

on $PM_{2.5}$.

279. Dr. Valberg is a toxicologist at Gradient Corporation, where he has provided litigation services as an expert witness since 1990. Litigation consulting constitutes between 40% and 60% of his time. Valberg Test., Tr. Vol. 5-A, 98:20-100:15.

280. As part of litigation consulting, Dr. Valberg has provided testimony on behalf Clean Air Act Defendants in which he has unsuccessfully offered the same opinions he offered in this case. In a Clean Air Act case concerning excess SO_2 emissions released by an illegally modified plant, Dr. Valberg testified that the resulting $PM_{2.5}$ caused no harm to human health based on his opinion that sulfate particles are harmless. Valberg Test., Tr. Vol. 5-A, 103:4-104:25 (referring to United States v Cinergy Corp., 618 F.Supp.2d 942, 950 (S.D. Ind. 2009).[8]

281. The Cinergy court found that Dr. Valberg's opinions were contrary to mainstream science. In rejecting Dr. Valberg's opinions, that court concluded his opinions were a "minority view" that is contrary to the "bulk of the scientific literature on the subject [that] concludes that $PM_{2.5}$ has significant effects on human health." United States v. Cinergy Corp., 618 F.Supp.2d 942, 950 (S.D. Ind. 2009).

282. Dr. Valberg has also provided expert witness testimony in tobacco litigation. His opinions in tobacco cases have departed from the scientific consensus as well. Valberg Test., Tr. Vol. 5-A, 102:9-103:3; Geanacopoulos v. Phillip Morris USA Inc., No. 98-6002, 33 Mass. L.Rptr. 308, 2016 WL 757536, at *9 (Mass. Dist. Ct. Feb. 24, 2016) ("Dr. Valberg's analysis of the data provided by the published studies was shown to be inconsistent and contrary to the consensus of the scientific community.").

[8] The Cinergy opinion at 618 F.Supp.2d 942 was reversed by the Seventh Circuit. See 623 F.3d 455 (7th Cir. 2010). I cite the Cinergy opinion at 618 F.Supp.2d 942 several times in this memorandum opinion. These citations are for propositions that did not form the grounds for the Seventh Circuit's reversal.

283. In addition to litigation consulting, Dr. Valberg also provides consulting services to parties who want to comment on EPA regulatory proceedings. Valberg Test., Tr. Vol. 5-A, 119:5-8.

284. Dr. Valberg submitted comments to the EPA on behalf of the Utility Air Regulatory Group (UARG), a group of electric generating utilities, as well as other industry trade associations. In those comments, Dr. Valberg argued against lowering $PM_{2.5}$ standards. Valberg Test., Tr. Vol. 5-A, 125:22-126:20; see 78 Fed. Reg. 3086, 3111 (Jan. 25, 2013) (Def. Ex. AS). These comments included the same views expressed by Dr. Valberg in this litigation. The EPA rejected the comments and extensively explained its reasons for rejecting them. See id. at 3111-3120.

285. The EPA specifically rejected Dr. Valberg's testimony on the following points: (1) that the causal relationship the EPA found between $PM_{2.5}$ and human health impacts is not credible, id. at 3112-13; (2) that toxicological and epidemiology studies indicate a lack of "coherence or biological plausibility" between $PM_{2.5}$ and human health effects, id. at 3114(3); (3) that observed health effects of $PM_{2.5}$ are due to "confounding" variables, id. at 3115, and are biased by exposure measurement error, id. at 3118; (4) that the EPA's no-threshold determination is not credible, id. at 3119; and (5) that $PM_{2.5}$ should be regulated on a constituent-by-constituent basis rather than on a mass basis, id. at 3119.

286. Dr. Valberg also previously submitted comments criticizing the EPA's 2009 Integrated Science Assessment. Valberg Test., Tr. Vol. 5-A, 119:9-20. In those comments, Dr. Valberg argued the evidence was too weak to support the conclusion that $PM_{2.5}$ is harmful. On that basis, he urged the EPA to reconsider its determination that $PM_{2.5}$ exposure causes adverse health effects. The EPA rejected these comments. Valberg Test., Tr. Vol. 5-A, 119:25-121:22.

iv. The Evidence Does Not Support Ameren's Argument that Rush Island's Excess Emissions Are Harmless

287. Based in part on Dr. Valberg's and Dr. Fraiser's flawed testimony, Ameren makes five arguments why Rush Island's Excess SO_2 emissions are harmless. Ameren argues (1) that $PM_{2.5}$ concentrations below NAAQS do not pose a risk to human health, (2) that sulfate $PM_{2.5}$ is not toxic, (3) that epidemiological studies have too much variation and uncertainty to show a linear, no-threshold concentration-response function for $PM_{2.5}$, (4) that incremental changes smaller than the EPA's Significant Impact Levels (SILs) are meaningless, and (5) that modeling performed on behalf of the EPA in this litigation is "[u]ncertain, [o]verstated, and [u]nreliable." I will discuss the first three arguments here and the fourth and fifth arguments when addressing facts about the EPA's modeling.[9]

<u>The EPA Does Not Guarantee No Human Health Impacts Due to $PM_{2.5}$ Concentrations Below the NAAQS</u>

288. Pursuant to the Clean Air Act, the EPA must set the NAAQS at levels "the attainment and maintenance of which in the judgment of the Administrator, . . . allowing an adequate margin of safety, are requisite to protect the public health." 42 U.S.C. § 7409(b)(2).

289. Based on this language, Ameren argued throughout the trial that the NAAQS are protective of human health, and that any $PM_{2.5}$ concentration below the NAAQS would not pose a meaningful risk of harm to human health.

290. The structure of the Clean Air Act, the EPA's statements concerning the NAAQS, and the scientific consensus concerning $PM_{2.5}$ refute this argument.

291. Pursuant to the Clean Air Act, pollution sources in areas with air quality meeting

[9] In its proposed findings of fact, Ameren also presents two other arguments that are really subsets of the first argument (concerning NAAQS) and the fourth argument (concerning SILs).

the NAAQS must obtain PSD permits and must install BACT. When Congress added the PSD elements of the Clean Air Act, it acknowledged that reducing pollution in non-attainment areas was insufficient to meet the lofty goals of the Clean Air Act. See Envtl. Def. v. Duke Energy Corp., 549 U.S. 561, 567-68 (2007). Under this framework, neither Congress nor the EPA has characterized the NAAQS as eliminating all risk or all human health impacts. In fact, Ameren's expert Dr. Fraiser admitted that the NAAQS do not establish a zero-risk threshold. FOF ¶ 264.

292. Instead of referring to the NAAQS as a zero-risk, zero-impact threshold, the EPA has repeatedly stated that $PM_{2.5}$ has no known threshold. See FOF ¶ 271. Dr. Schwartz relied on the EPA's statements when testifying that the linear concentration-response function for $PM_{2.5}$ extends to concentrations below NAAQS. Id.

293. NAAQS attainment does not negate all the other evidence demonstrating human health impacts of $PM_{2.5}$, as Ameren argues. If this argument were true, then no human health impacts would ever arise from ambient air pollution across the United States, except for limited parts of California.

294. For these reasons, the evidence does not demonstrate that the NAAQS establish a zero-risk, zero-impact threshold, below which no human health impacts are meaningful.

The Toxicity of Sulfate $PM_{2.5}$ Cannot be Differentiated from Other Constituents

295. The scientific community has not determined whether sulfates are any less or more harmful than any other constituent of $PM_{2.5}$. FOF ¶ 243. Nonetheless, Ameren argues that sulfate $PM_{2.5}$ is harmless. Dr. Valberg has unsuccessfully made this argument to the EPA on behalf of other clients. Valberg Test., Tr. Vol. 5-A, 122:23-123:19.

296. Neither the EPA nor Congress has determined that sulfate-based particulates should be excluded from the total $PM_{2.5}$ mass when evaluating the health effects of $PM_{2.5}$.

Valberg Test., Tr. Vol. 5-A, 111:17-19, 113:2-5.

297. The consensus scientific opinion is that all $PM_{2.5}$ particles are toxic, including $PM_{2.5}$ derived from power plant SO_2 emissions. Researchers have not been able to determine the precise relative toxicities of different $PM_{2.5}$ constituents. In the absence of consistent evidence that any constituent has a different impact, the scientific community treats particles from all sources, including sulfates, as having the same toxicity. Schwartz Test., Tr. Vol. 3-A, 23:11-13, 23:22-24:19, 58:23-59:24; Tr. Vol. 3-B, 34:22-35:13, 39:12-22.

298. The EPA's Federal Register Notices announcing the $PM_{2.5}$ NAAQS in 2013 and 2006 cite evidence of sulfate $PM_{2.5}$'s toxicity. See 78 Fed. Reg. 3086, 3122-23 (Jan. 25, 2013) (Def. Ex. AS); 71 Fed. Reg. 61,144, 61,163 (Oct. 17, 2006). The 2006 Federal Register Notice stated that "[i]n short, there is not sufficient evidence . . . to suggest that any component should be eliminated from the indicator for fine particles. The Staff Paper continued to recognize the importance of an indicator that not only captures all of the most harmful components of fine particles (i.e., an effective indicator), but also emphasizes control of those constituents or fractions, including sulfates, transition metals, and organics that have been associated with health effects." 71 Fed. Reg. 61,144, 61,163; see also 62 Fed. Reg. 36,652, 38,666 (July 18, 1997) (noting that "the available scientific information does not rule out any one of these components as contributing to fine particle effects").

299. The World Health Organization has singled out combustion-related $PM_{2.5}$ as consistently demonstrating toxicity. Combustion-related $PM_{2.5}$ includes the sulfate $PM_{2.5}$ created by Rush Island's excess emissions. Schwartz Test., Tr. Vol. 3-A, 58:23-59:24.

300. I find that sulfate $PM_{2.5}$ is harmful and contributes to the negative human health impacts of $PM_{2.5}$ noted above.

Dr. Schwartz's Testimony Concerning Health Impacts of $PM_{2.5}$, Based on Epidemiological Studies, is Credible

301. Ameren seeks to discredit Dr. Schwartz's testimony by pointing to variation in the results of epidemiological studies and meta-analyses of those studies. See Ameren's Proposed Findings of Fact, ECF No. 1110, at ¶¶ 166-69. For example, Ameren discusses the results of seven studies used to inform a Regulatory Impact Analysis in California. Id. Some of those studies found a positive, but statistically insignificant slope; one found a positive, insignificant slope; and some of the studies found a positive and statistically significant slope. Schwartz Test., Tr. Vol. 3-B, 22:18-26:14.

302. In his testimony, Dr. Schwartz's explained that variability among different studies' statistical significance does not thwart his analyses. Dr. Schwartz included studies such as these in his meta-analyses, because the meta-analyses incorporate the findings of vast amounts of data and publications to determine the overall trend. Dr. Schwartz used his most recent, most comprehensive meta-analysis when determining the concentration-response relationship for $PM_{2.5}$, as applied to this case. Id. at 23:19-24:8.

303. Schwartz also demonstrated a vast knowledge of these underlying publications, explaining the conditions and results of studies when questioned about them. Id. at 22:25-26:25.

304. For these reasons, the variation in some epidemiological studies does not undermine Dr. Schwartz's testimony concerning the health impacts of $PM_{2.5}$.

c. Rush Island's Excess Pollution Affects the Entire Eastern Half of the United States

i. Plaintiff's Experts Presented Detailed and Credible Modeling Results

305. To quantify the human health impacts of Rush Island's excess emissions, the EPA presented photochemical grid modeling results. Chinkin Test., Tr. Vol. 2-B, 17:23-30:16.

Photochemical grid modeling is a computer modeling technique that tracks the "fate and transport" of air pollution in the atmosphere, namely how pollutants chemically change and where those pollutants travel. Chinkin Test., Tr. Vol. 2-B, 25:15-17 (describing the "fate and transport" of pollution as an assessment of "how air pollution is formed and moves").

306. Most SO_2 released from a power plant converts to $PM_{2.5}$ before being deposited in the environment. Chinkin Test., Tr. Vol. 2-A, 99:9-14. The rate at which SO_2 is converted into $PM_{2.5}$ varies between about 1 percent and 10 percent per hour and is faster in warmer and more humid weather and slower in cool and dry weather. Chinkin Test., Tr. Vol. 2-A, 97:20-98:16.

307. The variation in this rate does not substantially change the ultimate volume of $PM_{2.5}$ resulting from the SO_2 pollution. Under certain circumstances the conversion process may take longer. Slightly more SO_2 may be deposited if conversion rates are slower, but most of the SO_2 that remains in the atmosphere will be converted to $PM_{2.5}$. Chinkin Test., Tr. Vol. 2-A, 97:20-99:23; see also Chinkin Test., Tr. Vol. 2-B, 30:2-16. In general, the SO_2 emitted in the center of the country will transform into $PM_{2.5}$ before it is blown out to sea. Chinkin Test., Tr. Vol. 2-A, 100:6-9.

308. The EPA hired expert Lyle Chinkin to conduct atmospheric fate and transport modeling based on the facts in this case. Chinkin is an expert in atmospheric air quality modeling, air pollution fate and transport analysis, and air quality measurements. Chinkin has more than 40 years of experience working with photochemical models. He has used those models to analyze air quality issues ranging from single-source impacts for private clients to regulatory analyses for state and federal agencies. Chinkin Test., Tr. Vol. 2-A, 91:16-93:1, 94:14-20; Chinkin Resume (Pl. Ex. 1322).

309. Chinkin used a photochemical model called CAMx to estimate the impact of Rush

Island's excess pollution on downwind areas. CAMx is a reliable, state-of-the-science, peer-reviewed computer modeling program that is regularly used by both industry members and government regulators. Chinkin Test., Tr. Vol. 2-B, 4:12-5:20, 9:15-22.

310. Models like CAMx are used by air quality scientists, facility operators, and regulators to evaluate (1) the impact of a single source's pollution on the surrounding area, or (2) the downwind effect of an entire state's pollution portfolio. The EPA has long used air quality modeling like CAMx to assess the public health benefits associated with proposed rules and regulations. Chinkin Test., Tr. Vol. 2-B, 6:13-7:7.

311. To isolate the air quality impact from Rush Island's excess SO_2 pollution, Chinkin used a standard analytic technique known as a "with and without analysis." He ran the photochemical grid model twice, once in a "base case" and again in a "controlled case" scenario. In the base case, the inputs include the country's emissions profile and meteorology (wind, humidity, temperature, etc.), and the outputs are meant to replicate the ambient air quality. In the second controlled case scenario, the model setup remains unchanged except the emissions from one source—Rush Island—are reduced to account for the installation of pollution controls, specifically wet FGD. The differences in modeled $PM_{2.5}$ air quality concentrations between the two models are attributable to the difference in SO_2 contributed to the atmosphere from the examined source. Chinkin Test., Tr. Vol. 2-B, 8:3-9:9.

312. Photochemical modeling is time-consuming and expensive. CAMx divides the continental United States into 12-kilometer-square grids and then twenty-five planes of grid squares stacked upon each other, resulting in nearly 2.5 million cubic cells. In each of these cells, the model examines the concentration and influx of atmospheric constituents, calculates chemical reactions, and quantifies the resulting matter's transport into neighboring cells. The

model repeats these steps at five-minute intervals until it calculates an entire year's worth of reactions and physical transport. Because of the immense breadth of data and time-stepped calculations that are performed, modeling a year of pollution effects in CAMx can take weeks. Furthermore, developing the inputs for CAMx, including a verified and reliable emissions inventory, can take months. For these reasons, modeling more than a single year's worth of emissions is often impracticable. Chinkin Test., Tr. Vol. 2-B, 9:23-10:14.

313. A modeled year of results can be useful for estimating emissions impacts for other years, provided that year's weather and temperature data are fairly representative. In 2011, the weather and temperature data were representative of the weather and temperature data for the period Chinkin studied. Specifically, 2011's weather and temperature data were close to the median for years 2007 through 2016. For this reason, Chinkin chose to run the CAMx model for the 2011 emissions and meteorological data sets. Chinkin Test., Tr. Vol. 2-B, 29:9-30:16.

314. Although it is affected by temperature and other parameters, the relationship between the SO_2 concentrations and $PM_{2.5}$ formation is linear. As a result, the modeled $PM_{2.5}$ concentrations for 2011 can be scaled up or down on a percentage basis to estimate air quality impacts for other years. These estimates will not be perfectly accurate, but choosing a representative year such as 2011 decreases the overall bias and allows a larger timespan of emissions to be estimated without unnecessarily increasing litigation costs. Chinkin Test., Tr. Vol. 2-B, 29:18-24; see also id. Tr. Vol. 2-A, 98:22-99:8.

315. Modeling outputs will not perfectly match monitoring data. Any given monitor provides a point measurement of air quality at its location. In contrast, a photochemical grid model returns average air quality concentration values for a 12-square-kilometer area. Some of the locations within the modeled 12-kilometer grids will have higher concentrations, and others

will have lower concentrations. Nevertheless, comparing base case modeling results to monitors helps gauge whether the model is accurate. Chinkin Test., Tr. Vol. 2-B, 15:3-17:7.

316. Chinkin's base case model performed "exceptionally" well when compared with national monitoring networks, with error and bias measures well within industry standards for providing reliable results. Chinkin Test., Tr. Vol. 2-B, 17:8-18.

ii. The Model Predicts Rush Island's Excess Emissions Increased $PM_{2.5}$ Concentrations Across the Entire Eastern Half of the United States

317. The CAMx modeling Chinkin performed indicates that Rush Island's excess pollution impacts the entire Eastern United States. Chinkin Test., Tr. Vol. 2-B, 28:7-15. Ameren's own modeling expert, Ralph Morris, admitted that photochemical grid modeling showed excess pollution from Rush Island impacted $PM_{2.5}$ concentrations in Pennsylvania, Michigan, Louisiana, and even Florida. Morris Test., Tr. Vol. 5-A, 5:2-17.

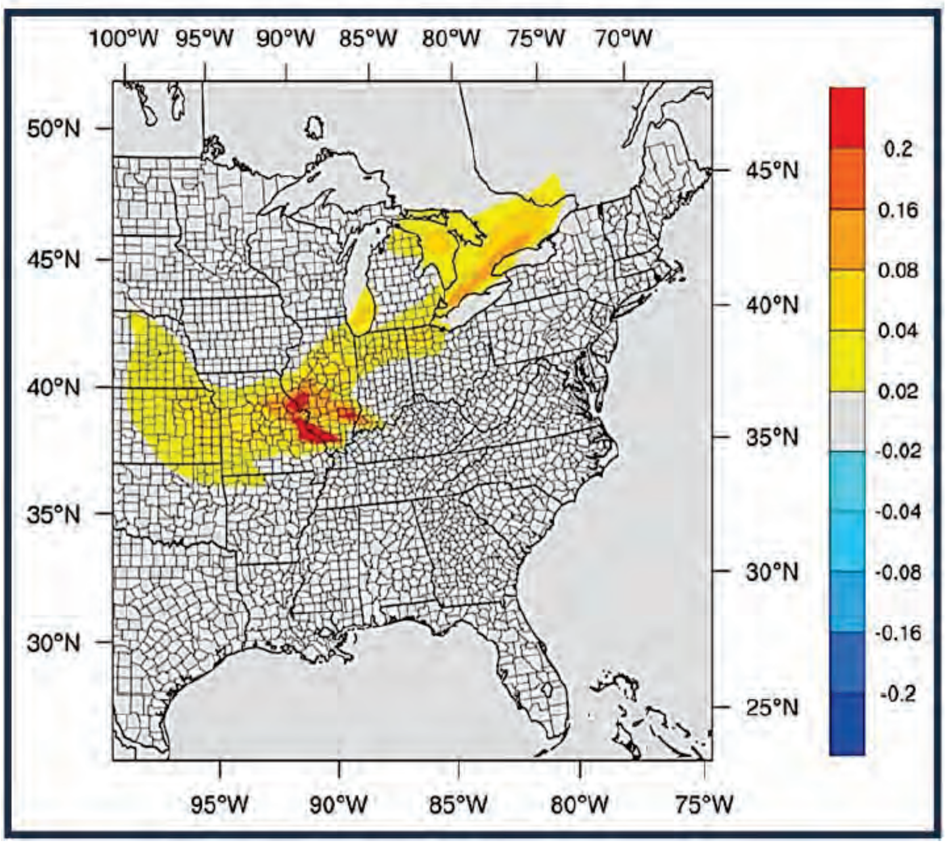
318. The impact of Rush Island's excess pollution depends in part on the wind and weather. See, e.g., Chinkin Test., Tr. Vol. 2-B, 23:18-25:7; Model Results Maps (Pl. Exs. 1373-76).

319. On some days, the pollution's largest impact on air quality occurs relatively close to the plant. For example, as shown in Figure 4, on August 18, 2011, CAMx modeling shows Rush Island's excess pollution contributed as much as 2.25 $\mu g/m^3$ to ambient $PM_{2.5}$ concentrations in the greater St. Louis area. At the same time, some of the excess pollution was predicted to extend hundreds of miles further in a band stretching from Kansas to north of the Great Lakes. When describing this result, Chinkin testified: "I've been doing this for 30 plus years. That is a very large impact. *It's one of the largest I've seen from a single source on a single day*." Pl. Ex. 1369; Chinkin Test., Tr. Vol. 2-B, 17:23-20:2 (emphasis added).

320. On other days, excess SO_2 pollution from Rush Island has its greatest air quality

impact hundreds of miles away. For example, as shown in Figure 5, on March 15, 2011, air quality modeling indicates Rush Island's excess SO_2 predominantly affected air quality to the southwest of the plant. The largest contributions for that day measured more than 0.02 $\mu g/m^3$ and occurring around Houston, Texas. <u>See</u> Pl. Ex. 1372. Regarding this result, Chinkin testified: "[C]onsidering it's one source and [the pollution has] now traveled hundreds if not a thousand miles away, that's a very large impact." Chinkin Test., Tr. Vol. 2-B, 22:2-19.

<u>Figure 4</u>



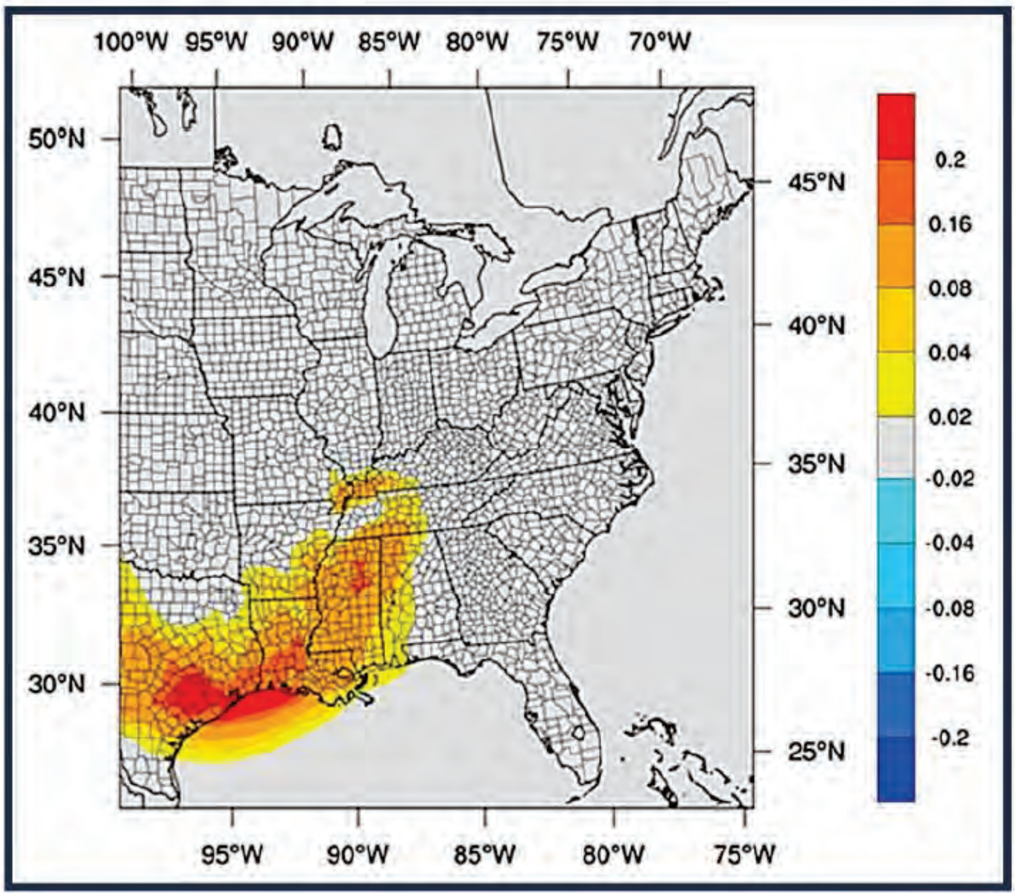
Pl. Ex. 1369 (described at Chinkin Test., Tr. Vol. 2-B, 17:23-20:2).

321. On more than 250 days in 2011 (70% of the days in the year), Rush Island's

excess SO_2 pollution contributed more than 0.1 μg/m^3 to downwind $PM_{2.5}$ concentrations. Chinkin Test., Tr. Vol. 2-B, 26:14-15.

322. During more than 90 days in 2011 (25% of the year)—and about half of summer days—Rush Island's excess pollution contributed more than 0.25 μg/ m^3 to downwind $PM_{2.5}$ concentrations. Chinkin Test., Tr. Vol. 2-B, 26:15-20.

Figure 5

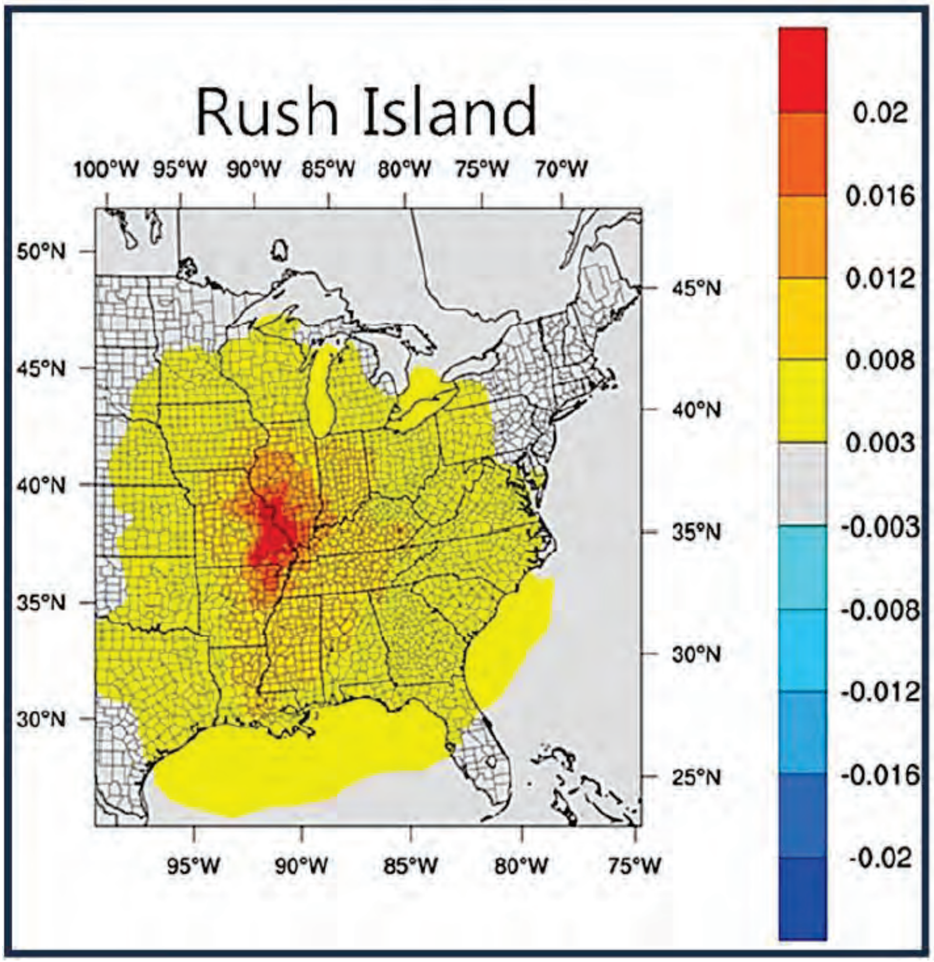


Pl. Ex. 1372 (described at Chinkin Test., Tr. Vol. 2-B, 22:2-19).

323. Compiling daily impact results into a single map and averaging the results provides a view of the annual average impact from Rush Island's excess SO_2 pollution on $PM_{2.5}$ concentrations. As seen in Figure 6, the area affected by Rush Island's excess SO_2 pollution

extends from the Gulf of Mexico to the Great Lakes, and from the middle of Kansas to the Atlantic coast.

Figure 6



Pl. Ex. 1364 (described at Chinkin Test., Tr. Vol. 2-B, 27:15-29:8).

324. The model predicted that at least one grid cell would have $PM_{2.5}$ concentrations 0.057 µg/ m^3 greater when averaged throughout the entirety of 2011. Chinkin Test., Tr. Vol. 2-B, 27:15-29:8.

d. Results of Two Different Models Show Rush Island's Excess Emissions Increased the Risk of Hundreds to Thousands of Premature Deaths

325. Plaintiffs presented two independent quantification methods to measure the harm from Rush Island's excess pollution. The first method relies on the results of a peer-reviewed risk assessment of 407 power plants, including Rush Island, published by Dr. Schwartz in 2009. Schwartz Test., Tr. Vol. 3-A, 88:11-89:18. The second method relies on the CAMx air quality modeling performed specifically for this case by the EPA's expert Chinkin.

326. Both risk assessments modeled $PM_{2.5}$ transport and concentration in ambient air. Using those concentrations, they estimated premature deaths in the exposed population. In doing so, both assessments applied the same approach used by public health agencies to quantify the risk of premature mortalities from exposure to $PM_{2.5}$, including the U.S. Centers for Disease Control, the World Health Organization, the National Academy of Sciences, and the EPA. Schwartz Test., Tr. Vol. 3-A, 83:6-87:9.

327. As described below, the models differ based on how they calculate concentrations and exposure. Despite these differences, the models showed consistent, comparable results among each other.

i. Dr. Schwartz Published a Peer-Reviewed Quantitative Risk Assessment for Rush Island's SO_2 Emissions in 2009

328. Unrelated to any litigation, the EPA's expert Dr. Schwartz previously co-authored a peer-reviewed, quantitative risk assessment of emissions from coal-burning power plants, including Rush Island. That assessment, "Uncertainty and Variability in Health-Related Damages from Coal-Fired Power Plants in the United States," was published in 2009 in the scientific journal "Risk Analysis." Schwartz Test., Tr. Vol. 3-A, 87:17-91:5.

329. Dr. Schwartz's 2009 risk assessment modeled SO_2 and resulting $PM_{2.5}$ pollution

using a pollution transport model known as a reduced-form model. The reduced-form model was calibrated to ensure consistency with actual monitoring data. Schwartz Test., Tr. Vol. 3-A, 89:19-90:10.

330. Reduced form models are commonly used in the scientific community to perform quantitative risk assessments. For instance, the National Academy of Sciences has used the reduced form model in performing similar risk assessments, and cited Dr. Schwartz's 2009 study in doing so. Schwartz Test., Tr. Vol. 3-A, 90:11-19.

331. Dr. Schwartz's 2009 risk assessment calculated 95% confidence intervals and incorporated uncertainties both for the modeled $PM_{2.5}$ exposure estimates as well as the concentration-response relationship. Schwartz Test., Tr. Vol. 3-A, 91:11-94:21. A 95% confidence interval means there is a 95% chance that the number of premature deaths that occurred as a result of excess pollution falls in the range identified in a given study. There is a remaining 5% probability (2.5% above the interval and 2.5% below the interval) that the number falls outside the identified range. Id.

ii. Dr. Schwartz Also Quantified Risk Based on Chinkin's CAMx Modeling

332. Dr. Schwartz also performed a second quantitative risk assessment based on the results of Chinkin's air quality modeling in this case using the CAMx model. Schwartz Test., Tr. Vol. 3-A, 95:5-95:14.

333. To evaluate impacts on premature mortality from the CAMx air quality concentrations, Dr. Schwartz relied on the most up-to-date concentration-response function for $PM_{2.5}$ available in the literature. Dr. Schwartz paired that concentration-response function with a reliable and peer-reviewed EPA risk assessment tool known as "BenMAP." BenMAP includes population and baseline mortality data for the entire country, including the areas impacted by

Rush Island's pollution. Schwartz Test., Tr. Vol. 3-A, 95:15-96:17.

334. Dr. Schwartz derived the specific concentration-response from a published, peer-reviewed meta-analysis he co-authored. The meta-analysis included all data points published by over 50 long-term epidemiological studies, with the goal of creating the best current function. Meta-analysis is "the standard approach for trying to integrate multiple studies . . . and come up with . . . the best estimate." Schwartz Test., Tr. Vol. 3-A, 96:2-11, 97:3-100:17.

335. Dr. Schwartz's meta-analysis included 95% confidence intervals reflecting uncertainty in the calculated $PM_{2.5}$ concentration-response relationship. These confidence intervals are narrower than those derived in Dr. Schwartz's 2009 risk assessment, because the meta-analysis incorporated results from millions of study participants. Schwartz Test., Tr. Vol. 3-A, 99:6-25, 101:21-102:7.

336. The confidence intervals for Dr. Schwartz's CAMx-based risk assessment do not include any uncertainty related to the accuracy of the modeled $PM_{2.5}$ exposure estimates; CAMx is a deterministic model that produces a precise number based on the laws of physics and chemistry and specific inputs. Public health professionals routinely use deterministic models to estimate health effects from incremental changes in air pollution. Chinkin Test., Tr. Vol. 2-B, 8:12-9:1; Schwartz Test., Tr. Vol. 3-A, 93:10-15, 102:8-104:6.

iii. Rush Island's Excess Emissions Caused Hundreds to Thousands of Premature Deaths

337. Public health risk assessments demonstrate the overall effect of exposing a population to an increased risk of harm. They do not identify a specific individual who was, or will be, harmed by an exposure. Schwartz Test., Tr. Vol. 3-A, 82:14-87:2, 104:19-107:2.

338. Based on the two risk assessments described above, Dr. Schwartz calculated premature deaths *expected* to result from Rush Island's excess emissions. This metric represents

an increased risk of harm, not any specific person's death. Table 1 shows Dr. Schwartz's calculated expected premature mortality, based on Rush Island's excess emissions. For 2007 to 2016, Dr. Schwartz calculated 637 and 879 expected premature mortality events based on the reduced form model and CAMx model, respectively. Dr. Schwartz calculated that after 2016, an average of 62 or 86 premature mortality events per year are expected, based on the reduced form and CAMx models, respectively. Schwartz Test., Tr. Vol. 3-A, 91:11-24, 95:25-96:4, 101:15-20, 104:15-18.

Table 1

Premature Mortality	Reduced Form Model (95% confidence interval)	CAMx Model (95% confidence interval)
Per Thousand Tons	3.9	5.4
2007-2016	637 (172 - 1,436)	879 (738 - 1,215)
2017 and beyond	62/ year	86/ year

339. Dr. Schwartz's risk assessments demonstrate that Rush Island's excess emissions pose substantial risk of harm to the exposed populations. They also show that the harm will continue until Rush Island's excess emissions stop. Schwartz Test., Tr. Vol. 3-A, 82:14-83:4, 107:3-16, 109:1-13.

340. The similarity of results, 95% confidence intervals, and peer-reviewed nature of these models provide me with a high degree of confidence in my conclusion that Rush Island's excess emissions have harmed public health and welfare. Schwartz Test., Tr. Vol. 3-A, 87:17-88:8, 89:19-90:10, 91:11-24, 94:13-21, 101:1-102:25, 109:1-13.

e. Ameren's Criticisms of the EPA's Model Are Not Persuasive

341. Ameren makes two main criticisms of the EPA's modeling methods and results: (1) that incremental changes smaller than the EPA's Significant Impact Levels (SILs) are meaningless, and (2) that modeling performed on behalf of the EPA in this litigation is

"[u]ncertain, [o]verstated, and [u]nreliable."

342. The SILs are "screening tools the EPA uses to determine whether a new source may be exempted from certain requirements under § 165 of the Act, 42 U.S.C. § 7475." Sierra Club v. E.P.A., 705 F.3d 458, 459 (D.C. Cir. 2013). "[Section] 165(a)(3) requires that an owner or operator . . . demonstrate that emissions from construction or operation of the facility will not cause or contribute to any violations of the increment more than once per year, or to any violation of the NAAQS ever." Id. at 460.

343. The EPA has not alleged, and its case does not depend on, any NAAQS or PSD increments violations in this case.

344. As a result, Ameren's SILs argument does not make the EPA's modeling methods or results less credible or convincing.

345. With respect to SILs, Ameren asserts that changes in concentrations below the EPA's established SILs do not represent a meaningful or significant threat to human health.

346. The SILs were designed for use in the PSD permitting process, to determine if, despite the installation of BACT, the creation or modification of a source would lead to NAAQS violations. Knodel Test., Tr. Vol. 1-A, 64:25-66:25, 92:23-93:25; NSR Manual (Pl. Ex. 1190), at AM-REM-00544163; MDNR Rule 30(b)(6) Dep., Aug. 10, 2018, Tr. 135:9-20, 135:25-136:4.

347. The SILs were derived from a statistical analysis of the limits of monitoring data, based on a finite network of variably-placed monitors. Morris., Tr. Vol. 5-A, 6:20-25. Recognizing that "there is an inherent variability in the air quality" "due to fluctuating meteorological conditions and changes in day-to-day operations of all air pollution sources in an area," the EPA developed the SILs using "a statistical analysis of the variability of air quality, using data from the U.S. ambient monitoring network for ozone and $PM_{2.5}$." (Ex. HB at HB_12.).

348. The EPA has relied on modeled concentration changes below the SILs in calculating human health benefits—including changes even below 0.01 µg/ m^3, orders of magnitude less than the 0.2 µg/ m^3 SIL value Ameren's expert Ralph E. Morris used as a comparator. Morris Test., Tr. Vol. 5-A, 14:10-16:20; Schwartz Test., Tr. Vol. 3-A, 108:3-25.

349. Independently, Ameren argues that the EPA's modeling results are "[u]ncertain, [o]verstated, and [u]nreliable." Ameren makes this argument based on (1) model noise, (2) the EPA's use of 2011 meteorology data as representative of other years, (3) the EPA's use of a baseline for its Labadie model that included FGD controls on Rush Island, and (4) the difference between 12-kilometer grid cell estimates and monitors point estimates.

350. I find that Ameren's arguments about these features do not render the EPA's modeling methods or results less credible or convincing.

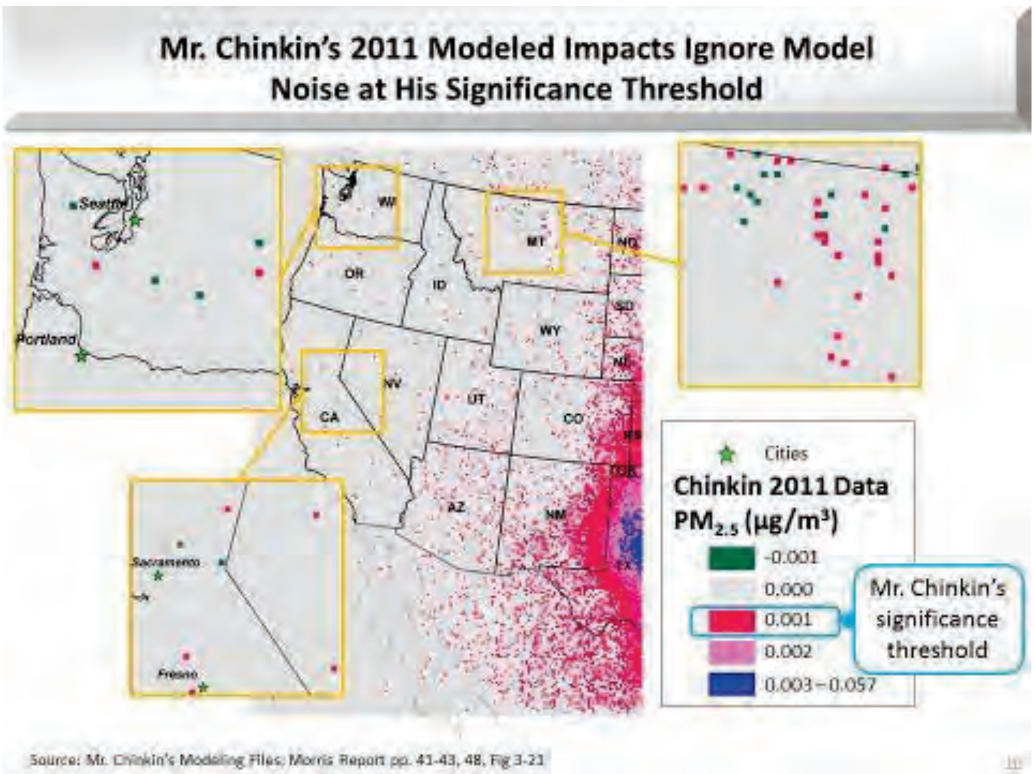
351. First, large-scale models—including the one from the EPA's expert Chinkin—include some noise. This is because algorithms conducting millions of calculations can produce data (the noise) that are not a direct result of the variables that are the focus of the model. In this case, for example, some of the data in Chinkin's model were not tied to a hypothetical reduction in SO_2 pollution. Ameren's expert Morris correctly notes that when relying on "this kind of approach using one simulation subtracting from another," the modeler "need[s] to be very careful" that "[he is] looking at concentrations above model noise." Morris Test. Tr. Vol. 4-B, 79:22-89:12.

352. Ameren argues that the presence of model noise near the EPA's 0.001 µg/m^3 modeling threshold makes the EPA's CAMx results unreliable. Ameren specifically points to model noise found in Montana, Washington, and California as shown in Def. Figure A.

353. Model noise is both positive and negative in these areas. Ameren does not present

any evidence demonstrating that the model noise has led to any bias or that the model noise played any significant role in the final results of the CAMx modeling. Therefore, Ameren's model noise argument does not make the EPA's modeling methods or results unreliable or unconvincing.

Def. Figure A



354. Second, Ameren argues that the EPA should have used year-specific meteorology data for every year since the Rush Island major modifications in 2007. I agree with Ameren that the EPA's model results would have been even more precise if they had run the voluminous and expensive CAMx model twelve or more times, for every year from 2007 through 2018. However, the EPA made a reasonable choice to run the data-, time-, and resource-intensive CAMx model four times using 2011 as a representative year (with a base and emissions-

controlled case for both Rush Island and Labadie). Ameren did not present sufficient evidence to demonstrate that this approach was unreliable or unconvincing.[10]

355. Third, Ameren argues that the EPA should have used the same baseline emissions scenario for its Rush Island and Labadie modeling. When the EPA modeled the impact of installing pollution equipment on Labadie, its base case assumed that pollution controls would also be installed on Rush Island, due to the outcome of this litigation. The point of the modeling was to determine whether emissions reductions from Labadie would affect the same population impacted by Rush Island's excess emissions. The EPA reasonably assumed that I would not order emissions reductions at Labadie if I did not also order emissions reductions at Rush Island. Under that condition, it would be inappropriate to use the same base case for Rush Island and Labadie CAMx modeling. Ameren's argument regarding baseline emissions does not make the EPA's modeling methods or results unreliable or unconvincing. Chinkin Test., Tr. Vol. 2-B, 31:21-33:22.

356. Fourth, Ameren argues that differences between 12-kilometer grid-cell model results and point-measurements of the $PM_{2.5}$ concentration near St. Louis make the EPA's CAMx modeling unreliable and unconvincing. As I explained above, modeling outputs will not perfectly match monitoring data. Any given monitor provides a point measurement of air quality at its location. In contrast, a photochemical grid model returns average air quality concentration values for a 12-square-kilometer area. FOF ¶ 312; Chinkin Test., Tr. Vol. 2-B, 15:3-17:7.

357. Ameren's argument about differences between monitoring data and modeled results does not make the EPA's modeling methods or results unreliable or unconvincing. The

[10] For example, Ameren did not provide a copy of the 2017 guidance document that Ameren's expert Morris says encourages modelers to use year-specific data. Morris Test., Tr. Vol. 4-B, 94:3-95:12. Without more information concerning that guidance, I cannot determine the weight to give this guidance.

EPA's expert Chinkin compared his model results to all the available monitoring data and found that his base case model performed "exceptionally" when compared with the actual data from national monitoring networks. FOF ¶ 316; Chinkin Test., Tr. Vol. 2-B, 17:8-18.

V. RUSH ISLAND'S EXCESS POLLUTION IS BEST REMEDIATED BY DECREASING EMISSIONS AT THE NEARBY LABADIE ENERGY CENTER

358. Ameren's violation of the Clean Air Act at Rush Island has resulted in more than 162,000 tons of excess SO_2 pollution through 2016. That amount is expected to grow to 275,000 tons by the time Rush Island finally complies with the PSD program. FOF ¶ 210-11.

359. Accordingly, Plaintiffs seek an injunction requiring Ameren, over time, to reduce pollution from its nearby Labadie plant in an amount equal to Rush Island's total excess emissions. By reducing future SO_2 emissions from the Labadie plant, Ameren can, ton for ton, remedy the harm it caused by failing to install pollution control technology that should have been installed in 2007 and 2010.

360. The Labadie plant is located near Labadie, Missouri, about 35 miles west of St. Louis. The plant consists of four units, each of which can generate about 600 megawatts of electricity, about as much as Rush Island's units can generate. Integrated Resource Plan (Pl. Ex. 1247), at USTREXR0006246 to 6247. Ameren plans to retire the four Labadie units in 2036 and 2042. Michels Test., Tr. Vol. 5-B, 18:20-23, Michels Dep., Aug. 14, 2018, Tr. 14:1-23, 109:21-110:13.

361. Dr. Staudt looked at multiple options for reducing future SO_2 emissions from the Labadie plant: natural gas conversion, wet FGD, dry FGD, DSI, and DSI with the addition of a fabric filter.

362. All these options are technically and practically achievable at Labadie. Staudt Test., Tr. Vol. 1-B, 102:11-103:6. The capital costs range from $55 million for DSI on all four

Labadie units to about $1 billion for wet FGD on all four units. Staudt Test., Tr. Vol. 1-B, 102:15-103:11. The operating costs range from $31 million/year for DSI with a fabric filter to a high but variable operating cost for a natural gas conversion. Id. at 103:12-20. The operating costs for DSI without a fabric filter would be about $53 million/year. Id. at 105:19-20. Natural gas conversion would have the highest emissions reductions, virtually eliminating SO_2 emissions. After that, wet FGD would achieve the greatest reductions, followed by dry FGD, DSI-FF, and DSI. The higher the reductions, the faster the remediation. Staudt Test., Tr. Vol. 1-B, 104:1-17.

363. The reduction capabilities of installing DSI without a fabric filter on all four units and wet FGD on two units are relatively close. It would take about the same amount of time to offset the excess pollution with these two technologies. Assuming, on the high side, annual uncontrolled emissions of about 38,000 tons per year, DSI on all four units would remove 19,000 tons per year and offset the excess within about 14 or 15 years, while wet FGD on two units would remove 17,000 tons per year and offset the excess in a little over 16 years. Staudt Test., Tr. Vol. 1-B, 106:23-107:11, 108:2-7.

364. The cost-effectiveness of the two options is also relatively similar: $4300/ton for wet FGD on two units compared to $3100/ton for DSI on four units. Id. at 107:12-15.

365. DSI could be installed in 18 months, more quickly than wet FGD. Staudt Test., Tr. Vol. 1-B, 106:8-20, Tr. Vol. 2-A, 16-17; Snell Test., Tr. Vol. 4-B, 30:17-31:6.

a. Reducing Future Pollution from Labadie Will Remediate the Harm from Rush Island for the Same Populations and to the Same Extent

366. The harm from Ameren's excess SO_2 emissions was imposed on tens of millions of people living in the communities impacted by Rush Island's pollution. As a result, these populations experienced increased risks of adverse health effects, including increased risk of

premature mortality. Schwartz Test., Tr. Vol. 3-A, 82:14-83:4, 110:10-22.

367. The linear concentration-response relationship for $PM_{2.5}$ exposure means that, in the range of concentrations studied, any incremental decrease in exposure produces a positive impact on public health. FOF ¶ 263; see also Schwartz Test., Tr. Vol. 3-A, 48:3-50:13.

368. Reducing pollution from Labadie by an amount equal to Rush Island's excess emissions will reduce the risk of adverse health effects and premature mortality in the exposed population by an amount equal to the increased risk from Rush Island's excess emissions. Schwartz Test., Tr. Vol. 3-A, 20:23-21:8, 110:10-22.

369. The populations that will benefit from these reductions are almost identical to those who were harmed by Rush Island's excess pollution. As a result, there is a particularly tight factual nexus between remedy and harm. This tight nexus is demonstrated by Dr. Schwartz's 2009 risk assessment. For most coal-fired power plants, the assessment showed significant variability in the health impacts of emissions depending on where each ton was emitted. Schwartz Test., Tr. Vol. 3-A, 88:9-89:12. However, Ameren's Rush Island and nearby Labadie plants had nearly identical health impacts per ton of SO_2, because they impact roughly the same populations. Schwartz Test., Tr. Vol. 3-A, 110:24-111:23, 116:23-118:4.

370. Chinkin's CAMx modeling confirms this close nexus. Chinkin modeled the benefits of installing pollution control options at Labadie in the same way he studied the impacts of Rush Island's excess pollution. This modeling shows that the two plants have similar pollution-impact profiles, affecting the same populations and to the same extent. Chinkin Test., Tr. Vol. 2-B, 31:21-33:5, 36:16-37:22.

371. Chinkin's CAMx modeling indicated that scrubber technology operated at two of Ameren's Labadie units would reduce SO_2 pollution by about the same amount in the same

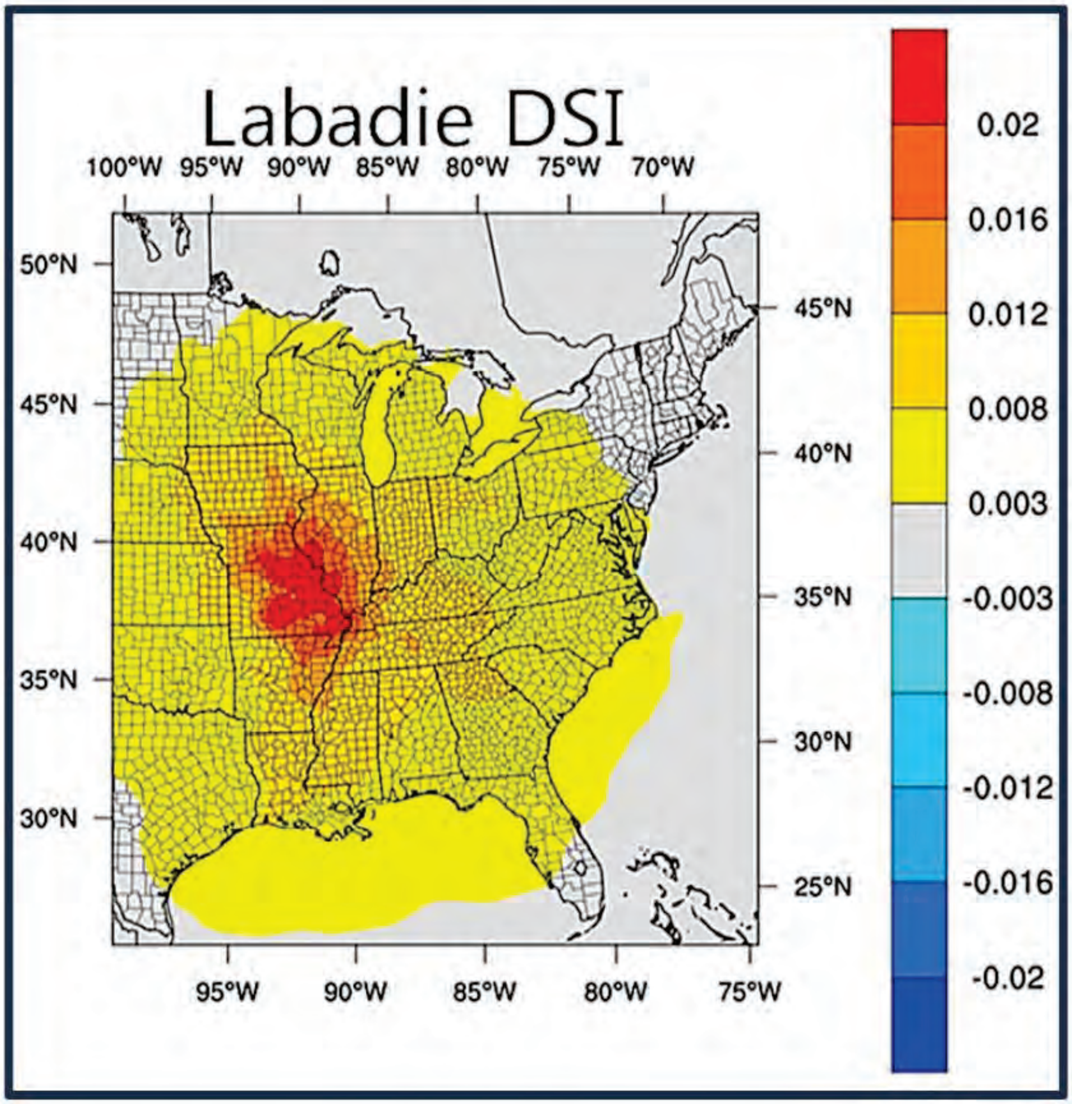
geographic region as Rush Island's excess pollution. Based on 2011 data, this control technology would have a maximum average annual impact of 0.054 µg/ m^3 (compared to 0.057 µg/ m^3 for Rush Island's excess pollution), and a maximum daily downwind impact on $PM_{2.5}$ concentrations of 2.44 µg/ m^3 (compared to 2.25 µg/m^3). Chinkin Test., Tr. Vol. 2-B 33:6-34:12; Model Results Map (Pl. Ex. 1362).

372. Similarly, the CAMx modeling shows that DSI technology operated at all four of Ameren's Labadie units would reduce SO_2 pollution by about the same amount in the same geographic region as Rush Island's excess pollution, as shown in Figure 7. Chinkin Test., Tr. Vol. 2-B, 34:20-36:5 Schwartz Test., Tr. Vol. 3-A, 111:24-112:8.

373. I find that reducing emissions SO_2 pollution from Ameren's Labadie plant will, on a ton-for-ton basis, benefit the same populations—and to the same extent—that suffered the harm from Rush Island's excess pollution. This finding is based on both the reduced form modeling prepared by Dr. Schwartz in his published 2009 risk assessment, as well as the CAMx modeling prepared by Chinkin for this case.

374. Ameren did not present evidence or testimony challenging Chinkin's conclusion that the SO_2 pollution from the Labadie Energy Center affects downwind $PM_{2.5}$ concentrations to the same scope and degree as the SO_2 pollution from the Rush Island facility.

Figure 7



Pl. Ex. 1362.

b. Society Will Benefit If Ameren Offsets Its Excess Emissions

375. The societal benefits associated with offsetting Ameren's excess pollution are substantial. Reducing the pollution from Labadie in an amount equal to Rush Island's excess emissions will result in an equal amount of avoided health effects, including premature mortality,

in the same population. Schwartz Test., Tr. Vol. 3-A, 20:23-21:8, 110:10-22.

376. These benefits have substantial economic value. In his 2009 risk assessment, Dr. Schwartz quantified the social cost Rush Island and Labadie's pollution, as well as the pollution of 405 other coal-fired power plants. In this study, Dr. Schwartz applied standard, peer-reviewed values used by public health professionals and the EPA to estimate economic benefits of pollution reduction. Schwartz Test., Tr. Vol. 3-A, 112:10-116:22. Based that study, Dr. Schwartz estimated the social benefits from remedying Rush Island's excess emissions would far surpass the costs of any control technology used. Compare Schwartz Test., Tr. Vol. 3-A, 116:23-118:4 with Def. Exs. IB & IC and FOF ¶ 362 (Labadie costs).

377. Chinkin's CAMx-derived benefits estimates are even higher than the results of the 2009 risk assessment, confirming that the benefits of remediating Rush Island's excess pollution exceed the costs. Compare Schwartz Test., Tr. Vol. 3-A, 118:16-24 with Def. Exs. IB & IC and FOF ¶ 362.

c. Ameren's Surrendering of Pollution Allowances Would Not Remedy Harms to the Populations Affected by Rush Island's Excess Emissions

378. Ameren offered to surrender SO_2 emission allowances under the Cross-State Air Pollution Rule (CSAPR) as mitigation for Rush Island's excess pollution. See Ameren Trial Brief, ECF Doc. 1071, at 13-15. CSAPR is a market-based program issued under the Good Neighbor Provision of the Clean Air Act and designed to reduce air pollution from upwind states to the benefit of downwind states. Knodel Test., Tr. Vol. 1-A, 100:10-16, 102:16-20; see 42 U.S.C. § 7410(a)(2)(D)(i).

379. Under CSAPR, which went into effect in 2015, the EPA establishes an SO_2 emission budget for each state. Knodel Test., Tr. Vol. 1-A, 100:10-101:17, 102:21-23. Each state then allocates allowances to individual units, with each allowance authorizing the source to

emit one ton of pollution. Knodel Test., Tr. Vol. 1-A, 101:22-102:8.

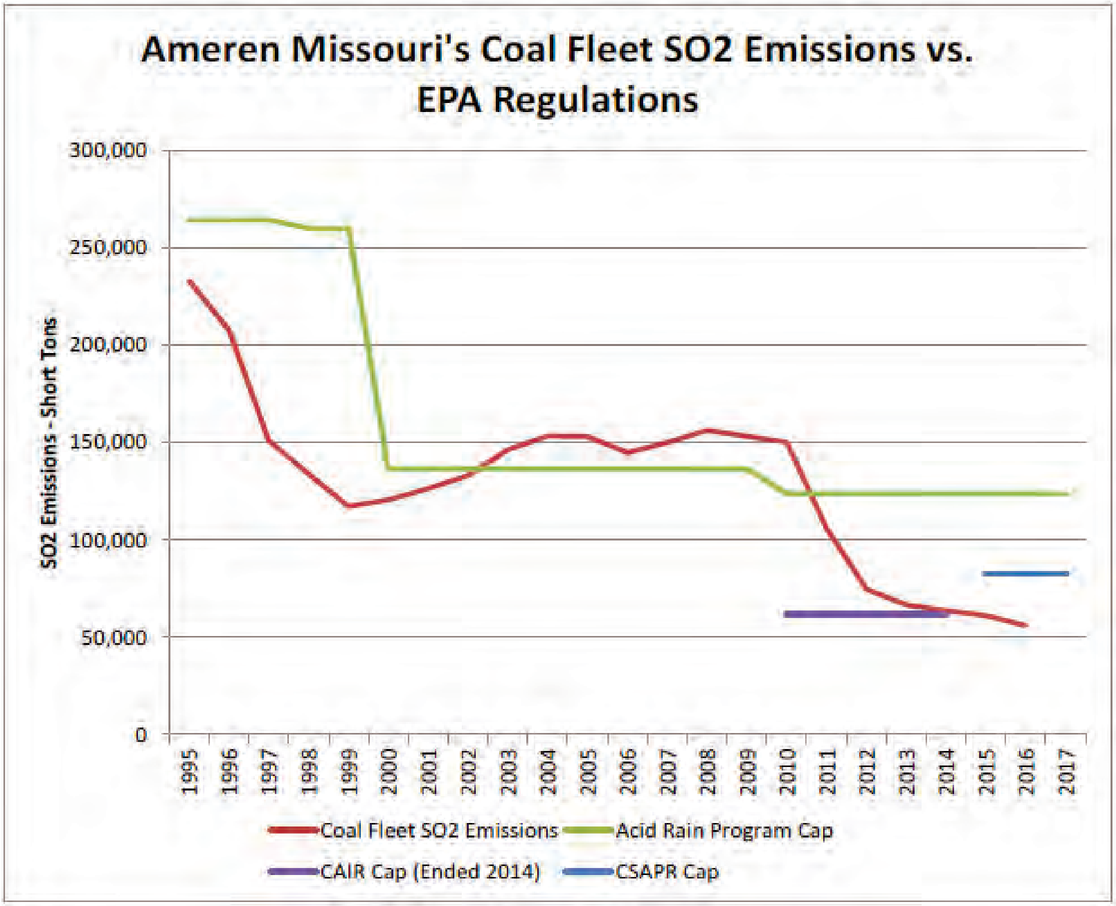
380. Allowances are freely tradable among regulated units, brokers, and other parties. (Harvey Decl. at 18.) During each year of the CSAPR programs, each regulated unit must monitor and report its SO_2 emissions. Shortly after the end of the year, the unit must surrender one eligible "allowance" for each ton of its reported emissions for the year. Id. If a utility does not use its allowances in a given period, it can carry over the unused allowances. The utility may either sell the allowances to another source in the same trading region or use the carryover allowances itself. Knodel Test., Tr. Vol. 1-A, 102:4-15, 102:24-103:3.

381. Missouri is part of Group 1 of the CSAPR SO_2 allowance trading program. Group 1 consists of 16 states, including those as far away as Wisconsin, Michigan, New York, Virginia, and North Carolina. Michels Test., Tr. Vol. 5-B, 12:19-13:23.

382. The Parties stipulated that, as of the beginning of 2019, Ameren held 237,184 CSAPR SO_2 allowances. ECF No. 1077-1 at 3; Pre-Trial Hearing Tr. 31:18-32:3 (Ameren counsel agreeing to use the United States' number); Michels Test., Tr. Vol. 5-B, 14:2-5.

383. In its 2017 Integrated Resource Plan, Ameren presented a graph (reproduced here as Figure 8) showing that its fleetwide SO_2 emissions are below the cap established by CSAPR, and that the allowance surplus is increasing each year:

Figure 8



Def. Ex. PV, at PV_5; Michels Test., Tr. Vol. 5-B, 14:8-15:5.

In this graph, the blue line represents Ameren's emissions limit based on its annual allocation of CSPAR allowances. Id. The red line represents the tons of SO_2 emitted from the entirety of Ameren's coal fleet in Missouri. The green and purple lines represent Ameren's respective limits for the Acid Rain Program and the Clean Air Interstate Rule (CAIR), the predecessor to CSAPR. As shown in Figure 8, the CAIR program had lower emissions limits for Ameren's fleet of power plants than any other program shown. Ameren never met the more challenging emissions limitations of CAIR, although its fleetwide emissions decreased during the CAIR program. By the time the CAIR program ended in 2014, Ameren's fleetwide emissions were about equal to the CAIR limit and substantially lower than the new CSAPR emissions limit.

384. Generally, power plant owners and operators have met the CSAPR limit by large margins. As of the end of 2016, Group 1 sources had banked 2,924,713 SO_2 allowances. EPA Report, “2016 Program Progress: Cross-State Air Pollution Rule and Acid Rain Program,” (Pl. Ex. 1442).

385. The price for Group 1 SO_2 allowances is currently “very low” according to Ameren’s trial expert economist. Celebi Test., Tr. Vol. 5-B, 72:9-11. Each allowance is about $2.50 under current market prices. Knodel Test., Tr. Vol. 1-A, 107:18-21.

386. Ameren did not present evidence or an argument demonstrating that surrendering allowances would actually decrease emissions. In its proposed findings of fact, Ameren stated that:

> Ameren currently relies on the use of CSAPR allowances to comply at Rush Island. For the period when CSAPR began in 2015 through 2018, Ameren has been allocated an average of 21,477 allowances per year, and has exceeded those allowances in several years. (Michels, Tr. Vol. 5-B, 7:14-8:4.) Based on these trends, it is reasonable to assume that Rush [I]sland’s emissions may exceed allowances in the future as well.

Ameren’s Proposed Findings of Fact, ECF No. 1110 at ¶277.

387. The cited testimony does not support Ameren’s assertions. Michels, Tr. Vol. 5-B, 7:14-8:4. Instead, the testimony demonstrates that Rush Island has exceeded its allowances in only one year (2017), and over the past four years, Rush Island has accumulated 9,625 net allowances. Over its entire fleet, Ameren has accumulated 237,184 net allowances during the same period. ECF No. 1077-1at 3; Pre-Trial Hearing Tr. 31:18-32:3 (Ameren counsel agreeing to use the United States’ number); Michels Test., Tr. Vol. 5-B, 14:2-5.

388. From CSAPR’s effective date in 2015 through 2018, Rush Island has had the following allowances and actual emissions:

a. 2015: 24,310 allowances and 18,253 tons of emissions,

b. 2016: 24,237 allowances and 17,379 tons of emissions,

c. 2017: 18,686 allowances and 22,167 tons of emissions,

d. 2018: 18,675 allowances and 18,484 tons of emissions.

389. Ameren did not present evidence to demonstrate that CSAPR emissions limitations would become more difficult to meet. Instead, Ameren presented evidence that it would gain surplus credits for six years after the retirement of its Meramec Energy Center. Michels, Tr. Vol. 5-B, 8:16-20. These surplus credits would make CSAPR easier to meet.

390. Nor did Ameren present any evidence that, by trading allowances, it would actually decrease emissions in the same geographic area impacted by Rush Island and Labadie.

391. Ameren could trade its surplus allowances to power plants in Wisconsin, Michigan, New York, Virginia, or North Carolina. Michels Test., Tr. Vol. 5-B, 12:19-13:23.

392. The evidence does not support Ameren's assertion that surrendering its CSAPR emissions allowances would lead to actual emissions reductions remedying the harm to the populations impacted by Rush Island's excess emissions.

VI. ADDITIONAL EQUITABLE FACTORS SUPPORT THE REQUESTED REMEDIES

a. Liability Standards Were Well Understood in the Industry

393. I have already concluded that a reasonable power plant operator would have known that the modifications undertaken at Rush Island Units 1 and 2 would trigger PSD requirements. I have also concluded that Ameren's failure to obtain PSD permits was not reasonable. Ameren Missouri, 229 F.Supp.3d at 915-916, 1010-14.

394. After the liability trial in this case, I found that at the time of the Rush Island modifications, "the standard for assessing PSD applicability was well-established." It was also

"well-known" that the types of unpermitted projects Ameren undertook risked triggering PSD requirements. Id. at 915.

395. Despite these findings, Ameren now seeks to avoid PSD permitting by arguing that, if it knew about the consequence of its actions, it would have never triggered PSD in the first place. At trial, Ameren expert Campbell testified that Ameren could have used several options to avoid New Source Review (NSR) requirements. According to Campbell, Ameren would have used one of those "avoidance" options, if only it had known that the Rush Island modifications might be found to trigger PSD. Campbell Test., Tr. Vol. 4-A, 135:2-5. Campbell's avoidance options included canceling the projects, reducing the projects emissions without a permit, or reducing the projects emissions with a "minor permit." Campbell Test., Tr. Vol. 4-A, 49:7-19. The parties have referred to Campbell's opinions on this subject as his "PSD avoidance" theory.

396. Assuming they were viable, Ameren did not take any of the options identified by Campbell. Instead, Ameren proceeded with the projects without obtaining the required permits.

397. Campbell admitted that his PSD avoidance theory relies on an assumption that Ameren did not appreciate the risks of violating NSR when it undertook the largest modification in plant history. Campbell Test., Tr. Vol. 4-A., 136:5-9. Campbell did not talk to any Ameren employees about whether they ascertained the risks of violating NSR. Nor did Campbell talk to any Ameren employees about whether they would have taken or been able to take any of the avoidance options that he presented during his testimony. Id. 136:19-137:15.

398. Ameren's documents indicate that Ameren was aware of the possibility that NSR would be triggered at Rush Island. For example, on May 1, 2009, Ameren met with engineering firm Black & Veatch to review contracting strategies and to allow Black & Veatch to

"understand internal AmerenUE drivers." May 13, 2009 Conference Memorandum (Pl. Ex. 1111), at AM-REM-00319195. Included among the "Questions for thought" discussed at that meeting was "What is the tolerance for risk?" Id. at AM-REM-00319198, 319222. The Conference Memorandum summarizing the discussion of that question identified that "NSR is likely the biggest potential issue." Id. at 319199. Addressing a question about cash flow for any FGDs at Rush Island, the May 2009 Conference Memo identified that "NSR or EPA will likely be the driver to shift the schedule early." Id.

399. A June 2010 presentation to Ameren's Corporate Project Oversight Committee (CPOC) similarly identified "New Source Review" as one of several Clean Air Act "driving forces for additional control equipment" that Ameren was monitoring. See June 1, 2010 CPOC Presentation, Scrubber Technology Assessment, Rush Island Plant (Pl. Ex. 1099), at AM-REM-00288980; see also Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 59:25-60:10.

400. A February 2010 CPOC presentation identified NSR as among the relevant environmental concerns facing Rush Island. Specifically, the presentation identified NSR's "permitting and control requirements for new sources and existing sources that undergo 'major modifications.'" See February 5, 2010 Project Review Board Presentation—Rush Island FGD (Pl. Ex. 1100), at AM-REM-00289009, 011.

401. Campbell also testified that Ameren could avoid PSD by restricting operations. This opinion is similarly unsupported. To avoid PSD by restricting operations, a source can obtain a permit known as a synthetic minor permit. A synthetic minor permit limits a source to operate below significance thresholds under the PSD program. Knodel Test., Tr. Vol. 1-A, 67:5-14, 97:25-98:7.

402. Ameren did not apply for a synthetic minor permit prior to undertaking the

modification of Unit 1 in 2007 nor the modification of Unit 2 in 2010. Knodel Test., Tr. Vol. 1-A, 67:15-20; MDNR Rule 30(b)(6) Dep., Aug. 10, 2018, Tr. 137:5-9.

403. Ameren's director of corporate analysis, the official in charge of resource planning, testified that he was not aware of any instance where Ameren voluntarily restricted the operations of Rush Island. Michels Test., Tr. Vol. 5-B, 4:19-20, 5:1-9; Michels Dep., Aug. 14, 2018, Tr. 156:13-17.

404. Owners of baseload plants such as Rush Island generally avoid limiting plant operations, which are designed to run as much as possible. Staudt Test., Tr. Vol. 1-B, 20:16-24, 97:13-23; see also Ameren Missouri, 229 F. Supp.3d at 917 (Liability Findings ¶ 6 (Rush Island units are "baseload units" that "generally operate every hour they are available to run"), ¶ 7 ("The Rush Island units are among Ameren's most cost-effective units and carry much of the system load."), ¶ 59 (Rush Island units gain "economic advantage … by burning cheaper coal then their competitors")).

405. Dr. Staudt testified that he was not aware of any instance in which the owner of a baseload power plant like Rush Island accepted a limitation on operations in the way that Campbell suggests. Staudt Test., Tr. Vol. 2-A, 13:23-14:12. ("[T]hat doesn't happen very often, or I'm not sure if it's ever happened on a electric-generating unit.").

406. Despite its expert testimony, Ameren did not present any company witness or documents suggesting the pursuit of a synthetic minor permit was a realistic possibility, or ever considered for Rush Island.

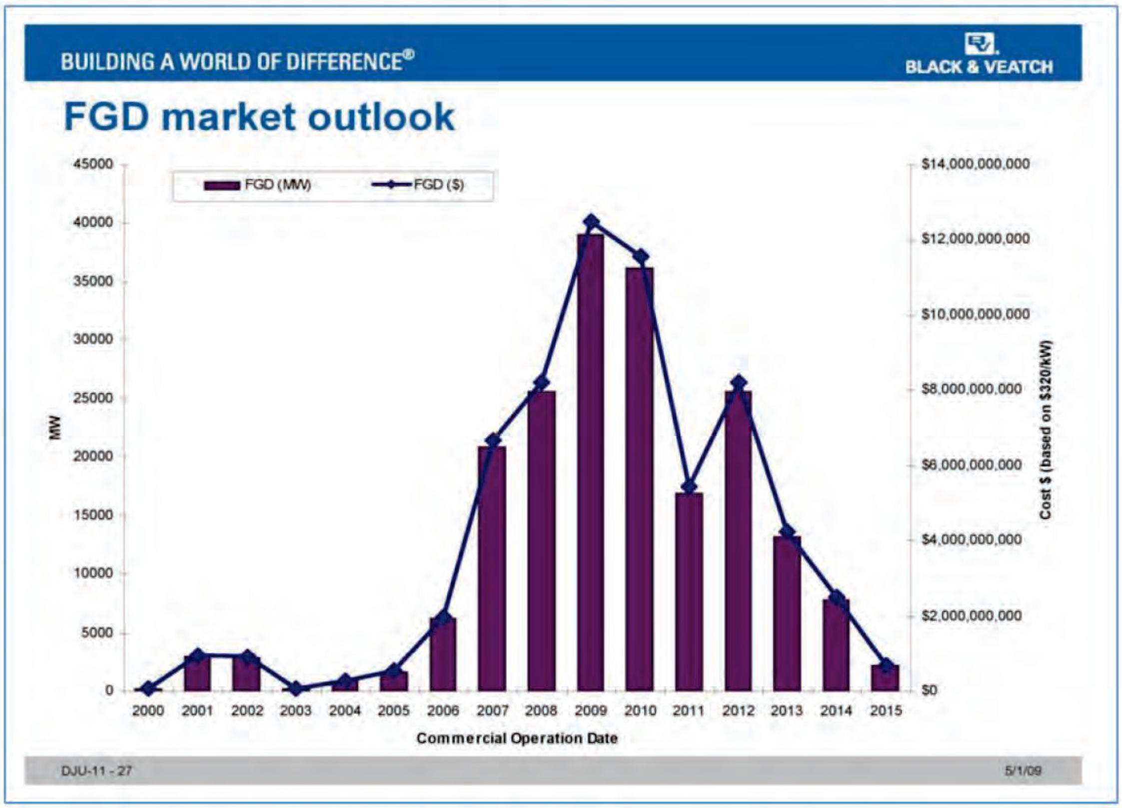
407. While Rush Island began burning lower sulfur coal after its modifications, Ameren has not accepted a permit limit at that level. Nothing currently requires Rush Island to burn lower sulfur coal. Staudt Test., Tr. Vol. 2-A, 17:5-16; Knodel Test., Tr. Vol. 1-A, 67:25-

68:19, 69:18-20.

b. Ameren Has Benefitted from Delaying Compliance at Rush Island

408. Between 2007 and 2010 was a period of peak market demand for the installation of scrubbers in the electric utility industry, as illustrated by Figure 9.

Figure 9



Pl. Ex. 1111, at AM-REM-00319231.

409. Ameren avoided this period of peak market demand to its benefit, as discussed in internal company documents. Staudt Test., Tr. Vol. 1-B, 28:3-31:1; Ex. 1111, at AM-REM-00319199, 231; Ameren's April 2011 Presentation for MPSC, Ex. 1009, at AM-02225216 (Ameren's business strategy "[a]llows Ameren Missouri to defer capital investments on environmental retrofits" and "delay its construction needs to avoid the likely timeframe of

greatest environmental retrofit construction.")

410. Ameren's internal documents also make clear that Ameren has understood for many years the possibility that scrubbers would be required as a result of NSR violations at Rush Island. Ex. 1009, at AM-02225205 ("New Source Review lawsuit by EPA may require flue gas desulfurization (FGD) systems or scrubbers at Rush Island."), and AM-02225216 (2011 fuel switch strategy "[a]llows Ameren Missouri additional time to complete its detailed engineering design should scrubbers ultimately be required.");

411. Today, the scrubber market is "slow" and there would be lots of "very eager suppliers" to get Ameren's business. That means not only that Ameren benefitted from the delay, but also that an FGD could be installed much more quickly today because the resources are more available. Staudt Test., Tr. Vol. 1-B, 32:2-33:3.

412. By delaying wet FGD scrubbers for more than ten years, Ameren also sold more power from Rush Island than it would have had it complied with the law. Operating a scrubber changes the dispatch cost of a unit (the cost that unit needs to break even in the market). Celebi Test., Tr. Vol. 5-B, 68:18-69:18. Because the unit's dispatch cost will increase, it may run less. The unit will also sell less energy to the grid because some of its energy is needed to power the scrubber itself. Celebi Test., Tr. Vol. 5-B, 68:18-70:15.

413. The sources that installed scrubbers when required have been at a competitive disadvantage to Rush Island. In contrast, by not installing scrubbers in 2007 and 2010, Ameren benefited from the ability to spend capital on other items or issue dividends.

c. Ameren Admits It Can Afford to Comply With the Requested Remedies

i. Ameren Has Abundant Financial Resources

414. Ameren Missouri and Ameren Corporation are "financially strong." Kahal Test.,

Tr. Vol. 2-A, 53:11-19, 59:23-60:5 (discussing the strength of Ameren's financial reports). Ameren Corporation is the sole owner of Ameren Missouri. Kahal Test., Tr. Vol. 2-A, 55:3-25. Ameren has strong credit ratings, access to capital on favorable terms, and can access far more capital than it needs for its current capital spending plans. Kahal Test., Tr. Vol. 2-A, 69:25-70:5.

415. Each year, Ameren reports financial information for Ameren Corporation and Ameren Missouri to the Securities and Exchange Commission (SEC). Kahal Test., Tr. Vol. 2-A, 56:9-16. In its latest Form 10-K, Ameren submitted the financial information contained in Table 2 for the calendar year 2018.

Table 2. Ameren Corporation and Ameren Missouri 2018 Financial Information

	Ameren Corporation	Ameren Missouri
Assets	$27,215,000,000	$14,291,000,000
Operating Revenue	$6,291,000,000	$3,589,000,000
Net Income	$815,000,000	$478,000,000
Shareholder Dividends	$451,000,000	$375,000,000
Capital Spend	$2,336,000,000	$914,000,000
Operating Cash Flow	$2,170,000,000	$1,260,000,000

Ameren 2019 10-K (Pl. Ex. 1340), at USTREXR0003003, 3055, and 3057.

416. Ameren also reports financial information to the Federal Energy Regulatory Commission (FERC) in a document called the FERC Form 1. Ameren reported the following financial data in its FERC Form 1s for the years 2012 through 2017.

Table 3: Ameren Corporation 2012-2017 Financial Information (dollars)

	Net Income	**Capital Spending**	**Dividends**	**Cash Flow**
2012	420,000,000	611,000,000	400,000,000	995,000,000
2013	399,000,000	668,000,000	460,000,000	1,135,000,000
2014	394,000,000	770,000,000	340,000,000	943,000,000
2015	356,000,000	631,000,000	575,000,000	1,239,000,000
2016	360,000,000	751,000,000	355,000,000	1,161,000,000
2017	326,000,000	786,000,000	362,000,000	1,018,000,000
Average	376,000,000	703,000,000	415,000,000	1,082,000,000

Pl. Exs. 1331-36; see Rule 1006 Summary of FERC Form 1s (Pl. Ex. 1388).

417. In the SEC Form 10-K and FERC Form 1s:

a. ***Assets*** refers to total property owned by the company and provides a sense of the company's size.

b. ***Operating revenue*** is the total amount the company receives from its services.

c. ***Net income*** means the after-tax profits of the business.

d. ***Shareholder dividends*** refers to the money paid to the owners of the company. Ameren Corporation has individual public shareholders, while Ameren Missouri is wholly owned by Ameren Corporation. Therefore, all Ameren Missouri's dividends go to Ameren Corporation.

e. ***Capital spend*** means the total capital spending.

f. ***Operating cash flow*** refers to the net funds that the company earns after expenses such as operating and maintenance spending, taxes, interest, and other costs. Throughout the period, the cash flow roughly equals the total of capital spending and dividends, indicating that the company is using its cash to fund capital projects with internally generated revenue and paying the rest in dividends.

Kahal Test., Tr. Vol. 2-A, 57:16-59:22, 63:10-64:12.

418. Ameren has three main options for financing capital projects. It can use revenues from its operations, obtain funds from debt markets, or issue new common stock (through the parent company). Kahal Test., Tr. Vol. 2-A, 66:21-67:24.

419. Ameren's stock has performed "extremely well" over the past five years. Kahal Test., Tr. Vol. 2-A, 60:8-17. Ameren's Form 10-K indicates that the parent company's stock price grew by more than 16% per year from 2013 to 2018. Ameren 2019 10-K (Pl. Ex. 1340), at USTREXR0003002; Kahal Test., Tr. Vol. 2-A, 60:8-61:6. This growth was considerably larger

than indexes reflecting the electric utility industry or the broader stock market. Id. Ameren's stock performance means that the company would have access to equity markets, if needed, to finance capital projects. Kahal Test., Tr. Vol. 2-A, 60:8-61:6.

420. In February 2019, Ameren announced a $6.3 billion capital spending program for the next five years. Ameren Feb. 15, 2019 Press Release (Pl. Ex. 1341). This program represents an increase in spending from the recent past, when capital spending averaged about $700 million per year. Kahal Test., Tr. Vol. 2-A, 64:13-65:21; Ameren Feb. 15, 2019 Press Release (Pl. Ex. 1341).

421. Ameren's strong credit ratings allow it to access debt markets on very favorable terms. Kahal Test., Tr. Vol. 2-A, 65:22-66:20. The corporate credit ratings for both Ameren Corporation and Ameren Missouri are at the top end of the triple B range, while the secured debt for Ameren Missouri is rated medium single A. Kahal Test., Tr. Vol. 2-A, 65:22-66:20.

ii. Ameren Agrees It Can Finance the Requested Relief

422. Ameren can afford to finance the pollution controls at issue in this case. Kahal Test., Tr. Vol. 2-A, 53:11-54:12. Ameren presented no evidence to the contrary. Instead, Ameren's lead counsel stated at trial that Ameren "can afford anything this Court orders." Ameren Closing Argument, Tr. Vol. 6, 34:12-13.

423. The annual capital cost of installing FGD at Rush Island is only about half as large as Ameren's average annual dividend in recent years. Installing FGD at both Rush Island units would result in about $200 million per year in capital costs over the four-year construction period plus an estimated $27 to $38 million in operating and maintenance costs once the FGD systems begin operating. Kahal Test., Tr. Vol. 2-A, 71:5-12; Callahan Dep., Nov. 8, 2017, Tr. 195:5-12. Ameren's average dividend payment to its parent company is about $415 million per

year and its operating cash flow is more than $1 billion. See Rule 1006 Summary of FERC Form 1s (Pl. Ex. 1388, summarizing Pl. Ex. 1331 through 1336). Compared to these metrics, the wet FGD operating costs "are a very small number." Kahal Test., Tr. Vol. 2-A, 71:5-22.

424. Plaintiffs also presented evidence of several pollution control options at Labadie, including FGD and DSI to offset the excess emissions from Rush Island. Dr. Staudt estimated that the capital cost of FGD at two Labadie units would be $465 million with $29 million in annual operating costs. Staudt Test., Tr. Vol. 1-B, 105:12-106:24; see also Kahal Test., Tr. Vol. 2-A, 71:5-22. Dr. Staudt also estimated that installing DSI at all four Labadie units would mean a capital cost of $55 million and annual operating costs of $53 million. Staudt Test., Tr. Vol. 1-B, 104:21-105:11.

425. These costs are a small fraction of Ameren's $6.3 billion capital plan for the next five years and its $1.1 billion annual operating cash flow. Kahal Test., Tr. Vol. 2-A, 64:13-65:21; Rule 1006 Summary of FERC Form 1s (Pl. Ex. 1388, summarizing Pl. Ex. 1331-1336).

426. The EPA's expert Matthew Kahal testified that Ameren could afford to implement any of the mitigation options identified by Dr. Staudt for Labadie or Rush Island. Kahal Test., Tr. Vol. 2-A, 71:23-72:1, 78:10-17. This testimony was not challenged on cross or by any Ameren witnesses.

iii. The Projected Ratepayer Impact of the Requested Relief Is Less Than Ameren's Yearly Rate Increases

427. As of 2016, Ameren Missouri had 1.2 million customers. Celebi Test., Tr. Vol. 5-B, 26:16-20.

428. Ameren is a regulated monopoly. Kahal Test., Tr. Vol. 2-A, 51:12-19. When Ameren incurs costs that are not being recovered by its rates, it can seek a rate increase from the Missouri Public Service Commission. Kahal Test., Tr. Vol. 2-A, 51:12-52:4. The Public Service

Commission reviews the request and determines whether any rate increase is appropriate to allow Ameren to recover its costs. Kahal Test., Tr. Vol. 2-A, 51:12-52:4.

429. In the ratemaking process, Ameren receives a profit (known as the rate of return) on capital spending. Kahal Test., Tr. Vol. 2-A, 68:24-69:19; Celebi Test., Tr. Vol. 5-B, 42:24-43:8 (noting inclusion of rate of return). The rate of return is set by the Missouri Public Service Commission. Kahal Test., Tr. Vol. 2-A, 68:24-69:24. In recent years, the rate of return for Missouri utilities has been about 9.5%. Kahal Test., Tr. Vol. 2-A, 68:24-69:24.

430. Expert witnesses for both parties calculated how much installing pollution controls could affect the rates paid by Ameren customers if Ameren seeks to recover those costs from ratepayers. See Kahal Test., Tr. Vol. 2-A, 72:21-25; Celebi Test., Tr. Vol. 5-B, 66:11-19.

431. Ameren could choose not to recover those costs from its ratepayers. The Public Service Commission could also elect not to allow full cost recovery, especially if it determines the costs are the result of Ameren's decision not to comply with the Clean Air Act. Kahal Test., Tr. Vol. 2-A, 77:7-78:6; Celebi Test., Tr. Vol. 5-B, 66:11-67:19.

432. The EPA's expert Matthew Kahal testified that wet FGD at Rush Island would result in an increase in customer rates of about 2.8% over 20 years (assuming the Missouri Public Service Commission allows full rate recovery). Kahal Test., Tr. Vol. 2-A, 74:22-75:1. Ameren's expert Dr. Metin Celebi found that FGD at Rush Island would increase customer rates by 2.4%.[11] Kahal Test., Tr. Vol. 2-A, 80:23-82:4.

433. For DSI at the Labadie station, Kahal testified that the controls could result in an increase to customer rates of between 0% and 2% over 14 years. Kahal Test., Tr. Vol. 2-A, 77:7-

---

[11] Despite his expert opinions, Dr. Celebi did not testify about the individual percentage increases due to the scrubbers at Rush Island and DSI at Labadie. Kahal read his expert disclosure report and testified about the contents of that report. Celebi Test., Tr. Vol. 5-B, 64:21-65:9.

79:12. Dr. Celebi calculated a 1.4% rate increase if Ameren sought to recover the costs of implementing DSI from consumers. Kahal Test., Tr. Vol. 2-A, 81:25-82:1.

434. Overall, Kahal estimated that installing FGD at both Rush Island units and DSI at all four Labadie units would increase customer rates from 2.8 to 4.8%, while Dr. Celebi estimated that those controls would increase rates by 3.8%. Kahal Test., Tr. Vol. 2-A, 80:23-82:4; Celebi Test., Tr. Vol. 5-B, 64:21-65:9.

435. Rate increases in that range are in keeping with Ameren's typical rate changes from year to year. Dr. Celebi testified that Ameren's rates increased 5.4% from 2016 to 2017, and that Ameren's 2017 Integrated Resource Plan predicted that rates would increase 2.9% per year over the period from 2018 to 2037. Celebi Test., Tr. Vol. 5-B, 65:15-66:10.

436. The rates Ameren charges its customers are well below the national average. In 2016, Ameren's rates were 14% lower than the national average. Kahal Test., Tr. Vol. 2-A, 72:4-20; Celebi Test., Tr. Vol. 5-B, 57:15-24. Even with the rate increases estimated by Kahal or Dr. Celebi, Ameren customers' rates would still be around 10% lower than the national average. Kahal Test., Tr. Vol. 2-A, 82:6-15. Ameren's rates are also at or below the median rates for utilities in both Missouri and in surrounding states. Celebi Test., Tr. Vol. 5-B, 82:2-83:14.

437. In December 2017, a change in the tax laws reduced Ameren's income tax rate, resulting in a 6.1% decrease in customer rates. Kahal Test., Tr. Vol. 2-A, 82:16-83:2, 83:15-23; Ameren Presentation, "Building a Brighter Energy Future," Feb. 14, 2019 (Pl. Ex. 1337) at USTREXR0002371; Celebi Test., Tr. Vol. 5-B, 84:2-8. The potential rate increases predicted by Dr. Celebi and Kahal are smaller than the rate decrease resulting from the tax law changes. Celebi Test., Tr. Vol. 5-B, 84:2-16.

iv. Ameren's Average Estimates of Rate Increase Are Misleading

438. At trial, and in its proposed findings of fact, Ameren asserted that the costs of installing FGD at Rush Island and DSI at Labadie would be disproportionate to the harm of its excess emissions.

439. Ameren's expert, Dr. Celebi, conducted rate impact analyses for controls that might be installed on Rush Island and Labadie. Celebi Test., Tr. 5-B 62:3-63:10. He analyzed that the annual average total cost for wet FGD at Rush Island and DSI at Labadie would be $196 million per year, for a total of $4.1 billion over the entire period. He then estimated a per customer cost of $3,422.

440. Dr. Celebi's per customer estimates are unrepresentative of the typical customer's experience, because he does not differentiate based on residential, commercial, or industrial users. A three-bedroom home does not use the same amount of electricity, nor pay the same electricity bill, as a department store or an aluminum smelter. When residential, commercial, and industrial ratepayers are lumped together, the larger sources have a disproportionate influence on the total electricity use and the average cost of electricity, per customer. Ameren could have accommodated these differences by differentiating residential, commercial, and industrial ratepayers or, at the very least, calculating a median value, but it did not.

441. Additionally, in part, Dr. Celebi presented his results as an average per-customer cost over twenty years of operation. When presenting these results, Dr. Celebi often failed to indicate whether his estimates were in 2016 dollars, 2025 dollars, or some other years' dollars. See, e.g., id. at 62:19-23, 63:8-10. Because the value of money changes over time due to, for example, inflation, Dr. Celebi's failure to provide the reference year makes his testimony more ambiguous.

442. I find that Ameren's average per customer rate increase estimates in dollars do not reflect the typical customer's experience.

CONCLUSIONS OF LAW

As I noted in the introduction to this opinion, my conclusions of law from the liability phase significantly influence my findings of fact and conclusions of law in the remedies phase. In the liability phase, I found that Ameren violated the Clean Air Act by making major modifications that increased SO_2 emissions at Rush Island without obtaining the proper Prevention of Significant Deterioration (PSD) program permit and installing the Best Available Control Technology (BACT). Sulfur dioxide (SO_2) has been regulated under the Clean Air Act for 50 years. Once emitted, most SO_2 converts into fine particulate matter ($PM_{2.5}$), a pollutant known to cause increased risks of premature mortality, heart and lung disease, and other adverse health effects. Modern pollution controls can dramatically reduce SO_2 emissions, saving lives in the process.

While the rest of the electric industry made great strides in reducing SO_2 pollution, Rush Island lagged behind, rising steadily in the ranks to become one of the country's largest sources of SO_2. That pollution contributed to $PM_{2.5}$ levels across much of the Eastern United States, a range extending from Texas and Minnesota to the Atlantic Ocean. The emissions were allowed because Rush Island was grandfathered into the Clean Air Act Amendments of 1977. Rush Island lost its grandfathered status when Ameren conducted major modifications of the plant, redesigning and rebuilding essential parts of its two boilers. These major modifications increased Rush Island's emissions, based on Ameren's own operating data, and Ameren should have expected the increase.

Now, in the remedies phase, the EPA seeks to bring Ameren's Rush Island facility into compliance with the law and to remediate the harm from the more than 162,000 tons—and counting—in excess SO_2 that Rush Island emitted after Ameren failed to obtain a PSD permit there. Specifically, the EPA seeks an order requiring Ameren to (1) apply for a PSD permit at Rush Island, (2) propose wet FGD as the BACT in its Rush Island permit application, (3) meet an emissions limitation of 0.05 lb SO_2/mmBTU, and (4) reduce emissions at Labadie on a ton-per-ton basis to remedy the more than 162,000 excess SO_2 emissions released by Rush Island.

Once Ameren installs BACT at Rush Island, it should capture nearly 99% of SO_2 emissions there. By that time, Rush Island will have emitted nearly 275,000 tons of excess pollution, impacting $PM_{2.5}$ concentrations across the Eastern United States. Ameren must reduce pollution released into those areas. Accordingly, the EPA presented evidence on control measures that Ameren could implement at its nearby Labadie Energy Center in order to remediate the excess emissions. The pollution from that facility affects the same communities—and to the same degree—as Rush Island's pollution on a ton-per-ton basis. Therefore, efforts to reduce Labadie's pollution would be closely tailored to remedy the harm created by Rush Island's excess emissions.

Ameren presents seven arguments against the relief the EPA requests at Rush Island and Labadie. First, Ameren argues that it should be allowed to obtain a minor permit, instead of the statutorily-required PSD permit. According to Ameren, if it had known better, it would have pursued other, less expensive compliance options than PSD permitting. I need not entertain this hypothetical or speculate what might have been. Ameren made a major modification that lengthened the life of, and increased emissions at Rush Island. It cannot now undue these modifications or regain its grandfathered status. Ameren must obtain a PSD permit.

Second, Ameren argues that the Missouri Department of Natural Resources (MDNR) should determine the Best Available Control Technology for Rush Island. I have already discussed this argument in my order denying Ameren's motion for summary judgment. United States v. Ameren Missouri, 372 F. Supp. 3d 868, 873 (E.D. Mo. 2019). At summary judgment, Ameren did not demonstrate, as a matter of law, that I do not have authority to determine what Ameren must propose as BACT. Id. In this case, I am not issuing a permit, replacing the notice and comment process, or otherwise altering the nature of the PSD permitting process. Consistent with my authority to restrain violations and "require compliance" with the Clean Air Act, the relief in this case merely orders Ameren to submit an application that proposes wet FGD as BACT. 42 U.S.C. § 7413(b)(3).

Third, Ameren argues that, if I do determine BACT, I should order the installation of the least effective control technology, DSI without a fabric filter. DSI is about half as effective as scrubber technology, and it has never been accepted as BACT for a coal-fired electric generating unit. Ameren would like the BACT analysis to settle on the "least expensive option" capable only of "moderate" emissions reductions. Deciding BACT based primarily on a cost-benefit analysis would itself be in conflict with the Clean Air Act, which requires emissions limits "based on the maximum degree of reduction" available. 42 U.S.C. § 7479(3).

Fourth, Ameren argues that the eBay factors do not support the EPA's requested relief. Based on my analysis of the eBay factors, I conclude that the EPA's requested remedy is narrowly tailored to the harm suffered, addresses irreparable injury that could not be compensated through legal remedies, serves the public interest, and is warranted when considering the balance of hardships in this case.

Fifth, Ameren argues that any relief ordered at Labadie would constitute a penalty waived by the EPA before the liability trial. The installation of DSI at Labadie is an equitable remedy that is narrowly tailored and does not penalize Ameren. DSI's capital costs are minimal, and when Ameren has fully accounted for Rush Island's excess emissions, it may choose to discontinue use of its DSI system. Ameren may also choose to install a more capital-intensive technology if it decides to do so, but I will not require that Ameren does so.

Sixth, Ameren argues that Sierra Club v. Otter Tail Power Co., an Eighth Circuit case concerning the statute of limitations for suing to remedy a PSD violation, essentially gives Ameren immunity for all the excess pollution it released after failing to obtain a PSD permit for Rush Island. See 615 F.3d 1008, 1011 (8th Cir. 2010). Ameren's reliance on Otter Tail is misplaced. The statute of limitations did not expire before the United States commenced this case against Ameren, and I do not find in this case that Ameren's operation without a permit is an ongoing violation. The "excess emissions" or "excess pollution" references throughout this opinion describe the pollution that Rush Island has emitted in excess of what it would have released had Ameren installed BACT as required by the PSD program.

Finally, Ameren argues that it should be able to surrender allowances from a distinct regulatory program that could otherwise be traded to plants in Wisconsin, Michigan, New York, Virginia, or North Carolina. Ameren presented no evidence at trial to demonstrate that surrendering allowances would actually decrease emissions and $PM_{2.5}$ concentrations in the communities affected by Rush Island. Therefore, this proposal is not narrowly tailored to remedy the harm suffered.

Pollution from Rush Island is regulated for a reason, and Rush Island remains one of the largest sources of SO_2 in the country. Applied to the record evidence, the broad scientific consensus dictates the conclusion that the $PM_{2.5}$ that resulted from the excess SO_2 pollution at Rush Island has harmed—and continues to inflict harm on—the public in the form of premature mortality and myriad other adverse health effects.

To remedy its violations, Ameren must obtain the necessary PSD permit for the facility, implement the best available control technology, and undertake emissions reductions at its Labadie plant commensurate with Rush Island's volume of excess pollution.

I. THE CLEAN AIR ACT REQUIRES THE BEST AVAILABLE CONTROL TECHNOLOGY FOR MODIFIED POWER PLANTS IN PSD AREAS

The 1970 Clean Air Act (CAA) was designed in part to "speed up, expand, and intensify the war against air pollution in the United States with a view to assuring that the air we breathe throughout the Nation is wholesome once again." H.R. Rep. No. 91-1146, at 1 (1970), reprinted in 1970 U.S.C.C.A.N. 5356, 5356; Wis. Elec. Power Co. v. Reilly, 893 F.2d 901, 909 (7th Cir. 1990) (quoting legislative history). One primary purpose of the statute is "to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population." 42 U.S.C. § 7401(b)(1).

Not satisfied with the results achieved under the 1970 statute, Congress added the New Source Review program to the Act in 1977 to ensure that additional requirements were imposed on new and modified sources of air pollution. New York v. EPA, 413 F.3d 3, 10 (D.C. Cir. 2005). The PSD component of NSR was "aimed at giving added protection to air quality" while fostering economic growth in a manner consistent with preservation of existing clean air resources. Envtl. Def. v. Duke Energy Corp., 549 U.S. 561, 567 (2007) (noting that "NSPS . . . did too little to "achiev[e] the ambitious goals of the 1970 Amendments"); 42 U.S.C. § 7470. In areas that already meet the NAAQS, the 1977 amendments required BACT on new and modified sources that would otherwise increase pollution. Hawaiian Elec. Co. v. EPA, 723 F.2d 1440, 1447 (9th Cir. 1984) ("Congress found that it was important to reduce pollution levels below those mandated by the standards and that the best means of doing so was to require the installation of BACT on all sources which would otherwise increase pollution."). Pursuant to the PSD program, modification of a major source is prohibited unless, among other requirements:

> (1) a permit has been issued for such proposed facility in accordance with this part setting forth emission limitations for such facility . . .
>
> (3) the owner or operator of such facility demonstrates . . . that emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of [among other things] any . . . national ambient air quality standard [NAAQS] in any air quality control region . . . [AND]
>
> (4) the proposed facility is subject to the best available control technology for each pollutant subject to regulation . . . .

42 U.S.C. § 7475(a); see also id. §7479(2)(C) (explaining that modification of a source constitutes "construction" with respect to the requirement to obtain a permit). Among the other five requirements listed in this section, modification of a source is prohibited unless the owner (1) obtains a PSD permit, (2) installs BACT at the facility, and (3) demonstrates that, even when BACT is installed, permitted emissions from that facility will not violate the NAAQS.

II. THE EBAY STANDARD GOVERNS INJUNCTIVE RELIEF

The liability phase of this case established that Ameren violated the Clean Air Act when it modified Rush Island "without obtaining the required permits [and] installing best-available pollution control technology." United States v. Ameren Missouri, 229 F. Supp. 3d 906, 914 (E.D. Mo. 2017). The question presented now is what to do about Ameren's violations.

Section 113(b) of the Clean Air Act authorizes district courts to "restrain such violation[s], to require compliance, . . . and to award any other appropriate relief" where a source owner or operator "has violated or is in violation of" statutory or regulatory prohibitions. 42 U.S.C. § 7413(b). Courts have jurisdiction to craft "complete relief in light of the statutory purposes;" that jurisdiction is "not to be denied or limited in the absence of a clear and valid legislative command." Mitchell v. Robert De Mario Jewelry, 361 U.S. 288, 291-92 (1960); see also Weinberger v. Romero-Barcelo, 456 U.S. 305, 313 (1982) (courts enjoy the entire range of their historic equitable powers to craft relief unless Congress placed limitations on those powers "in so many words or by necessary and inescapable inference").

When considering injunctive relief, a court evaluates whether

> (1) [the plaintiff] has suffered irreparable injury; (2) . . . remedies available at law, such as monetary damages, are inadequate to compensate for the injury; (3) . . . considering the balance of hardships between the plaintiff and defendant, a remedy in equity is warranted; and (4) . . . the public interest would not be disserved by a permanent injunction.

eBay Inc. v. MercExchange, L.L.C.: 547 U.S. 388, 391 (2006).

In addition to the eBay factors, several principles guide the crafting of remedies in a case like this. First, the ordered relief must enforce the statutes created by Congress:

> If Congress has prohibited certain behavior, I do not have discretion to determine "whether enforcement is preferable to no enforcement at all." United States v. Oakland Cannabis Buyers' Coop., 532 U.S. 483, 497 (2001). In these circumstances, my discretion is limited to evaluating how equitable considerations "are affected by the selection of an injunction over other enforcement mechanisms." Id.

Ameren Missouri, 372 F. Supp. 3d 868, 877.

Courts cannot "override Congress' policy choice, articulated in a statute, as to what behavior should be prohibited." Oakland Cannabis Buyers' Coop., 532 U.S. 483, 497 (2001). A remedy should grant "complete" relief to fulfill the statute's purposes. C.f. Mitchell, 361 U.S. at 296 (noting "little room for . . . discretion not to order" equitable reimbursement and that a court either proceeding under general equity powers or the Fair Labor Standards Act has authority to order "legal relief[] necessary to do complete justice between the parties.").

Next, "[a]n injunction must be tailored to remedy specific harm shown." Rogers v. Scurr, 676 F.2d 1211, 1214 (8th Cir. 1982). The injunction should be "no more burdensome to the defendant than necessary to provide complete relief to the plaintiffs." Califano v. Yamasaki, 442 U.S. 682, 702 (1979). Where, as here, the United States seeks to enforce a public interest statute, a court places "extraordinary weight . . . upon the public interests" because the "suit involve[es] more than a mere private dispute." United States v. Marine Shale Processors, 81 F.3d 1329, 1359 (5th Cir. 1996) (citing Virginian Ry. v. Sys. Fed'n No. 40, AFL, 300 U.S. 515, 552 (1937)).

Additionally, where an injunction will remediate environmental harm, courts have considered "(1) whether the proposal 'would confer maximum environmental benefit,' (2) whether it is 'achievable as a practical matter,' and (3) whether it bears 'an equitable relationship to the degree and kind of wrong it is intended to remedy.'" United States v. Deaton, 332 F.3d 698, 714 (4th Cir. 2003) (quoting a standard articulated in United States v. Cumberland Farms of Conn., Inc., 826 F.2d 1151, 1164 (1st Cir.1987) and echoed in United States v. Sexton Cove Estates, Inc., 526 F.2d 1293, 1301 (5th Cir. 1976)).

III. AMEREN MUST MAKE RUSH ISLAND COMPLIANT BY OBTAINING A PSD PERMIT WITH EMISSIONS LIMITATIONS BASED ON WET FGD

The PSD program's BACT requirement is a "technology-forcing" standard that is meant to "stimulate the advancement of pollution control technology," a central goal of the 1977 Amendments. Wis. Elec. Power Co. v. Reilly, 893 F.2d 901, 909 (7th Cir. 1990) ("The legislative history suggests and courts have recognized that in passing the Clean Air Act Amendments, Congress intended to stimulate the advancement of pollution control technology."). The BACT requirement codified at 42 U.S.C § 7475(a)(4) is the cornerstone of the PSD program. It advances both Congress's public protection and technology-driving aims. Accordingly, my remedies determination is based on a careful examination of what constitutes BACT for Rush Island.

a. BACT Sets Emissions Limitations Based on the Maximum Degree of Pollution Reduction Achievable

As defined by Congress in the Clean Air Act, BACT is an "emissions limitation based on the maximum degree of reduction of each pollutant subject to regulation." 42 U.S.C. § 7479(3); see also Sierra Club v. Otter Tail Power Co., 615 F.3d 1008, 1011 (8th Cir. 2010). Determining BACT is a case-by-case endeavor that incorporates consideration of "energy, environmental, and economic impacts and other costs." 42 U.S.C. § 7479(3); 40 C.F.R. § 52.21(b)(12) (further defining BACT). While BACT is determined on a case-by-case basis, "the permitting authority's analysis must in all circumstances give effect to the purpose of BACT, which is to promote the use of the best technologies as widely as possible." In re Gen. Motors, Inc., 10 E.A.D. 360, 364 (E.A.B. 2002).[12] As noted by the Ninth Circuit, BACT requires use of "the most current, state-of-the-art pollution controls" available. Grand Canyon Trust v. Tucson Elec. Power Co., 391 F.3d 979, 983 (9th Cir. 2004). "[F]ailure to consider all available control alternatives in a BACT analysis constitutes clear error," unless the control alternative would require the evaluator to "redefine the source." Helping Hand Tools v. U.S. Envtl. Prot. Agency, 848 F.3d 1185, 1194 (9th Cir. 2016).

In practice, BACT follows a "top-down" approach used by the EPA and MDNR to ensure that the most effective technology is actually selected. FOF ¶ 77. The Supreme Court has explained the top-down process as providing:

> that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent—or "top"—alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgement agrees, that technical considerations, or energy, environmental, or economic impacts justify a

[12]The Environmental Appeals Board (EAB) is the final decision-maker on administrative appeals arising under environmental statutes administered by EPA, including the Clean Air Act. See Sierra Club v. Wisconsin DNR, 787 N.W.2d 855, 867 n.6 (Wis. App. 2010).

conclusion that the most stringent technology is not "achievable" in that case. Alaska, Dep't of Envtl. Conservation v. EPA, 540 U.S. 461, 475-76 (2004) (quoting EPA's Draft New Source Review Workshop Manual, Oct. 1990 [Pl. Ex. 1190] ("NSR Manual") at B2); see also Chipperfield v. Mo. Air Conserv. Comm'n, 229 S.W.3d 226, 239-40 (Mo. Ct. App. 2007). "So fixed is the focus on identifying the 'top', or most stringent alternative, that the analysis presumptively ends there. . . ." In re Northern Mich. Univ. Ripley Heating Plant, 14 E.A.D. 283, 294 (E.A.B. 2009). The top option constitutes BACT unless something unique about the plant prevents it from using the same "top" controls.[13] Id.

The top-down method consists of five steps: (1) identify all applicable control technologies; (2) remove any technically infeasible controls; (3) rank feasible controls by effectiveness; (4) determine if the most effective option is achievable considering the energy, environmental and economic impacts; and (5) select a BACT emissions limitation. Pl. Ex. 1190 [NSR Manual] at AM-REM-00544123-MDNR; see also FOF ¶ 74.

b. Industry Experience and Ameren's Own Analyses Show FGD Technology Is Economically and Technically Feasible at Rush Island

The parties do not dispute the outcome of the first three steps in the BACT analysis.[14] As the parties agree, there are four available control technologies, all of which are technically feasible for Rush Island. FOF ¶¶ 180-81. As ranked in descending order of effectiveness, these

[13] The Ninth Circuit has stated that "the burden of proof [is] on the 'applicant to justify why the proposed source is unable to apply the best technology available.'" Citizens for Clean Air v. U.S. EPA, 959 F.2d 839, 845 (9th Cir. 1992) (quoting NSR Manual). To meet that burden, the source must "demonstrate that the technology is technically or economically infeasible." Id.; see also FOF ¶ 76. If the "top" control is eliminated in Step 4, the next most effective technology is considered, and so on, until the most effective remaining option is selected as BACT. Alaska, Dep't of Envtl. Conservation v. U.S. E.P.A., 298 F.3d 814, 822 (9th Cir. 2002), aff'd sub nom. Alaska Dep't of Envtl. Conservation v. E.P.A., 540 U.S. 461 (2004).

[14] While Dr. Staudt included natural gas conversion in his BACT analysis, Dr. Staudt and the EPA agree with Ameren that natural gas conversion is not an appropriate technology for consideration. Tr. Vol. 2-A, 21:6-17, 22:23-23:18.

are:

(1) Wet FGD technology (sometimes called a "wet scrubber")
(2) Dry FGD technology (sometimes called a "dry scrubber")
(3) DSI implemented in parallel with a fabric filter
(4) DSI implemented as a stand-alone control

FOF ¶ 113. Based on these options, the next question is whether the "top" control—wet FGD technology—should be eliminated as not "achievable" after an evaluation of its energy, environmental, or economic impacts. The great weight of evidence presented at trial shows wet FGD is achievable.

Over the last forty years, about 200,000 megawatts of coal-fired electric generating capacity have been fitted with FGD technology. See Figure 1; FOF ¶ 14. FGD scrubbers are currently installed on hundreds of coal-fired electric generating units, including about 84% of the coal-fired electric generating capacity in the United States. See FOF ¶ 16. While other plants adopted FGD technology en masse, Rush Island has lagged behind. In 2007, the Rush Island plant ranked 154th in the nation in SO_2 emissions. Ten years later, it was the tenth-most SO_2 polluting plant in the nation. FOF ¶ 18.

Ameren suggested at trial that FGD technology is more appropriate for new plants as opposed to existing plants. Ameren's suggestion is contradicted by the evidence. Of the more than 170,000 MW of coal-fired electric generating capacity now controlled with wet FGD, about 120,000 MW are retrofitted units. See Figure 2; FOF ¶ 17. About three quarters (90,000 MW) of that retrofitted generating capacity has been installed between 2005 and 2015. Figure 2, FOF ¶ 17.

The emissions reductions achievable by FGD do not depend on whether the technology is built with new plant or retrofitted on an existing one. FOF ¶ 162. The prevalence of FGD at both new and existing units indicates that FGD is achievable at Rush Island. As the EPA noted in the NSR Manual: "In the absence of unusual circumstance, the presumption is that sources within the same source category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category." Pl. Ex. 1190 [NSR Manual] at AM-REM-00544146-MDNR; FOF ¶ 79.

Ameren has provided no evidence of an unusual circumstance at Rush Island that is relevant to the BACT determination. FOF ¶ 219. Ameren's BACT expert Colin Campbell testified that Rush Island's status as an existing plant not otherwise required to install BACT constitutes an unusual circumstance. Id. However, as shown in Figure 2, more FGD-controlled generating capacity exists at retrofitted, existing plants than at new plants. See also FOF ¶ 17.

Based on its own studies, Ameren has no evidentiary basis to rule out FGD in Step 4. At trial, Ameren only briefly mentioned energy or environmental impacts of wet FGD. Specifically, Ameren's expert Snell discussed the auxiliary power consumed by FGD systems, which reduced power output to the grid. FOF ¶ 190. Snell also mentioned wastewater costs and mercury controls. FOF ¶ 192. However, Ameren did not explain how these energy and environmental impacts made wet FGD unachievable. Nor did Ameren suggest that these environmental impacts are different from the kinds of impacts experienced at other pulverized coal-fired power plants. See NSR Manual (Pl. Ex. 1190), at AM-REM-00544146-MDNR; Staudt Test. Vol. 1-B, at 63:14-64:6.

Around the time Ameren was rebuilding Rush Island Unit 2, Ameren was also studying how and whether FGD might be installed at Rush Island. Ameren's engineering studies, undertaken over a period of years at a cost of about $8 million, concluded that wet FGD was both economically and technically feasible at Rush Island. The engineering studies determined that wet FGD was the best option for the plant to control SO_2. FOF ¶ 29-31.

The economic impacts of implementing wet FGD do not render the technology unachievable. The EPA's expert Dr. James Staudt estimated, based on Ameren's engineering studies, that the direct capital costs of implementing wet FGD technology at Rush Island would be $582 million in 2016 dollars. FOF ¶ 124. That total translates to an "average" cost-effectiveness of $3,854 per ton of SO_2 removed. FOF ¶ 225. Even according to Campbell's testimony, this value is well below MDNR's threshold for acceptable average cost effectiveness. Id., n.7. Ameren did not present any evidence or testimony demonstrating that $3,854 per ton was too high or out-of-line with the average cost effectiveness incurred by other electric utilities with FGD.[15] Id. In fact, Ameren's own engineering study concluded that the cost of wet FGD at Rush Island would be consistent with industry benchmarks. FOF ¶ 226. MDNR and other agencies have concluded that both wet and dry FGD are economically acceptable for pulverized coal-fired power plants. For all these reasons, there is no basis for excluding FGD technology from the BACT assessment at Step 4, whether based on energy, environmental, economic impacts or other costs.

The last step of the BACT analysis (Step 5) involves determining an achievable emission rate based on the chosen wet FGD technology. As with Steps 1 through 3, there is no material dispute about what the achievable emission rates would be for wet FGD at Rush Island. FOF ¶¶ 229-31. Wet FGD has been widely adopted over the years, and its performance continues to improve. Wet FGD's emissions rates have steadily fallen. See Figure 3; FOF ¶ 221. By 2016, the top 50% of FGD-equipped plants averaged a 12-month emission rate of 0.058 lb/mmBTU, and the top 20% of FGD-equipped plants averaged a 12-month emission rate

[15] Ameren's BACT expert Campbell testified that he reached no conclusions on whether the average cost-effectiveness of wet FGD would be considered unacceptable in this case. FOF ¶ 225.

of 0.024 lb/mmBTU. See Id. These numbers have fallen by more than 20% between 2008 and 2011 and by another 20% or more between 2011 and 2016. See Figure 3. Ameren's engineering studies echo the broader trend of increasing effectiveness. In the first two phases of its study, Ameren identified its Rush Island FGD design-rate as 0.06 lb/mmBTU. FOF ¶ 33. In late 2010, Ameren lowered the target design-rate of its planned scrubbers to 0.04 lb/mmBTU. FOF ¶ 52.

Based on a reasonable compliance margin, Dr. Staudt testified that BACT for the Rush Island units at the time of the illegal modification would have been 0.08 lb/mmBTU for Unit 1 and 0.06 lb/mmBTU for Unit 2, both on a 30-day rolling average. FOF ¶ 202-03. The record showed these rates were reasonable given the technological capabilities at those times and consistent with the nearly two-dozen contemporaneous BACT determinations at similar facilities. FOF ¶ 100-105. Ameren presented no evidence at trial to dispute that these emissions rates were achievable. Ameren's expert Campbell even testified that 0.05 lb/mmBTU was achievable. FOF ¶ 231. If applied today, the evidence shows that wet FGD could meet a 30-day rolling-average emissions limitation no less stringent than 0.05 lb/mmBTU. FOF ¶ 233.

c. Ameren's Arguments Against PSD Permitting Mischaracterize Case Law, Ameren's Permitting Options, and the Nature of BACT

Ameren presents three arguments to avoid permitting under the PSD program. First, Ameren argues it need not install BACT because it would have sought less costly ways avoid PSD permitting had it known its major modifications would trigger PSD obligations. Second, Ameren argues that I should not make any BACT determination as part of my ruling, because that decision is appropriately left to the permitting authority MDNR. Third, Ameren argues that DSI—a far less-effective (and less costly) control technology than wet FGD—should be considered BACT at Rush Island. None of these three arguments is persuasive.

i. As a Major Stationary Source That Performed Major Modifications, Ameren Must Obtain a PSD Permit, Not a "Minor Permit"

Ameren argues that had it known its modifications would trigger PSD obligations, it might have sought a synthetic minor permit. With a minor permit, a source can limit its emissions below a threshold that would trigger PSD requirements. FOF ¶ 401. At trial, Ameren's expert Campbell testified in support of this theory. See Campbell Test., Tr. Vol. 4-A, 49:9-24, 80:20-83:7.

This argument is not supported by law. First, it requires speculation about what actions Ameren might have taken, rather than an examination of what actions Ameren actually took. By statute and regulation, once Ameren undertook major modifications, Ameren was required to comply with BACT. Rush Island Units 1 and 2 are modified facilities; they cannot obtain "minor" permits for their "major modifications." To find otherwise would require me to ignore the statue and regulations. See 42 U.S.C. § 7475(a)(1), (4); 40 C.F.R. § 52.21(j)(3) (any "major modification shall apply best available control technology"); 40 C.F.R. § 52.21(r)(1) (any source that modifies without permit approval is subject to enforcement); United States v. Ohio Edison Co., 276 F. Supp.2d 829, 850 (S.D. Ohio 2003) (a "modification triggers permitting requirements under the CAA as well as the duty to install pollution controls."). The statute and the regulations set forth "without exception" that all major modifications are subject to CAA requirements. Oregon Envtl. Council v. Oregon Dep't of Envtl. Quality, No. 91-13-FR, 1992 WL 252123, *22-23 (D. Or. Sept. 24, 1992).

NSR requirements apply to all major modifications, including those illegally constructed. The United States District Court for the District of Oregon explained:

> The [State Implementation Plan] does not exempt a source of pollutants from the new source review requirements simply because the 'major modification' was constructed prior to the issuance of a requisite permit. Moreover, if such an

> exemption were allowed, a windfall would be created for those major new or modified sources that disregarded the SIP-mandated requirements.

Oregon Envtl. Council v. Oregon Dep't of Envtl. Quality, 1992 WL 252123, at *23. Other district and appellate courts have made similar rulings. See, e.g., United States v. Midwest Generation, 720 F.3d 644, 646 (7th Cir. 2013) (modifying plant without a permit is a "risky strategy" because, if challenged, the plant may need "to undertake a further round of modifications to get the permit"); United States v Cinergy Corp., 618 F.Supp.2d 942, 961-62, 965 (S.D. Ind. 2009) (holding that the only compliance alternative "was to apply for the necessary permits or shut down the units"); United States v. Louisiana-Pacific Corp., 682 F. Supp. 1141, 1166 (D. Colo. 1988) ("requirements of the [PSD] program have been met only upon receipt of PSD permits").

Ameren "must suffer the consequences of the action it chose to take—even if these, or some of these, might have been avoided had it taken a different course of action." United States v. Westvaco Corp., 2015 WL 10323214, at *8 (Md. Feb. 26, 2015). Ameren's "initial failure to comply with the requirements of the Clean Air Act" should not "now inure to its benefit." New York v. Niagara Mohawk Power Corp., 263 F. Supp. 2d 650, 663 (W.D.N.Y. 2003). It cannot now obtain a minor permit as a means of avoiding PSD permitting. Ameren must come into compliance with the law by obtaining a PSD permit and meeting BACT emissions limitations.

Even if Ameren's argument that it should be allowed to apply for a minor permit had merit, it is unsupported by the evidence. The facts that run contrary to Ameren's assertion that it would have applied for a minor permit include:

- The PSD standards were clear long before Ameren undertook the Rush Island modifications. FOF ¶¶ 393-394.
- Ameren did not present any company witness or document suggesting the pursuit of

a synthetic minor permit was a realistic possibility. FOF ¶ 406.

- Ameren's director of corporate analysis testified that he was not aware of any instance where Ameren voluntarily restricted the operations of Rush Island. FOF ¶ 403, and
- Restricting Rush Island's operations would have been inconsistent with the purposes of the modifications. FOF ¶ 404.

Ameren did not present evidence of any baseload power plant operator restricting a facility's operations in the manner Ameren now claims in hindsight it would have. Because they are the cheapest generating sources and so reliably dispatched, utilities like Ameren hesitate to put operating or fuel limitations on their baseload plants. Cinergy, 618 F. Supp. 2d 942, 947 (S.D. Ind. 2009) (quoting testimony of Cinergy witness). Ameren's post hoc PSD-avoidance argument runs contrary to the facts in this case and is not supported by the law.

ii. None of Ameren's Arguments or Evidence Prevent Me From Ordering Ameren to Propose Wet FGD as BACT

In its proposed conclusions of law, Ameren renews its argument from summary judgment that I cannot and should not make a BACT determination. According to Ameren, I should leave any BACT determination to the permitting authority MDNR, respecting its notice and comment process. As I noted in my order denying summary judgment, Plaintiffs have not asked me to write and issue a permit. Ameren Missouri, 372 F. Supp. 3d 868, 873, Instead, Plaintiffs request that I order Ameren to propose wet FGD as BACT in the permit application Ameren submits to MDNR. This requested relief does not violate any of the principles raised by Ameren in its motion for summary judgment. Id. Additionally, the cases Ameren previously cited in its motion for summary judgment do not support its argument that I cannot order Ameren to propose wet FGD as BACT. Id. (citing Westvaco, 2015 WL 10323214, at *11 (D. Md. Feb. 26, 2015) ;

Cinergy, 618 F. Supp. 2d 942, 955 (S.D. Ind. 2009). Ameren does not present any other citations or evidence to support this argument.

I conclude that I am able to order Ameren to propose wet FGD as BACT.

iii. Ameren's Arguments for the Least Effective Control Technology, DSI, Contradict the Nature and Definition of BACT

Ameren argues that DSI, a technology that removes about 50% of SO_2 emissions, constitutes BACT for Rush Island. DSI is about half as effective as FGD and has never been accepted as BACT for coal-fired electric generating units. FOF ¶ 167. Ameren prefers DSI because it is less costly overall and per-ton than other control technologies. However, BACT does not permit a source to install the most cost-effective technology. The plain language of the statute requires emissions limits "based on the maximum degree of reduction" available. 42 U.S.C. § 7479(3).

To support its position, Ameren argues that FGD technology should have been excluded at Step 4 of the BACT analysis because of its "economic impacts." The costs Ameren cites are not based on any unique physical or operational characteristics of Rush Island. Ameren was unable to identify any material feature that distinguishes Rush Island from the rest of the industry or electric market. Ameren's argument is premised entirely on its expert Campbell's economic analysis. That analysis was inconsistent with BACT permitting practices and Campbell's own past guidance, and I give Campbell's testimony little weight. FOF ¶¶ 134-40.

In BACT permitting, two cost metrics are often consulted, (1) average cost-effectiveness, and (2) incremental cost-effectiveness. FOF ¶¶ 82-83. The EPA's expert Dr. Staudt calculated average cost-effectiveness for wet FGD at Rush Island and determined the costs were achievable. FOF ¶ 199. Dr. Staudt made his calculations according to the standard overnight cost methodology. FOF ¶ 124.

In their calculations, Ameren's experts included costs that are traditionally excluded from BACT analyses for consistency and comparison's sake. Ameren's expert Snell admitted that his cost estimates were not developed for the purpose of a BACT analysis. FOF ¶ 128. Ameren's expert Campbell still included Snell's cost estimates in his incremental cost-effectiveness comparison. Incremental cost-effectiveness considers the per-ton change in cost of reducing SO_2 pollution using two compared technologies. Based on that comparison, Campbell eliminated wet FGD from his BACT analysis. Ameren's experts offered no opinions on the average cost-effectiveness of wet FGD.[16]

According to Campbell, the incremental cost-effectiveness of wet FGD compared to DSI exceeds a threshold used by MDNR in BACT determinations. FOF ¶ 141. This explanation misstates how incremental cost-effectiveness analysis usually operates in reality. Measuring incremental cost may be useful when evaluating control options ranked next to each other with similar control efficiencies. FOF ¶ 83. Campbell did not compare incremental technologies, he compared one of the most effective control technologies with one of the least. FGD technology can remove 95% or more of SO_2 emissions, while DSI can remove only 50%. These differences in effectiveness are not incremental.

"[W]here a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if any, between the application of the control technology on those other sources and the particular source under review." Pl. Ex. 1190 [NSR Manual] at AM-REM-00544148-MDNR. Ameren's analyses do not provide any distinguishing characteristic of wet FGD implementation at Rush Island that makes the technology unachievable or significantly more costly than other similar

[16] Ameren's sole reliance on incremental cost-effectiveness to eliminate wet FGD while ignoring average cost-effectiveness is inconsistent with a proper top-down analysis. FOF ¶ 84.

sources.

Ameren's main attempt to differentiate Rush Island from other plants depends on a false distinction between new plants and existing, retrofitted plants. Specifically, Ameren points out that the New Source Performance Standards (NSPS) do not apply to existing plants such as Rush Island. However, the NSPS emission rate does not fundamentally change the BACT methods or results. FOF ¶¶ 87-89; Ameren Missouri, 2019 WL 1384631, at *3 (citing Columbia Gulf at *4). Instead, the NSPS emission rate serves as a "floor" for any BACT determination; BACT at any facility cannot be less stringent that the NSPS for that source category. 42 U.S.C. § 7479(3). Ameren's new-versus-existing plant distinction does not demonstrate that Rush Island is so unusual as to make wet FGD unachievable.

d. SO_2 BACT For Rush Island Was Wet FGD Technology at the Time of the Modifications and Remains So Today

The parties do not dispute what control technologies are available to reduce SO_2 emissions, whether those technologies could be implemented at Rush Island, or their relative effectiveness: wet FGD is the most effective control technology, and it is technically and economically feasible at Rush Island. The parties disagree, however, about whether wet FGD is achievable "taking into account energy, environmental, and economic impacts and other costs." 42 U.S.C. § 7479(3). Based on the evidence presented at trial, wet FGD is achievable when taking into account these factors. FOF ¶¶ 184-88, 200.

Although the specific emission rate may vary somewhat, FGDs are the best available SO_2 controls at coal-fired power plants. Chipperfield v. Mo. Air Conserv. Comm'n, 229 S.W.3d 226, 240 (Mo. Ct. App. 2007) ("In general, pulverized coal-fired boilers burning low-sulfur coal, such as Powder River Basin ("PRB") coal, may use dry FGD, while boilers burning high-sulfur coals, such as eastern bituminous coal, must use wet FGD."); Cinergy, 618 F.Supp.2d 942, 955

("BACT would require a scrubber that removed 99% of the SO_2"). The evidence presented at trial does not provide any support for the proposition that FGD technology, the "top control" for SO_2 removal, should be ruled-out based on "energy, environmental, and economic impacts" associated with its application. As a result, I conclude the following:

(1) At all times pertinent to this case, BACT for SO_2 pollution at Rush Island would have been determined based on the application of wet FGD technology.

(2) At the time of the Unit 1 major modification in 2007, BACT for SO_2 pollution would have required a 30-day rolling-average emissions rate of no more than 0.08 lb/mmBTU. FOF ¶ 208.

(3) At the time of the Unit 2 major modification in 2010, BACT for SO_2 pollution would have required a 30-day rolling-average emissions rate of no more than 0.06 lb/mmBTU. Id.

(4) At present, BACT for SO_2 pollution at Rush Island requires a 30-day rolling-average emissions rate of no more than 0.05 lb/mmBTU. FOF ¶ 213.

e. The eBay Factors Require Rush Island to Comply with PSD Permitting and BACT Emissions Limitations

The United States asks this Court to order Ameren to apply for a PSD permit within 90 days from the issuance of a final order, and to implement BACT no later than four and one-half years from this Court's order. A balancing of the eBay factors confirms that an injunction directing Ameren to propose wet FGD as BACT at Rush Island is an appropriate method to end Ameren's violation of the PSD program at Rush Island.

When considering injunctive relief, I evaluate whether:

> (1) [the plaintiff] has suffered irreparable injury; (2) . . . remedies available at law, such as monetary damages, are inadequate to compensate for the injury; (3) . . . considering the balance of hardships between the plaintiff and defendant, a remedy in equity is

> warranted; and (4) . . . the public interest would not be disserved by a permanent injunction.

eBay Inc. v. MercExchange, L.L.C.: 547 U.S. 388, 391 (2006).

Ameren concedes the first two factors of the eBay standard are "in essence satisfied" in this case. (Def. Closing Arg., Tr. Vol. 6, 33:23-25 ("And I agree with the Government that the first two factors are - the eBay factors are in essence satisfied.")). Ameren argues, however, that the costs of pollution controls, borne by Ameren and passed onto ratepayers, weight the balance of hardships and public interest prongs in Ameren's favor.

i. The Communities Downwind of Rush Island Have Been Irreparably Injured

Environmental harm, "by its nature . . . is often permanent or at least of long duration, i.e., irreparable." Amoco Prod. Co. v. Gambell, 480 U.S. 531, 545 (1987); see also, United States v. Production Plated Plastics, Inc., 762 F. Supp. 722, 729 (W.D. Mich. 1991) (violations of an environmental statute usually result in irreparable injury); Ohio Valley Envt'l Coalition v. U.S. Army Corps of Engineers, 528 F. Supp.2d 625, 630 (S.D. W.Va 2007) ("because to damage the environment is often irreversible, this harm is frequently justification for a restraining order or an injunction"). I have closely reviewed the evidence presented at trial concerning harms the public has suffered because of the excess SO_2 emissions resulting from Ameren's failure to obtain a permit. Based on that evidence, I conclude that Ameren's failure to obtain a permit caused irreparable damage.

At trial, the EPA presented voluminous data demonstrating that Rush Island's excess emissions have increased the risk of heart attack, asthma attack, stroke, and premature death in downwind communities. FOF ¶¶ 251-53. Dr. Schwartz testified at length about the concentration-response relationship between $PM_{2.5}$ concentrations and premature mortality. Dr.

Schwartz and Lyle Chinkin also explained how SO_2 converts to $PM_{2.5}$, and the mechanisms by which $PM_{2.5}$ can cause harm. Id.; ¶¶ 240, 305-07.

In contrast, Ameren's experts Dr. Valberg and Dr. Fraiser testified contrary to the scientific consensus on $PM_{2.5}$'s human health impacts. Dr. Fraiser contradicted the scientific consensus that that $PM_{2.5}$ is a no-threshold pollutant that causes increased mortality on a linear basis.[17] Dr. Fraiser also offered opinions that were outside her area of expertise. FOF ¶¶ 274-75. Dr. Valberg's testimony in other cases and regulatory matters, on the same topics as were before me, has frequently been rejected by the EPA and courts. FOF ¶¶ 281-84.

Rush Island's excess emissions have created harmful $PM_{2.5}$ that has increased the risk of human health impacts in downwind communities. FOF ¶ 265. The EPA's independent modeling efforts estimated that the excess emissions have contributed to hundreds of premature deaths. FOF ¶ 338, Table 1. These environmental and human health impacts demonstrate irreparable injury from Rush Island's PSD violation. Cinergy, 618 F. Supp. 2d at 964 (finding irreparable harm from "significant health and environmental effects in the form of $PM_{2.5}$" resulting from excess SO_2). The first eBay factor is satisfied.

ii. Legal Remedies Are Inadequate to Remedy the Harm

Damages are inadequate to address the harm from excess emissions at Rush Island. See Def. Closing., Tr. Vol. 6, at 33:23-25; Gambell, 480 U.S. at 545 (explaining that environmental harm "can seldom be adequately remedied by money damages"). The facts of the case demonstrate that money damages would be inadequate here. Because of Rush Island's excess emissions, an increased risk of disease and premature mortality extends across thousands of miles of the Eastern United States. The public and environmental nature of the harm render

[17] Dr. Fraiser admitted, however, that the NAAQS do not guarantee zero risk. FOF ¶ 273.

monetary awards ineffectual: There is no individual to compensate. The additional risks of disease and premature mortality are spread across the population of the Eastern United States. Legal remedies alone cannot address the harm.

iii. The Balance of Hardships Weighs in Favor of an Injunction Ordering Ameren to Install Wet FGD at Rush Island

This opinion contains extensive discussion of the harm the downwind communities are suffering due to Ameren's decision to ignore the statutory requirement that it install pollution controls at the modified Rush Island. The Plaintiffs are suing to enforce a statute enacted to reduce the kind of harm Ameren's excess pollution has created, and they would suffer great hardship if I allow Ameren to continue to operate Rush Island without BACT. Meanwhile, an injunction ordering Ameren to comply with the Clean Air Act and install BACT imposes a relatively minor hardship on Ameren. Ameren will have to install at Rush Island the same pollution controls that power utility companies—including Ameren—must install at facilities across the country.

Ameren admits that it can "afford anything this Court orders." Def. Closing Arg., Tr. Vol. 6, 34:13. At the same time, Ameren expresses concern that its customers will bear the costs of compliance in the form of rate increases. Ameren asserts that the average customer will have to pay thousands more dollars over 20 years to reimburse Ameren for its capital expenditures.

This alleged hardship does not tip the balance in Ameren's favor. The costs of pollution controls are a cost of doing business; the Clean Air Act struck that balance when it mandated BACT measures for new and modified sources. See Introduction supra. Moreover, nothing in this order requires Ameren to recover the costs of compliance and remediation from its ratepayers. Ameren does not need to submit the costs as reimbursable, and the Missouri Public Service Commission has the discretion to allow only partial cost-recovery or to bar recovery because the costs result from Ameren's Clean Air Act violations. FOF ¶ 431.

Even if the control costs are passed onto ratepayers in their entirety, the resulting rate increase would be within the range of recent rate increases. FOF ¶¶ 435. On this point, Ameren presented conflicting, unrepresentative, and mischaracterized cost estimates. FOF ¶¶ 439-442. For example, one of Ameren's methods calculated average cost increase estimates and assumed that the cost of installing pollution controls will apply equally to all customers, regardless of whether they are residential, commercial, or industrial. FOF ¶ 440. This method over-estimates the costs that most of its customers, especially residential customers, will bear. Id.

In contrast, the EPA presented cost estimates on a percentage basis, and compared them with Ameren's recent cost increases. According to the EPA, the total cost of installing FGD at Rush Island and DSI at Labadie would lead to rate increases between 2.8 and 4.8%. FOF ¶ 434. Ameren also presented evidence using this methodology and calculated a similar percentage increase of 3.8%. Id. Of course, the Rush Island portion of these rate increases would have been borne by the ratepayers ten years ago had Ameren complied with the law.

For context, these projected increases are less than the most recent annual increase levied by Ameren (5.4%), as well as the rate decrease that was triggered by the 2017 federal tax law (6.1%). FOF ¶¶ 435, 437. Regardless of whether Ameren is allowed by the PSC and ultimately passes on the costs of compliance to customers, Ameren can readily finance and install wet FGD at Rush Island while staying profitable.

iv. Compliance at Rush Island Serves the Public Interest

The United States brought this civil action to enforce a public interest statute. The United States has clearly established that it is in the public interest for Ameren to comply with the Clean Air Act.

Ameren's argument to the contrary depends entirely on the costs it asserts this injunction will impose on rate-payers. As I discuss above in Section VI.c.iii, the estimated cost increases are modest. The estimated value of the benefit to the public is much larger than estimated costs to Ameren. FOF ¶¶ 375-77.

f. Ameren's Arguments That Rush Island's Excess Pollution Was Not Harmful Are Not Convincing

To influence the eBay analysis, Ameren argues that Rush Island's excess SO_2 pollution was either harmless as a matter of law (because of certain regulatory thresholds), or harmless as a matter of fact (based on the testimony of Ameren's toxicology experts). These arguments do not withstand scrutiny.

i. The National Ambient Air Quality Standards (NAAQS) Do Not Establish a Safe Threshold For SO_2 Pollution

Ameren's claim that the NAAQS render PSD requirements unnecessary is contradicted by the plain language and history of the PSD program and the NAAQS. Congress enacted the PSD program to address pollution occurring in areas already meeting the public health protections set forth in the NAAQS. C.f. TVA v. Hill, 437 U.S. 153, 194 (1978) ("[I]t is … the exclusive province of the Congress not only to formulate legislative policies and mandate programs and projects, but also to establish their relative priority for the Nation.").

The NAAQS predate the PSD program and exist to protect public health and welfare. 42 U.S.C. § 7409(b). The process of setting the NAAQS does not require the EPA to "definitively identify pollutant levels below which risks to public health are negligible." American Trucking Ass'n v. EPA, 283 F.3d 355, 369-70 (D.C. Cir. 2002). When it makes NAAQS determinations, "EPA does not purport to set the NAAQS at a level which would entirely preclude negative health outcomes." North Carolina v. TVA, 593 F. Supp. 2d 812, 822 n.6 (W.D.N.C. 2009), rev'd on other grounds 615 F.3d 291 (4th Cir. 2010). As even Ameren's expert Dr. Fraiser agrees, the NAAQS do not set a black-and-white threshold below which $PM_{2.5}$ poses no risk to human health. FOF ¶ 273.

The EPA's years of implementing the Clean Air Act and the PSD program also contradict Ameren's argument. The EPA has emphasized *ad nauseum* that there is no known safe threshold below which incremental increases in $PM_{2.5}$ exposure do not create incremental increases in risk to human health and welfare. 78 Fed. Reg. 3086, 3098, 3118-19, 3148 (Jan. 15, 2013); Final Integrated Science Assessment (Dec. 2009) at 2-12, 2-25 & 6-75 [Pl. Ex. 1209]; 71 Fed. Reg. 61144, 61158 (Oct. 17, 2006); 62 Fed. Reg. 38652, 38670 (July 18, 1997).

The EPA's scientific determinations mirror the broad consensus of the world's public health authorities. The great weight of the evidence demonstrates that $PM_{2.5}$ has a linear concentration-response function down to concentrations well below the NAAQS. See FOF ¶¶ 266-272. The overwhelming weight of evidence supports that $PM_{2.5}$ is a no-threshold pollutant, meaning it can pose risks to human life and health at any concentration level. See, e.g., 78 Fed. Reg. 3086, 3092, 3119 (Jan. 15, 2013) (citing Lead Industries v. EPA, 647 F.2d at 1156 n.51); FOF ¶¶ 256-62.

Ameren is not the first company to argue that the NAAQS set thresholds that shield against or limit PSD obligations. Hawaiian Electric (HECO) maintained before the Ninth Circuit that the EPA could not "impose emission restrictions that are more stringent than necessary to protect NAAQS" in a PSD permit. Hawaiian Electric v. EPA, 723 F.2d 1440, 1446-47 (9th Cir. 1984). The Ninth Circuit rejected the argument. After recounting the legislative history and examining the statute's text, the court concluded, "it is absurd for HECO to maintain that EPA may not, through a PSD permit, require pollution controls which yield air quality better than

NAAQS." Id. Similarly, I will not ignore the harm from Rush Island's excess emissions merely because these excess emissions were released in an attainment area with $PM_{2.5}$ levels below the NAAQS.

ii. The "Significant Impact Levels" Do Not Determine the Meaningfulness of Human Health Impacts

Similar to its NAAQS assertions, Ameren argues that pollution impacts below the EPA's "significant impact levels" (or SILs) are harmless. Ameren points out that the EPA has established a SIL of annual $PM_{2.5}$ impacts of 0.2 $\mu g/m^3$ for some areas. This value is almost four times higher than the highest impact of Rush Island's excess emissions when averaged over an entire year. SILs are not a valid means of determining the significance of downwind health effects. Instead, SILs are a regulatory tool for assessing whether a source's emissions might exceed NAAQS despite the installation of BACT. See FOF ¶¶ 342-48. Ameren's use of the SILs as a benchmark for its excess pollution is not supported by pertinent law or relevant fact.

Clean Air Act Section 165(a)(3) requires operators looking to implement a major modification to demonstrate that the pollution from the modified facility will not cause or contribute to a downwind NAAQS exceedance. 42 U.S.C. § 7475(a)(3). The EPA established the SILs to be screening tools aimed at identifying which facilities might lead to NAAQS exceedances. Pl. Ex. 1205 [Guidance on Significant Impact Levels] at USTREXR0003853-3855. But "[t]he SIL values identified by the EPA have no practical effect unless and until permitting authorities decide to use those values in particular permitting actions." Id. at 3-4.

Just as the NAAQS do not establish a "zero-risk" threshold under which pollution is safe, the SILs do not establish a level below which there is no risk of harm from a facility's pollution. The SILs are, at bottom, a compliance demonstration tool, helping permit applicants and permitting authorities determine whether additional air quality modeling of a proposed source is needed. They provide NAAQS modeling guidance for the PSD permitting process.

The EPA's practice of assessing the benefits of Clean Air Act regulations further supports this legal analysis. The EPA models the effects of pollution concentration reduction by amounts well below the SILs, including the effects of changes less than 0.01 μg/ m^3. FOF ¶ 348. Ameren's SILs argument does not overcome the wealth of evidence demonstrating that Rush Island's emissions led to irreparable harm that should be remedied.

iii. Ameren's Reliance on Scientific Uncertainty Is Misguided and Its Reliance on Fringe Toxicological Evidence Is Unpersuasive

Finally, Ameren asserts there is too much uncertainty about any harm from its excess emissions to justify the expense associated with installing scrubbers. Ameren's counsel argued in closing that "[t]here are uncertainties at every stage of the causal relationship that plaintiffs must prove." Def. Closing., Tr. Vol. 6, at 34:19-21. Ameren complains that Plaintiffs do "not identify[] or even predict[] any person's real-world death." ECF No. 1068 at 4. This argument mischaracterizes the level of scientific certainty needed and displayed in this case. There is widespread consensus among public health agencies and scientists that $PM_{2.5}$ causes adverse health effects, including cardiovascular effects such as heart attacks and strokes, respiratory effects such as asthma attacks, and premature mortality. FOF ¶¶ 251-54.

Ameren's reliance on individualized uncertainty misconceives the case. This is not a toxic tort case. The Clean Air Act curbs harm borne by a population, not a single person. By enacting the Clean Air Act, Congress sought "to protect public health and welfare from any actual or potential adverse effects" from air pollution. 42 U.S.C. § 7470(1) (emphasis added). Public health regulation evaluates and communicates risk, not diagnoses or proximate causes of any one individual's health problems or death. Numerous epidemiological studies reviewed by the experts in this case have shown that increases to SO_2 and $PM_{2.5}$ concentrations increase the risk to the public of lung disease, heart disease and premature mortality. FOF ¶¶ 260-62.

Further, Ameren overstates and misconstrues the nature of uncertainties presented in the EPA's modeling. There is no question that $PM_{2.5}$ increases the risk of premature mortality. Instead, the primary uncertainties in the EPA's case relate to specific quantifications of that risk. In his analyses, Dr. Schwartz laid no claim to absolute precision. On the contrary, Dr. Schwartz carefully documented the uncertainty in his risk assessments by providing peer-reviewed, 95% confidence intervals that bounded the certainty of his estimates. FOF ¶¶ 331, 335. Taken together, Dr. Schwartz's two assessments show that Rush Island's excess pollution has substantially harmed public health and welfare.

Next, Ameren insists that, though epidemiology can show correlation, it can never establish causation. Sulfate $PM_{2.5}$ is only one component of a mixture that Ameren believes should be isolated for rigorous epidemiological or toxicological analysis. Ameren's toxicologists argue that there is no toxicological literature that establishes the poisonous dosage of $PM_{2.5}$ or sulfate. This argument incorrectly interprets the relevant scientific literature. The scientific consensus is that $PM_{2.5}$ exposure is harmful at all relevant exposure levels. This consensus is not based exclusively on epidemiological research. <u>See, e.g.</u>, FOF ¶ 259; <u>see also generally</u> Pl. Ex. 1209 [NAAQS ISA] (considering, among other things, "controlled human exposure studies" and "toxicological studies"). It also derives from the findings of toxicologists and medical practitioners endeavoring to settle on a coherent, cross-discipline understanding of the relationship between health effects and changes in ambient $PM_{2.5}$ concentrations. FOF ¶ 259. Ameren's attempts to inject uncertainty into the broad scientific consensus do not undermine the wealth of evidence demonstrating human health impacts due to sulfate-created $PM_{2.5}$ particles.

Finally, the structure of the Clean Air Act itself disposes of Ameren's argument.

Congress made clear in passing the Clean Air Act that when a source "increases the amount of any air pollutant," it must be subject to NSR (among other requirements). See, e.g., 42 U.S.C. § 7411(a)(4). Even in attainment areas with low $PM_{2.5}$ concentrations, the Clean Air Act requires facilities like Rush Island that undergo major modifications to install BACT. See 42 U.S.C. § 7475(a)(3). Regardless of whether Ameren is correct about the harm $PM_{2.5}$ causes at low concentrations, the Clean Air Act grants courts jurisdiction to provide "appropriate relief" to remedy Ameren's violation. See 42 U.S.C. § 7413(b)(3).

IV. LABADIE MUST REDUCE EMISSIONS COMMENSURATE WITH THE EXCESS EMISSIONS RELEASED BY RUSH ISLAND

a. The eBay Factors Support the EPA's Requested Injunctive Relief at Labadie

Injunctive relief at Rush Island will bring the plant into compliance with the PSD program, ending the release of excess SO_2 emissions and $PM_{2.5}$ there. However, BACT measures at Rush Island will not redress the harm from the last ten years. A balancing of the eBay factors leads me to conclude that injunctive relief is necessary at Labadie in order to remediate Rush Island's excess emissions.

i. The Same Irreparable Injury Analysis of Rush Island's Excess Emissions Applies to Labadie

The record establishes that in the last ten years, Rush Island's release of more than 162,000 tons of excess SO_2 pollution has increased the risk of adverse health effects, including premature mortality. The EPA's experts quantified these effects at trial. FOF ¶ 376-77. Dr. Schwartz testified at length about the concentration-response relationship between $PM_{2.5}$ concentrations and premature mortality. Dr. Schwartz and Lyle Chinkin also explained how SO_2 is transported from Rush Island across the country, its conversion to $PM_{2.5}$, and the mechanisms by which $PM_{2.5}$ can cause harm. These environmental and human health impacts demonstrate irreparable injury from Rush Island. Cinergy, 618 F. Supp. 2d at 964.

ii. Legal Remedies Are Inadequate to Remedy the Harm

Ameren admits there is no adequate remedy at law to address the environmental harm documented in this case. Def. Closing., Tr. Vol. 6, at 33:23-25. Because the environmental harm and health risks are spread across the population of the Eastern United States, there is no one person or discrete group of people to compensate. I find that an "economic award would not sufficiently compensate" for injuries and the increased risk of harm resulting from Ameren's failure to obtain a PSD permit at Rush Island. Franklin County Power, 546 F.3d at 936; see also Westvaco, 2015 WL 10323214, at *9 (D. Md. Feb. 26, 2015); Cinergy, 618 F. Supp. 2d at 961.

iii. Plaintiffs Suffer the Balance of the Hardships

The balance of hardships for equitable relief at Labadie compares well with the balance of hardships at Rush Island. On one hand, Rush Island's excess emissions have created a widespread risk of harm to public health. On the other hand, accounting for those excess emissions requires some cost on Ameren's part. The costs of pollution reductions at Labadie are well within Ameren's financial capabilities. FOF ¶¶ 440-444. Implementing DSI on the four Labadie units would cost $55 million dollars in capital investment and then $53 million a year in operating costs. FOF ¶ 362. Ameren did not present any evidence that paying these costs would cause it any hardship. On the contrary, Ameren Missouri's FERC Form 1 filings reveal it has an exceptionally strong and profitable financial standing. FOF ¶¶ 415-16. If the Missouri Public Service Commission does not allow Ameren to seek reimbursement for the cost of implementing DSI, Ameren can readily finance it with a fraction of the annual dividends it has issued in recent years. See FOF ¶¶ 415 Table 2, 416 Table 3.

iv. Pollution Reductions at Labadie Serve the Public Interest

An award of injunctive relief at Labadie to account for Ameren's excess emissions serves the public interest. This remedy protects life and health through full enforcement of the protections Congress set forth in the permitting scheme of the Clean Air Act. The cost of remediating the harm from Rush Island's excess emissions pales in comparison to the public health benefit. Using standard, peer-reviewed estimates, Dr. Schwartz estimated the monetary value of social benefits that would accrue from offsetting Rush Island's excess emissions. The benefits of emissions reductions would far surpass any financial costs Ameren will face. FOF ¶¶ 375-76. Remediating the harm from non-compliance also reduces any economic advantage Ameren gained by violating the law, placing it on more equal footing with companies that have complied with the Clean Air Act.

b. Reducing Pollution from Nearby Labadie Is Relief Narrowly Tailored to Remedy the Harm from Ameren's Violations.

To remediate the harm from Rush Island's excess pollution, the EPA requests that Ameren reduce SO_2 emissions from its Labadie plant in an amount equal to Rush Island's excess emissions. The goal of this requested relief is to reduce $PM_{2.5}$ concentrations for the same population that experienced increased $PM_{2.5}$ concentrations and increased risk of adverse health effects due to Rush Island's failure to obtain a PSD permit.

Ameren argues that because Labadie is "totally innocent," and Ameren has not violated the Clean Air Act there, my order that Ameren install pollution controls at Labadie is an "extreme remedy" that constitutes a penalty. On the contrary, the remedy is based on straightforward equitable principles and the authority I have under the Clean Air Act "to restrain" violations, "to require compliance," and "to award any other appropriate relief." 42 U.S.C. § 7413(b). I have 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. United States v. Cinergy, 582 F. Supp. 2d 1055, 1060-61 (S.D. Ind. 2008).

This relief is narrowly tailored "to remedy specific harm shown." Rogers v. Scurr, 676 F.2d 1211, 1214 (8th Cir. 1982). There is a tight geographic nexus between the harms Rush Island caused and the benefits gained through reducing Labadie's emissions. Pollution from Labadie affects the same communities as those affected by Rush Island, and to the same degree. FOF ¶ 369. Accordingly, any efforts undertaken to reduce at Labadie pollution would correspond ton-for-ton with the harm caused by Rush Island's excess emissions. Pl. Exs. 1362 & 1364; FOF ¶¶ 368, 373. Controlling Labadie's emissions offers a rare opportunity to right Ameren's wrong on the same terms.

This relief also respects the persuasive factors considered by other courts evaluating environmental remedies. Specifically, reducing emissions at Labadie (1) "would confer [the] maximum environmental benefit," allowed, (2) is "achievable as a practical matter," and (3) bears "an equitable relationship to the degree and kind of wrong it is intended to remedy." United States v. Deaton, 332 F.3d 698, 714 (4th Cir. 2003).

First, this order achieves the maximum possible environmental benefit in this case. When Ameren reduces emissions at Labadie commensurate with the excess emissions from Rush Island, Ameren will have put the public in the place it would have been absent Ameren's Clean Air Act violation. Second, there is no dispute that commonly available pollution controls (DSI, FGD) are achievable as a practical matter. No obstacle stands in the way of DSI or FGD being installed on Labadie. FOF ¶ 362. Finally, the remedy bears an equitable relationship to Rush Island's excess emissions because of the tight geographical link between Rush Island's emissions and Labadie's emission. Ameren's ton-for-ton reductions at Labadie will lower the risks of premature mortality and disease in the same communities impacted by Ameren's Rush Island violations.

c. DSI Installation at Labadie Is Not a Penalty

At trial, Ameren argued that any injunction against its Labadie plant would constitute a penalty, which the EPA waived when it moved to strike its jury demand. As I ruled at the time, "[w]hen relief 'goes beyond remedying the damage caused to the harmed parties by the defendant's action,' [ ] it is properly viewed as punitive and therefore legal in nature." U.S. v. Ameren Missouri, No. 4:11 CV 77 RWS, 2016 WL 468557, at *1 (E.D. Mo. Feb. 8, 2016) (quoting Johnson v. S.E.C., 87 F.3d 484, 488 (D.C. Cir. 1996)). Ameren correctly notes that I cannot issue injunctive relief that would constitute a penalty. However, Ameren's application of that legal principle to the facts of this case is incorrect. By ordering emissions reductions up to, but not surpassing, the excess emissions from Rush Island, I am ordering relief that goes exactly to "remedying the damage caused to the harmed parties by the defendant's action." Id.

To further ensure that any relief at Labadie does not surpass the damage caused by Rush Island, I will order Ameren to base its relief at Labadie on DSI control technology. The capital costs of DSI without a fabric filter are a small fraction of the capital costs of any other control technology. While FGD installation at two units may cost more than $500 million, DSI installation on Labadie's four units would cost only $55 million. FOF ¶ 424. Operating DSI without a fabric filter on all four Labadie units would cost about $53 million per year. Id. As a result, the overall expense of DSI comes predominantly from operating expenses. Ameren can therefore install DSI on Labadie's four units, operate DSI for as many years as necessary to remediate Rush Island's excess emissions, and terminate its use of DSI without suffering significant lost capital assets. Installing DSI—or some more effective pollution control technology—at Labadie provides the relief necessary to remedy the harm from Rush Island without penalizing Ameren.

By the time Rush Island implements BACT measures and comes into compliance with PSD, the facility will have emitted nearly 275,000 excess tons of SO_2. FOF ¶ 211. The record shows Ameren has multiple options to reduce Labadie's emissions by the same amount. If they are implemented soon, these measures will reduce SO_2 pollution by as much as 250,000 tons before 2036, the year two of the four Labadie units are slated for retirement. Installing DSI at Labadie will reduce SO_2 pollution in the area commensurate with the volume of Rush Island's excess emissions, and will benefit the same communities burdened by the harm caused by the violations. I will order Ameren to begin operating Labadie with DSI, or a more effective pollution control, beginning no later than three years after this order.

V. AMEREN'S FAIR NOTICE ARGUMENT FAILS

Ameren argues that I should not order injunctive relief at either Rush Island or Labadie because the EPA did not provide fair notice of its regulatory interpretations of the Clean Air Act. Fair notice is an administrative law concept that "preclude[s] an agency from penalizing a private party for violating a rule without first providing adequate notice of the substance of the rule." Howmet Corp. v. E.P.A., 614 F.3d 544, 553 (D.C. Cir. 2010) (quoting Satellite Broad. Co., Inc. v. FCC, 824 F.2d 1, 3 (D.C.Cir.1987). When evaluating whether this constitutional requirement has been met, courts determine whether a regulated party "would be able to identify, with 'ascertainable certainty,' the standards with which the agency expects parties to conform." Id. at 5353-54 (quoting Gen. Elec. Co. v. U.S. E.P.A., 53 F.3d 1324, 1329 (D.C. Cir. 1995), as corrected (June 19, 1995)). The "ascertainable certainty" standard does not require an agency to define how a given regulation applies to every set of facts. That function is served by adjudication. See United States v. Cinemark USA, Inc., 348 F.3d 569, 580 (6th Cir. 2003) ("An agency's enforcement of a general statutory or regulatory term against a regulated party cannot be defeated on the ground that the agency has failed to promulgate a more specific regulation.") (citing SEC v. Chenery Corp., 332 U.S. 194, 201 (1947)).

Courts also consider "whether the regulated party received, or should have received, notice of the agency's interpretation in the most obvious way of all: by reading the regulations." Howmet Corp. v. E.P.A., 614 F.3d at 553 (quoting Gen. Elec., 53 F.3d 1324, 1329). The regulations at issue concern the EPA's definition of "projected actual emissions." The regulations provide instructions in how regulated entities should determine projected actual emissions. Specifically,

> the owner or operator of the major stationary source:
> (a) Shall consider all relevant information, including but not limited to, historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans under the approved State Implementation Plan; and
> (b) Shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions

40 C.F.R. § 52.21(b)(41)(ii). The regulations also allow a "demand growth exclusion" where owners and operators

> Shall exclude . . . that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (b)(48) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth

Id. § 52.21(b)(41)(ii)(c).

Ameren argues that the EPA failed to give notice of how it applies these two subparagraphs to the facts of any given case. Ameren also argues that "on its face" the "all relevant information" standard in 40 C.F.R. § 52.21(b)(41)(ii)(a) fails to provide "ascertainable certainty."

These arguments are unconvincing. The regulation in question is not "baffling and inconsistent" or "unclear" in the way that courts have found other regulations subjected to fair notice challenges. E.g. Gen. Elec., 53 F.3d at 1330. Instead, the regulation provides a clear, if flexible standard: owners and operators of major stationary sources "[s]hall consider all relevant information . . . ." 40 C.F.R. § 52.21(b)(41)(ii). Immediately after this standard, the regulation provides examples of specific factors that should be considered, including "historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the state or federal regulatory authorities, and compliance plans under the approved State Implementation Plan." Id. The EPA evaluated these same factors when presenting evidence before me that Ameren's projected emissions had increased. Ameren Missouri, 229 F. Supp. 3d at 946-71. Ameren had fair notice of how "projected annual emissions" should be determined under § 52.21(b)(41)(ii).

Ameren also objects to the EPA's application of the demand growth exclusion. The demand growth exclusion applies when a power plant's projected emissions increases are caused by an increase in system-wide demand growth. Ameren argues that the EPA only considered plant-specific, rather than system-wide, demand growth. Ameren also objects to a "restaurant" metaphor that the EPA used to explain temporal demand for electricity generation.[18]

---

[18] At the liability phase of the trial, the EPA used a restaurant metaphor to explain the relationship between a baseload power plant and system-wide electricity demand. Specifically, the EPA suggested that a baseload power plant is analogous to a high-demand restaurant that has no available seating during the lunch and dinner rushes. Increased demand for meals during these times does not increase the number of meals served at the restaurant. The EPA presented this metaphor for argumentative purposes only. This metaphor does not reveal any new aspect of the regulations at hand. As a result, there is no "fair notice" issue at stake.

In making these arguments, Ameren mischaracterizes how the EPA applied the demand growth exclusion. The EPA did not evaluate market demand at Rush Island. Instead, the EPA evaluated Rush Island's relationship to system-wide demand. Specifically, the EPA presented evidence that Rush Island is a baseload power plant that runs as frequently as possible. Ameren Missouri, 229 F. Supp. 3d at 972-73. This means that Rush Island's own generating capacity and maintenance needs, rather than demand, determine when it is operated. Id. at 975. Because Ameren mischaracterizes the EPA's approach to the demand-growth exclusion, its fair-notice argument fails.

Finally, Ameren argues that the EPA failed to give fair notice that it would use an actual emissions standard—as opposed to a projected emissions standard—when determining whether Ameren made a major modification at Rush Island. According to Ameren, Missouri's 2007 State Implementation Plan only referred to a pollution source's "potential to emit." After the liability phase trial, I found that both Rush Island's projected and actual emissions increased due to its major modifications. Id. at 952-54, 956-58. Ameren does not argue any fair notice issue concerning the "projected emissions" aspect of the regulation. If projected emissions were the only criteria to determine major modifications, then Ameren would still be liable for major modifications at Rush Island. Consequently, there is no fair notice issue at stake. Ameren's fair notice arguments fail and do not provide a reason to deny the EPA's requested injunctive relief.

CONCLUSION

In the 1977 Clean Air Act Amendments, Congress struck a balance. The Act allowed then-existing power plants to continue emitting high levels of pollution until their owners made major modifications at those plants. At that point, they would have to apply for a PSD permit and meet reduced emissions requirements. For thirty years, Ameren benefitted from this policy, operating Rush Island without the need to apply for a PSD permit. When Ameren decided to make major modifications to expand Rush Island's capacity, Ameren refused to play by the rules Congress set. It did not apply for the required PSD permit, and in so doing skirted PSD's requirement to install the best available technology to control the pollution Rush Island emits.

To remedy its violation of the Clean Air Act, Ameren must now apply for a PSD permit for Rush Island within ninety days, propose wet FGD as BACT in its permit application, and implement BACT no later than four and one-half years from this order. However, to stop there would be to abet Ameren's Clean Air Act violation and to ignore the public harm that violation has caused. Mindful of my authority to grant other appropriate injunctive relief under the Clean Air Act, I cannot ignore that harm.

In addition to the relief I order at Rush Island, I will also order Ameren to reduce its pollution at Labadie in an amount equal to Ameren's excess emissions at Rush Island. Ameren may choose whether it will achieve the reductions by installing DSI or some other more effective pollution control at Labadie. This is not a penalty for Ameren's violation of the Clean Air Act; it is an attempt to put the Plaintiffs in the place they would have been had Ameren complied with PSD program requirements from the start. The ton-for-ton reduction at Labadie directly remediates the public harm Ameren has caused and reverses the unjust gain Ameren has enjoyed from its violation of the Clean Air Act at Rush Island.

Accordingly,

IT IS HEREBY ORDERED THAT Defendant Ameren shall apply for a Prevention of Significant Deterioration permit for the Rush Island Energy Center within ninety days of the date of this Order. Ameren must propose wet flue-gas desulfurization as the technology-basis for its Best Available Control Technology proposal.

IT IS FURTHER ORDERED THAT Defendant Ameren shall operate Rush Island Units 1 and 2 in compliance with an emissions limit that is no less stringent than 0.05 lb SO_2/mmBTU on a thirty-day rolling average within four and one half years of the date of this Order.

IT IS FURTHER ORDERED THAT Defendant Ameren shall install a pollution control technology at least as effective as dry sorbent injection at the Labadie Energy Center within three years from the date of this Order. That technology shall remain in use at Labadie until Ameren has achieved emissions reductions totaling the same amount as the excess emissions from Rush Island, as defined in this Order, through the time Ameren installs BACT at Rush Island.

IT IS FURTHER ORDERED THAT I will retain jurisdiction over this case until Ameren has fully implemented the remedies set forth in this Order.

RODNEY W. SIPPEL
UNITED STATES DISTRICT JUDGE

Dated this 30th day of September, 2019.

Keith Majors
Case Participation

Cases to which I have been assigned and have filed testimony, Staff report, or memorandum are shown in the following table:

Utility	Case Number	Issues	Exhibits
Spire Missouri	GR-2025-0026	ISRS	Staff Memorandum
Ameren Missouri	ER-2024-0319	Rush Island, Storm Costs	Direct Testimony
Evergy West	ER-2024-0189	Transmission Expense, Plant Investment	Direct, Rebuttal, Surrebuttal Testimony
Spire Missouri	GA-2024-0257	CCN	Staff Memorandum
Ameren Missouri	EF-2024-0021	Policy, Retired Plant Securitization	Rebuttal, Surrebuttal Testimony
Confluence Rivers	WR-2023-0006 & SR-2023-0007	Policy, Revenue Requirement	Direct, Rebuttal, and Surrebuttal Testimony
Ameren Missouri - Electric	ER-2022-0337	Revenues, Allocations, Bad Debt, Rush Island	Direct, Rebuttal, and Surrebuttal Testimony
Spire Missouri	GO-2022-0171	ISRS	Staff Memorandum
Evergy Metro and Evergy West	ER-2022-0129 & ER-2022-0130	Revenues, Jurisdictional Allocations, Bad Debt, Sibley Retirement	Direct, Rebuttal, Surrebuttal Testimony
Ameren Missouri	ER-2021-0240 & GR-2021-0241	Facilities Transactions	Surrebuttal Testimony
Spire Missouri	GR-2021-0108	Corporate Allocations, Rate Case Expense	Staff Report, Rebuttal, Surrebuttal
MAWC	SA-2021-0074	CCN	Staff Memorandum
Evergy Metro and Evergy West	EO-2021-0032	Various	Staff Report
Spire Missouri	GO-2021-0030 & GO-2021-0031	ISRS	Staff Memorandum
Raytown Water	WR-2020-0264	Various	Staff Memorandum
Summit Natural Gas	GA-2020-0251	CCN	Staff Memorandum
Liberty Utilities	WM-2020-0174	CCN	Staff Memorandum
Missouri American Water Company (MAWC)	WA-2019-0366	CCN	Staff Memorandum
Ameren Missouri	ER-2019-0335	Allocations, Affiliation Transactions	Staff Report
MAWC CCN	SA-2019-0367	CCN	Staff Memorandum
United Services	SA-2019-0161	CCN	Staff Memorandum
KCP&L & KCP&L GMO	ER-2018-0145 & ER-2018-0146	Synergy and Transition Costs Analysis, Transmission Revenue and Expense	Staff Report
Laclede Gas and Missouri Gas Energy	GR-2017-0215 & GR-2017-0216	Synergy and Transition Costs Analysis, Corporate Allocations	Staff Report, Rebuttal, Surrebuttal

Utility	Case Number	Issues	Exhibits
KCP&L & KCP&L GMO	ER-2016-0156 & ER-2016-0285	Income Taxes, Pension & OPEB	Staff Report, Rebuttal, Surrebuttal
KCP&L & KCP&L GMO	EO-2016-0124	Pensions, Rate Comparison	Staff Report
KCP&L & KCP&L GMO	EC-2015-0309	Affiliate Transactions, Allocations	Surrebuttal Testimony
KCP&L	ER-2014-0370	Income Taxes, Pension & OPEB, Revenues	Staff Report, Rebuttal, Surrebuttal
KCP&L	EU-2015-0094	DOE Nuclear Waste Fund Fees	Direct Testimony
KCP&L	EU-2014-0255	Construction Accounting	Rebuttal Testimony
Veolia Kansas City	HR-2014-0066	Income Taxes, Revenues, Corporate Allocations	Staff Report
Missouri Gas Energy	GR-2014-0007	Corporate Allocations, Pension & OPEB, Incentive Compensation, Income Taxes	Staff Report, Rebuttal, Surrebuttal
Missouri Gas Energy ISRS	GO-2013-0391	ISRS	Staff Memorandum
KCP&L & KCP&L GMO	ER-2012-0174 & ER-2012-0175	Acquisition Transition Costs, Fuel, Legal and Rate Case Expense	Staff Report, Rebuttal, Surrebuttal
Missouri Gas Energy ISRS	GO-2011-0269	ISRS	Staff Memorandum
Noel Water Sale Case	WO-2011-0328	Sale Case Evaluation	Staff Recommendation
KCP&L & KCP&L GMO	ER-2010-0355 & ER-2010-0356	Acquisition Transition Costs, Rate Case Expense	Staff Report, Rebuttal, Surrebuttal
KCP&L Construction Audit & Prudence Review	EO-2010-0259	AFUDC, Property Taxes	Staff Report
KCP&L, KCP&L GMO, & KCP&L GMO – Steam	ER-2009-0089, ER-2009-0090, & HR-2009-0092	Payroll, Employee Benefits, Incentive Compensation	Staff Report, Rebuttal, Surrebuttal
Trigen Kansas City	HR-2008-0300	Fuel Inventories, Rate Base Items, Rate Case Expense, Maintenance	Staff Report
Spokane Highlands Water Company	WR-2008-0314	Plant, CIAC	Staff Recommendation
Missouri Gas Energy ISRS	GO-2008-0113	ISRS	Staff Memorandum

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

[PROPOSED] STIPULATED ORDER

Pursuant to the Court's powers to impose an equitable remedy (ECF #1315 at 12), and pursuant to the stipulation of the Parties, the Court orders the mitigation relief set forth below. With notice from the United States that nothing in its public comment process warrants withdrawal from this proposal, the Court finds this stipulated remedy to balance "what is necessary, what is fair, and what is workable." *Class v. Norton*, 376 F. Supp. 496, 501 (D. Conn. 1974) *aff'd in part and rev'd in part on other grounds*, 505 F.2d 123 (2d Cir. 1974) (*quoting Lemon v. Kurtzman*, 411 U.S. 192, 200 (1973)).

Accordingly,

IT IS HEREBY ORDERED THAT:

Ameren Missouri ("Ameren") shall implement two mitigation projects:

(1) A project to support the distribution of stand-alone HEPA purifier devices to residential customers within Ameren's service territory located predominantly in Eastern Missouri, prioritizing distribution to low-income households, and

(2) A project to promote the transition to electric school buses for schools in the St. Louis metropolitan and surrounding areas with the charging stations necessary to support these vehicles.

The Parties recognize that the targets regarding the number of stand-alone HEPA purifiers and electric buses may not be achievable due to lack of participant interest or other factors outside of Ameren's control. In the event certain benchmarks are not met when implementing these programs, Ameren shall administer funds for the purpose of implementing weatherization and energy efficiency upgrades.

I. RESIDENTIAL HEPA PURIFIER PROGRAM:

A. <u>Program Objective</u>: In this program (the "HEPA Purifier Program") Ameren shall offer $200 vouchers to at least 125,000 residential account holders for the purchase of a stand-alone High Efficiency Particulate Air (HEPA) purifier device, sourced by a qualified vendor.

B. Program Parameters: Prioritizing low-income and/or disadvantaged[1] communities, Ameren will identify and select residential customers within its service territory to receive the offers. Customers will be solicited via mail, email, or bill insert with a QR code or link to a dedicated website, where vouchers can be used to obtain a free HEPA purifier. Eligible customers may also place a phone order through Ameren's customer service department. Ameren shall make its first 25,000 offers to residents in census tracts within service territory zip codes with median income levels at or near the midpoint income level of the 125,000 account holders. During this initial solicitation, Ameren shall endeavor to identify and address any distribution or other implementation issues that may arise with initiation of the program. Following the initial solicitation, Ameren will make offers to residential customers within service territory zip codes in order of census tract, starting with the lowest median income and moving to the highest median income, until at least 125,000 offers have been tendered. A sample of census tract numbers and corresponding zip codes of eligible residential customers is appended hereto as Exhibit A. All taxes and shipping will be paid by Ameren.

C. Offer and Reminder Parameters: Offers will expire not less than 90 days from the date of issue. Offer recipients shall be provided at least one reminder to participate ("Reminder Notice"), sent approximately 30 days after the offer, except that residential customers in census tracts where information available to Ameren indicates that the median area income is $25,000 or less shall be provided at least two Reminder Notices, sent approximately 30 days and 60 days after the offer. For all offer recipients, a final reminder ("Expiration Notice") will be sent at least 14 days before the expiration of the offer period. The method of delivery of Reminder Notices and Expiration Notices will be via mail, email, or bill insert, at Ameren's discretion.

[1] For purposes of this Order, "disadvantaged" communities are those that are marginalized, underserved, and overburdened by population, where the census tract faces both significant environmental or climate burdens as well as socio-economic burdens, as identified by the Council on Environmental Quality's Climate and Economic Screening Tool, https://screeningtool.geoplatform.gov/en/.

D. Purifier Parameters: Ameren and/or its vendor shall select a HEPA purifier model or models that achieve a minimum Clean Air Delivery Rate ("CADR") of 195.[2]

E. Program Deadlines: Within ninety (90) days of entry of this Order, Ameren shall create a dedicated website to process customer redemption requests, finalize marketing plans, and line up sourcing of the HEPA purifier products. Offers may occur in stages, with the first series of offers to be made not later than 120 days of entry of this Order. The program will remain open until Ameren tenders at least 125,000 offers and the customers' opportunity to accept those offers has expired.

F. Escrowed Funds for Weatherization and Energy Efficiency Projects: Customer demand for, and uptake of, the $200 offers for HEPA purifiers is uncertain. If Ameren has implemented the HEPA Purifier Program in accordance with the program requirements set forth above and 75,000 or more vouchers have been redeemed, then Ameren shall be deemed to have satisfied its obligations under the HEPA Purifier Program and no further actions are required. But if fewer than 75,000 vouchers have been redeemed, Ameren shall administer (or provide for the administration of) the sum of $5,000,000 (Five Million Dollars) for the Weatherization Program described in Section III below.

II. ELECTRIC BUSES AND CHARGING INFRASTRUCTURE PROGRAM:

A. Program Objective: In this program (the "Bus Program") Ameren shall deposit $36,000,000.00 (Thirty-Six Million Dollars) (the "Bus Funds") in an escrow account to be used with the goal, depending upon individual school district needs and participation, of procuring and putting into service eighty (80) zero-emissions, all-electric buses ("Electric Buses") to replace class 4-8 school buses with a gross vehicle rating greater than 14,001lbs. Additionally, Ameren shall administer the Bus

[2] Air purifiers with a CADR of 195 are effective at cleaning a room approximately 300 square feet in size. *See* https://www.epa.gov/indoor-air-quality-iaq/guide-air-cleaners-home#tips.

Funds to include one charging station (with no fewer than two charging ports) per Electric Bus. Each charging station shall include a vendor warranty of not less than twenty-four months.

B. Program Parameters: Ameren may partner with one or more third-party organizations to implement this program, provided that Ameren limits the use of Bus Funds for any administrative expenses associated with implementation of the Bus Program to no greater than 10% of the Bus Funds. For clarity, vendor and engineering costs attributable to site design, facility and/or utility service upgrade costs to support electrification, and the costs of charging station installation and manufacturing are all deemed to be project costs; they do not count as administrative costs. In coordination with any implementation partners, Ameren will develop criteria for program participation that prioritize school districts and service areas with low-income students/users and/or disadvantaged communities, including the Special School District of St. Louis County.

C. Program Deadlines: Within ninety (90) days of entry of this Order, Ameren shall initiate negotiations with bus manufacturers to define base specifications, including, if necessary, adjustments to meet specific school district needs. Solicitations to participating school districts shall occur no later than August 1, 2025. The placement of Electric Bus procurement orders and/or the issuance of selection awards to school districts may occur on a rolling basis and shall be completed no later than December 31, 2026. Ameren may deposit the Bus Funds into escrow in three annual increments or in one lump sum with the first annual increment or lump sum being deposited within thirty (30) days of entry of this Order.

D. Decommissioning Replaced Diesel Buses: Except as provided below, the provision of an Electric Bus to a school district under this program shall be conditioned on the decommissioning of a diesel bus. So that school districts are able to provide transportation on a reliable basis, confirmation of decommissioning shall be required within 18 months of the delivery of an Electric Bus. Replaced diesel buses shall be decommissioned as follows:

a. Where the diesel bus being replaced is model-year 2010 or older, it shall be scrapped or rendered inoperable by cutting a 3-inch hole in the engine block of the retired vehicle and disabling its chassis by cutting the vehicle's frame rails in half. It shall then be made available for recycling.

b. Where the replaced vehicle is model-year 2011 or newer, it shall be scrapped, sold, or donated.

Where a school district does not already own or control a diesel bus, it will not be required to decommission a diesel bus to receive an Electric Bus under this program. Any costs associated with decommissioning buses shall be borne by the school districts. In certifying the completion of the Bus Program, Ameren may rely on a school district's or its implementation partner's certification that decommissioning has occurred.

E. Escrowed Funds for Weatherization and Energy Efficiency Project: Schools' demand for, and uptake of, Electric Buses for their fleets is uncertain. As of December 31, 2026, any Bus Funds that have not been spent on or allocated to purchases of Electric Buses, associated charging stations, and Bus Program administration costs shall be committed to the Weatherization Funds as described in Section III below.

F. Bus Program Completion: The Bus Program shall be deemed complete when: (a) all Bus Funds have been spent or allocated in accordance with the requirements set forth in Sections II(A) through II(E) above, and (b) the Weatherization Funds, if any, have been spent in accordance with the requirements of the Weatherization Program in Section III below. Ameren's certification of completion may rely on the certifications of any vendors or implementation partners. For clarity, subject to the limitation on administration costs provided in Paragraph II(B), in no event shall Ameren be required to fund or spend more than $36,000,000.00 (Thirty-Six Million Dollars) on the Bus Program.

III. WEATHERIZATION AND ENERGY EFFICIENCY PROJECTS

A. Program Objective: The funding, if any, that is allocated pursuant to Sections I(F) and II(E) above (the "Weatherization Funds"), shall be used by Ameren to administer weatherization and energy efficiency projects that will reduce energy consumption by residential buildings in Ameren's service area (the "Weatherization Program"). Examples of such projects include installation of floor, wall, and attic insulation; sealing of windows and doors; duct sealing; and passive solar retrofits.

B. Program Participation: As a condition to receiving Weatherization Funds, participating organizations must agree to expend such funds within three (3) years of receipt.

C. Program Parameters: Ameren may partner with one or more third-party organizations to implement the Weatherization Program, provided that Ameren limits those organizations' administrative expenses to no greater than 10% of the Weatherization Funds. Ameren will (in coordination with any implementation partners) develop criteria for program participation that prioritizes districts and service areas with low-income and disadvantaged communities. Activities undertaken to implement this program shall not include the replacement of combustion appliances but shall otherwise be administered in accordance with Missouri Department of Natural Resources (MDNR) policies (*see*, *e.g.*, https://dnr.mo.gov/document-search/missouri-weatherization-assistance-program-technical-manual-2023). Such activities shall be conducted by appropriately qualified and licensed contractors.

D. Program Completion: The Weatherization Program shall be deemed complete when all Weatherization Funds have been spent in accordance with the requirements set forth in Sections III(A) through III(C) above. Ameren's certification of completion may rely on the certifications of any vendors or implementation partners.

IV. CERTIFICATIONS AND COMPLETION

By stipulating to this order, Ameren certifies to this Court the truth and accuracy of each of the following:

1. That, other than in compliance with this Order, Ameren is not required to perform the work necessary to complete the mitigation projects by any federal, state, or local law or regulation, and it is not required to perform the work necessary for these mitigation projects by any agreement, grant, or as injunctive relief awarded in any other action in any forum;

2. That the projects are not actions that Ameren was committed to performing or implementing other than in resolution of this Order;

3. That Ameren has not received and will not receive credit for any of these mitigation projects in any other enforcement action or as a resolution of claims before any other tribunal, and

4. That any activity performed pursuant to this Order will not be funded—in whole or in part—by any other program, such as EPA's Clean School Bus Program or existing weatherization subsidies.

5. For clarity, Ameren's agreement herein shall not preclude it from participating in or funding other programs that relate to bus or electric vehicle electrification, weatherization or energy efficiency, or HEPA purifier distribution, so long as any other such programs are not funded by the projects established herein.

V. REPORTING

By January 31st and July 31st of each year following this Order and until such time as all mitigation projects are complete, Ameren shall file a report that specifies:

1. The completion date of the HEPA Purifier Program website;

2. The number of HEPA purifier vouchers offered and the number redeemed;

3. The number of Electric Buses ordered by school districts and whether or not such school districts agreed to decommission diesel buses and an estimate as to when, as provided herein, such decommission shall occur;

4. The amount of funds, if any, allocated to the Weatherization Program pursuant to Section I(F) and II(E) above; and

5. The identity of any organizations with which Ameren has partnered for the implementation of the Weatherization Program.

Ameren shall file a notice with this Court certifying its compliance with and completion of each of this Order's mitigation project requirements, once Ameren has satisfied all such requirements. Ameren's certification of compliance may be based on certifications of compliance provided by its implementation partners.

VI. ENTIRE AGREEMENT

All of the terms and requirements of this Stipulated Order are set forth herein. Ameren has not agreed to any other performance, compliance, reporting, or certification obligations other than those expressly set forth herein.

____

RODNEY W. SIPPEL
UNITED STATES DISTRICT JUDGE

So ORDERED this ___ day of _______, 2024.

Company Name: GMO Electric
Case Description: 2010 GMO Elec Rate Case
Case: ER-2010-0356

Response to Majors Keith Interrogatories – Set MPSC_20100628
Date of Response: 07/13/2010

Question No. :0125
Is GMO seeking recovery of the $3 million civil penalty levied against Jeffery Energy Center in the January 2010 settlement agreement listed on page 15 of the 2009 GPE Annual Report?

RESPONSE:
No. In January 2010, outside the test year in this case, GMO recorded its 8% share of the civil penalty below the line and is therefore not seeking recovery of this cost.

Response by Leigh Anne Jones, Accounting

Attachment: Q0125 GMO Verification.pdf

Verification of Response

Kansas City Power & Light Company
AND
KCP&L Greater Missouri Operations

Docket No. ER-2010-0356

The response to Data Request #_____0125_____ is true and accurate to the best of my knowledge and belief.

Signed: Tom Rush

Date: July 13, 2010

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

UNITED STATES OF AMERICA,	)	
	)	
Plaintiff,	)	
	)	
vs.	)	Case No. 4:11 CV 77 RWS
	)	
AMEREN MISSOURI,	)	
	)	
Defendant.	)	

MEMORANDUM OPINION AND ORDER

"'Why don't you go up to the Range?' somebody said to me.
'The air is pure, and they have the best water on earth.'"

- W.P. Kinsella
Shoeless Joe

TABLE OF CONTENTS

INTRODUCTION

Plaintiff the United States of America, acting at the request of the Administrator of the United States Environmental Protection Agency ("EPA"), filed this suit against defendant Ameren Missouri ("Ameren") on January 12, 2011. The United States alleges that Ameren committed various violations of the Clean Air Act, 42 U.S.C. § 7401 *et seq.*, the Missouri State Implementation Plan, and Ameren's Rush Island Plant Title V Permit when it allegedly undertook major modifications at its Rush Island Plant in Festus, Missouri without obtaining the required permits. For the reasons that follow, I conclude the United States has established that Ameren violated the Clean Air Act and its operating permit by carrying out the Rush Island projects without obtaining the required permits, installing best-available pollution control technology, and otherwise meeting applicable requirements.

The modern Clean Air Act was passed in 1970 in order "'to speed up, expand, and intensify the war against air pollution in the United States with a view to assuring that the air we breathe throughout the nation is wholesome once again.'" *United States v. Duke Energy Corp.* ("*Duke Energy 2010*"), No. 1:00 CV 01262, 2010 WL 3023517, at *2 (M.D.N.C. July 28, 2010) (quoting H.R. Rep. No. 91-1146, at 1 (1970), reprinted in 1970 U.S.C.C.A.N. 5356). By 1977, Congress had determined that earlier programs "did too little" to achieve air quality goals and added the New Source Review program ("NSR"), including the Prevention of Significant Deterioration ("PSD") provisions at issue in this case. *See Envtl. Def. v. Duke Energy Corp.*, 549 U.S. 561, 567-68 (2007) ("*Duke Energy 2007*"); *New York v. EPA*, 413 F.3d 3, 12-13 (D.C. Cir. 2005). The PSD program is designed to *prevent* significant increases in pollution, an objective built into the very name of the program. *United States v. Ameren Missouri ("Ameren SJ Decision")*, Case No. 4:11 CV 77 RWS, 2016 WL 728234, at *13 (E.D. Mo. Feb. 24, 2016).

The program is designed to prevent future significant increases in pollution, in part, by requiring major-emitting facilities to employ state-of-the-art pollution controls.

When it enacted the PSD program, Congress required all new major-emitting facilities to comply with PSD requirements by installing state-of-the-art pollution controls at the time of construction. Recognizing the expense and burden of installing such controls, however, Congress did not require facilities then in existence to immediately install pollution controls. Rather, Congress allowed these facilities to continue to operate without installing such controls on the condition that if they ever modified their facilities, they would calculate the impact of those modifications, report the planned modifications to the EPA, obtain the requisite permits, and install the required pollution control technologies at that time. PSD rules apply to "major modifications," which occur when there is a "physical change" or change in the method of operation of a major stationary source that would significantly increase net emissions. *See Ameren SJ Decision*, 2016 WL 728234, at *4. An increase of 40 tons or more per year of sulfur dioxide ("SO_2"), the pollutant discussed in this case, is "significant" under the regulations. 40 C.F.R. § 52.21(b)(23)(i).

Congress enacted these modification provisions to ensure that facilities that were grandfathered into the program would not be allowed "perpetual immunity" from PSD's requirements. *Ala. Power Co. v. Costle*, 636 F.2d 323, 400 (D.C. Cir. 1979). Under the PSD program:

> [O]ld plants [are treated] more leniently than new ones because of the expense of retrofitting pollution-control equipment. But there is an expectation that old plants will wear out and be replaced by new ones that will be subject to the more stringent pollution controls that the Clean Air Act imposes on new plants. One thing that stimulates replacement of an old plant is that aging produces more frequent breakdowns and so reduces a plant's hours of operation and hence its output.

United States v. Cinergy Corp., 458 F.3d 705, 709 (7th Cir. 2006).

Ameren's Rush Island plant includes two coal-fired electric generating units, Units 1 and 2. These units went into service in 1976 and 1977 and were grandfathered into the PSD program. Neither unit has air pollution control devices for SO_2. The Rush Island plant currently emits about 18,000 tons of SO_2 per year. The Rush Island units are big sources of pollution, so even small performance improvements or increases in unit availability can lead to a 40-ton increase in SO_2. It only takes an availability improvement of 0.3% or an additional 21 hours of operation at full power for the Rush Island units to emit more than 40 tons of SO_2.

By 2005, some of the major boiler components in Units 1 and 2 were causing problems that forced Ameren to frequently take the units out of service and made the units underperform, reducing the amount of electricity Ameren could generate and sell from the units. Ameren decided to fix these problems by replacing the problem components with new, redesigned components. Courts in PSD enforcement actions have long recognized that "[i]f the repair or replacement of a problematic component renders a plant more reliable and less susceptible to future shut-downs, the plant will be able to run consistently for a longer period of time," burning more coal and emitting more pollution. *United States v. Ala. Power Co.*, 730 F.3d 1278, 1281 (11th Cir. 2013); *see also United States v. Ohio Edison*, 276 F. Supp. 2d 829, 834-35 (S.D. Ohio 2003). When these conditions occur, as they did here, they trigger a utility's obligation to conduct PSD review, secure the appropriate permits, and install required pollution controls.

This standard for assessing PSD applicability was well-established when Ameren planned its component replacement projects for Units 1 and 2. Ameren's testifying expert conceded that the method used by the United States' experts—which showed that Ameren should have expected the projects to trigger PSD rules—has been "well-known in the industry" since 1999.

But Ameren did not do any quantitative PSD review for the project at Unit 1 and performed a late and fundamentally flawed PSD review for Unit 2. And Ameren did not report its planned modifications to the EPA, obtain the requisite permits, or install state-of-the-art pollution controls. Instead, Ameren went ahead with the projects, spending $34 to $38 million on each unit to replace the problem components. It executed these projects as part of "the most significant outage in Rush Island history," taking each unit completely offline for three to four months. Ameren's engineers justified the upgrade work to company leadership on the basis that the new components would eliminate outages and the investment would be returned in recovered operations.

The evidence shows that by replacing these failing components with new, redesigned components, Ameren should have expected, and did expect, unit availability to improve by much more than 0.3%, allowing the units to operate hundreds of hours more per year after the project. And Ameren should have expected, and did expect, to use that increased availability (and, for Unit 2, increased capacity) to burn more coal, generate more electricity, and emit more SO_2 pollution.

Now that the projects have been completed, the evidence shows that Ameren's expected operational improvements actually occurred. Replacement of the failing components increased availability at both units by eliminating hundreds of outage hours per year. Unit 2 capacity also increased. Ameren's employees have admitted that those availability increases would not have happened but for the projects. As a result of the operational increases, the units ran more, burned more coal, and emitted hundreds of tons more of SO_2 per year.

In response to these projects, the United States filed this suit against Ameren, alleging that Ameren violated the Clean Air Act, the Missouri State Implementation Plan, and Ameren's

Rush Island Plant Title V Permit by performing major modifications on Units 1 and 2 without obtaining the required permits, installing state-of-the-art pollution control technology, or otherwise complying with applicable requirements.

Previously, in ruling on the parties' summary judgment motions, I set out several of the legal standards at issue in this case. *See Ameren SJ Decision*, 2016 WL 728234, at *13 (ruling on the parties' various motions for partial summary judgment and evidentiary motions); *United States v. Ameren Missouri*, 158 F. Supp. 3d 802, 804 (E.D. Mo. 2016) (denying Ameren's motion for full summary judgment). I held a twelve day non-jury trial beginning on August 22, 2016. The parties filed post-trial briefs and proposed findings of fact and conclusions of law on September 30, 2016 and argued outstanding evidentiary issues that were raised at trial. On October 12, 2016, the parties filed responses to each other's post-trial briefs.

After consideration of the testimony given at trial, the exhibits introduced into evidence, the parties' briefs, and the applicable law, I make the following findings of fact and conclusions of law, which largely adopt those proposed by the United States. As discussed below, I conclude the United States has established that Ameren should have expected, and did expect, the projects at Rush Island to increase unit availability (and, for Unit 2, to increase capacity), which enabled Ameren to run its units more, generate more electricity, and emit significantly more pollution. The United States has also established that Ameren actually emitted significantly more pollution as a result of the projects. Ameren has failed to establish that either the routine maintenance or demand growth defenses apply to shield it from liability. As a result, I conclude that the United States has established by a preponderance of the evidence that Ameren violated the PSD and Title V provisions of the Clean Air Act.

FINDINGS OF FACT

I. BACKGROUND CONCERNING THE DEFENDANT, THE RUSH ISLAND PLANT, AND THE APPLICABLE REGULATIONS

A. The Defendant

1. Defendant Ameren Missouri is a Missouri corporation. Defendant's incorporated name is Union Electric Company, but Defendant conducts business under the name Ameren Missouri. Answer to Third Amended Complaint ("Answer"), at ¶ 10 (ECF No. 250); Joint Stipulations of Fact ("Joint Stip."), at ¶ 1 (ECF No. 743).

2. As a corporate entity, Ameren is a "person" within the meaning of the Clean Air Act Section 302(e), 42 U.S.C. 7602(e) and 10 C.S.R. 10-6.020(2). Answer, at ¶ 11; Joint Stip., at ¶ 2.

3. At all times relevant to this case, Ameren has been the owner and/or operator of the Rush Island Plant in Festus, Jefferson County, Missouri. Answer, at ¶¶ 12, 57; Joint Stip., at ¶ 3.

B. The Rush Island Coal-Fired Power Plant

4. The Rush Island coal-fired power plant ("Rush Island Plant") consists, in part, of Units 1 and 2, which are coal-fired electric generating units. Rush Island Units 1 and 2 went into commercial service in 1976 and 1977, respectively. Answer, at ¶¶ 13, 59; Joint Stip., at ¶ 4.

5. The Rush Island units were originally designed to have an approximately 30-year life. Testimony of U.S. Power Plant Expert Bill Stevens, Trial Transcript Volume ("Tr. Vol."), 1-B 50:24-51:4, 69:4-11. The components of large units like the Rush Island units typically have a life of between 30 and 40 years. Stevens Test., Tr. Vol. 1-B 81:19 – 82:1.

6. The Rush Island units were designed as baseload units, meaning they generally operate every hour that they are available to run. Design Data Report (Pl. Ex. 297), at AUE-00022523, 22526; Testimony of Retired Ameren Vice President Charles Naslund, Tr. Vol. 6-A, 55:4-7; Anderson Dep., Dec. 4, 2013, Tr., 63:21 – 64:6; Pope Dep., Sept 20, 2013, Tr. 121:18 – 122:11; Testimony of U.S. Utility System Modeling Expert Dr. Ezra Hausman, Tr. Vol. 4-B, 26:15-10; Testimony of EPA Engineer Jon Knodel, Tr. Vol. 1-A, 75:16 – 75:24; 76:21–76:25.

7. The Rush Island units are among Ameren's most cost-effective units and carry much of the system load. Retired Ameren executive vice president Charles Naslund described the units as "two workhorses." Naslund Test., Tr. Vol. 6-A, 50:3-12.

8. Burning coal at Rush Island Units 1 and 2 generates combustion gases containing sulfur dioxide ("SO_2"). The SO_2 gases at Rush Island Units 1 and 2 are passed through a smokestack directly to the atmosphere, as neither unit has air pollution control devices for SO_2. Testimony of U.S. Emissions Expert Ranajit Sahu, Tr. Vol. 5, 43:9 – 44:24; Knodel Test., Tr. Vol. 1-A, 73:7 – 73:9.

9. The Rush Island plant currently emits about 18,000 tons per year of SO_2. Knodel Testimony, Tr. Vol. 1-A, 73:16 – 73:18. If Ameren operated scrubbers at Rush Island that achieved emissions reductions comparable to other plants in the region that currently operate scrubbers, SO_2 emissions would be reduced to several hundred tons per year. Knodel Test., Tr. Vol. 1-A, 108:3 – 108:5.

C. Facts Concerning General Applicability of the Prevention of Significant Deterioration Program

10. The Clean Air Act's New Source Review ("NSR") program consists of a Prevention of Significant Deterioration ("PSD") program and a Nonattainment New Source

Review program. The PSD program applies in areas that are in attainment with the National Ambient Air Quality Standards ("NAAQS") for a particular pollutant or are unclassifiable. 42 U.S.C. §§ 7471, 7475. Knodel Test., Tr. Vol. 1-A, 52:11 - 53:4.

11. The Rush Island Plant is located approximately 50 miles south of St. Louis, Missouri, in the southern tip of Jefferson County, which is currently designated as in nonattainment with the NAAQS for SO_2. Knodel Test., Tr. Vol. 1-A, 53:8 – 53:15 At the time of the 2007 and 2010 projects at issue in this case, Jefferson County was classified as in attainment with the NAAQS for SO_2. Answer, at ¶ 19.

12. At all times relevant to this case, the Rush Island Plant has been a fossil-fuel fired steam electric plant of more than 250 million British thermal units per hour heat input, and has had the potential to emit more than 100 tons per year of SO_2. The Rush Island Plant is a "major emitting facility" as defined by 42 U.S.C. § 7479(1), and a "major stationary source" as defined by 40 C.F.R. § 52.21(b)(1) and 42 U.S.C. § 7602(j). Answer, at ¶¶ 58, 59; Knodel Test., Tr. Vol. 1-A, 53:16 – 54:1.

13. Rush Island Units 1 and 2 are each a "major emitting facility" as defined by 42 U.S.C. § 7479(1), a "major stationary source" as defined by 40 C.F.R. § 52.21(b)(1), and an "electric utility steam generating unit" as defined by 40 C.F.R. § 52.21(b)(31). Joint Stip., at ¶ 5.

14. At the time of the 2007 and 2010 projects, the applicable EPA-approved Missouri PSD regulations were found in the 2003 version of 40 C.F.R. § 52.21, as incorporated into Missouri Rule 10 C.S.R. 10-6.060. Before a major source of air pollution located in such an area designated as in attainment with the NAAQS undergoes a "major modification," the owner or operator of the source must obtain a PSD permit that imposes emission limits. *See* January 21,

2016 Memorandum and Order (ECF No. 711); 40 C.F.R. § 52.21(a)(2), (j); 71 Fed. Reg. 36,486 (June 27, 2006).

15. The PSD regulations define "major modification" as "any physical change … that would result in" a significant net emission increase in actual emissions from a major stationary source. *See* January 21, 2016 Memorandum and Order (ECF No. 711); 40 C.F.R. § 52.21(a)(2)(i).

16. Under the PSD regulations, a "physical change" does not include "routine maintenance, repair and replacement." 40 C.F.R. § 52.21(a)(2)(iii).

17. Under the PSD regulations, a "significant" increase in SO_2 is 40 tons per year. 40 C.F.R. § 52.21(b)(23)(i).

D. Notice of the Violations Alleged in the Complaint

18. The EPA issued a Notice of Violation on January 26, 2010, and issued amended Notices of Violation on October 14, 2010 and May 27, 2011. The Notices of Violation identified, *inter alia*, the alleged violations arising from the 2007 and 2010 major modifications of Rush Island Units 1 and 2 that are at issue in this case. Answer, at ¶ 6; Joint Stip., at ¶ 6.

19. The Notices of Violation were provided to Ameren and the State of Missouri, in accordance with 42 U.S.C. § 7413(a). Answer, at ¶ 6; Joint Stip., at ¶ 7.

20. The United States filed its original Complaint on January 12, 2011 (ECF No. 1), an Amended Complaint on June 28, 2011 (ECF No. 36), a Second Amended Complaint on October 30, 2013 (ECF No. 165), and a Third Amended Complaint on April 24, 2014 (ECF No. 249). The Amended Complaint, Second Amended Complaint, and Third Amended Complaint alleged, *inter alia*, violations arising from the 2007 and 2010 major modifications of Rush Island

Units 1 and 2 that are at issue in this case, and were filed more than 30 days after notice of the violations was provided as required by 42 U.S.C. § 7413(a). Joint Stip., at ¶ 8.

21. The United States provided notice of the commencement of this action to the State of Missouri, as required by 42 U.S.C. § 7413(b). Knodel Test., Tr. Vol. 1-A, 87:4 - 87:23.

II. FACTS CONCERNING THE 2007 AND 2010 BOILER UPGRADES AT RUSH ISLAND UNITS 1 AND 2

22. The major modifications in this case arise from construction projects undertaken by Ameren in 2007 and 2010 at Rush Island Units 1 and 2. The 2007 major modification occurred at Rush Island Unit 1 during a major boiler outage that began on February 17, 2007 and ended on May 28, 2007. The 2010 major modification occurred at Rush Island Unit 2 during a major boiler outage that began on January 1, 2010 and ended on April 9, 2010. Stevens Test., Tr. Vol. 2-A, 24:9 -24:15; 2007 Post Outage Report (Pl. Ex. 34), at AM-02252210; 2010 Post Outage Report (Pl. Ex. 46), at AM-02739973.

A. The Boiler Components at Issue and Their Role in Burning Coal to Generate Electricity

23. Rush Island Units 1 and 2 each include a large boiler where coal is burned to convert water into steam. The boilers are comprised of a number of major components, including the economizers, reheaters, lower slope panels, and air preheaters at issue. The economizer, reheater, and lower slope panels are each comprised of bundles of steel tubes designed to carry high-temperature, high-pressure steam to the turbines. Altogether, the boilers in large coal-fired units like those at Rush Island are constructed of hundreds of miles of tubing. Exposing the steel tube bundles in the major boiler components to the heat from burning coal converts water into steam. The steam is sent to the turbines, including a high pressure turbine, an intermediate pressure turbine, and a low pressure turbine. The turbines spin a generator, which

produces electricity. Unlike the tubular boiler components, the air preheater does not consist of steel tube bundles; it consists of metal heat exchanging surfaces that preheat additional air used for combustion of coal in the boiler. Stevens Test., Tr. Vol. 1-B, 55:9 - 55:13, 57:13 - 61:6; *see also* Welcome to Rush Island Plant Presentation (Pl. Ex. 35), at AM-02253169-173.

24. The Rush Island boiler house is approximately 270 feet tall from the ground to the rooftop. Stevens Test., Tr. Vol. 1-B, 95:10-16. Each boiler is approximately 230 feet tall. Stevens Test., Tr. Vol. 1-B, 95: 10-18; Welcome to Rush Island Presentation, (Pl. Ex. 35), at AM-02253171. Each furnace is approximately 60 feet wide and 50 feet deep. Stevens Test., Tr. Vol. 1-B, 96:2-5.

25. The specific boiler components at issue in the major modifications are the economizer, reheater, lower slopes, and air preheaters that were replaced at Rush Island Unit 1 in 2007, and the economizer, reheater, and air preheaters that were replaced at Rush Island Unit 2 in 2010. Knodel Test., Tr. Vol. 1-A, 81:9 - 82:8; Stevens Test., Tr. Vol. 1-B, 46:2-12.

26. The Rush Island economizers are located in the convection section of each boiler. Stevens Test., Tr. Vol. 2-A, 29:11-24. The purpose of the economizer, which is the first tubular heat exchanging component in the boiler, is to take heat from the hot gases in the boiler and transfer it to high pressure boiler feedwater. When it leaves the economizer, the water is close to turning into steam. It then flows to a steam drum before being circulated through waterwall tubes that form the walls of the boiler furnace, and on to a section of the boiler known as the superheating section, before being sent as steam to the high pressure turbine. Stevens Test., Tr. Vol. 1-B, 58:12 – 60:6.

27. Each economizer at Rush Island Unit 1 and 2 weighed approximately 600 tons. Stevens Test., Tr. Vol. 2-A, 34:22 – 35:7. The original Unit 1 and Unit 2 economizers had

identical designs. They each had two banks – an upper and a lower bank – with 276 assemblies per bank, and had a spiral-finned design, with a staggered arrangement. The diameter of each tube was 1.75 inches. Stevens Test., Tr. Vol. 2-A, 29:25 - 30:18; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080276; Ameren's Response to Request for Admission ("RFA") Nos. 362, 364, 365, 367 (ECF. No. 785-1).

28. The Rush Island reheaters are located at the top of each boiler's furnace. Stevens Test., Tr. Vol 2-A, 41:14-42:13. The purpose of the reheater is to reheat steam after it has passed through the high pressure turbine, before being sent back to the intermediate and low pressure turbines. Stevens Test., Tr. Vol. 1-B, 60:7 – 60:17.

29. The original Rush Island reheaters each had a front section and a rear section. The front section had 72 side-by-side assemblies, each of which was over 50 feet tall. The front assemblies were spaced on ten inch centers. The original front section had a sloped bottom, which created a close clearance between the bottom of the reheaters' front section and each boiler's nose. The rear section had 145 assemblies, each of which was around 26 feet tall. Both the front and rear reheater sections were spaced, not platenized, meaning there was no material that connected one tube to the next. Stevens Test., Tr. Vol. 2-A 42:2 - 43:2; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080428; RFA Nos. 386, 387, 389, 390.

30. Rush Island's lower slope tubes are part of the waterwall tubes and are located in the bottom of the furnace area of the boiler. Stevens Test., Tr. Vol. 1-B, 61:15-24, Tr. Vol. 2-A, 51:2 -51:19.

31. In addition to the economizers, reheaters, and lower slopes, the other primary boiler components at issue in this case are the air preheaters, which help warm combustion air entering the boiler. Forced draft ("FD") fans are used to push combustion air into the boiler, and

before entering the furnace the cold combustion air passes through the lower portion of the air preheater. Once in the furnace, the air mixes with pulverized coal and creates flue gas which heats the water and steam in the boiler tube components. Among other things, the flue gas contains tiny particles of ash known as flyash. Stevens Test., Tr. Vol. 1-B, 57:13 – 58:11; Tr. Vol. 2-A, 56:21-57:11.

32. The hot flue gas resulting from coal combustion flows up through the furnace and then from the back pass of the boiler down through the top of the air preheater, before going to the electrostatic precipitator and then being sucked out by induced draft ("ID") fans and sent up the stack. During this process, the air preheater rotates, allowing the hot flue gas exiting the boiler to warm up the forced draft air that is entering the boiler. Stevens Test., Tr. Vol. 2-A 13:10-14, 56:21-58:8; Testimony of U.S. Power Plant Expert Robert Koppe, Tr. Vol. 3-A, at 16:16-17:2.

33. Rush Island Units 1 and 2 each have two air preheaters. Each air preheater is approximately 40 feet tall and is located approximately 100 feet from ground level. Stevens Test., Tr. Vol. 2-A 13:10-14, 67:21-68:5. Each air preheater weighed at least a couple hundred tons. Stevens Test., Tr. Vol. 2-A 59:3-6.

34. The original Rush Island air preheaters were Ljungstrom regenerative air preheaters. Specification No. EC-5491 (Pl. Ex. 10), at AM-00080275. Each original air preheater had three layers: a hot layer, an intermediate layer, and a cold layer. RFA Nos. 329, 332. Each layer was made up of air preheater baskets of various sizes. There were 216 hot end baskets, and each basket was 42 inches thick. There were 216 intermediate end baskets, and each basket was 16 inches thick. RFA No. 333, 334. There were 24 cold end baskets, and each basket was 12 inches thick. Stevens Test., Tr. Vol. 2-A 57:12 - 58:21; RFA No. 335.

35. Because the tubes that comprise the economizers, reheaters, and lower slopes are in constant contact with flue gas and/or combusting coal, these tubes are subject to deterioration over the life of the boiler and eventually develop leaks, which require repair or replacement. When the tubes degrade and the walls become too weak, the high pressure steam or water can burst through, resulting in a boiler tube leak. Large leaks require a unit to shut down while the portion of the tube that ruptured is repaired, which typically lasts two to three days. Koppe Test., Tr. Vol. 3-A, at 14:16-15:9; Stevens Test., Tr. Vol. 1-B, 65:15 - 66:7.

36. Typically, the length of tube replaced when fixing a boiler tube leak would be on the order of several feet of tube. Stevens Test., Tr. Vol. 1-B, 79:4 - 79:19. Such repairs would be part of the day-to-day responsibility of plant maintenance staff and would involve no design changes to the component. Stevens Test., Tr. Vol. 1-B, 65:15 – 66:15, 69:4 – 69:11.

37. Similarly, on occasion some cold end air preheater baskets might need to be replaced due to corrosion. Stevens Test., Tr. Vol. 2-A, 58:14-21.

38. It is well known in the industry that a well-designed section of new boiler tubes should have almost no leaks at all for the first 20 years, before the tubes eventually begin to wear out and start to fail. Koppe Test., Tr. Vol. 3-A 50:11-50:16; Vasel Dep., Aug. 15, 2013, Tr. 131:11-132:24 (Ameren was not expecting any tube leaks with the new economizer).

39. In light of the harsh conditions in which they operate, boiler components typically have a finite design life of between 20 to 40 years of operation. Stevens Test., Tr. Vol. 1-B 83:5-15. At that point, routine maintenance may no longer be sufficient to maintain desired operations, and an alternate approach may be required to optimize and extend the life of the unit. Vol. 1-B, Stevens Test., 82:2-20.

40. As a result, if a utility like Ameren wants to operate a boiler like the Rush Island boilers beyond 25 to 35 years, one strategy would be to replace the major boiler components, including the reheater. Stevens Test., Tr. Vol. 1-B 83:5-21, 84:5-6. Likewise, an economizer should be expected to last approximately 35 years and lower slope tubes should be expected to last approximately 40 years. Stevens Test., Tr. Vol. 1-B 83:22-84:4, 84:7-8. Ameren's expert witness, Mr. Jerry Golden, similarly testified that the typical life of a reheater is about 30 years, the typical life of an economizer is about 35 years, and the typical life of a lower furnace is about 40 years. Golden Test., Tr. Vol. 8-A, 18:2 – 18:11.

41. Life extension activities historically have been considered in the utility industry to be different than typical maintenance activities. The distinction was explained by Mr. Stevens, and is also discussed in an authoritative engineering text published by Babcock and Wilcox known as the "Steam Book." Stevens Test., Tr. Vol. 1-B 76:7 – 76:16, 78:4-7, 80:6-17.

42. According to the Steam Book, prior to the 1980s, it was assumed that older plants would be torn down to make room for newer, larger, more efficient units, and it was common to retire plants after 35 to 40 years of service. That assumption changed when utilities began to engage in life extension activities. The concept of "Life Extension and Upgrades" is discussed in a chapter in the Steam book by that name, while routine maintenance is discussed separately. Golden Test., Tr. Vol. 8-A, 32:16-33:8; Stevens Test., Tr. Vol. 1-B, 78:4-79:3.

43. The Steam Book describes a case-study involving the replacement of an economizer as a "life extension" project. In that life extension case study, a staggered economizer at a coal-fired generating unit was experiencing pluggage and gas flow resistance, resulting in erosion and tube failures. It was replaced with a new, redesigned, in-line

economizer, which alleviated the operational problems and allowed for higher availability and reliability. Stevens Test., Tr. Vol. 1-B 84:19-87:19.

44. By contrast, typical maintenance activities on coal-fired fired boilers are those done on a day-to-day basis to keep the power plant running in its current condition. Such typical maintenance includes things like replacing small sections of tubing, not replacing entire boiler components. Stevens Test., Tr. Vol. 1-B 64:15-66:15; 77:23-78:3, 78:20-79:19, 80:6-12.

45. Similarly, Ameren's Work Order Procedure Manual defines routine maintenance activities as those that "relate to work performed regularly by Ameren employees or contractors on an ongoing basis in the customary and normal course of business to operate or maintain facilities and equipment." Ameren Work Order Procedure (Pl. Ex. 7), at AM-00066968; Stevens Test., Tr. Vol. 1-B 71: 15-72:7. Such routine activities are not subject to the requirements of Ameren's Work Order Procedures. Pl. Ex. 7, at AM-00066960, 66968; Stevens Test., Tr. Vol. 1-B 72:9-14; Moore Dep., Sept. 16, 2014, Tr. 22:11-22.

46. Ameren's Administrative Design Control Manual provides that any activity that changes "any design or operating feature of the plant that is described by drawings or other design documents" is not considered routine maintenance. Ameren Administrative Procedure Design Control Manual (Pl. Ex. 495), at AM-0223699; Stevens Test., Tr. Vol. 2-A, 70:24-71:2.

B. Operational Problems Leading up to the 2007 and 2010 Boiler Upgrades

47. The Rush Island Units were originally designed to burn Southern Illinois Bituminous Coal. Rush Island Resurfacing Study (Pl. Ex. 20), at AM-00499384; Stevens Test., Tr. Vol. 1-B, 100:24 -101:4, Tr. Vol. 2-A, 92:10-92:15. Around 1990, Rush Island began to burn coal from the Powder River Basin in Wyoming, known as PRB coal. Stevens Test., Tr. Vol. 1-B, 101:5-14. By 1995, the Rush Island units were burning 100 percent PRB coal. Stevens

Test., Tr. Vol. 1-B, 101:15-20; Meiners Test., Tr. Vol. 7-A, 102:10-12; Meiners Dep., April 8, 2014, Tr. 237:9-238:11; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080275; Project Approval Package (Pl. Ex. 3), at AM-00072837.

48. Ameren chose to switch to PRB coal, which has less sulfur, in order to comply with the Clean Air Act's separate "Acid Rain" rules. As Ameren explained in an internal 1992 Acid Rain "Compliance Strategy" document, "a significant advantage of a fuel switch strategy is that it delays an irreversible decision to construct scrubbers." Report from Union Electric: Compliance Strategy, Clean Air Act Amendments (Pl. Ex. 798), at AUE-00020365; Knodel Test., Tr. Vol. 1-A, 102:16-21.

49. The Acid Rain rules are part of a program under Title IV of the 1990 Clean Air Act Amendments designed to reduce by about 50% precursors of acid rain, or acid deposition, from coal-fired power plants. These pollutants include SO_2 and nitrogen oxides. Knodel Test., Tr. Vol. 1-A, 55:13-19; *see* 42 U.S.C § 7651 *et seq*.

50. According to retired Ameren senior vice president Charles Naslund, PRB coal is the cheapest fuel option for the Rush Island plant, and Ameren has the cheapest fuel costs in the regional transmission area, known as the Midcontinent Independent System Operator ("MISO") area. "So when I bid in my units, basically my units are always picked up pretty much baseload because I'm the cheapest." Naslund Dep., Sept. 18, 2014, Tr. 144:17 – 145:7; Knodel Test., Tr. Vol. 1-A, 104:22-105:09. The economic advantage provided by burning cheaper coal than their competitors means Rush Island Units 1 and 2 run a higher percentage of the time. Naslund Test., Tr. Vol. 6-A, 48:7-49:3.

51. Although PRB coal was cheaper and had less sulfur, it differed in other important characteristics, including having a lower heating value and higher moisture content, meaning that

more coal needed to be burned to achieve the same output from the units. Stevens Test., Tr. Vol. 1-B, 101:21-102:15; Pope Dep., Sept. 20, 2013, Tr. 71:18-72:9. Because the Rush Island plant was not designed for coal with these characteristics, Ameren knew that switching to PRB would eventually cause operational problems at the units. Meiners Dep., April 8, 2014, Tr. 237:9-238:1; Pope Dep., Sept. 20, 2013, Tr. 73:12-74:12. For instance, Ameren's Acid Rain Compliance Strategy specifically identified the fact that "the low heat content and the higher moisture of these coals generally result in operational problems that reduce capability." Report from Union Electric: Compliance Strategy, Clean Air Act Amendments (Pl. Ex. 798), at AUE-00020397.

52. The anticipated problems from switching to PRB coal for which the units were not designed were realized, causing related operational problems across the entire boiler. These problems worsened over time, and by the mid-2000's, these components were also suffering from additional operational problems due to age-related deterioration, including tube leaks in the boiler components. Fred Pope, Rush Island's former General Manager of Engineering and Technical Services, said Ameren took interim measures to "defer as long as we could the potential component replacements that…we anticipated would eventually come as the result of individual components reaching the end of their life, and we recognized that when that occurred, we would…..adjust the design of those components…to accommodate western coal." Pope Dep., Sept. 20, 2013, Tr. 73:12-74:11.

53. As described further below, these operational problems included boiler tube leaks, slagging, fouling, and plugging, which adversely affected the economizers, reheaters, lower slopes, and air preheaters. These problems, which were extensively described in Ameren's documents, forced each of the units to be completely shut down (in outages) for periods of time,

or to have their electricity generation limited to less than full power (derated) for periods of time. Stevens Test., Tr. Vol. 1-B 102:16-102:24, 105:18-105:20, 107:6 - 109:13; Tr. Vol. 2-A, 7:16-8:20, 59:7-60:22, 63:22-65:7; Koppe Test., Tr. Vol. 3-A, 14:5-15; *see* Project Approval Package (Pl. Ex. 1), at AM-0072580 (noting "tube leaks" and "load reductions due to flyash pluggage" at Unit 1), 72585 (recounting that "switch to 100% PRB coals has caused flyash pluggage" and noting boiler tube leaks at Unit 1), 590 (describing need for Unit 1 replacements following switch to PRB coal); Project Approval Form (Pl. Ex. 2), at AM-00072829 (noting "tube leaks" and "load reductions due to flyash pluggage" at Unit 2); Project Approval Package (Pl. Ex. 3), at AM-00072831 & 837 (same statements for Unit 2); Project Approval Package (Pl. Ex. 6), at AM-00072912 (describing "major boiler modifications" at both units to address components "experiencing an increase in tube leaks" and planned redesigns for PRB coal); July 15, 2005 Email (Pl. Ex. 45) at AM-0266037, 38 (noting derates due to "permanently plugged" air preheaters); September 18, 2009 Memo (Pl. Ex. 26), at AM-00954160 (Unit 2 air preheaters "have continued to foul"); October 15, 2009 Memo (Pl. Ex. 23), at AM-00926322-323 (describing problems in Unit 2 reheater and economizer following switch to PRB coal); Specification No. EC-5491 (Pl. Ex. 10), at AM-00080276-279 (describing problems in Unit 1 and 2 boiler components); Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966724-725, 731-736, 740-742, 745, 750-753 (describing problems in components).

1. Boiler tube leaks

54. As discussed above, boiler tube leaks occur in tubular components such as economizers, reheaters, and lower slopes, and large leaks require a unit to shut down for repairs which typically last two to three days. FOF 35.

55. The rates of boiler tube failures are generally unlike the failure rates that may occur in other equipment in a boiler. Other boiler equipment tends to have failure rates that stay constant with time as long as the utility keeps up with its maintenance. But as boiler tube components degrade and reach the end of their useful life, their failure rates increase with time and become repetitive given the miles of deteriorated tubing, any inch of which can fail. As the component reaches the end of life, the failures will keep increasing even though the utility repairs specific leaks. Koppe Test., Tr. Vol. 3-A, 52:8-54:15.

56. The Rush Island Units were experiencing boiler tube leaks in the years leading up to the 2007 and 2010 major boiler outages, particularly in the three boiler tube components at issue in this case. Koppe Test., Tr. Vol. 3-A 14:5-15. As Ameren's documents described the situation for the Rush Island plant as of 2005, "[t]here were a total of 10 reheat leaks in the reheaters in 2004 alone" along with "a total of 4 economizer tube leaks" and "12 lower slope tube leaks." Project Approval Package (Pl. Ex. 3), at AM-00072837; *see also id*. at AM-00072831 (noting problems that were "causing tube leaks" in the lower slopes and that "[t]here have been tube leaks in the economizer sections and reheater pendants"); Project Approval Package (Pl. Ex. 1), at AM-00072585, 72590 (identical document for Unit 1); 2008 State of the System Presentation (Pl. Ex. 15), at AM-00196730-735 (presentation identifying lost megawatt-hours from boiler tube leaks at both units).

2. Slagging and fouling

57. Slagging is the accumulation of liquid ash on the walls of the furnace and on components that are located at the top of the furnace, including superheaters and reheaters. Slag condenses or solidifies, eventually becoming like rock or concrete. Slag can bridge between tubes causing plugging, which limits flow through the unit. Slag can also fall down through the

furnace, causing tube leaks in the lower slope tubes. Stevens Test., Tr. Vol. 1-B, 104:23 – 105:17; Tr. Vol. 2-A, 51:02-52:25

58. Slag buildup on the reheaters would fall to the bottom of the furnace, causing damage to the lower slope tubes. Stevens Test., Tr. Vol. 2-A 44:1-21; Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966735; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080278; Boll Dep., Sept. 5, 2014, Tr. 68:11-70:5. The slag falls caused “a vast number of gouges” on the lower slope tubes, which would often require a unit shutdown to repair. Pl. Ex. 28, AM-00966722, at 745. The slag falls at the Rush Island units were at times as large as an automobile. Stevens Test., Tr. Vol. 2A, 54:2-14; Boll Dep., Sept. 5, 2015, Tr. 69:22-70:5. In addition, the lower slope tubes were experiencing problems related to 30 years of exposure to liquid ash and molten slag. Stevens Test., Tr. Vol. 2-A 51:20 – 52:25, 54:2 – 14; Pl. Ex. 28, at AM-00966745; Project Approval Package (Pl. Ex. 1), at AM-00072585; Project Approval Package (Pl. Ex. 3), at AM-00072831.

59. Before the 2007 major boiler outage, Ameren undertook efforts to repair the tube leaks caused by falling slag. For instance, Ameren would pad-weld over areas eroded by flowing slag and would replace leaking sections of tubes. However, because the buildup of slag was a recurring problem that was not being controlled adequately, problems continued. Stevens Test., Tr. Vol. 2-A 54:15-55:8.

60. Fouling is the deposit of solid particles of ash on heat transfer surfaces. When fouling builds up on itself, it can plug the gas flow path between boiler tubing, limiting gas flow across the component, and through the unit. Fouling also leads to higher velocity gas flows through the areas that are not plugged, which causes erosion and tube failures. Stevens Test., Tr. Vol 1-B, 102:16-103:23, Tr. Vol. 2-A, 32:7-32:23.

3. Pluggage

61. Pluggage at Rush Island Units 1 and 2 occurred in the reheaters and economizer boiler tube components and in the air preheaters. Pluggage in boiler tube components occurs when ash material bridges the spaces between tubes, limiting gas flow. Stevens Test., Tr. Vol. 1-B, 103:24 - 104:4, 104:16 - 104:22. Ash also accumulates on the air preheater surfaces, restricting flue gas flow through the air preheaters and reducing the unit's output. Stevens Test., Tr. Vol. 2-A 59:7 - 60:22; July 15, 2005 Email (Pl. Ex. 45), at AM-0266037, 38; September 18, 2009 Memo (Pl. Ex. 26), at AM-000954160; Koppe Test., Tr. Vol. 3-A, 14:11-14:15, 17:5-17:11.

62. Ameren's documents specifically identified the switch to PRB coal as the reason for increased flyash pluggage and load reductions. Project Approval Package (Pl. Ex. 1), at AM-00072585 ("The switch to 100% PRB coals has caused flyash pluggage in the reheater and economizer. The pluggage in the existing staggered economizer has caused load reductions."); Rush Island Resurfacing Study (Pl. Ex. 20) at AM-00499388 ("changing fuels resulted in economizer performance problems…and maintenance problems…"); Bosch Dep., June 12, 2014, Tr. 38:25 – 39:7; *see also* July 15, 2005 Email (Pl. Ex. 45) at AM-0266037, 38 (noting derates due to "permanently plugged" air preheaters).

63. Mr. Koppe and Mr. Stevens explained that the boiler components were all suffering from the same underlying pluggage problem that collectively contributed to limiting air and gas flow through the boiler, thus reducing the amount of coal that could be burned. Stevens Test., Tr. Vol. 1-B, 108:13-109:13; Koppe Test., Tr. Vol. 3-A, 28:7-14, 29:2-8; see also Koppe Test., Tr. Vol. 4-A, at 46:23-47:18 (discussing the cumulative effect of the air preheaters,

reheater, and economizer pressure differentials on overall pressure drop throughout the boiler and its impact on the ID fans).

64. Jeff Shelton, an Ameren trial witness, similarly testified that because they all collectively contribute to the problem, the air preheaters, economizer, and reheater have to be looked at together when considering the effects of pluggage on the unit's ability to generate. Shelton Test., Tr. Vol. 10-A, 106:13-24.

65. Pluggage in the economizer with PRB ash was exacerbated by the original economizer's staggered alignment design, which created a torturous flow path for the flue gas and ash. Together with the switch to PRB coal, the economizers' staggered alignment also resulted in erosion, thinning, and tube leaks. Stevens Test., Tr. Vol. 2-A 30:19 - 32:14, 33:9-22, 40:11-19.

66. Ameren attempted to remedy the problems in the economizer through soot blowing and off-line cleanings, but these efforts did not solve the problem. Pluggage and erosion kept occurring, and the end of the economizers' lives were approaching. Stevens Test., Tr. Vol. 2-A 32:7-23.

67. The original design of the reheaters also exacerbated pluggage due to PRB coal. The spacing of the reheaters, along with the use of PRB coal, led to pluggage of the gas lanes through the reheaters. Contemporaneous documents indicated that "fouling is a daily concern," that pluggage occurred in certain areas of the reheater across the entire boiler width, and that shotguns and dynamite needed to be used to remove the pluggage. Stevens Test., Tr. Vol 2-A, 43:3-45:13; Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966735.

68. Ameren attempted to address the problems with the reheaters through cleanings, including soot blowing, and even dynamite. Strubberg Dep., Nov. 5, 2013, Tr. 162:7-19, 174:9-

23. However, because of end of life considerations, it became necessary to replace the reheaters. Stevens Test., Tr. Vol. 2-A, 44:22 – 45:13, 47:20-24.

69. The original air preheaters also consistently experienced pluggage. With the switch to PRB coal, ash accumulated on the air preheater surfaces and built up on itself. Ultimately, the pluggage also led to an end-of-life situation for the air preheaters. Stevens Test., Tr. Vol. 2-A 59:7 – 60:22. As an internal Ameren email stated, "It sounds like we have to live with the load limitations on RI due to fan capacity limits. Is there anything else we should look at, or as Jon suggests, is this beyond recovery due to the permanently plugged air heaters." July 15, 2005 Email (Pl. Ex. 45), at AM-0266037; Cardinale Dep., July 31, 2014, Tr. 84:3 – 21 (air preheater fouling was "permanent"); *see also* September 18, 2009 Memo (Pl. Ex. 26), at AM-000954160 (noting continued air preheater fouling).

70. The specific mechanisms by which pluggage from PRB coal restricted air and gas flow and limited boiler operation were explained by Mr. Koppe. As noted previously, each boiler's FD fans push air in through the air preheaters where it is warmed up before it enters the furnace areas of the boiler. Koppe Test., Tr. Vol. 3-A 16:16-20. The very hot gases then flow up through all of the boiler tube components and back through the other side of the air preheaters, through the precipitator, and then are sucked out by ID fans, before going out the stack. Koppe Test., Tr. Vol. 3-A 16:20-17:2. When pluggage gets bad enough, it is no longer possible to push enough air into the furnace to burn as much coal as could otherwise be burned. That reduces the amount of coal that is burned, which reduces the amount of steam that is generated, which reduces the amount of electricity that is produced. Koppe Test., Tr. Vol. 3-A, 17:3-11.

71. Pluggage limited the amount of coal that could be burned in several ways. First, pluggage impacted the pressure differentials (also known as "delta P") across the air preheater and economizer, which limited air and gas flow and reduced the amount of coal that could be burned. As discussed above, the hot gases flow through the boiler as air is pushed into the boiler by FD fans and pulled by ID fans. The amount of air pushed into the furnace has to be in balance with the amount of gas that goes out of the furnace. As a component gets plugged, it takes more pressure to push the gas through it. The "delta P" represents the change in pressure from the inlet to the outlet of the various boiler components. When the pressure drop gets too high, the amount of gas flow out of the furnace must be reduced, which requires reducing the amount of air coming into the furnace, which reduces the amount of coal the boiler can burn. Koppe Test., Tr. Vol. 3-A, 17:12-18:21.

72. Second, pluggage also impacted the FD and ID fans. As pluggage got worse, the ID fans, which create a vacuum to suck air out of the boiler, had to work harder and harder to pull air, and eventually got to the point where they were "fan-limited" and could not suck any more without damaging equipment. Cardinale Dep., July 31, 2014, Tr. 103:17-205:17. So the ID fans had to reduce power, which also reduced the amount of coal that could be burned. Koppe Test., Tr. Vol. 3-A., 19:18-20:16.

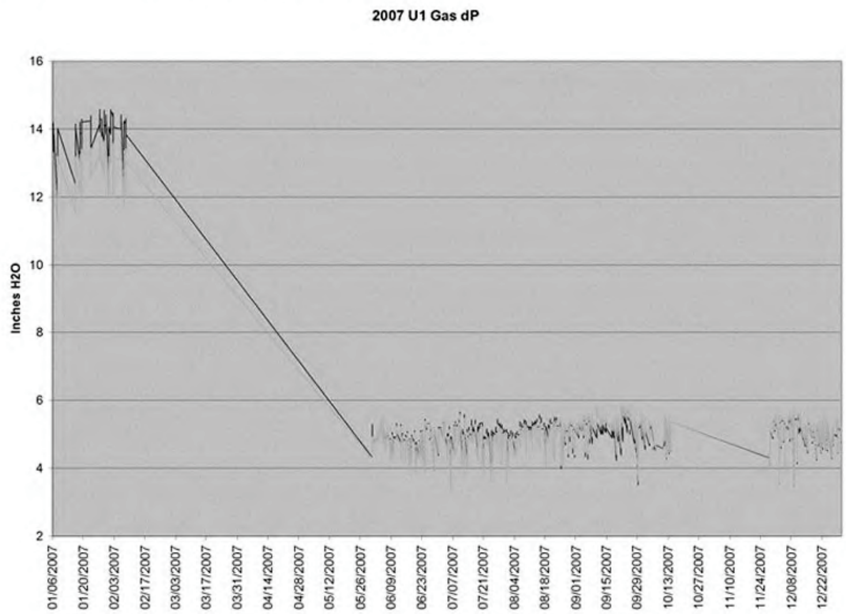
73. As the air preheaters plugged up more and more, the FD fans also had to work harder and harder to get air into the boiler. Bosch Dep., June 12, 2014, Tr. 38:25 – 40:11. Eventually the FD fans were maxed out and they could not push any more air, which limited the amount of coal that could be burned. Bosch Dep., June 12, 2014, Tr. 39:19 – 40:11. This typically happened in the summertime. Koppe Test., Tr. Vol. 3-A, at 20:17-21:11; Koppe Test., Tr. Vol. 4-A 44:13-23 ("on the rare occasions when I have before seen units limited by FD fans,

it is because the pluggage has gotten so severe in the summer months the FD fans use up all their margin and can't push any more air"); Birk Dep., Sept. 24, 2013, Tr. 194:7-16; *see also* July 2005 email, Pl. Ex. 45 (discussing "permanently plugged air heaters" and noting that the units "run out of FD fans when ambient temps come up in the summer months").

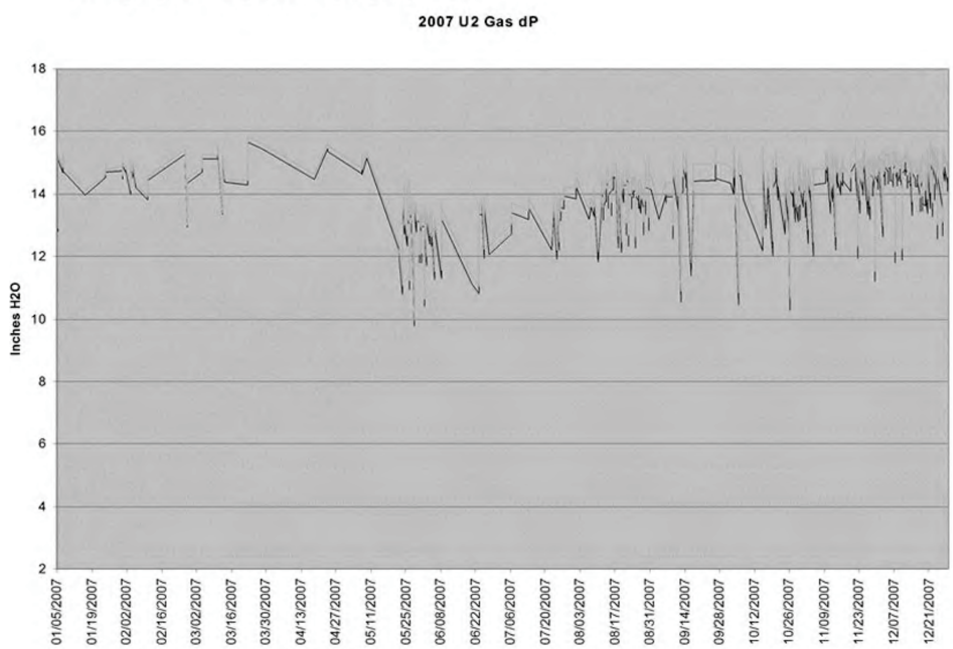
74. In the short term, Ameren coped with pluggage by shutting the units down periodically to conduct high-pressure washes to try to clean out some of the pluggage. Koppe Test., Tr. Vol. 3-A 22:3-12.; Stevens Test., Tr. Vol. 2-A, 59:7-22; Cardinale Dep., July 31, 2014, Tr. 41:15-43:10. This ameliorated the problem somewhat, but it did not solve it. Koppe Test., Tr. Vol. 3-A 22:3-12. The pressure drop would improve somewhat following a cleaning, but "much of the deposits in the air heater were so hard that they couldn't be removed even with a high-pressure wash." *Id*. at 25:12-21; Stevens Test., Tr. Vol. 2-A, 66:8-23; Cardinale Dep., July 31, 2014, Tr. 84:3-21.

75. Evidence of these problems was specifically discussed in company presentations to Ameren executives and memorialized in documents such as the 2008 "State of the System" report. 2008 State of the System (Pl. Ex. 15), AM-00196593, at AM-00196898-923; Meiners Test., Tr. Vol. 7-B, 58:20-59:8 (State of the System presentations were an opportunity to review the performance of plant equipment with Ameren executives). For instance, the 2008 State of the System report included a graphical representation of the high differential pressure problems caused by pluggage, showing very high differential pressure ranging from 12 to over 14 inches of water pressure at the beginning of 2007 at both Unit 1 and Unit 2. The two graphs are found in Pl. Ex. 15, at AM-00196909-10:

2007 U1 Gas dP



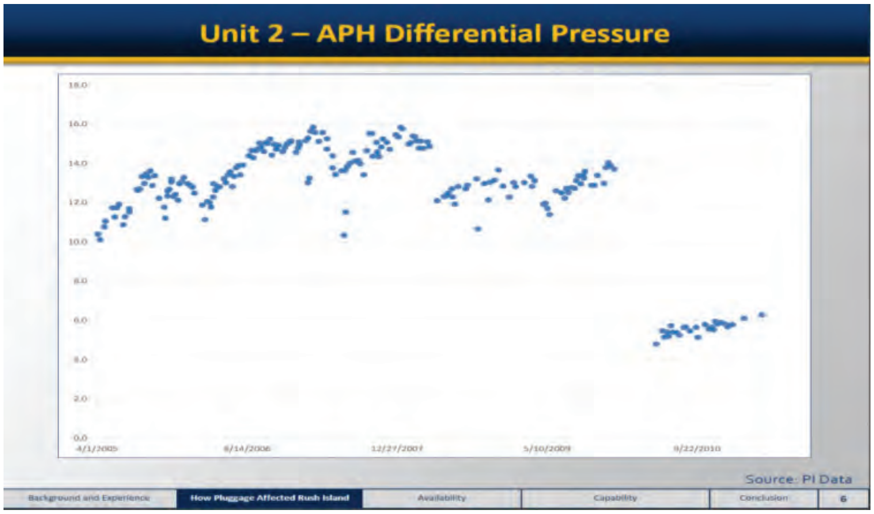
2007 U2 Gas dP



76. At Unit 1, the graphs indicate that differential pressure at Unit 1 dramatically dropped from about 14 inches of water pressure in early 2007 down to 4 to 6 inches of water pressure after the Unit 1 air preheaters were replaced in the Spring of 2007. Pl. Ex. 15, at AM-00196909. At Unit 2, the graph shows the permanence of the pluggage. As compared to the dramatic improvement achieved at Unit 1 due to the boiler component replacements, the Unit 2 graph shows only a very small improvement in differential pressure (from 14 down to 12 inches) following a washing of Unit 2 in the Spring of 2007, which almost immediately crept back up to 14 inches. Pl. Ex. 15, at AM-00196910. Koppe Test., Tr. Vol. 3-A, at 23:15 – 26:3.

77. The differential pressures described in the 2008 State of the System report before the boiler components were replaced were extremely high and caused load reductions. Koppe Test., Tr. Vol. 3-A, at 24:12-25:4. Ameren's trial witnesses Joseph Sind and Andrew Williamson referred to such differential pressures as "extremely high" and indicative of "high pluggage." Sind Test., Tr. Vol. 9-B, at 26:16 – 18 (air preheater differential pressures above even 11 inches are "extremely high"); Williamson Test. Tr. Vol. 9-B, at 44:4-11 (air heater differential pressure of 15 inches indicates "high pluggage").

78. Mr. Koppe's analysis of the company's operational data showed that the same high differential pressures reported in the 2008 State of the System report plagued Unit 2 throughout the years leading up to the 2010 major boiler outage. As Mr. Koppe's review of Ameren's data demonstrated, Unit 2's differential pressure at full load ranged between 10 and 16 inches of water in the years leading up to the projects, before dramatically improving following the 2010 major boiler outage. Koppe Test., Tr. Vol. 3-A 25:22-27:17 (discussing Koppe demonstrative 6).



79. Rush Island's operational data was also compiled in periodic full load tests, which Ameren generally performed on a weekly basis in order to determine the maximum output the unit could achieve at that time. Koppe Test., Tr. Vol. 3-B, 35:17-36:4. During full load tests, the unit tries to generate as much output as it can. Sind Test., Tr. Vol. 9-B, at 30:1-7; Williamson Test., Tr. Vol. 9-B, 42:11-20 (former Rush Island Superintendent of Operations testifying that he reviewed full load tests on a regular basis so he could understand what the capability of the units were); *see also* November 2007 email (Pl. Ex. 130), at AM-02635983 (Rush Island performance engineer James Bosch discussing full load test results after being asked to determine the "capacity" of Unit 1).

80. Plaintiff's Exhibit 928 is a compilation of these full load tests at Unit 2. In addition to reporting actual data such as pressure differentials, each full load test included a row for a possible narrative description of what was limiting load at the time. *See* Pl. Ex. 928, at Spreadsheet Cell B.2 ("Load Limited by"). In addition to the consistently high reported differential pressures, the full load tests performed during the PSD baseline period for Unit 2 (March 2005 to April 2007) are replete with examples where Ameren engineers went out of their

way to indicate in the narrative description of the load test reports that load was limited by the pluggage that is at issue in this case.[1]

81. Ameren also specifically quantified the generation losses due to the boiler components in company presentations. For instance, the 2008 State of the System presentation attributes 185,286 megawatt-hours of lost production at Unit 2 in 2007 to the air preheaters, as compared to only 15,197 megawatt-hours during that same year at Unit 1, which was the year the air preheaters were replaced at Unit 1. 2008 State of the System (Pl. Ex. 15), at AM-00196900.

82. Ameren trial witness David Strubberg conceded that the reported Unit 1 losses were smaller due to the replacement of the air preheaters. Strubberg Test., Tr. Vol. 8-A, 80:12-81:22 (discussing excerpt of presentation in Pl. Ex. 14). Similarly, a July 2006 email from Mr. Strubberg concerning the potential risks of postponing the Unit 1 major boiler outage estimated an approximately 35 MW load reduction due to pluggage. Strubberg Test., Tr. Vol. 8-A, 90:11-91:10.

83. The pluggage at Unit 2 continued to get worse in the years leading up to the 2010 major boiler outage. As ash plugged up the economizer or air preheater, some of it could be removed relatively easily. But a hard layer of ash deposit would form on the surfaces that could

[1] *See* Pl. Ex. 928, at Cell O.2 ("FD Fan Capacity"), W.2 ("ID FAN SUCT PS"), Y.2 ("ID Fan suction press"); AJ.2 ("ECON PLUGGAGE ID FAN SUCT). AK.2 ("Due to pluggage in boiler, it limits ID fan suction pressure"); AL.2 ("limited by the ID fan suction pressure…Boiler is plugged"); AO.2 ("ID suction Supht [sic] plugged Econ plugged"); AP.2 ("ID Fan Suction (Plugged Boiler)"); AQ.2 ("ID Fan Suction (Plugged Boiler)"), BD.2 ("02 blr pluggage"), BF.2 ("FD FANS"); BV.2 ("APH Pluggage"), BW.2 ("APH Pluggage"), BX.2 ("APH Pluggage"), BY.2 ("APH Pluggage"), BZ.2 ("ID Fan Suction Pressure"), CA.2 ("ID FAC SUCTION PRESS."), CC.2 ("ID Fan Suction"); CE.2 ("Blr Pluggage"), CH.2 ("APH Pluggage), CI.2 ("Suction Press."), CJ.2 ("APH Pluggage"), CK.2 ("APH Pluggage"), CN.2 ("ID Fan Suction Pressure"), CO.2 ("APH Pluggage"), CP.2 ("ID suc press Blr & APH's plugged"), CQ.2 ("APH Pluggage"), CR.2 ("ID FAN SUCT"), CS.2 ("APH Pluggage"), CT.2 ("Aph Pluggage"), CU.2 ("APH Pluggage"), CV.2 ("ID fan suction pressure").

not be removed "short of going in with a chisel and chiseling it out inch by inch. So as time went on, the thickness of these hard layers increased and that means that even after washing these components, the pressure drops were still very high." Koppe Test., Tr. Vol. 3-B, 20:1 – 21:7. This inability to remove the load limitations with high pressure washes was specifically identified in project justification documents for Unit 2. An Ameren memo reported: "A high pressure wash can restore some of the pressure loss, but the gains are dimensioning [sic] with an ever increasing accumulation of hardened fly ash." September 18, 2009 Memo (Pl. Ex. 26), at AM-000954160.

84. By 2008, pluggage of the Unit 2 air preheaters had gotten so bad that Ameren had to install a bypass as a temporary measure to allow gas to get around the pluggage. Koppe Test., Tr. Vol. 3-B, 21:8-21:19; Caudill Test., Tr. Vol. 10-B, 40:25-41:7; Cardinale Dep., July 31, 2014, Tr. 103:17-105:17 ("What they did on Unit 2, put in a pipe bypass around the air preheater because they really had serious pluggage problems."). The effect of the bypass would be to increase the electrical output of the unit and decrease its efficiency. Koppe Test., Tr. Vol. 3-B, 21:25 – 22:10; Cardinale Dep., July 31, 2014, Tr. 43:1-45:10 ("certainly bypassing the air preheater is not something you want to do"). Out of all the plants that Mr. Koppe has assessed throughout his career, he has never seen another example of such a bypass being installed. Koppe Test., Tr. Vol. 3-B, 21:20 – 21:24.

85. The effects of pluggage were also well-documented in other contemporaneous documents. Ameren described the pluggage at Unit 2 in a letter it sent to EPA's Clean Air Markets Division in 2008, "Unit 2 generation has been limited to approximately 90 percent of normal load since the middle of 2007 due to gas flow restrictions in the air preheater." April 7, 2008 Letter (Pl. Ex. 934), at AM-00015890-MDNR. When shown the document at trial, Ameren

capability expert witness Mr. Marcus Caudill referred to that amount as a "huge" load limitation. Caudill Test., Tr. Vol. 10-B, 39:19 – 41:14.

86. Similarly, in a December 16, 2009 email, which was written after the boiler work had been performed on Unit 1 but before it had been performed on Unit 2, Ameren employee Jeff Shelton wrote that the difference between the Unit 1 and Unit 2 capabilities grew bigger in the summer "due to draft limitations on Unit 2 and that following the boiler work this outage, we expect Unit 2 to not be as limited in the summer due to the draft issues." December 6, 2009 Email (Pl. Ex. 508), at AM-02248370; Shelton Test., Tr. Vol. 10-A, 93:21-94:18.

87. Mr. Shelton recognized that Unit 2 was draft limited in prior years as well. For instance, Mr. Shelton observed in 2008 that Unit 2 "ran into limitations due to gas path pluggage and air heater dps." December 18, 2008 Email (Pl. Ex. 542); at AM-02462552; Shelton Test., Tr. Vol. 10-A, 96:3-97:4.

88. In light of this evidence, Ameren's expert witness on the capability of the units, Marcus Caudill, agreed that Rush Island Units 1 and 2 were experiencing pluggage that was causing load reductions and derates prior to the 2007 and 2010 outages. Caudill Test., Tr. Vol. 10-B 35:18-22.

4. Availability losses caused by the replaced components prior to the 2007 and 2010 outages as reported to the Generating Availability Data System

89. Ameren uses the Generating Availability Data System ("GADS") to collect and track operating data for the Rush Island plant, including event data and performance data. The event data tracks causes of lost generation such as derates and full outages, while performance data tracks statistics such as generation, fuel usage, and hours of operation. Anderson Test., Tr. Vol. 7-A, 5:22-6:14.

90. Plaintiff's expert Mr. Robert Koppe, who has been a power plant performance consultant since the 1970s, had a leading role in developing the GADS database, including writing the manual that all utilities use in deciding how to report their data. Koppe Test., Tr. Vol. 3-A 7:18 – 11:4. Mr. Koppe developed the original list of cause codes that all utilities use to report events in GADS. *Id*. at 10:17-11:4, 40:9-13.

91. Throughout his career, Mr. Koppe has been hired by dozens of utilities to analyze the performance of their generating units. Koppe Test., Tr. Vol. 3-A 11:5-20. He has analyzed performance issues relating to hundreds of generating units. *Id*. at 13:17-25.

92. GADS is an industry-wide database that collects information on the performance of power plants and the effects that various problems have on that performance. Koppe Test., Tr. Vol. 3-A 10:5-11. GADS was developed so that utilities could improve the performance of their generating units. *Id*. at 10:12-16.

93. Whenever a unit has a problem that limits the amount of electricity it can generate, it is supposed to be reported as an "event" in the GADS data. That could be because the unit was operable but its maximum output was reduced (derated) or because the unit could not operate at all because it was in an outage. Koppe Test., Tr. Vol. 3-A 31:1-9.

94. A statistic known as equivalent availability takes account of the effects of such deratings and outages on the availability of the unit to operate. Koppe Test., Tr. Vol. 3-A at 30:1-19. A derating reflects times when the unit was not capable of operating at its maximum output due to an equipment problem. *Id.*

95. Staff at the Rush Island plant contemporaneously record event data that identifies the causes of lost availability. These event data are then further reviewed for accuracy on a

monthly basis before being uploaded into the company's GADS system. Anderson Test., Tr. Vol. 7-A, 15:9-18.

96. The Ameren performance engineer at the Rush Island plant who was responsible for ensuring the accuracy of the GADS event data was James Bosch. Anderson Test., Tr. Vol. 7-A 42:9-15; Koppe Test., Tr. Vol. 3-A 32:25 – 33:3; Meiners Test., Tr. Vol. 7-B, 38:13-24.

97. It is common for utilities to track the causes of their unavailability so that they can quantify the effects that each problem or component is having on availability. In order to improve availability, utilities need to know what the problems are. Koppe Test., Tr. Vol. 3-A at 31:17-24.

98. Ameren is no different. Unit availability, particularly at low-cost units like the Rush Island units, is very important to Ameren. The company tracks availability "quite closely" and awards salary bonuses under its "Key Performance Indicator" program to some employees based in part on meeting availability targets. Naslund Test., Tr. Vol. 6-B, 8:7-16; Response to Interrogatory No. 65 (ECF No. 823); Moore Rule 30(b)(6) Dep., Sept. 16, 2014, 123:12-124:15; February 6, 2007 Email (Pl. Ex. 103), at AM-02272420.

99. The Key Performance Indicator bonuses are paid for by Ameren's customers. Moore Rule 30(b)(6) Dep., Sept. 16, 2014, 124:16-125:9.

100. Improving unit availability was always a goal for Ameren. If a unit is experiencing forced outages, the company would like it to perform better. Naslund Test, Tr. Vol. 6-B, 11:17-24; 13:15-18. Mr. Naslund, vice president of power operations, told the 1500 Ameren employees under his supervision that perfect availability would be 100%. *Id.*; Generation Times Article (Pl. Ex. 930), at AM-02583221.

101. Staff at the Rush Island plant use GADS data to assess the status of the plant's equipment, and to adjust their predictions of future availability. Anderson Test., Tr. Vol. 7-A 59:25-60:6; Vasel Dep., Aug. 15, 2013, Tr. 83:22-25.

102. The availability targets set by the company are identified down to the tenth of a percentage point. The company also uses availability predictions to know how much coal to buy. Naslund Test., Tr. Vol 6-B, 10:20-11:9; *see also* February 6, 2007 Email (Pl. Ex. 103), at AM-02272420 (discussing proposal to adjust availability KPI bonus target by half a percentage point).

103. Ameren specifically used GADS data to analyze whether to do major capital projects. Koppe Test., Tr. Vol. 3-A at 31:25-34:3. Mr. Bosch, who did not testify at trial, reiterated the importance of such data to the capital project justification process in a 2002 email: "In order to place capital projects in the budget, they must be justified through the EVA program. EVA is a corporate justification software package which incorporates all the required components to derive a recommendation for project approval. ***The most compelling input in the justification calculation is lost generation. These lost generation figures are compiled and easily accessible in the NERC/GADS reporting program***." June 25, 2002 Email (Pl. Ex. 99), at AM-02254509 (emphasis added); Bosch Dep., June 12, 2014, Tr. 73:11-74:8; Pope Dep., Sept. 20, 2013, Tr. 25:17-26:4 (management needed to know that there was an economic benefit before approving an investment).

104. Ameren's EVA Program, or Economic Value Added program, was used to compare two scenarios from a financial point of view in order to justify projects and look at the alternatives. Boll Dep. Tr., Dec. 12, 2013, 126:15-127:11; Generation EVA Instructions, (Pl. Ex. 331), at AM-00491836. The company's financial model for justifying projects based on their

availability impacts is capable of determining the effect on anticipated revenue of as little as a 0.1 percentage point change in expected availability. Meiners Test., Tr. Vol. 7-B, 44:23-45:1; June 15, 2009 CPOC Email (Pl. Ex. 895), at 02632840.

105. Ameren also uses GADS availability data to report the causes of lost generation at a plant to financial analysts on quarterly conference calls. Anderson Test., Tr. Vol. 7-A, 16:12 – 16:19.

106. In this case, Mr. Koppe looked at every single event reported in the GADS data for the 60 months prior to the project and determined which ones "would not have occurred but for the problems at issue in the components at issue in this case." Koppe Test., Tr. Vol. 3-A, 34:7-12. Mr. Koppe reviewed each GADS event and description as reported by Ameren for the relevant time period and then reviewed other sources of information to understand the cause of each event. Koppe Test., Tr. Vol. 3-A, 38:18-39:3.

107. Mr. Koppe specifically included the GADS data for the PSD baseline period for Unit 1 that has been used by Ameren in this litigation (February 2005 to January 2007). During that baseline period, problems in the economizer, reheater, lower slopes, and air preheaters caused Unit 1 to lose 336.1 equivalent full power hours of generation per year, which is equivalent to roughly 14 days of operation per year. Koppe Test., Tr. Vol. 3-A, 45:15-46:24. The unit was completely shut down in outages for 246.4 hours per year due to problems in the components at issue and lost the equivalent of another 89.7 full power hours of operation due to deratings. *Id*. These losses were widespread and covered a large fraction of all the months in the baseline. Koppe Test., Tr. Vol. 3-A, 46:25-47:6.

108. Mr. Koppe also specifically reviewed the GADS data for the PSD baseline period for Unit 2 used by Ameren in this litigation (April 2005 to March 2007). During the baseline

period, problems in the economizer, reheater, and air preheaters caused Unit 2 to lose approximately 245 equivalent full power hours of availability per year. The unit was completely shut down in outages for 145.5 hours per year due to problems in the components at issue and lost the equivalent of another approximately 100 full power hours of operation due to deratings. Koppe Test., Tr. Vol. 3-A, 74:7 – 75-2; Sahu Test., Tr. Vol. 5 78:20-79:13.

109. The deratings experienced at Units 1 and 2 were not short-term or one-time events. For instance, Unit 1 was continuously derated for the entire months of June, July, August, September, and October 2006, meaning that the unit was continuously derated every single day of each of those months. Unit 2 similarly experienced continuous derates. Anderson Test., Tr. Vol. 7-A, 50:21-52:16.

110. Mr. Koppe's compilation of derates included certain GADS events identified as "FD fan capacity" limitations because the units would not have been limited by FD fan capacity had it not been for pluggage in the air preheater. Koppe Test., Tr. Vol. 4-A, at 60:9-61:3; *see also* Koppe Test., Tr. Vol; 3-A, 96:19-97:18.

111. Rush Island Plant staff similarly attributed such fan capacity problems to the boiler components at issue. For instance, a spreadsheet attached to an April 30, 2006 email from Robert Meiners indicates that plant staff determined that Units 1 and 2 were experiencing load limitations during the summer of 2005 that would be eliminated once the reheaters, economizers, and air preheaters were replaced. *See* April 30, 2006 Email and Attached Condition Assessment (Pl. Ex. 106), at Rush Island Spreadsheet Tab, Line 63 (noting that "FD Fans" at Unit 1 and Unit 2 "[c]urrently limit load during summer, but should be eliminated with boiler pressure part and APH"); Anderson Test., Tr. Vol. 7-A, 49:8-25.

112. As described by Ameren's engineers at the time, the output of the Rush Island units was limited due to "fan capacity limits" resulting from the "permanently plugged air heaters" at the units. July 15, 2005 Email (Pl. Ex. 45) at AM-0266037 (also noting that the "Unit 2 Air Pre-heater delta P's [were] running at 12 inches at full load" and that the "baskets will have to be replaced on the APH's to make an impact on FD fans"); July 21, 2004 Email (Pl. Ex. 555), at AM-02485899; *see also* FOF 80 & n.2 (summarizing descriptions in weekly full load tests). The limitation on the unit's ability to operate was estimated to cost Ameren approximately $25,000 per day. July 15, 2005 Email (Pl. Ex. 45), at AM-02666038.

5. Reduction in the maximum capability of Unit 2 prior to the 2010 outage

113. In addition to lost availability due to outages and derates as reported in GADS, the switch to PRB coal also resulted in a significant reduction in the reported maximum hourly capability of the units prior to the major boiler outages. Koppe Test., Tr. Vol. 3-A 90:11-91:4, Vol. 4-A, 33:10-34:2.

114. The capability of a unit is the maximum electric output that it can produce at that time if asked to do so. Koppe Test., Tr. Vol. 3-A, 84:14-23. The terms "capability" and "capacity" are often used interchangeably. *Id*. at 85:25-86:5

115. Ameren issued annual capability tables, which "represent the expected average output of each unit based on typical ambient conditions." *See, e.g.*, 2011 Capability Table (Pl. Ex. 257), at AM-00067232. The reported capability of a unit is an estimate of what the utility expects the capability of the unit to be in the following year. Koppe Test., Tr. Vol. 3-A, 84:23-85:2. The magnitude of a reported derating is affected by the reported capability. *Id*. 85:3-10; *see* December 2010 Capability Table (Pl. Ex. 257), at AM-00067232.

116. Gross capability or gross electrical output is the amount of electricity that the generator produces. Net capability or net electrical output is the amount of electricity that goes out to the grid. The difference between net and gross capability is the electricity the plant itself uses to operate, otherwise referred to as auxiliary load. Koppe Test., Tr. Vol. 3-A, 85:11-17; Koppe Test., Tr. Vol. 3-B, 11:6-15; Shelton Test., Tr. Vol. 10-A, 84:10-15.

117. A reduction in auxiliary load is an improvement in net efficiency, but it does not affect the amount of coal that the unit is capable of burning. It just means that less power is used to run the plant and more power is sent to the grid. Generator output is the same, heat input is the same, but more megawatts can be sent to the grid. Koppe Test., Tr. Vol. 3-B, 11:16-12:4; Shelton Test., Tr. Vol. 10-A, 85:8-10.

118. Ameren lowered the reported capability of Unit 2 substantially from 2005 to 2006. The reduction was about 10 megawatts in the winter and 20 megawatts in the summer. Unit 2's reported capability remained essentially the same until 2010 and then increased substantially in 2010 and 2011. Koppe Test., Tr. Vol. 3-A, 88:13-23.

119. The reduction in reported capability was the result of the effects of pluggage. Koppe Test., Tr. Vol. 3-A, 90:11-91:4. In 2005, pluggage caused Unit 2 to frequently not be able to meet its reported capability. Koppe Test., Tr. Vol. 4-A, 33:10-34:2. Similarly, Unit 2 was unable to meet its reported capability in the summer of 2005 due to FD fan capacity limitations. January 4, 2006 Email (Pl. Ex. 157), at AM-027432293; Koppe Test., Tr. Vol. 3-A, 91:9-95:11. The reason the fans were running out of capacity in the summer was because of pluggage in the boiler, specifically pluggage in the air preheater. Koppe Test., Tr. Vol. 3-A, 96:19-97:18. As Ameren documents describe it, the output of the Rush Island units was limited due to "fan capacity limits" resulting from the "permanently plugged air heaters" at the units.

July 15, 2005 Email (Pl. Ex. 45), at AM-02666037. Such problems with summer capacity were also identified in the project justification documents for Unit 2, where Ameren reiterated that "the current air preheater baskets have continued to foul to the extent that fans are load limited particularly in the summer months." September 18, 2009 Memo (Pl. Ex. 26), at AM-000954160; *see also* Cardinale Dep., July 31, 2014, Tr. 84:3 – 21 (noting that air preheater fouling was "permanent").

120. The capability of Unit 2 prior to the 2010 major boiler outage was also measured in Ameren's weekly full load tests. The average capability of Rush Island Unit 2 as measured by Ameren in all of the full load tests that were conducted during the PSD baseline period (March 2005 to April 2007) was only 620 gross megawatts. Koppe Test., Tr. Vol. 3-B, 35:17-36:4, 45:12-46:5; *see* Pl. Ex. 928 (Rule 1006 summary of full load tests for Unit 2).

121. In the years leading up to the 2010 major boiler outage at Unit 2, Ameren further quantified the megawatt capability loss that was due to the boiler components at issue. In Ameren's 2008 annual "State of the System" presentation in 2008, it assigned "25-30 MW" to the Unit 2 "BLR/AHS replacement" in addition to another 13 megawatts that could be gained from replacing the low pressure turbine. 2008 State of the System (Pl. Ex. 15), at AM-00196628.

122. Ameren assigned 22.5 megawatts to the reheater, economizer, and air preheater in a financial analysis for the 2010 major boiler outage. Economic Value Added (EVA) Financial Analysis for Unit 2 (Pl. Ex. 48), at "Data Entry" Sheet; Koppe Test., Vol. 3-B, 30:4-32:23. The 22.5 megawatt value was a weighted average based on Ameren's estimate that the component replacements would allow Unit 2 to produce 30 more megawatts of capacity during the three summer months and 20 more megawatts for the remainder of the year. Koppe Test., Tr. Vol. 3-

B, at 27:7-32:23; see Pl. Ex. 48, at "Data Entry" Sheet; July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465690 ("30 MW gain in summer (3 mos), 20 MW gain balance of year from Reheater, Economizer and APH investment").

123. Ameren's final work order authorizations for the reheater, economizer, and air preheater, completed in the fall of 2009, similarly described that the "combined" effect of these component replacements would result in a "gain of 30 MW in the summer and 20 MW in the winter" at Unit 2. October 15, 2009 Memo (Pl. Ex. 23), at AM-00926323; *see* September 18, 2009 Memo (Pl. Ex. 26), at AM-00954160 (same language in air preheater justification that "gain of 30 MW in the summer and 20 MW in the winter will be obtained with the combined reheater, economizer, and air preheater replacements").

124. Ameren witness David Boll testified in his deposition that these predicted additional megawatts represented "regained capacity" that had been lost due to the inability to pull gas flow through the plugged air preheaters. Boll Test., Tr. Vol. 8-B, 51:23-52:4, 54:21-25.

125. A summary of the anticipated benefits of the work written in 2010 similarly referred to the fact that "[a]pproximately 30 Megawatts of unit capacity will be recovered during the hottest months because of lower gas flow pressure drops through the new economizer and air preheaters." March 31, 2010 Email re Newsletter (Pl. Ex. 893), at AM-02229417.

C. The Approval and Engineering Process for the 2007 and 2010 Major Modifications

126. The formal approval and engineering process for the 2007 and 2010 major boiler projects began at least three years prior to the first outage. The replacement of all four components was considered together for planning purposes, beginning as early as 2004. For instance, by December 2004, Ameren had created a preliminary budget for replacement of the Unit 1 economizer, reheater, lower slope tubes, and air preheaters, at an estimated capital cost of

more than $25 million. Stevens Test., Tr. Vol. 2-A 5:2-7; December 20, 2004 Generating Engineering Budget Project Proposal (Pl. Ex. 323); RFA 393.

127. A 500-page Project Book for Unit 1 was compiled as a reference for the work to be completed during the Unit 1 outage. The replacement of the economizer, reheater, lower slope tubes and air preheaters were coordinated by Alstom Power and generally treated together within the Project Book. Rush Island Unit 1 Project Book (Pl. Ex. 63), at AUE-00156352 (collectively referring to "Reheater, Economizer, Lower Slope, Air Heater Rotor Replacements" as a single major project); *id*. at 365 (same), 519 (same), 539 (same); Stevens Test., Tr. Vol. 2-A. 17:1- 18:10.

128. The documentation in the Project Book also confirmed that one purchase order for engineering, materials, and construction services was issued to Alstom Power as early as 2005, which included the replacement of the economizer, reheater, lower slope tubes, and air preheaters. Pl. Ex. 63, at AUE-00156395-398.

129. The replacements of the economizers, reheaters, lower slopes, and air preheaters were all approved under Ameren's Work Order Procedures. Stevens Test., Tr. Vol. 1-B 72:15-21, 91:19 – 92:3.

130. While the air preheaters were also subject to their own work order justification process, the air preheater justification documents specifically combined the air preheater replacements with the reheater, economizer, and lower slopes as part of a "major refurbishment" at both Unit 1 and Unit 2. October 5, 2005 Memo (Pl. Ex. 6), at AM-00072912; Stevens Test., Tr. Vol. 2-A 9:24-10:18.

131. Similarly, prior to replacing the Unit 2 air preheaters, Ameren reiterated its reliance on the "combined" effect of the air preheaters, reheater, and economizer for purposes of

justifying the replacements. September 18, 2009 Memo (Pl. Ex. 26), at AM-00954160; October 15, 2009 Memo (Pl. Ex. 23), at AM-00926323 (same); *see also id*. at AM-00926322 ("Load reductions of 30 MW in the summer and 20 MW for the remainder of the year can be avoided with the new boiler components and the re-designed air preheater.").

132. Ameren's documents also indicate that the replacement of all the components was combined to "gain efficiencies in procurement, design and installation" and described the air preheater replacements as "part of a Major Mechanical Work Package to include the Economizer, Reheater and Lower Slope portion of the boiler." Project Approval Package (Pl. Ex. 1), at AM-00072590; Project Approval Package (Pl. Ex. 4), at AM-00072859; Stevens Test., Tr. Vol. 2-A 10:19-11:18, 13:23-14:7.

133. The engineering specification issued by Ameren called for bids from outside engineering firms for the design, fabrication, and installation of the boiler components at Rush Island Units 1 and 2. Ameren consolidated the replacement of the economizer, reheater, lower slope tubes, and air preheaters for purposes of issuing the specifications. Specification No. EC-5491 (Pl. Ex. 10); Stevens Test., Tr. Vol. 2A 15:19 - 16:13.

134. Ameren provided specific design requirements for the replacement components, including a number of significant design changes that were intended to upgrade and improve the performance of the boiler as a whole. Stevens Test., Tr. Vol. 2-A, 32:24-33:22, 34:8-12, 45:14-46:25, 55:9-56:4, 66:5-67:9; October 15, 2009 Memo (Pl. Ex. 23), at AM-00926322 (noting combined project objectives of redesigned economizer and air preheater).

135. In contrast with routine work undertaken at utility plants, the replacement of the economizers, reheaters, lower slopes, and air preheaters required approvals of executives at the highest level of the company, including Ameren's CEO. The approval process required at least

10 layers of approval review. Stevens Test., Tr. Vol. 2-A 7:5-15, 13:15-22; Project Approval Package (Pl. Ex. 1), at AM-00072580; Project Approval Form (Pl. Ex. 2), at AM-00072829; Project Approval Package (Pl. Ex. 4), at AM-00072850; Project Approval (Pl. Ex. 5), at AM-00072906.

136. In August of 2005, Gary Rainwater, then the Ameren CEO, authorized the expenditure of $23,148,000 to replace the economizer, reheater, and lower slope panels at Rush Island Unit 1. Stevens Test., Tr. Vol. 2-A 7:5-15; Project Approval Package (Pl. Ex. 1), at AM-00072580. Mr. Rainwater also authorized the expenditure of $24,988,000 for the same work at Unit 2. Project Approval Form (Pl. Ex. 2), at AM-00072829. Earlier in the spring of 2005, Ameren Missouri Chief Operating Officer Thomas R. Voss authorized the expenditure of approximately $6.9 million for the design, fabrication, and installation of new air preheaters at Unit 1, and, in October of 2005, authorized approximately $7.5 million for similar work at Unit 2. Stevens Test., Tr. Vol. 2-A 13:15-22; Project Approval Package (Pl. Ex. 4), at AM-00072850; Project Approval (Pl. Ex. 5), at AM-00072906.

137. After the 2007 major boiler outage at Unit 1, Unit 2 went through a second justification process in 2009. The Unit 2 major boiler outage had to be approved by an additional committee known as the Capital Project Oversight Committee ("CPOC"), Ameren's CEO Warner Baxter, and the full Board of Directors. Meiners Test., Tr. Vol. 7-B, 45:8-25, 46:6-47:11; May 16, 2009 Email (Pl. Ex. 347), at AM-02637756. On August 14, 2009, Mr. Baxter reported that the outage had been approved. August 14, 2009 Email (Pl. Ex. 553), at AM-02480812.

D. Ameren Justified Replacing the Economizers, Reheaters, Lower Slopes, and Air Preheaters Because They Would Improve Operations and Allow the Units to Generate More

138. Ameren's contemporaneous project authorization documents identified the new economizers, reheaters, lower slopes, and air preheaters as components that were "improved" and "redesigned" in order to fix the operational problems that had been caused by burning PRB coal and age-related deterioration. Stevens Test., Tr. Vol. 2-A, 8:21- 9:6; Project Approval Package (Pl. Ex. 1), at AM-00072580; Project Approval Package (Pl. Ex. 3), at AM-00072831; Boll. Dep. Tr., Dec. 12, 2013, 164:24-165:26, 168:19-169:6; Birk Dep., Sept. 24, 2013, Tr. 194:1-16; Meiners Dep., April 8, 2014, Tr. 237:18-238:11; Pope Dep., Sept. 20, 2013, Tr. 73:12-74:11.

139. Ameren described the planned "major boiler modifications for Rush Island 1 and 2" as follows:

> For several years we have been planning major refurbishment of the Rush Island 1 and 2 boilers, which have operated for nearly 30 years without replacing any of the major components. The major scope elements include the following major components which are experiencing an increase in tube leaks and fatigue issues, and have been redesigned to improve future operation and maintenance:
>
> - Reheater – redesigned for PRB coal
> - Economizer – redesigned for PRB coal
> - Lower Slope – ruggedized design to better withstand slag falls
> - Air Preheater – redesigned for ease of future basket replacement.

Project Approval Package (Pl. Ex. 6), at AM-00072912; Stevens Test., Tr. Vol. 2-A 9:24-10:18.

140. Ameren's expert Jerry Golden agreed that the components replaced at Rush Island were redesigned. Golden Test., Tr. Vol. 8-A, 10:6-10; see also RFA Nos. 377 to 383, 386-387, 389-390, 395-401, 407. Further descriptions of these redesigns are provided below.

141. *Economizer Redesign*: The design of the new economizers was substantially different from the original design. The redesigned economizers were in-line, rather than the original staggered design, which allowed gas to flow through the boiler more easily. The new economizer design made the economizers less subject to fouling and pluggage. Stevens Test., Tr. Vol. 2-A 32:24 – 33:22; 34:8-12; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080325-329; Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966728-730.

142. *Reheater Redesign*: The design for the new preheaters was significantly different from the original design. Stevens Test., Tr. Vol., 2-A 45:14 - 18; Boll Dep. Tr., Sept. 5, 2014, 68:11-70. The spacing between the tubes was increased from 10 to 15 inch centers, and the number of front assemblies was reduced from 72 to 48. The bottom of the reheaters was changed from a sloped bottom that closely tracked the boilers' nose to a horizontal bottom. The number of rear assemblies was decreased from 145 to 96 assemblies, and their height was increased. Similar to the design change for the front assemblies, the spacing between each tube was increased. Additionally, both the front and rear assemblies were platenized. Together, these changes allowed more space for gas and ash to flow through the reheaters without plugging or fouling. Stevens Test., Tr. Vol. 2-A 45:14 - 46:25; October 15, 2009 Memo (Pl. Ex. 23), at AM-00926322; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080329-332; Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966737-738.

143. *Lower Slopes Redesign*: The design for the new lower slope tubes at Unit 1 was a different design than the original lower slope tubes. Specifically, the new lower slope tubes had a thicker wall to prevent tube leak problems caused by slag falls. The space between each tube was decreased, adding greater strength to assist in slag fall protection. Additionally, the structural support was replaced to provide additional strength. Together, these changes made

the lower slope tubes stiffer, more rigid, and less likely to be crushed so easily. Stevens Test., Tr. Vol. 2-A 55:9 - 56:4; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080332-334; Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966748-749.

144. *Air Preheaters Redesign*: The new, redesigned air preheaters were changed from the original three-layer Ljungstrom regenerative basket design to a two-layer design. The new two-layer air preheaters had a hot end layer and a cold end layer. In each air preheater, each layer had 24 baskets, each of which was 29 inches deep. While the original air preheaters each had 456 baskets, the new air preheaters had only 48 baskets total. The design was changed in order to minimize the outage time required for cleaning the baskets in the future. Stevens Test., Tr. Vol. 2-A 57:12 - 58:21, 66:5 - 67:9; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080279, 348-353; RFA Nos. 331, 334.

145. Ameren specifically justified performing these boiler upgrades because they were expected to reduce forced outages due to tube leaks, eliminate load reductions, and increase the capability and availability of the units to operate. One of the specific expectations identified in the project justifications was that the replacements would eliminate outage time due to the components for the next 20 years. Stevens Test., Tr. Vol. 2-A 7:16-8:20, 25:12 – 26:11, 27:13-23, 59:7-60:22; 63:22-65:7; Golden Test., Tr. Vol. 8-A 12:14 – 13:8.

146. These expected improvements were explicitly stated in Ameren's project justification documents. For instance, after describing the "new, improved, redesigned" economizer, reheater, and lower slopes, **Ameren's project authorization for Unit 1 stated that "as a result" of the replacements, "Rush Island will eliminate forced outages due to reheater tube leaks for 20 years, eliminate 30 to 50 MW load reductions due to flyash pluggage of the current economizer, and reduce the number of tube leaks caused by slag**

falling on the furnace lower slopes." Project Approval Package (Pl. Ex. 1), at AM-00072580 (emphasis added); *see also* Project Approval Package (Pl. Ex. 4), at AM-00072858 (noting expected improvement in pressure drop across the air preheater, and two week reduction in future outage costs due to quicker basket replacements); October 15, 2009 Memo (Pl. Ex. 23), at AM-00926322 (project objectives include avoiding "load reductions" and "minimizing future forced boiler outages for the next 20 years"); September 18, 2009 Memo (Pl. Ex. 26), at AM-0954160 (noting that air preheater replacement "will reduce the gas side pressure loss across the air preheaters from 14 to 5 inches" of water pressure, and that project would result in a megawatt "gain").

147. Ameren expected that the work would reduce the number of forced outages due to these components "to zero." Project Approval Package (Pl. Ex. 1), at AM-00072585-586 ("Flyash pluggage of the economizer will be eliminated or greatly reduced due to the in-line spiral fin economizer… Forced outages due to tube leaks in the reheater and economizer will be reduced to zero."); *see also id*. at 590 ("completing this project will eliminate all the problems"); Project Approval Form (Pl. Ex. 2), at AM-00072829 (same statements for Unit 2); Project Approval Package (Pl. Ex. 3), at AM-00072831-833, 837 (same statements for Unit 2); Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966731, 740, 750 (identifying avoided costs associated with avoiding derates and outages due to boiler tube leaks); *see also* Vasel Dep., Aug. 15, 2013, Tr. 131:11-132:24.

148. Ameren ultimately decided not to replace the lower slopes at Unit 2 during the 2010 major boiler outage and therefore adjusted the overall availability improvement expected from the work downwards by 0.1% from 4.3% to 4.2%. June 15, 2009 CPOC Email (Pl. Ex. 895), at AM-02632840; Meiners Test., Tr. Vol. 7B, 34:9-35:25.

149. Further evidence of Ameren's expectation of availability improvements is found in Plaintiff's Exhibit 126, which was a presentation that Mr. Meiners made to senior executives at a business plan meeting. Meiners Test., Tr. Vol. 7-B, 27:21-24, 28:18-20. One of the purposes of the presentation was to discuss component replacements and the condition of the reheater, economizer, air preheater, and lower slopes. *Id*. 28:10-17. At the end of the presentation, Mr. Meiners presented a graph showing that Rush Island's availability would increase by almost 5%, from about 90% in 2005-2006 to 95% in the first year after both major boiler outages had been completed. *Id*. 31:15-21

150. Ameren's experts agreed that the expressed purpose of the work at each unit was the same: to improve capability and eliminate deratings. For instance, Mr. Golden confirmed that the work at both units was intended to eliminate pluggage and fouling of the economizers and reheaters, to eliminate future forced and maintenance outages caused by tube leaks, and to eliminate pluggage problems and deratings from the air preheaters. Golden Test., Tr. Vol. 8-A, 10:11-21, 13:16 – 13:21.

151. Mr. Golden also agreed that the purpose of replacing the lower slopes at Unit 1 was to eliminate tube leaks in the lower slope and damage resulting from slag falls and erosion following the switch to PRB coal. Golden Test., Tr. Vol. 8-A, 10:22-25.

152. Ameren's expert Mr. Caudill conceded that the expected benefits of replacing the components included reducing forced outages and eliminating or greatly reducing flyash pluggage at the units. As Mr. Caudill put it, "[b]asically that's what Ameren expected" based on a review of Ameren's project justifications. Caudill Test., Tr. Vol. 10-B, 36:10-37:2, 37:17-38:10.

153. Mr. Caudill also agreed that pluggage in the reheater, economizer, and air preheaters contributed to high differential pressure, which Ameren expected to reduce as a result of replacing the reheater, economizer, and air preheaters. Caudill Test., Tr. Vol. 10-B, 34:17-35:1, 35:14-17. In addition to eliminating load reductions, such improvements in differential pressure can result in some increase in net efficiency, but not gross efficiency. Caudill Test., Tr., Vol. 10-B, 35:11-13; Koppe Test., Tr. Vol. 3-B, 11:16-12:4, 28:18-29:4. Mr. Caudill conceded that Ameren did not justify the replacement of the economizers, reheaters, and air preheaters based on any expectation that they would result in an improvement in gross unit efficiency. Caudill Test., Tr. Vol. Vol. 10-B, 44:24-45:12.

154. Mr. Caudill also conceded that Rush Island Units 1 and 2 were experiencing pluggage that was causing load reductions and derates prior to the 2007 and 2010 outages and that eliminating pluggage that is causing derates will allow a unit to generate at a higher gross load. Caudill Test., Tr. Vol. 10-B, 35:18-22, 37:3-16.

155. Ameren's final, updated justification for the 2010 major boiler outage reflected the company's expectation that the replacements would enable the unit to operate more and to produce more megawatts when operating. The justification identified two types of performance improvements from the boiler work: a capacity increase and an equivalent availability improvement. As described in a 2009 work order authorization request:

> A gain of 30 MW in the summer and 20 MW in the winter will be obtained with the combined reheater, economizer and air preheater replacements. …. Also included in the justification is an approximate 3-4% improvement in equivalent availability of the unit.
>
> **Assumptions**: It is assumed that these boiler modifications will result in an improved operation of the unit that is at least equal to, if not better, than that currently experienced with Unit 1 which had similar modifications in 2007. This includes fewer load restrictions, improved equivalent availability and elimination of potential catastrophic failure of the economizer.

October 15, 2009 Memo (Pl. Ex. 23), AM-00926323; *see also id*. at AM-00926322 ("Load reductions of 30 MW in the summer and 20 MW for the remainder of the year can be avoided with the new boiler components and the re-designed air preheater."); Stevens Test., Tr. Vol. 2-A, 25:12- 26:11; 27:3-23.

156. The justification of additional generation from the replacements is also found in the financial analysis tool that was used to justify the 2010 outage. The availability gain used in the final financial analysis was the equivalent of "15 days of generation." Economic Value Added (EVA) Financial Analysis for Unit 2 (Pl. Ex. 48); Meiners Test., Tr. Vol. 7-B, 18:6-11, 18:21-19:16.

157. Ameren's final financial evaluation separately included a 22.5 MW "projected annual increase … in plant capacity" as a result of the replacement of the reheater, economizer, and air preheater. Economic Value Added (EVA) Financial Analysis for Unit 2 (Pl. Ex. 48), at "Data Entry" Sheet; Koppe Test., Tr. Vol. 3-B, 30:4-32:23. This capacity increase was based on Ameren's estimate that the component replacements would allow Unit 2 to produce 30 more MW of capacity during the three summer months and 20 MW for the remainder of the year. Koppe Test., Tr. Vol. 3-B, at 27:7-32:23; Pl. Ex. 48, at "Data Entry" Sheet; July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465690 ("30MW gain in summer (3 mos), 20MW gain balance of year from Reheater, Economizer and APH investment").

158. The 22.5 MW increase in capacity was separate from the availability input used in the model. July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465690 (describing megawatt capability "gain" from boiler upgrade separately from 4.2% equivalent availability impact); Koppe Test., Tr. Vol. 3-B 30:8-31:7. It represented an increase over the capability that

Unit 2 was able to achieve during the pre-project period. Koppe Test., Tr. Vol. 3-B, 28:2-12. The financial impact included significant "incremental power sales" that were calculated to have a favorable impact on ratepayers, shareholders, and earnings. July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465691.

159. These boiler capacity and availability gains were also identified separately from an additional 15 megawatt capability gain from replacing the LP turbine with a more efficient design. July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465690 (describing gains separately in project economic analysis).

160. During the final 2009 approval process for the Unit 2 outage, Mr. Meiners reiterated the accuracy of these forecasts to Ameren's CEO, Mr. Baxter. May 16, 2009 Email (Pl. Ex. 347), at AM-02637756 ("I do believe the model is now a much more accurate representation of the economic benefits."); Meiners Test., Tr. Vol. 7-B, at 46:9-47:11.

E. Implementation of the 2007 and 2010 Major Modifications

161. Ameren installed the new economizer, reheater, two air preheaters, and lower slope panels at Rush Island Unit 1 during an outage that began on February 17, 2007 and ended on May 28, 2007. 2007 Post Outage Report (Pl. Ex. 34), at AM-02252210.

162. On January 24, 2007, almost one month before the Unit 1 major boiler outage was to start, there were already 54 contractors on site. The previous week, 17 truckloads of tubing arrived on site and a crane was being constructed for use in replacing the reheater. Rush Island Project Book (Pl. Ex. 63), at AUE-00156343; Overhead Photo of Laydown Areas (Pl. Ex. 414), AM-00222751. This level of activity on-site, a month before the work had even started, is not typical of routine maintenance at a power plant. Stevens Test., Tr. Vol. 2-A, 18:14-19:19.

163. Ameren installed the new economizer, reheater, and two air preheaters at Rush Island Unit 2 during an outage that began on January 1, 2010 and ended on April 6, 2010. Vol. 2A, Stevens Test., 24:9-15; 2010 Post Outage Report (Pl. Ex. 46), at AM-02739973.

164. The replacements took years to design and plan and required the special fabrication of components that were not otherwise available at the Rush Island plant. Specification No. EC-5491 (Pl. Ex. 10), at AM-00080233; Rush Island Project Book (Pl. Ex. 63), at AUE-00156362. Ameren's expert, Jerry Golden, acknowledged at trial that these replacements were not *de minimis* activities. Golden Test., Tr. Vol. 8-A, 33:9-18.

165. The size and extent of the components replaced during the 2007 and 2010 major boiler outages was massive, with the economizers, reheaters, and air preheaters each weighing hundreds of thousands of pounds. Stevens Test., Tr. Vol. 2-A, 13:10-14, 34:22-35:7, 50:11-13, 59:3-6, 67:21-68:5. For example, the new reheaters included two outlet headers that weighed 36,000 pounds each and 144 reheater tube assemblies, including 48 front pendant assemblies that were each approximately 49 feet tall and 96 rear pendant assemblies that were each approximately 35 feet tall. Stevens Test., Tr. Vol 2-A, 45:14-46:25, 50:10-13; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080330-332; RFA Nos. 386-387, 390, 395-398. If the Rush Island economizer's tubing was laid from end-to-end, the length of tubing would stretch around 140 miles. Stevens Test. Tr. Vol. 1-B, 79:20 – 80:5.

166. Given the complexity of the replacements, the components needed to be designed, engineered, and constructed by outside contractors, such as Alstom Power - the original manufacturer of the boilers, and numerous other contractors. The work involved was substantial, requiring hundreds of thousands of man-hours, and was well beyond the capacity of Ameren's

own staff. Stevens Test., Tr. Vol. 2-A, 21:18 – 22: 18; 2007 Post Outage Report (Pl. Ex. 34), at AM-02252259, 260; 2010 Post Outage Report (Pl. Ex. 46), at AM-02739979.

167. Heavy machinery was required to facilitate the removal of old components and installation of new, redesigned components. Multiple monorails were installed in order to maneuver the components. Stevens Test., Tr. Vol. 2-A, 18:24-19:11; 36:6-18; 38:11-19. Multiple large cranes were constructed to remove and lower the old assemblies to the ground and lift the new assemblies to the necessary height within the boiler. Each outage required the construction of two Manitowoc 888 cranes, as well as several other cranes, including Manitowoc 222 and 2250 cranes. Stevens Test., Tr. Vol. 2-A, 18:14-19:19; 48:12-20; 2007 Post Outage Report (Pl. Ex. 34), at AM-0225210; 2010 Post Outage Report (Pl. Ex. 46), at AM-02739973. The largest Manitowoc crane had to be tall enough to remove 50-foot reheater assemblies through the roof at an approximately 270 foot elevation. Stevens Test., Tr. Vol. 2-A, 48:4 -15.

168. The process of removing each old component and installing each new component was highly complex. For the boiler components, each original assembly was cut out and removed one-by-one. Stevens Test., Tr. Vol 2-A, 36:11-19. Cuts had to be made in the side of the boiler lagging and walls at various elevations, including one at around a 200 foot elevation, as well as in the roof of the boiler house. Stevens Test., Tr. Vol. 2-A, 38:11-19, 47:25- 48:3. It would take months to facilitate the removal and re-installation. Stevens Test., Tr. Vol. 2-A, 38:25 – 39:9; 49:2 – 7. Many craftsmen were involved in the cutting and welding process. Stevens Test., Tr. Vol. 2-A, 50:20-51:1.

169. The 2007 major boiler outage at Rush Island Unit 1 lasted 100 days and required more than 1,000 workers and 448,539 total hours of labor, of which 402,109 hours were performed by contractors. Ninety-one percent of the work done during the Unit 1 major boiler

outage was performed by contractors. While other work was performed, the replacement of the economizer, reheater, air preheaters, and lower slope panels was the most significant and costly work performed during the outage. Stevens Test., Tr. Vol. 2-A, 21:18 – 22: 18; 2007 Post Outage Report (Pl. Ex. 34), at AM-0225259, 260.

170. The 2010 major boiler outage at Rush Island Unit 2 lasted approximately 100 days and required more than 350,000 hours of labor, of which 290,953 hours were performed by contractors. An average of 360 contractor staff worked two 10-hour shifts six days a week during the outage. 2010 Post Outage Report (Pl. Ex. 46), at AM-02739976.

171. The 2007 and 2010 major boiler outages were significantly different than typical power plant maintenance, repair, and replacement activities undertaken on a day-to-day basis. Ameren itself did not characterize the replacement of major components such as the reheaters, economizers, air preheaters, and lower slopes at issue in this case as “routine.” Instead, Ameren described the work as “major boiler modifications” and identified the work as not recurring and not routine in its project documents. Stevens Test., Tr. Vol. 1-B, 65:24- 66:10, 66:8-71:2; Vol. 2-A, 9:24- 10:18, 11:19-12:2; October 5, 2005 Memo (Pl. Ex. 6), at AM-00072912; Project Approval Package (Pl. Ex. 1), at AM-00072591; Project Approval Package (Pl. Ex. 3), at AM-00072838; RFA No. 460.

172. The 2007 and 2010 major boiler outages were unprecedented events for Rush Island Units 1 and 2. After the 2007 major boiler outage, Ameren’s Vice President Mark Birk referred to the outage as the “most significant outage in Rush Island history.” May 29, 2007 Email (Pl. Ex. 31). Mr. Birk specifically called out the replacement of several components – including the economizer, reheater, lower slope, and air preheaters – as distinct from “the routine maintenance that had to be performed” during the outage. *Id*. The 2010 major boiler

outage was similarly referred to as "among the most significant in [company] history." Jerry Odehnal Report (Pl. Ex. 40); *see* Vasel Dep., Aug. 15, 2013, Tr. 272:2-23 (describing exhibit 40); see also 2010 State of the System presentation , Pl. Ex. 41, at AM-02493747 (distinguishing the air preheater, reheater and economizer replacements from the "routine maintenance" done during the 2010 outage).

173. By the time of their replacements in 2007 and 2010, the reheaters, economizers, and air preheaters were more than 30 years old, nearing the end of their expected lives. These components had never before been replaced at Rush Island Units 1 and 2. Stevens Test. Tr. Vol. 1-B, 50:24-51:4, 81:19-82:1, 84:9-13; 108:13-109:3; Tr. Vol. 2-A, 9:24-10:18, 43:3-25; Golden Test., Tr. Vol. 8-A, 16:7-16; Vasel Dep., Aug. 15, 2013, Tr. 131:11-132:6; October 5, 2005 Memo (Pl. Ex. 6), at AM-00072912 ("units have operated for nearly 30 years without replacing any of the major components"); Unit 2 ELT Progress Report (Pl. Ex. 110), at AM-02465689 ("The MBO [major boiler outage] is being undertaken to change out 2 major boiler components and the APH that are end of life…"); Unit 2 ELT Progress Report (Pl. Ex. 456), at AM-00953927.

174. Projects such as the economizer, reheater, air preheater, and lower slope replacements are not performed frequently during the life of a typical utility unit. Stevens Test., Tr. Vol. 1-B, 91:11-18. Ameren's expert Mr. Golden agreed that the typical life of a reheater is about 30 years, the typical life of a primary economizer is about 35 years, and the typical life of a lower slope is about 40 years. Golden Test. Tr. Vol. 8-A, 18:2-11. Mr. Golden also testified that complete air heater replacements (including the rotor and all baskets), like the ones done at Rush Island, are not done frequently at any unit. Golden Test., Tr. Vol. Vol. 8-A, 19:9-15.

175. Even looking exclusively to how common work is performed across the utility industry, Mr. Golden was able to identify few, if any, projects that rival the 2007 and 2010 major boiler outages at other Ameren plants or elsewhere in the utility industry. Mr. Golden has worked on 14 NSR cases since 2000 on behalf of electric utilities. Golden Test., Tr. Vol. 8-A, 6:3-16. During that time, he has collected a list of 18,300 projects undertaken at coal-fired power plants that he says are both capital projects and cost more than $100,000. Golden Test., Tr. Vol. 8-A, 25:11-14; 25:24-26:2, 26:13-16. However, Mr. Golden was not able to identify *any* coal-fired unit in the electric utility industry that has replaced the economizer, the reheater, the lower slopes, and the air preheater together. Golden Test., Tr. Vol. 8-A, 19:3-8; *see also* Vasel Dep., Aug. 15, 2013, Tr. 154:11-24 (unable to recall any other outage at Ameren when all components were replaced).

176. Similarly, even for the relatively few air preheater replacements that Mr. Golden did identify (35 out of approximately 1,200 coal-fired generating units operating in 2007), Mr. Golden was unable to testify that all were complete replacements or were comparable to those at Rush Island. Golden Test., Tr. Vol. 8-A, 20:2-23, 28:3-12, 28:17-29:5.

F. The Cost of the 2007 and 2010 Major Modifications

177. Replacement of the reheater, economizer, air preheaters, and lower slope at Rush Island Unit 1 ultimately cost approximately $34 million. Stevens Test. Tr. Vol 2A, 22:24-23:3; Golden Test., Tr. Vol. 8-A, 23:7-10.

178. Replacement of the reheater, economizer, and air preheaters at Rush Island Unit 2 ultimately cost more than $38 million. Stevens Test., Tr. Vol 2-A, 28:5-9; Golden Test., Tr. Vol. 8A, 23:7-10.

179. Ameren's budget for the Rush Island plant is divided into an Operation and Maintenance ("O&M") component and a Capital component. Stevens Test., Tr. Vol. 1-B, 89:23-90:3.

180. A capital project is one that would improve the value of the asset. Stevens Test., Tr. Vol. 1-B, 91:1-10.

181. The component replacements at issue in this case were capital projects. The projects were actually funded out of Ameren's capital budget rather than its O&M budget. Stevens Test., Tr. Vol. 1-B, 89:23-90:3, Vol. 2-A 5:12-17; Golden Test., Tr. Vol. 8-A, 23:14-15.

182. Costing $34 to $38 million, the boiler component replacements at Unit 1 and 2 were the costliest capital projects ever done at the Rush Island plant. Golden Test., Tr. Vol. 8-A, 23:7-19. By way of comparison, Rush Island's entire annual O&M budget for the Rush Island plant was about $25 million. Meiners Test., Tr. Vol. 7-B, 23:24-24:2.

183. The boiler component replacement projects were among the most expensive boiler projects that Ameren identified to EPA as ever having been undertaken at any of its plants. Knodel Test., Tr. Vol. 1-A, 81:9 – 82:8.

III. THE 2007 AND 2010 BOILER UPGRADES EACH RESULTED IN A SIGNIFICANT NET EMISSIONS INCREASE OF SO_2 WITHIN THE MEANING OF THE PSD REGULATIONS

184. The 2007 and 2010 boiler upgrades triggered PSD if: (1) Ameren should have expected them to result in a significant (i.e., more than a 40 tons-per-year) SO_2 increase; or (2) a 40 tons-per-year SO_2 increase related to the boiler upgrades actually occurred. *Ameren SJ Decision*; *see also* 40 C.F.R. § 52.21(a)(2)(iv)(*b*), (*c*).

185. As described further below, Ameren should have expected the 2007 and 2010 boiler upgrades to increase the availability of the units, thereby resulting in more than 40 tons per

year of increased SO_2 emissions. At both units, these availability improvements resulted from eliminating significant outages and derates that had been plaguing the boilers prior to the upgrades. Removing the problems that had been limiting their pre-project availability should have been expected to increase their post-project operations and emissions. In addition, for at least the 2010 boiler upgrade, Ameren should have expected the new economizer, reheater, and air preheaters to increase the maximum megawatt generating capability of the unit, resulting in increased annual emissions.

186. In addition, availability and hours of operation of Units 1 and 2 actually increased by an amount greater than that required to trigger PSD, just as Ameren expected, as did the megawatt capability of Unit 2.

187. Evidence for these expected and actual increases is found in Ameren's documents and project justifications, in its GADS and other operational data, and in the results of a computer modeling program called ProSym that Ameren uses to simulate the operations of its generating units. The United States' emissions experts, Mr. Koppe, Dr. Sahu, and Dr. Hausman, explained how this evidence demonstrates that the availability and capability improvements at Rush Island Units 1 and 2 would be expected to, and did, far exceed the 40 tons-per-year PSD threshold for SO_2. After a brief overview, the specific evidence supporting a finding that the 2007 and 2010 boiler upgrades resulted in significant SO_2 increases is reviewed in further detail below.

A. Overview

188. The Rush Island units are low-cost, baseload units, meaning that they will operate any additional hours that they are made available to operate. FOF 6. As some of the most cost-effective units in a large and interconnected electricity supply system that is vastly larger than

any individual unit, it was not a lack of demand that was holding the units back prior to the 2007 and 2010 boiler upgrades. These "work horse" units were already made to run every hour they were available to run. What held the units back prior to their upgrades was the forced outages and load limitations that were plaguing the boilers as a result of burning a coal for which they were not designed, along with the fact that key boiler components had degraded as they neared the end of their design lives. Fixing those problems was expected to, and did, result in increased operations.

189. Because they lack SO_2 pollution controls, the Rush Island units are very large sources of air pollution. FOF 8, 9. The large size of the units means that very small changes in performance can result in increased SO_2 emissions of more than 40 tons per year.

190. For example, it only takes 21 additional hours of full power operation at either unit to produce more than 40 tons of SO_2. Sahu Test., Vol. 5, 41:3-7, 45:25-46:4. Given that it typically takes two to three days to recover from even a single outage (FOF 35), eliminating just one outage would result in more than 40 additional tons per year of SO_2. Sahu Test., Vol. 5, 46:17-47:2, 62:2-63:10, 94:5-95:23; August 15, 2005 Presentation (Ex. 332), at AM-00966775, 794 (showing *inter alia* that one outage due to the economizer lasts three days).

191. Measured in terms of equivalent availability, it takes only about a 0.3 percentage point (i.e., one-third of a percentage point) increase in availability to produce more than 40 additional tons per year of SO_2 from these units. Hausman Test., Tr. Vol. 4-B, 66:15-25.

192. Similarly, increasing the capability of Rush Island Unit 2 by just 1.7 megawatts would result in an increase in SO_2 emissions of at least 40 tons per year. Sahu Test., Vol. 5, 41:11-14; 46:5-11; Hausman Test., Tr. Vol. 4-B, 58:4-60:2 (one megawatt increase in capacity produces 23 additional tons of SO2).

B. GADS-Based Emissions Calculations for Rush Island Units 1 and 2

193. The United States presented emissions calculations utilizing data generated by Ameren which was transmitted to the North American Electric Reliability Council ("NERC") and maintained in NERC's Generating Availability Data System. As explained above in Subsection II.B.4, GADS is an industry-wide database that collects information on the performance of power plants and the effects that various problems have on that performance. Ameren and other utilities use GADS data to track the causes of outages and derates so that they can assess the status of plant equipment and predict future availability. FOF 89, 92. As also described above, Ameren specifically uses GADS data to calculate "lost generation" when performing financial calculations to determine whether to perform capital projects. FOF 103.

194. Plaintiff's expert Mr. Koppe, who has been a power plant performance consultant for four decades and helped develop the GADS database, reviewed Ameren's GADS data to determine which outages and derates were caused by problems with the boiler components at issue in this case. FOF 90, 91, 106.

195. Mr. Koppe then quantified the expected effect of the 2007 and 2010 upgrades on availability. In performing his analyses, Mr. Koppe used the same basic approach that he used to assess expected performance impacts in his work for utilities over the past 40 years. Koppe Test., Vol. 3-A, 35:6-9 ("I've seen it used by many different utilities, including Ameren, and I've seen it in various industry publications.")

196. Mr. Koppe concluded that the company should have expected, and did expect, the 2007 and 2010 boiler upgrades to eliminate all of the availability losses that were due to the economizers, reheaters, lower slopes, and air preheaters. Koppe Test., Vol. 3-A, 48:24-49:6; *see also* Sahu Test., Vol. 5, 95:24-97:2. Ameren's project justifications were based on this very

assumption. Koppe Test., Tr. Vol. 3-A, 49:24-51:14. *See* FOF 145, 146, 147. Similarly, the effects of pluggage on the units were expected to be eliminated for at least decades into the future. Koppe Test., Vol. 3-A, 54:16-55:3.

197. Based on Ameren's documents and data, and relying on his decades of experience in the industry, Mr. Koppe then made an engineering judgment on the improvements in availability that would be expected to result from the 2007 and 2010 boiler upgrades. In order to determine whether eliminating the causes of unavailability related to the components at issue would result in an overall increase in unit availability, Mr. Koppe assessed the condition of the rest of the equipment at Rush Island Units 1 and 2 in order to ensure that other problems would not be expected to offset the performance improvements expected from the boiler upgrades. As Mr. Koppe explained, the boiler components replaced by Ameren were the "things that were really hurting them" in terms of availability, as they alone were causing roughly half of all the lost productivity at the units during the baseline period. Koppe Test., Vol. 3-A, 47:7-12; 75:3-11. "[P]roblems with all the rest of the equipment were only half of the losses, and here you had four problems that were half of all the lost productivity." *Id*. 48:2-8. However, he wanted to be sure that "the level of maintenance that was being done" on the remaining parts of the unit that were not being upgraded was sufficient to maintain the overall very good level of performance that those remaining components had experienced. Koppe Test., Vol. 3-A, 56:12-56:25.

198. As part of this review of the entire unit, Mr. Koppe reviewed GADS data and other contemporaneous company data and documents describing the overall condition of the units. Mr. Koppe reviewed, for example, reports identifying all of the maintenance and capital projects done during the outage, unit condition assessments prepared by company engineers, and presentations made by plant engineers to management about the condition of the unit. Koppe

Test., Vol. 3-A, 34:13-21, 51:20-57:17; *see also* GADS Events Data (Pl. Ex. 925), 2007 and 2010 Outage Reports (Pl. Ex. 34 and 46), Condition Assessments (Pl. Ex. 106 and 606), and State of the System Presentations (Pl. Ex. 15, 41, and 111). Based on his review of this evidence, Mr. Koppe concluded that the overall effect of everything else at the plant on availability would not offset the availability gains from the components at issue. Koppe Test., Vol. 3-A, 51:20- 66:5-67:3.

199. Evidence that other problems would not be expected to offset the performance improvements from the 2007 and 2010 boiler upgrades was also provided by Ameren witnesses at trial. As Mr. Naslund testified, as part of the new "super outage" concept that he championed, the company proactively addressed everything that might cause problems in the next six years at a unit to ensure the unit would run as well as possible and "improve unit availability." Naslund Test., Tr. Vol. 6-B 7:1- 8:6. After implementing the super outage process, forced outages in fact went down and availability went up. Naslund Test., Tr. Vol. 6-B, 6:19-25. Mr. Strubberg similarly testified that he was responsible for a condition-based maintenance program called the PRO/PMO program that helped keep the balance of individual components at high availability, and by doing that, it helped keep the units at high availability. Strubberg Test., Tr. Vol. 8-A, 35:21-23, 38:23-24, 39:21-25, 61:5-9, 77:8-12.

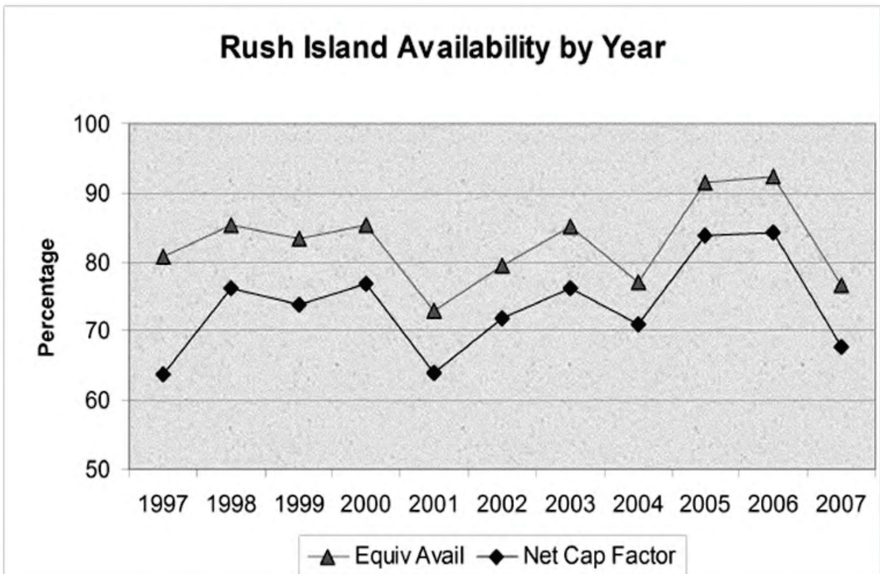
200. Once the expected impact on availability is determined for a unit, the next question is to determine whether that increased availability will actually be used to operate more in the future. Whether or not increased availability will result in an additional hour of operation in the future can sometimes be a "tricky question" for some units, "but it's not for these units, because these units operate for almost every single hour that they are able to operate. So if you increase the number of hours a unit is available to operate, that will result in an increase in the

number of hours the unit does operate." Koppe Test., Vol. 3-A, 35:17-26; *see also* Naslund Dep., Sept. 18, 2014, at 55:2-55:7.

201. This direct relationship between availability and generation at Rush Island was also confirmed by modeling performed by Dr. Hausman. As Dr. Hausman explained, if availability is improved, it means the unit can run more hours or it can run at a higher level for more hours. Hausman Test., Tr. Vol. 4-B, 39:9-13. For a relatively low-cost baseload unit, if it is able to produce more, it typically will produce more. As Dr. Hausman explained: "I think that's a fairly fundamental way to look at electricity markets. If I were to run a model and it ran less or used less fuel, there would be something very strange in that." Hausman Test., Tr. Vol. 4-B, 39:16–40:4; *see also id.* at 36:12–21. Dr. Hausman found exactly such a linear relationship between availability improvements and generation at Rush Island. Hausman Test., Tr. Vol. 4-B, 64:10-64:20, 71:7-25.

202. This direct relationship between availability and generation at baseload units like Rush Island was also obvious from presentations prepared by Ameren itself on the importance of availability, which showed availability tightly tracking plant generation. Strubberg Test., Tr. Vol. 8-A, 100:4-6, 100:15-17; 2008 State of the System (Pl. Ex. 15), at AM-00196620.

Rush Island Availability



Confidential/Trade Secret - Subject to Protective Order AM-00196620

203. The data also shows a relationship between unit availability and SO_2 pollution, as Ameren's expert Michael King acknowledged at trial. King Test., Tr. Vol. 6-B, 86:2-23.

204. The extraordinarily high use of Rush Island's availability was also confirmed in the GADS data that Mr. Koppe reviewed, which included data on how often the units were placed in a status known as "reserve shutdown." When a unit is in reserve shutdown, it is available to operate but does not for economic reasons. Koppe Test., Tr. Vol. 3-A, at 36:22-37:1.

205. The Rush Island units did not spend a single hour in reserve shutdown during the PSD baseline periods. Koppe Test., Tr. Vol. 3-A, 37:2-7; Naslund Dep., Sept. 18, 2014, Tr. 54:21-55:7; RFA Nos. 189, 192, 193, 203. In the five years before the projects, one of the units operated every single hour it was available, and the other operated 99.9% of the time. Koppe Test., Tr. Vol. 3-A, 37:8-18. That means that if a Rush Island unit "is available to operate another hour, it will operate for that hour; and that, of course, requires burning more coal and generating more emissions." Koppe Test., Tr. Vol. 3-A, 37:19-24; Naslund Test. Vol. 6-A, 50:3-13 (describing Rush Island units as "two workhorses"), 45:3-20 (since 2005, the Rush Island units "were staying up on load at much higher levels around the clock"), 48:7-49:3 (because the Rush Island units are among the cheapest units in MISO, they run a higher percentage of time); Naslund Dep., Sept. 18, 2014, Tr. 55:4-7.

206. Mr. Koppe's quantification of increased unit availabilities caused by the 2007 and 2010 boiler upgrades was then translated into emissions increases by Dr. Sahu, a combustion engineer and environmental permitting engineer, who has performed PSD calculations hundreds of times. Sahu Test., Vol. 5, 34:24-38:14. Dr. Sahu did not assume that Ameren would generate at full capacity every additional hour that it generated. Instead, he applied the same utilization factor that the units experienced during the PSD baseline period. Sahu Test., Tr. Vol 5, 51:5-53:16, 75:3-77:20.

207. Using the same baseline utilization factor is consistent with the fact that the units are baseload units that are used whenever they are available. In addition, the historic utilization factor of the units remained relatively stable, and Ameren documents indicate that it expected the utilization factor of the units to remain relatively stable going forward. Sahu Test., Tr. Vol. 5

57:15-58:21; September 9, 2006 Email and attached critical review spreadsheet (Pl. Ex. 333), at Rush 1 and Rush 2 tabs.

208. Use of a constant utilization factor was also confirmed by Ameren's witnesses. Ameren expert Marc Chupka opined in his expert report that it "would be reasonable to assume a constant utilization factor for projecting future emissions at least for some period of time" after the projects at issue in this case. Chupka Test., Tr. Vol. 8-B, 77:3-18. Similarly, Sandra Ringelstetter's work papers identified the baseline utilization factor and the utilization factor projected by Ameren for both Unit 1 and Unit 2. For Unit 1, the utilization factor was projected to stay basically the same (a change of 0.09%), while for Unit 2 it was projected to increase by about 2%. Def. Ex. NE, at "RI U1 2007 Summary" and "RI U1 2010 Summary."

209. Using the same utilization factor from the baseline period specifically eliminates the impact of other factors that could cause an increase in utilization of a unit when its availability improves, thus isolating just the effect of the boiler upgrades. For instance, whereas Ms. Ringelstetter identified a 2% increase in utilization factor at Unit 2, Dr. Sahu's use of the baseline utilization factor excludes any effects of increased demand on the units by calculating just the increase that is due to the availability improvements made possible by the upgrades. Sahu Test., Tr. Vol. 5, 75:18-76:5, 153:21-25.

210. In addition, as Dr. Sahu described, the general approach of applying a utilization factor to calculate the additional generation from an expected availability improvement is consistent with Ameren's practices and is well understood in the industry. The same basic formula is found in Ameren's availability worksheets, which translate availability improvements into generation for fuel budgeting purposes, as well as industry documents such as a 1985 study publication of the Electric Power Research Institute ("EPRI"). Sahu Tr., Vol. 5, 53:17-57:5. For

instance, Ameren's availability worksheets provide the following formula for calculating "expected annual plant generation" from an availability change: "Total Net mwhrs" equals "Plant Equiv. Avail. X Utilization Factor." Availability Worksheet (Pl. Ex. 250), at Spreadsheet Tab "Instructions." The 1985 EPRI study provides a similar formula. *See* Economic Evaluation of Plant-upgrading Investments (Pl. Ex. 241), at AME_RHK000011. Similarly, although Ameren has criticized Dr. Sahu's use of utilization factors as applied to both outages and derates in this case, Ameren itself uses utilization factors in a similar way outside of this litigation. For instance, in using a utilization factor to estimate future generation, Ameren's availability worksheets specifically defines the utilization factor as "the percent of mwhrs used after outages and derates." Availability Worksheet (Pl. Ex. 250), at Spreadsheet Tab "Instructions."

211. Dr. Sahu's emission calculations also used the same SO_2 emission factor from the baseline period. As with holding the utilization factor constant, reasons for using the baseline emission factor in the calculation of post-change emissions include the fact that Ameren documents indicate that the emission factor was expected to remain fairly stable. Sahu Test. Tr. Vol. 58:22-59:24, 89:6-89:13, September 9, 2006 Email and attached critical review spreadsheet (Pl. Ex. 333), at Rush 1 and Rush 2 tabs.

212. In addition, the project justification documents for the 2007 and 2010 boiler upgrades made no mention of *any* expected improvements in the gross efficiency of the units, a point that was conceded by Ameren's capability expert. Caudill Test., Tr. Vol. Vol. 10-B, 44:24-45:12; *see also* Sahu Test., Tr. Vol. 5 108:3-21.

213. While Ameren argued that it expected small reductions in auxiliary load as a result of the boiler upgrades, such reductions would result in an improvement in net efficiency, not gross efficiency, and as a result do not affect the amount of coal that the unit is capable of

burning. Rather, they just mean that less power is used to run the plant, so more of the gross generation recovered by the boiler upgrades could be sent to the grid. Koppe Test., Tr. Vol. 3-B, 11:16-12:4; Shelton Test., Tr. Vol. 10-A, 85:8-10. As Dr. Sahu explained, all of his calculations are based on gross megawatts because gross is what relates to how much SO_2 comes out of the boiler. Sahu Test., Tr. Vol. 5 52:16-24, 84:20-24.

214. Similarly, while Ameren did expect some improvement in efficiency at Unit 2 due to the contemporaneous replacement of the low pressure turbine, Dr. Sahu accounted for that in his calculations by factoring out both the additional megawatt capability of the new turbine and the heat rate of the turbine. Sahu Test. Tr. Vol. 5 84:9 – 85:1, 135:23-136:8, 137:9-15; 138:3-10, 181:21 – 182:4. Dr. Sahu's treatment of the low pressure turbine on the expected SO_2 emission rate was consistent with how Ameren itself treated the expected effect of the turbine outside of this litigation. For instance, Ameren's financial analysis was based on the assumption that the turbine-related efficiency improvements would allow Unit 2 to produce more megawatts, but would not result in the unit burning any less coal. Pl. Ex. 48, at "Data Entry" sheet (rows 149-152, col. D (and comment box) (showing that Ameren did not include efficiency benefit inputs for "decrease in fuel usage")), Pl. Ex. 110, at AM-02465690; Koppe Test., Vol. 3-B, at 29:9-32:9. As Dr. Sahu noted, Ameren's financial analysis shows that there was no expected fuel decrease associated with the capacity increase. Sahu Test. Tr. Vol. 5, 97:3 - 99:4.

215. Use of a constant emission factor was also corroborated by the United States' other experts. As Dr. Hausman explained, when a baseload unit like the Rush Island units is modified to become more efficient, it allows the unit to generate more electricity while consuming the same amount of coal. Hausman Test., Tr. Vol. 4-B, 37:6–18. Because a baseload plant has essentially an unlimited market for its very low-cost power, if it becomes more

efficient, it will burn the same amount of coal but produce more energy than it can sell into the market. Hausman Test., Tr. Vol. 4-B, 38:7–11. As a result, as Mr. Koppe also explained, the separate efficiency gain from the turbine would result in increased megawatts but would not change the full load heat input to the boiler. Koppe Test., Tr. Vol. 3-B, 29:9-32:9. This was also consistent with Ameren employee Jeff Shelton's testimony that a more efficient turbine can allow a unit to make more megawatts with the same amount of heat input. Shelton Test., Tr. Vol. 10-A, 85:14-20, 85:5-9.

216. Finally, use of a constant emission rate was also borne out by Ameren's operating data as reported to EPA, which confirmed that the post-project emission rate at Unit 1 stayed relatively constant, and actually increased somewhat at Unit 2 as compared to the PSD baseline periods. Sahu Test., Tr. Vol. 5, 109:14-22. At Unit 1, reported heat rate deteriorated slightly, from 9,282 Btu/Kwh to 9,447 Btu/Kwh, and the unit emitted approximately 21 more pounds per hour of SO_2 than it had in the baseline. Sahu Test., Tr. Vol. 5 110:6-111:6; Knodel Test., Tr. Vol. 1-A, 110:8-24. At Unit 2, reported heat rate deteriorated from 8,800 Btu/Kwh to 9,676 Btu/Kwh, and the unit emitted approximately 456 more pounds per hour of SO_2 than it had in the baseline. Knodel Test., Tr. Vol. 1-A, 111:8-20. Sahu Test. Tr. Vol. 5, 112:21-24. As a result, for every additional hour that Rush Island Units 1 and 2 were able to operate in the post project period, they actually emitted more SO_2 per hour.

217. Because Dr. Sahu's calculation is based on the incremental impact of the projects on unit performance calculated by Mr. Koppe, his entire predicted increase is related to the project. Sahu Test., Tr. Vol. 5, 49:21 – 50:3, 60:13-18, 61:15-17, 73:6 – 74:4, 77:11-20, 84:15 – 87:10.

218. Ameren presented testifying expert Michael King to critique the approach used by Mr. Koppe and Dr. Sahu. But Mr. King agreed that Mr. Koppe and Dr. Sahu "have the appropriate experience to estimate the effect of modifying a power plant on generation [and] emissions." King Test., Tr. Vol., 6-B, 65:17-21.

219. Another Ameren testifying expert, Marc Chupka, conceded that the method used by Mr. Koppe and Dr. Sahu for determining PSD emissions increases has at least been "well-known in the industry" since the first enforcement cases were filed in 1999. Mr. Koppe testified that he and Dr. Sahu had used the same basic formula in this case that he and other utilities have used for decades. Koppe Test., Tr. Vol. 3-A, 35:6-9; *see also* Sahu Test., Tr. Vol. 5, 53:17-57:5 (discussing Ameren and industry documents). Mr. Chupka himself has been asked to analyze utility projects using the same method employed by Mr. Koppe and Dr. Sahu numerous times. Chupka Test., Tr. Vol. 8-B, 74:14-21, 75:5-10.

1. Results of projected emissions increase calculations based on the GADS data at Rush Island Unit 1

220. As described further below, Ameren should have expected an increase of at least 600 tons per year of SO_2 emissions over the PSD baseline emissions as a result of the availability improvements caused by the 2007 boiler upgrade.

221. The PSD "baseline" period used by Ameren for Unit 1 in this litigation was the highest 24-month period of emissions in the five years before the 2007 boiler upgrade, which was February 2005 through January 2007. During that period, Unit 1 emitted 14,874 tons per year of SO_2. Sahu Test., Tr. Vol. 5, 49:8-20; Knodel Test., Tr. Vol. 1-A, 95:6-25.

222. During this baseline period, problems in the economizer, reheater, lower slopes, and air preheaters caused Unit 1 to lose 336.1 equivalent full power hours of generation per year,

which is roughly equivalent to 14 days of operation per year. Koppe Test., Tr. Vol. 3-A, 45:15-46:24. The unit was completely shut down in outages for 246.4 hours per year due to problems in the components at issue and lost the equivalent of another 89.7 full power hours of operation due to deratings. *Id*.

223. As explained by Mr. Koppe, the problems associated with the Unit 1 reheater, economizer, air preheater, and lower slopes caused about 50% of all the availability losses at Unit 1 during the baseline period. Koppe Test., Tr. Vol. 3-A, 47:7-12; 48:2-8.

224. These problems reduced Unit 1's availability during the baseline period by 3.8 percentage points. Sahu Test., Tr. Vol. 5, 63:11-64:5. Unit 1's availability was 92.1% during the baseline. Koppe Test., Tr. Vol. 3-A, 48:9-11. The average annual availability of Unit 1 over the entire five-year pre-project period was 87.5%. *Id*. 48:15-23

225. Based on his analysis of Ameren's operating data, including GADS, as well as contemporaneous documents, Mr. Koppe concluded that Ameren should have expected the 2007 boiler upgrade to eliminate all of the availability losses in the baseline period related to problems in the reheater, economizer, lower slopes, and air preheater components. Koppe Test., Tr. Vol. 3-A, 48:24-49:6, 66:5-12; *see also* Sahu Test., Tr. Vol. 5, 95:24-97:2.

226. Company documents and witnesses confirm that Ameren actually had such an expectation. Ameren expected that as a result of the 2007 boiler upgrade, availability losses attributable to the replaced components would be completely eliminated for years in the future. Meiners Test., Vol. 7-B, 40:1-18 ("Q. Right. If you do the project, in the future you won't have those causes of unavailability, right? A. Correct."); Boll. Test., Vol. 8-B, 46:11-47:10 ("that's probably a good bet"); FOF 145, 146, 147.

227. Based on his review of company documents and data, as well as his experience in the industry and his assessment of the overall condition of the rest of the unit, Mr. Koppe concluded that Ameren should have expected that the 2007 boiler upgrade would result in a substantial increase in the overall equivalent availability of Rush Island Unit 1. Koppe Test., Tr. Vol. 3-A, 34:13-21, 51:20-55:17, 66:5-12. The impact of the project alone would be to increase the availability of Unit 1 by 3.8 percentage points over baseline availability by eliminating all 336.1 EFPH of availability losses related to the reheater, economizer, lower slopes, and air preheater. Koppe Test., Tr. Vol. 3-A, 48:24-49:6; *see also* Sahu Test., Tr. Vol. 5, 95:24-97:2. If the four components had not been replaced, the availability of the unit would have been expected to decrease. Koppe Test., Tr. Vol. 3-A, 66:13-67:3.

228. Similar projected increases can be found in Ameren's availability forecasts. For example, the forecast for the 2006 Fuel Budget projected that Unit 1's long-term average availability would be 95.0% as a result of the "boiler improvements" done during the Unit 1 outage. This represents an increase of 7.5% over Unit 1's five-year pre-project average and about a 3% increase over Ameren's high baseline emissions period (a 3 percentage point improvement is the equivalent of about 10 more days of operation). Koppe Test., Tr. Vol. 3-A, 61:20-65:8; Meiners Test., Vol. 7-B, 39:16-25; September 23, 2005 Email (Pl. Ex. 214); September 28, 2005 Email attaching Availability Worksheet (Pl. Ex. 215), at Rush tab.

229. Ameren's 2006 Fuel Budget forecast showed a 4.2 percentage point improvement in Unit 1's forced outage rate after the work. Def. Resp. to Interrogatory No. 68; Boll Test., Vol. 8-B, 42:19-44:1. Ameren's Rule 30(b)(6) witness, David Boll, admitted in deposition testimony that the 4.2% improvement in the outage rate was "most probably due to the major outage" and could provide no other reason for the improvement. Boll Test., Tr. Vol. 8-B, 44:2-45:5; Boll

Dep. Dec. 12, 2013, Tr. 122:13-123:2; Aug. 17, 2007 Email and Attached Spreadsheet (Pl. Ex. 523), AM-02264672.

230. Similarly, Rush Island Plant Manager Robert Meiners gave a presentation to Ameren senior executives in which he discussed the condition of the reheater, economizer, air preheater, and lower slopes on Rush Island Unit 1 and the efforts to replace those components. At the end of the presentation, Mr. Meiners presented a graph showing that Rush Island's long-term availability would increase by almost 5 percentage points, from about 90% in 2005-2006 to 95% after both outages had been completed. Mr. Meiners admitted that even a one percent change in availability would be a significant change. Meiners Test., Tr. Vol. 7-A, 68:8-18; Tr. Vol. 7-B, 27:21-24, 28:10-20, 31:15-21, 33:4-6; Rush Island Business Plan Presentation (Pl. Ex. 126), at AM-02625397.

231. Before the Unit 1 project had been approved, Ameren was not forecasting an increase in availability; instead its forecasts were that availability would remain flat – 91%. That is because all of the other work done during the 2007 outage would maintain availability but would not cause an increase in availability. Koppe Test., Tr. Vol. 3-A, 65:13-66:4, 66:13-67:3.

232. Based on Mr. Koppe's availability analysis, and consistent with his review of company data and documents, Dr. Sahu translated the increased operations that were expected to result from the 2007 boiler upgrade into emissions and determined that the expected SO_2 increase from such operations was far more than 40 tons per year. Sahu Test., Vol. 5, 39:23-25, 40:21-24, 102:7-10, 113:22 – 114:1. Specifically, Dr. Sahu calculated that Ameren should have expected a net emissions increase of 607.8 tons per year of SO_2 over the PSD baseline emissions as a result of the replacement of the economizer, reheater, lower slopes, and air preheater. Sahu Test., Tr. Vol. 5, 49:8-50:14, 57:15-59:5, 92:22-93:17; 115:17-20.

233. Even without counting the effects of derates and focusing just on the outages caused by the components, the 2007 boiler upgrade would allow the unit to operate 246 more hours or about 10 more days per year by eliminating the outages associated with the reheater, economizer, lower slopes, and air preheaters. By itself, this would cause a more than 400 ton-per-year increase in emissions of SO_2. Koppe Test., Tr. Vol. 3-A, 49:12-23; Sahu Test., Vol. 5, 65:12-66:22.

2. Rush Island Unit 1 actual emission increases

234. Just as Ameren expected, Unit 1 experienced a substantial increase in availability following the 2007 boiler upgrade. In 2008, Rush Island Unit 1 had an equivalent availability of 96.77%. This was the highest equivalent availability of any unit in the entire Ameren system in 2008. Unit 1's equivalent availability in 2008 was higher than any 24-month period of equivalent availability since the Rush Island plant first began tracking availability data in 1982 and higher than any 12-month period since 1990. Anderson Test., Tr. Vol. 7-A 55:8-17, 56:22-58:2; Meiners Test., Tr. Vol. 7-B, 49:9-15, 55:18-23, 56:12-16; Strubberg Test., Tr. Vol. 8-A, 94:3-8, 95:1-4; Def. Resp. to RFA 299; Jan. 9, 2009 Email (Pl. Ex. 104), at AM-02272427 ("Rush Island 1 had the highest EAF [equivalent availability factor] at 96.77%"); *see also* Koppe Test., Tr. Vol. 3-A 67:4-69:3.

235. Rush Island Plant management received significant salary bonuses relating the Rush Island's availability in the year 2008, whereas they had received no such bonuses for the year before. Strubberg Test., Vol. 8-A, 100:23-102:3; Def. Response to Interrogatory No. 65.

236. In April 2009, Rush Island Unit 1 set an "all-time record run for days on line," breaking the "old plant record of 211 days [that] was set in 1990." April 7, 2009 Email re: "Rush Island Unit 1 Record Run" (Pl. Ex. 105), at AM-02276058; Strubberg Test., Tr. Vol. 8-A,

60:7-61:18 (admitting that Unit 1 had an equivalent availability of more than 98% during this period). Ameren Vice President Mark Birk specifically called out the replacement of the "reheater, economizer, and lower slopes" in 2007 as having "paid off" when he reported Unit 1's record availability to Ameren's CEO Warner Baxter. April 7, 2009 Email re: "Rush Island Unit 1 Record Run" (Pl. Ex. 105), at AM-02276058; *see also* Koppe Test., Tr. Vol. 3-A 69:12-70:12.

237. The GADS data confirmed that the cause of the improved availability was the improved performance of the components at issue that were replaced as part of the 2007 boiler upgrade. As Ameren should have expected, and did expect, all of the availability losses due to problems in the reheater, economizer, lower slopes, and air preheater were eliminated after the 2007 boiler upgrade. As a result, component-related availability losses were reduced from 336.1 EFPH per year to zero. Availability losses due to everything else also decreased slightly. Koppe Test., Tr. Vol. 3-A, 70:17-71:2, 81:8-17; Sahu Test., Tr. Vol. 5, 64:8-21.

238. Further reflecting the actual performance improvements resulting from the 2007 boiler upgrade, Ameren's reported GADS data further show that Unit 1's equivalent availability actually increased over the baseline period by 4.3 percentage points, from 92.1% to 96.4% in the relevant post-project period. *Id.*; Sahu Test., Vol. 5, 64:24-65:3; Koppe Test., Tr. Vol. 3-A, 71:18-72:14.

239. None of the availability improvements that actually occurred at Unit 1 would have happened if the reheater, economizer, lower slopes, and air preheater had not been replaced. Koppe Test., Tr. Vol. 3-A, 66:13-67:3; Meiners Test., Vol. 7-B, 57:11-16.

240. Similarly, Ameren's reported GADS data shows that Unit 1's operating time increased from 8,208 hours per year in the baseline to 8,568 hours per year during the highest post-project period of emissions, for an increase of 360 hours. This increase in operating hours

included the effect of eliminating the 246 outage hours per year during the baseline period that were caused by problems associated with the reheater, economizer, lower slopes, and air preheater. Koppe Test., Tr. Vol. 3-A, 73:3-15; Sahu Test., Tr. Vol. 5, 65:12-66:22, 109:7-13.

241. There is no question that these increased hours of operation were accompanied by more heat input. Annual heat input increased from 43,957,163 MMBtu per year in the baseline period to 45,442,171 MMBtu per year in the relevant post-project period. Sahu Test., Vol. 5, 109:25-110:5.

242. Similar increases are shown in Ameren's certified Continuous Emissions Monitoring System ("CEMS") data, which show that Unit 1 operated more hours and emitted more pollution per hour during the relevant post-project period as compared to the baseline period. The CEMS data show that Unit 1's operating time increased by 320 hours per year, from 8,278 hours per year in the baseline to 8,598 hours per year in the applicable post-project period. Furthermore, when it was operating, Unit 1 emitted 21 more pounds per hour of SO_2 than it had in the baseline (increasing from 3,593 pounds per hour in the baseline to 3,614 pounds per hour in the post-project period). Knodel Test., Tr. Vol. 1-A, 109:7-16, 110:8-111:7, 112:14-24.

243. Ameren's CEMS data also show that in 2008, the first calendar year after the 2007 boiler upgrade, Rush Island Unit 1 emitted more SO_2 than it had in any year since 1995. Knodel Test., Tr. Vol. 1-A 82:9-19. During the relevant post-project period, Unit 1 emitted 15,539 tons per year of SO_2, which is 665 tons per year more than Unit 1 actually emitted during the baseline period. Sahu Test., Tr. Vol. 5, 49:8 – 20, 111:7-16; Knodel Test., Tr. Vol. 1-A, 95:6-25.

244. Eliminating 246 outage hours by replacing the reheater, economizer, lower slopes, and air preheater, by itself, equates to SO_2 emissions of more than 400 tons per year. Sahu Test.,

Tr. Vol. 5, 41:3-7, 45:25-46:4, 65:12-66:22. Because all of the availability losses caused by the reheater, economizer, and air preheater in the baseline were eliminated (336 EFPH and 246 outage hours), (Koppe Test., Vol. 3-A, 67:7-73:19), it is clear that at least 40 tons of the overall 665 ton increase in actual emissions is related to the increased equivalent availability and additional operating hours enabled by the replacement of these components. Sahu Test., Tr. Vol. 5, 39:13-17, 64:6-66:22.

3. Results of projected emissions increase calculations based on the GADS data at Rush Island Unit 2

245. As described further below, Ameren should have expected an increase of approximately 400 tons per year of SO_2 emissions over the PSD baseline emissions as a result of the availability improvements caused by the 2010 boiler upgrade.

246. The PSD "baseline" period used by Ameren for Unit 2 in this litigation was the highest 24-month period of emissions in the five years before the 2010 boiler upgrade, which was April 2005 through March 2007. During that period, Unit 2 emitted 14,287.7 tons per year of SO_2. Sahu Test., Tr. Vol. 5, 72:17-73:5; Knodel Test., Tr. Vol. 1-A, 91:4-17.

247. During this baseline period, problems in the economizer, reheater, and air preheaters caused Unit 2 to lose approximately 245 equivalent full power hours of availability per year. The unit was completely shut down in outages for 145.5 hours per year due to problems in the components at issue and lost the equivalent of another approximately 100 full power hours of operation due to deratings. Koppe Test., Tr. Vol. 3-A, 74:7 – 75-2; Sahu Test., Tr. Vol. 5 78:20-79:19.

248. These problems reduced Unit 2's equivalent availability during the baseline period by 2.8 percentage points. Sahu Test., Tr. Vol. 5, 119:6-17; Koppe Test., Tr. Vo. 3-A

76:17-22. According to the company's GADS events data, Unit 2's availability was 94.5% during the baseline. The average annual availability of Unit 2 over the entire five-year pre-project period was about 92%. Koppe Test., Vol. 3-A, 75:3-75:23, 76:17-22.

249. The problems associated with the Unit 2 reheater, economizer, and air preheaters caused about 50% of all the availability losses at Unit 2 during the baseline period. Koppe Test., Tr. Vol. 3-A, 75:3-11; Sahu Test., Tr. Vol. 5, 79:20-80:12.

250. Based on his analysis of Ameren's operating data, including GADS, as well as other company documents, Mr. Koppe concluded that, just as at Unit 1, Ameren should have expected the 2010 boiler upgrade to eliminate all of the availability losses in the baseline period related to problems in the reheater, economizer, and air preheaters. Koppe Test., Vol. 3-A, 76:23-77:5.

251. As at Unit 1, based on his review of company documents and data, as well as his experience in the industry and his assessment of the overall condition of the rest of the unit, Mr. Koppe concluded that Ameren should have expected that the 2010 boiler upgrade would result in a substantial increase in the overall equivalent availability of Rush Island Unit 2. Koppe Test., Vol. 3-A, 34:7-21, 55:4-57:22, 73:25-74:2, 77:9-79:14, 84:4-13. The impact of the project alone would be to increase the availability of Unit 2 by 2.8 percentage points over baseline availability by eliminating all 243 EPFH of availability losses related to the reheater, economizer, and air preheaters. Koppe Test., Vol. 3-A, 76:23-77:8.

252. Similar projected increases can be found in Ameren's project documents and availability forecasts, which indicate that Ameren should have expected and did expect that Unit 2's equivalent availability would be similar to what Unit 1 achieved after the 2007 boiler upgrade. Koppe Test., Tr. Vol. 3-A, 77:9-20; Meiners Test., Tr. Vol. 7-B, 50:14-51:2.

253. For instance, Ameren updated its financial justification for the Unit 2 outage in 2009, and included in that justification was the expectation that Unit 2's availability would be as high as Unit 1's availability was in 2008 – almost 97%. Koppe Test., Tr. Vol. 3-A, 77:21-78:19; Meiners Test., Tr. Vol. 7-B, 45:8-25, 48:4-49:5, 50:14-51:2; Unit 2 ELT Progress Report, (Pl. Ex. 110), at AM-02465690; Updated Financial Analysis (Pl. Ex. 48), at "Data Entry" tab (row 155, col. F (and hidden comment: "4.3% gain related to outage work (u2 vs. u1)"). That would be a 4.3 percentage point improvement in equivalent availability over what Unit 2 had experienced in 2008, and would represent about 15 additional days of operation for Unit 2. *Id.*; Meiners Test., Vol. 7-B, 18:22-19:16 (the EAF input in the analysis was the equivalent of "15 days of generation").[2] Mr. Meiners personally assured Ameren's CEO Warner Baxter that inputs used in the updated financial analysis for the Unit 2 outage were accurate. Meiners Test., Tr. Vol. 7-B, 46:9-47:11; May 16, 2009 Email (Pl. Ex. 347), at AM-02637756 ("I do believe the model is now a much more accurate representation of the economic benefits.").

254. Unit 1's availability in 2008 was 96.77%. During the same year, Unit 2's availability was 92.42%. RFAs 299 and 300; Anderson Test., Tr. Vol. 7-A, 55:8-17, 56:22-58:2; Meiners Test., Tr. Vol. 7-B, 49:9-20.

255. All or essentially all of the 4.2 percentage point improvement was related to the components at issue. All of the other work done during the outage was done to keep the performance of the rest of the unit from getting worse but would not improve availability. Koppe Test., Vol. 3-A, 78:23-79:6; Koppe Test., Tr. Vol. 4-A, 99:22-100:2, 103:14-104:25; *see also* Meiners Test., Tr. Vol. 7-B, at 57:11-16 (none of the availability improvement would have

[2] As discussed above, the final EAF input was adjusted downward by 0.1%, from 4.3% to 4.2%, as result of eliminating the lower slope replacement from the final scope of the project. FOF 148.

occurred if the components at issue had not been replaced); February 6, 2007 Email (Pl. Ex. 103) ("In reality, until we have the economizer replacement, Unit 2's forced outage is going to get worse, not better.").

256. Ameren's updated Full Work Order Authorization for the reheater and economizer replacements similarly indicated that Ameren expected the "boiler modifications [to] result in an improved operation of the unit that is at least equal to, if not better, than that currently expected with Unit 2 which had similar modifications in 2007." The authorization quantified this amount as an expected "3-4% improvement in the equivalent availability of the unit." October 15, 2009 Memo (Pl. Ex. 23), at AM-00926323; Birk Dep., Sept. 24, 2013, Tr. 194:1-195:13. Mr. Meiners confirmed that the availability input used for the justification was almost 97%. Meiners Test., Tr. Vol. 7-B, 50:14-51:2.

257. Ameren also should have expected Unit 2's long-term average equivalent availability to increase from 92% to 95%. Because there is a 2-3% variation in long-term forecasts, Ameren understood that Unit 2's highest annual availability after the 2010 boiler upgrade would be 97-98%. Koppe Test., Tr. Vol. 3-A, 76:17-22, 79:7-14; Meiners Test., Tr. Vol. 7-B, 54:14-55:6; Hausman Test., Tr. Vol. 4-B, 65:9–19. Other forecasts done before the boiler upgrade also predicted greater than 95% as a long term availability after the Unit 2 outage. *See* Updated 2008 Fuel Budget forecast (Pl. Ex. 252) (projecting 97% EAF for Unit 2 after outage); Meiners Test, Vol. 7-B, 51:18-52:7.

258. Based on Mr. Koppe's availability analysis, and consistent with his review of company data and documents, Dr. Sahu translated the increased operations that were expected to result from the 2010 boiler upgrade into emissions increases, and determined that the expected SO_2 increase from such operations was far more than 40 tons per year. Sahu Test., Tr. Vol. 5,

39:23-25, 40:21-24, 78:13-19, 99:13-100:11, 102:7-10, 113:22 – 114:1. Specifically, Dr. Sahu calculated that Ameren should have expected a net emissions increase of 414.5 tons per year of SO_2 due solely to the improvements in equivalent availability that Ameren should have expected from the replacement of the economizer, reheater, and air preheater. Sahu Test., Tr. Vol. 5, 73:6-74:14, 115:17-20.

4. Rush Island Unit 2 actual emission increases based on availability

259. Just as Ameren expected, Unit 2 experienced a substantial increase in availability following the 2010 boiler upgrade. During the relevant post-project period, as Ameren should have expected and did expect, there were no availability losses at all due to the reheater, economizer, and air preheater. Availability losses due to all the rest of the equipment at the unit essentially stayed the same. Koppe Test., Tr. Vol. 3-A, 80:7-23; Sahu Test., Tr. Vol. 5, 80:13-81:1, 82:13-83:5; *see also* Pl. Ex. 746 (work paper showing no GADS events for reheater, economizer, and air preheater during post-project period).

260. Overall equivalent availability increased by 2.9 percentage points, from 94.5% in the baseline to 97.4% during the first 12 months after the 2010 boiler upgrade, the relevant post-project period in the case. Unit 2's equivalent availability during this period was higher than any 24-month period in the history of the plant, going back to when Ameren first began tracking availability data in 1982, and higher than any 12-month period since 1987. Koppe Test., Tr. Vol. 3-A, 88:24-89:6; Anderson Test., Tr. Vol. 7-A, 58:3-9, 58:24-59:13; *see also* Sahu Test., Tr. Vol. 5, 81:2-15; Pl. Ex. 746.

261. Ameren's witness, Scott Anderson, referred to the increase in Unit 2's availability before and after the 2010 outage as "night and day." Anderson Test., Tr. Vol. 7-A, 58:7-9 (It is "obvious that the plant went way too long without a planned outage before correcting the

problems that it had. I mean, it's night and day."). Ameren had specifically called Mr. Anderson to discuss what the GADS data showed about the availability of the Rush Island units. Anderson Test., Tr. Vol. 7-A, 31:23-32:19.

262. None of the availability improvements at Unit 2 would have occurred if the reheater, economizer, and air preheater had not been replaced. Koppe Test., Tr. Vol. 3-A, 66:13-67:3; Meiners Dep., Tr. Vol. 7-B, 57:11-16.

263. According to Ameren's GADS data, Unit 2's operating time increased from 8,408 hours/year in the baseline period to 8,583 hours/year in the applicable post-project period, for an increase of 175 hours per year. This increase in operating hours included the effect of eliminating 146 outage hours per year in the baseline period caused by problems associated with the reheater, economizer, and air preheater. Sahu Test., Vol. 5, 83:8-22, 112:6-11, 158:3-8; Koppe Test., Vol. 3-A, 83:20-84:3; *see also* Koppe Test., Tr. Vol. 4-A, 115:18-25 (If "half of all the outage time that's occurring is eliminated by the projects and the effect of all the other equipment in the unit stays the same, … then the availability of the unit as a whole increases, and it increases specifically because the projects have eliminated boiler tube leaks in these sections and have eliminated the effects of pluggage.").

264. There is no question that these increased hours of operation were accompanied by more heat input. Annual heat input increased from 42,326,578 MMBtu per year in the baseline period to 47,660,058 MMBtu per year in the post-project period. Sahu Test., Tr. Vol. 5, 112:17-20.

265. Similar increases are shown in Ameren's certified CEMS data, which show that Unit 2 operated more hours and emitted more pollution per hour during the relevant post-project period as compared to the baseline period. The CEMS data show that Unit 2's operating time

increased by 123 hours per year, from 8,478 hours per year in the baseline to 8,601 hours per year in the applicable post-project period. Furthermore, when it was operating, Unit 2 emitted 456 more pounds per hour of SO_2 than it had in the baseline (increasing from 3,371 pounds per hour in the baseline to 3,827 pounds per hour in the post-project period). Knodel Test., Tr. Vol. 1-A, 109:7-16, 111:8-20, 112:3-10, 113:1-21.

266. Ameren's CEMS data also show that in 2011, the first calendar year after the 2010 boiler upgrade, Rush Island Unit 2 emitted more SO_2 than it had in any year since 1995. Knodel Test., Tr. Vol. I-A 82:9-19. During the applicable period of highest post-project emissions, Unit 2 emitted 16,458.1 tons per year of SO_2, which is 2,171 tons per year more than Unit 2 actually emitted during the baseline period. Sahu Test., Tr. Vol. 5, 74:15-18, 78:9-12, 112:25-113:3; Knodel Test., Tr. Vol. 1-A, 97:11-98:5.

267. Because all of the availability losses and outage hours caused by the reheater, economizer, and air preheater in the baseline were eliminated (243 EFPH and 146 outage hours), and it only takes an additional 21 hours of operation for Rush Island Unit 2 to emit 40 tons of SO_2, at least 40 tons of the overall increase in emissions at Unit 2 are related to the increased equivalent availability and operating hours enabled by the replacement of these components. Sahu Test., Tr. Vol. 5, 80:13-84:4, 115:10-116:4, 165:15-25.

C. Emissions Increases Based on Unit 2 Capability Analyses

268. In addition to improving the availability of both units, the 2010 boiler upgrade should have been expected to increase the capability of Rush Island Unit 2. As described further below, because Unit 1 experienced a capability increase after the 2007 boiler upgrade, Ameren should have expected – and did expect – a similar increase to occur after the 2010 boiler upgrade at Unit 2. Koppe Test., Tr. Vol. 3-B, 19:20-25.

1. The expected capability and efficiency impact of the Unit 2 boiler upgrade

269. In October 2007, Ameren engineers noted that Unit 1 had experienced an increase in capability due to the boiler component replacements, and Rush Island Supervising Engineer Gregory Vasel asked the Plant's Performance Engineer James Bosch to quantify that increase: "I looked at the 2006 [project justification] for the U2 economizer, reheater, and lower slope, and it projects *no* increase in capacity. I asked Mr. Bosch to quantify the capacity increase we've realized on U1, as well as the aux power reduction we're seeing with running one of our ID fans in low speed. … I communicated this to Leo Reid, who is working on the [project justification] for Bob Schweppe." Vasel Email (Pl. Ex. 130), at AM-02635983 (emphasis in original); Koppe Test., Tr. Vol. 3-B, 12:17-13:4.

270. Mr. Bosch reviewed full load tests from before and after the Unit 1 outage and determined that there had been a 19 MW increase in Unit 1's gross capability (from 611 MW to 630 MW). Pl. Ex. 130, at AM-02635983. Ameren project engineer Leo Reid incorporated a "16MW increase in generating capacity" into an updated financial analysis for the Unit 2 project. *Id*. at AM-02635982. In assessing what caused the capacity increase, Mr. Vasel instructed Mr. Bosch to look at the "delta P reductions of the [air preheater] vs. ([reheater] + economizer) …" *Id*. at AM-02635981. The updated financial analysis was provided by Mr. Vasel to Ameren's Director of Power Operations Robert Meiners, and was described as the "best information" that the plant had at the time. *Id*.

271. Mr. Koppe reviewed Ameren's full load tests and Plant Information data ("PI data") for Unit 1 and confirmed Mr. Bosch's analysis showing a 19 megawatt increase in capability had occurred at Unit 1. Mr. Koppe also reviewed the Plant Information data and other company documents and confirmed that there was a "dramatic drop" in the differential pressures

in the air preheater and economizer after the Unit 1 boiler upgrade. For example, a graph presented in Ameren's 2008 State of the System meeting indicates a "tremendous reduction" in the air preheater delta P from 14 to 5 inches of water. An air preheater delta P of 14 inches is "extremely high," and a reduction to 5 inches shows that Unit 1's capability was no longer limited by the effects of pluggage. Koppe Test., Vol. 3-A, 22:13-25:4; Vol. 3-B, 13:5-23; 2008 State of the System, Pl. Ex. 15, at AM-00196909; *see also* Sind Test., Vol. 9-B, 26:16-18 (air preheater differential pressures above 11 inches are "extremely high"); Cardinale Dep., July 31, 2014, Tr. 84:3-21; *see* FOF 75, 76 (showing graphs).

272. Ameren subsequently increased Unit 1's capability rating to 630 MW gross. Mr. Bosch reported the results of his quantification of a 19 MW increase in an email dated November 1, 2007. Vasel Email (Plaintiff's Exhibit 130), at AM-02635983. The document officially revising the 2008 capability stated that the increase was based on plant staff's request to reflect performance improvements following the spring 2007 outage during which the reheater, economizer, and air preheaters were replaced. Shelton Test., Tr. Vol. 10-A, 89:10-23.

273. In February 2008, Rush Island Plant Manager David Strubberg gave a presentation at a State of the System meeting in which he discussed the "Future Priorities" for Rush Island. Among the priorities discussed by Mr. Strubberg was a "25-30 MW" capability increase expected as a result of the boiler component and air preheater replacements and a separate 13 MW capability increase expected due to the replacement of the LP turbine. 2008 State of the System (Pl. Ex. 15), at AM-00196628; Koppe Test., Vol. 3-B, at 24:2-25:2.

274. A few months later, in June 2008, Rush Island Superintendent of Operations Andrew Williamson was asked by Ameren's Dispatch Coordinator Steve Schoolcraft to estimate the predicted capability of Unit 2 following the outage. Mr. Williamson noted: "We did

experience a substantial increase on Rush 1 due to increased boiler performance with the new RH/Econ/APHs and should reasonably expect the same for Rush 2." June 2008 Email (Pl. Ex. 267), at AM-02660313. Mr. Williamson predicted that Unit 2's capability would be 625 MW (net), which is about 655 MW (gross), after the outage. Of this, Mr. Williamson predicted that the boiler component replacements at issue, alone, would increase Unit 2's capability to 615 MW (net), or roughly 645 MW (gross), and replacement of the low pressure turbine would add another 12-15 MW. *Id.* at AM-02660307-08; Koppe Test., Tr. Vol. 3-B, 25:3-26:11; Williamson Test., Tr. Vol. 9-B, 40:10-41:2, 41:7-42:1.

275. Later in 2008, Mr. Williamson's prediction that Unit 2 would be able to achieve 625 MW (net) after the work was incorporated into Ameren's 10-Year System Plan, and represented an increase of 44 MW over the capability of Unit 2 at the time. This was the only increase in capability across the entire Ameren system noted in the 10-Year Plan. 10 Year Plan Spreadsheet (Pl. Ex. 251), at "UE" tab (hidden comment to row 20, col. F: "Rush Island unit 2 net output is increased from 581 to 625 (44 MW increase) provided by Steve Schoolcraft"), and "UE Changes" tab (row 54: "Rush Island 2's net output were changed to 625 MW per the plant's request …"); Koppe Test., Tr. Vol. 3-B, 26:16-27:6.

276. As described above, in 2009, Ameren completed an updated financial analysis for the Unit 2 outage. In addition to improvements in equivalent availability, Ameren's updated analysis included a 22.5 MW "projected annual increase … in plant capacity" as a result of the replacement of the reheater, economizer, and air preheater. Financial Analysis for Unit 2 (Pl. Ex. 48), at "Data Entry" Sheet, row 147, col. B & E; Koppe Test., Tr. Vol. 3-B, 28:2-12, 30:4-32:23.

277. The capacity increase input in the financial analysis was based on Ameren's estimate that replacing the economizer, reheater, and air preheater would allow Unit 2 to produce

30 more MW of capacity during the summer and 20 more MW for the rest of the year. The capability benefits were based on the combined effect of all three component replacements, and represented an increase over what Unit 2 was able to achieve during the pre-project period. Koppe Test., Tr. Vol. 3-B, at 27:7-32:23; Pl. Ex. 48, at "Data Entry" Sheet, row 147, col. B & E (formula bar: 0.25*30 + 0.75*20); July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465690 ("30MW gain in summer (3 mos), 20MW gain balance of year from Reheater, Economizer and APH investment"), Pl. Ex. 347, at AM-02637758 (same), June 15, 2009 CPOC Email (Pl. Ex. 895), at AM-02632842 (same).

278. In the Fall of 2009, Ameren also completed updated Full Work Order Authorizations for the replacement of the reheater, economizer, and air preheater. Consistent with previous projections, Ameren engineers described that a "gain of 30 MW in the summer and 20 MW in the winter will be obtained with the combined reheater, economizer, and air preheater replacements." October 15, 2009 Memo (Pl. Ex. 23), at AM-00926323; September 18, 2009 Memo (Pl. Ex. 26), at AM-00954160. Similar statements were made in other Ameren documents. *See, e.g.,* Pl. Ex. 893, at AM-02229417 ("Approximately 30 megawatts of unit capacity will be recovered during the hottest months because of lower gas flow pressure drops through the new economizer and air preheaters.").

279. Based on his review of Ameren's documents and data, Mr. Koppe confirmed that Ameren should have expected, and did expect, an increase in Unit 2's capability of at least 22 MW (gross) as a result of replacing the economizer, reheater, and air preheater. That additional capability would result from eliminating the effects of pluggage and allow Unit 2 to burn more coal per hour. Koppe Test., Vol. 3-B, 33:14-34:1; *see also* Vol. 3-A, 27:18-25, 29:2-8, Vol. 4-A, 46:23-47:18.

280. Ameren should not have expected any sustainable change in gross efficiency as a result of the reheater, economizer, and air preheater replacements. There was no expected efficiency benefits used as an input in the original Unit 2 project justification. The updated project justification included a 0.5% reduction in auxiliary load for the economizer and air preheater replacements, which equates to about 3 MW of net capability. The 3 MW reduction in auxiliary load would improve net efficiency, not gross efficiency, and would not be expected to change the full load heat input of Unit 2. FOF 117. Ameren did not project any decrease in fuel usage as a result of any efficiency changes associated with the component replacements. Koppe Test., Vol. 3-A, 5:13-20, Vol. 3-B, 28:13-29:8, Ex. 110, at AM-02465690 Pl. Ex. 48, at "Data Entry" sheet, at rows 149-152 (no decrease in fuel usage input for auxiliary load reductions).

281. Ameren's best expectation for the effect of the LP turbine on unit efficiency is that it would increase Unit 2's capability by 12 MW, which is the amount that was guaranteed by the vendor. Sind Test., Vol. 9-B, 20:3-12, 26:23-28:3. Ameren's updated financial analysis for the Unit 2 outage estimated that the efficiency improvements associated with the LP turbine would allow Unit 2 to produce 15 more MW of capability. The analysis was based on the assumption that the turbine-related efficiency improvements would allow Unit 2 to produce more megawatts but would not result in the unit burning less coal. Pl. Ex. 48, at "Data Entry" sheet, rows 149-152 (no "decrease in fuel usage" input for turbine replacement) Pl. Ex. 110, at AM-02465690; Koppe Test., Vol. 3-B, at 29:9-32:9.

2. Actual increases in Unit 2's capability

282. Consistent with the results achieved after the Unit 1 project, there was a big improvement in Unit 2 in the air preheater differential as a result of the air preheater replacements, where the differential pressure went from about 15 inches of water to about 5

inches. Koppe Test., Tr. Vol. 3-A, 25:22-27:17; Sind Test., Tr. Vol. 9-B, 25:6-26:2 (Mr. Sind's capacity analysis showed a big decrease in air preheater differential pressure from 13-14 inches to less than 6 inches); Williamson Test., Tr. Vol. 9-B, 44:7-14 (differential pressure of 15 inches indicates "high pluggage").

283. The improvement in the air preheater differential pressure, along with improvements in the other limitations (economizer differential pressure and ID fan suction pressure), meant that Unit 2's capability and ability to burn coal was no longer limited by pluggage after the Unit 2 boiler upgrade. Koppe Test., Tr. Vol. 3-A, 27:18-25, 28:7-14, 29:2-8. During the PSD baseline period, when the unit was experiencing extensive pluggage, the average full load capability of Rush Island Unit 2 was only 620 gross megawatts. FOF 120; Koppe Test., Tr. Vol. 3-B, 35:17-36:4, 45:12-46:5; PX 928 (Rule 1006 summary of full load tests for Unit 2).

284. The increase in capability at Unit 2 was evident as soon as the unit returned to service after the 2010 outage. For example, on May 29, 2010, Ameren conducted a Full Load Test in which Unit 2's gross capability was measured to be 655 MW, exactly as Mr. Williamson had predicted in 2008. Compare May 29, 2010 Full Load Test (Pl. Ex. 236) (655.13 gross megawatts), with June 2008 Email (Pl. Ex. 267), at AM-02660307-08 (predicting 625 net megawatt); Williamson Test., Tr. Vol. 9-B 41:14-16 (confirming that 625 net megawatts equates to 655 gross megawatts); *see also* Sind Test., Tr. Vol. 9-B, 29:19-30:16. A full load test conducted in October 2010, after the unit had been in service for several months following the boiler upgrade, showed even higher capability. The gross capability measured during that test was 664 MW. October 19, 2020 Full Load Test (Pl. Ex. 913). No capability limitations were noted by plant engineers in either test report.

285. Similarly, in October 2010, Ameren performed a test to verify that the new reheater, economizer, and air preheater had satisfied their performance guarantees. Unit 2's capability during the performance test was recorded as about 659 MW (gross). Boiler Performance Test Report (Pl. Ex. 81), at AM-00482381.

286. Ever greater capability was noted among the "Bottom-Line Results" of the Unit 2 outage during the 2010 State of the System Meeting: "679 Gross MWs!" 2010 State of the System (Pl. Ex. 41), at AM-02493751.

287. After the 2010 outage, Ameren also reported a substantial increase in Unit 2's capability to its system operator, MISO, to NERC, and to the Missouri Public Service Commission. Specifically, in September 2010, Ameren reported to NERC that Unit 2's <u>summertime</u> peak capability had increased to 648 MW (gross), 617 MW (net), "due to work completed in the 2010 major boiler outage (replacement low pressure turbines and ***numerous boiler modifications***)." October 27, 2010 MISO Verification Test Data (Pl. Ex. 139), at AM-02663830 (emphasis added). Ameren provided the same information to NERC in September 2010. September 15, 2010 Capability Validation (Pl. Ex. 133), at AM-02645178; *see also* Koppe Test., Tr. Vol. 3-B, 46:6-47:22.

288. Later in December 2010, Ameren responded to a request from the Missouri Public Service Commission to identify any plant upgrades that it expected to result in an increase in the amount of electricity the plant would produce in the future. MPSC Data Request 0257 (Pl. Ex. 222); Koppe Test., Vol. 3-B, 50:22-51:11.

289. Ameren told the Missouri Public Service Commission that the 2010 outage, including the component replacements at issue, would result in a 34 MW increase in Unit 2's capability, which it characterized as having been based on a "significant capacity restoration[]"

of 22 MW and a "true capacity increase[]" of 12 MW. Ameren Resp. to DR 0257 (Pl. Ex. 223); Koppe Test., Vol. 3-B, 51:12-52:22. Joe Sind, the Ameren engineer who performed the analysis supporting Ameren's statements to the Missouri Public Service Commission, confirmed that the reported 12 MW "true capacity increase" was based on the company's best expectation of the impact of the LP turbine replacement on the capability of the unit. Sind Test., Tr. Vol. 9-B, 20:3-12, 27:12-28:3. Mr. Sind's work papers show that his capacity analysis only looked at changes in unit capability and air preheater differential pressures and that he reported increases in capability for other Ameren units where work had been done on air preheaters but no turbine work had occurred. Sind Test., Tr. Vol. 9-B, 22:3-23:17, 25:6-26:2.

290. Mr. Koppe confirmed the increase in capability reported by Ameren to the Public Service Commission was consistent with his review of "thousands of hours of operation at full power." Koppe Test, Tr. Vol. 4-A, at 49:16-23.

291. In its response to the Missouri Public Service Commission, Ameren also reported that a 2.4% efficiency improvement had occurred as a result of the 2010 overhaul, of which 1.9% was due to the LP turbine replacement and 0.5% was due to the reduction in auxiliary load caused by the air preheater and economizer replacements. Dec. 6, 2010 Email re: "Updated DR 0257 Spreadsheet" (Pl. Ex. 216), AM-02757946; Ameren Resp. to DR 0257 (Pl. Ex. 223), at AM-02762954; Sind Test., Tr. Vol. 9-B 26:23-28:3; Finnel Test., Tr. Vol. 10-A, 12:16-13:18. As a result, the increase in capability Ameren reported to the Missouri Public Service Commission was greater than the reported efficiency improvement, which means that Unit 2 would be capable of burning more coal as a result of the 2010 work. Sind Test., Vol. 9-B, 28:6-18; Koppe Test., Vol. 3-B, 52:3-22.

292. Ameren takes its obligation to provide truthful information to the Missouri Public Service Commission seriously. Meiners Rule 30(b)(6) Dep., Oct. 15, 2014, Tr. 19:5-13.

293. Outside of this litigation, Ameren has attributed only 12 MW of the megawatt capacity increase at Unit 2 to the replacement of the LP turbine. Even as recently as a January 2011 email, Mr. Shelton reconfirmed that the 1.9% improvement in efficiency that Ameren reported to the Missouri Public Service Commission equated to 12 MW. Mr. Shelton further stated that while there might be a little more increase, he could not quantify or estimate any such benefit because it would be too uncertain. Shelton Test., Tr. Vol. 10-A, 100:13-101:1, 102:11-103:20; January 21, 2011 Email (Pl. Ex. 935), at AM-02248224.

294. Ameren further raised the capability of Unit 2 after the 2010 boiler upgrade. In December 2010, the gross capacity of Rush Island Unit 2 was further increased to "better reflect the increase in output following the spring 2010 outage in which two new LP turbines were installed and several boiler components were replaced." The July 2011 gross capacity was listed as 641 MW, which was 26 MW greater than the July 2008 capacity, while the December 2011 gross capacity was listed as 653 MW. December 14, 2010 Capability Table (Pl. Ex. 257), at AM-00067232, 67235; Shelton Test., Tr. Vol. 10-A, 92:22-93:15.

295. Mr. Koppe also conducted an analysis of the company's operating data and found a very substantial increase in Unit 2's capability after the 2010 boiler upgrade. Koppe Test., Tr. Vol. 3-B, 5:25-6:3; *id*. at 19:14-19 ("comparing the baseline period to the post-project period, the capability of Unit 2 increased by a large amount"). Mr. Koppe's findings are consistent with Ameren's documents.

296. Mr. Koppe's analysis of the Plant Information ("PI") data focused on those hours in which Unit 2 was operated at "full load," as indicated by the fact that the turbine valves were

wide open, and accepting as much steam as the boiler could produce. Mr. Koppe's approach is consistent with the approach Ameren uses for its full load tests, which are weekly tests done by plant engineers to determine the capability of the units. Koppe Test., Tr. Vol. 3-B, 6:9-7:16, 8:20-9:8; Sind Test., Vol. 9-B, 30:1-7 (during a full load test, the plant is trying to generate as much output as it can).

297. The pre-project period in Mr. Koppe's analysis of the PI data was January 2006 through December 2007, which is the period of time closest to the PSD baseline for which Ameren produced a complete set of data. The capability of Unit 2 during that time was 615 MW. Koppe Test., Tr. Vol. 3-B, 34:2-35:13.

298. The post-project period in Mr. Koppe's analysis of the PI data was October 2010 to August 2011, because that period provided the "best measure … of how much the unit's actual capability had increased" as a result of the project. The post-project capability of Unit 2 was 653 MW (gross). Koppe Test., Tr. Vol. 3-B, 34:16-35:8.

299. Based on the Plant Information data, the overall increase in capability was 38 MW. This is a 6.2% increase in Unit 2's capability. Koppe Test., Vol. 3-B, 49:9-15.

300. Based on his analysis of the PI data, Mr. Koppe determined that 23.3 MW (3.8%) of the increase were related to the component replacements at issue, and 14.7 MW (2.4%) were related to efficiency improvements. The 23.3 MW related to the project at issue resulted in Unit 2 being able to burn more coal per hour. Koppe Test., Vol. 3-B, 34:2-35:13, 49:1-50:18.

301. A similar increase in capability is shown by looking at all of Ameren's full load tests conducted during the PSD baseline period and comparing them to the post-project period. Based on the full load tests, the average capability of Rush Island Unit 2 increased from 620 MW (gross) during the baseline period to 657 MW (gross) during the post-project period, for an

overall increase of 37 MW. Koppe Test., Tr. Vol. 3-B, 35:17-36:4, 45:12-46:5; see also Pl. Ex. 928 (1006 summary of full load tests for Unit 2).

3. Dr. Sahu's emission calculations based on Unit 2's capacity increase

302. As noted above, Dr. Sahu determined that a capability increase of only 1.7 MW at Rush Island Unit 2 will cause a 40 ton per year increase in SO_2 emissions. Sahu Test., Vol. 5, 41:11-14, 46:5-11.

303. Dr. Sahu calculated the emissions associated with an 18-MW increase in capability and determined that Ameren should have expected such an increase to result in an emissions increase of 416.8 tons per year of SO_2. Sahu Test., Vol. 5, 84:5-87:25.

304. The company's project justification documents indicate that it expected Unit 2's capability to increase as a result of the project by more than ten times the amount that would result in 40 additional tons of SO_2 per year. Because the actual and expected increase in capability far exceeded 1.7 MW, and exceeded the 18 MW used in Dr. Sahu's calculations, at least 40 tons of the overall increase in SO_2 emissions are related to the capability increase caused by the replacement of the economizer, reheater, and air preheater at Unit 2. Sahu Test., Tr. Vol. 5, 87:22-25, 97:3-98:16.

4. Nothing in Mr. Caudill's opinions negates Mr. Koppe's calculations of capability increases

305. In contrast with Mr. Koppe, Ameren's capability expert, Mr. Caudill, ignored Ameren's full load tests. He failed to even analyze the performance test that specifically assessed the post-project performance of the boiler upgrades. Although Mr. Caudill reviewed many Ameren performance test reports for turbines, including turbines at plants that are not at issue in this case, he did not review the performance test report for the new reheater, economizer,

and air preheaters that are actually at issue in this case. Caudill Test., Tr. Vol. 10-B, 53:7-54:6; Boiler Performance Test Report (Pl. Ex. 81).

306. Instead, Mr. Caudill simply applied "filters" to the pre- and post-project data that excluded more than 99% of the data in the periods he chose. For instance, the pre-project period he chose included 7,473 hours of data, but he filtered out all but 28 of those hours. Similarly, the post-project period he chose included 14,304 hours, but he filtered out all but 111 hours. Caudill Test., Tr. Vol. 10-B, 67:11-22. The effect of Mr. Caudill's decision to filter out 99% of the operating data was that he only included hours in his capability analysis when the unit was not load limited. Caudill Test., Tr. Vol. 11-A, 4:16-6:4. Rather than assess the actual capability of the Unit 2 boiler, Mr. Caudill excluded all of the effects of pluggage on the boiler's actual capability, including the thousands of hours of data that demonstrated the actual effects of pluggage when the boiler could not produce enough. Koppe Test., Vol. 3-B, 7:17-8:19.

307. Removing Mr. Caudill's filters drastically changes the results of his pre-and post-project comparisons. For instance, at Unit 2, the unfiltered data show that average hourly gross heat input actually increased by over 300 mmBTU per hour and that the maximum hourly gross heat input similarly increased by more than 300 mmBTU per hour. Caudill Test., Tr. Vol. 11-A, 7:10-8:2. Similarly, Mr. Caudill's unfiltered data show that average hourly MW increased by approximately 50 MW and that the maximum hourly megawatts increased by 29 MW. Caudill Test., Tr. Vol. 11-A, 8:3-15 (Caudill Cross Test.).

308. In addition to confirming that Unit 2 was actually operating at higher average hourly heat inputs after the 2010 outage, Mr. Caudill's unfiltered data also confirm that Unit 2 spent significantly more time operating at higher loads following the 2010 outage. For instance, during the pre-project period when Unit 2 was experiencing load limitations due to pluggage, it

spent only 10% of its operating hours at the highest load range identified by Mr. Caudill, with the largest fraction of the operating hours (40%) spent at the second highest load range. By contrast, after the 2010 outage the load range at which Unit 2 operated the most had shifted up to the highest load range identified by Mr. Caudill, with Unit 2 spending 40% of its operating hours at the highest load range after the 2010 outage as compared to 10% before the outage. Caudill Test., Tr. Vol. 11-A, 11:8-13:16. This is exactly what would be expected when a plugged boiler is no longer load limited following an upgrade.

309. Mr. Caudill also expressed an opinion on efficiency. However, his efficiency analysis suffered from at least two fundamental flaws that render it of little to no relevance here. First, Mr. Caudill conceded that his opinions do not address whether the projects were expected to, or did, cause increases in the total annual amount of generation or fuel burned at Rush Island. By analogy, Mr. Caudill explained that his analysis looked at the equivalent of miles-per-gallon rather than looking at the total gallons of fuel used in a year. Caudill Test., Tr. Vol 10-B, 11:20-12:12.

310. Second, Mr. Caudill did not analyze the required NSR pre-and post-project periods. Ameren itself has chosen specific two-year pre-project baseline periods to present in this case for purposes of determining whether its projects violated New Source Review. Vol. 10-B, 30:19-31:12 (Caudill Cross Test.). Yet Mr. Caudill only used approximately one year of pre-project data. And at Unit 2 there was not a single month in the pre-project period that Mr. Caudill used that actually overlapped with the two-year NSR baseline period that is at issue in this case. Caudill Test., Tr. Vol. 10-B, 32:4-33:17.

311. In addition, the time periods Mr. Caudill examined skew his results. For instance, he relied on pre-project periods when efficiency was significantly worse than it was during the

applicable NSR baseline period, effectively making the unit less efficient for purposes of his comparison. Ameren's Exhibit TW demonstrates that during the pre-project period selected by Mr. Caudill, Rush Island Unit 2 had the worst efficiency (i.e., the highest heat rate) in any of the five years leading up to the 2010 outage. Yet Mr. Caudill did not even look at data from those other years. Exhibit TW; Caudill Test., Tr. Vol. 10-B, 42:25-43:19.

D. PROSYM-BASED EMISSIONS CALCULATIONS

312. In addition to Dr. Sahu's translation of the performance improvements calculated by Mr. Koppe into calculations of emissions increases, the United States also presented emissions analyses performed by Dr. Ezra Hausman using Ameren's production cost modeling program.

313. Ameren's experts agree that using results from a production cost modeling run is an appropriate way to forecast future emissions for a New Source Review analysis. King Test., Tr. Vol. 6-B, 66:3-15; Chupka Test., Tr. Vol. 8-B, 80:14-17. In fact, Ameren expert Michael King admitted that he used production cost modeling runs in his New Source Review analyses in prior enforcement cases. King Test., Tr. Vol. 6-B, 66:16-19.

1. Production cost modeling at Ameren

314. "A production cost model is a computer application used to simulate an electric utility's generation system and load obligations." Finnell MPSC Test. (Pl. Ex. 439), at 3:10–11.

315. Ameren regularly uses a production cost model called ProSym to forecast its unit operations for a variety of business purposes, including fuel budgeting and rate case justifications before the Missouri Public Service Commission. Finnell MPSC Test. (Pl. Ex. 439), at 3:11–14; Ringelstetter Test., Vol. 11-B, 12:15–17.

316. Ameren's ProSym model is calibrated with actual load information to check its accuracy as a forecasting tool. Finnell Rule 30(b)(6) Dep., Nov. 22, 2013, Tr. 28:6-20. The calibration shows that the projection runs "come within a fairly high degree of accuracy." Finnell Rule 30(b)(6) Dep., Nov. 22, 2013, Tr. 28:6-29:13. According to Ameren, ProSym "does a good job of modeling the electric system and how it's operated." Finnell Rule 30(b)(6) Dep., Nov. 22, 2013, Tr. 29:2-13.

317. This computer simulation software uses a complex algorithm, but is basically a "supply and demand" model that predicts how the system operator, MISO, will dispatch Ameren's units hour-by-hour for a given period after taking into account various inputs like unit performance projections and load forecasts that Ameren develops as inputs into the program. Finnell Test., Tr. Vol. 9-B, 67:10–11; Hausman Test., Tr. Vol. 4-B, 41:17–23, 44:7–15.

318. As Ameren's witness Mr. Finnell explained, at Ameren, "[t]he fuel budget process involves collecting information from various work groups or [expert] areas in the company for items that are used in the ProSym model. The ProSym model is then executed, and the results are prepared and issued to various groups within the company." Finnell Test., Tr. Vol. 9-B, 66:22–67:1.

319. The fuel budgeting process typically involves forecasting unit operations for five years. Finnell Test., Tr. Vol. 9-B, 70:20- 21.

320. Ameren's modeling runs show how unit performance improvements interact with rising system loads or other market factors to affect unit operations. Hausman Test., Tr. Vol. 4-B, 40:7–12; Ringelstetter Test., Tr. Vol. 11-B, 56:10-21.

321. Jaime Haro, Ameren's manager in charge of load forecasting and risk management, testified at trial he had worked with the company's modeling department, and

confirmed that Ameren's modeling resources could be used to perform sensitivity analyses and investigate how different scenarios might impact operations at Ameren's units. Haro Test., Tr. Vol. 9-A, 133:1–14.

322. The inputs used by ProSym in simulating dispatch and operations can be divided into two types: market factors and unit characteristics. Hausman Test., Tr. Vol. 4-B, 42:13–17.

323. Market considerations that are input into ProSym include things like hourly load data—e.g., load forecasts for the market Ameren serves—as well as fuel costs, off-system market data, and system requirements. Finnell MPSC Test. (Pl. Ex. 439), at 3:3–5; Hausman Test., Tr. Vol. 4-B, 42:21–43:15.

324. Unit characteristics that are supplied for the model include measures of the unit's efficiency (also called its "heat rate" as it describes how much heat or fuel it takes for the unit to produce each unit of electricity), the unit's maximum capacity, the unit's projected availability, and other physical constraints such as how long it takes the unit to ramp up to full load if it is taken offline for any reason (its "ramping constraints"). Hausman Test., Tr. Vol. 4-B, 43:21–44:3.

325. As used by Ameren, the model takes into account two measures of unit availability when it projects unit operations: a unit's "forced outage rate," and its "partial outage rate." Hausman Test., Tr. Vol. 4-B, 52:25–53:20.

326. The forced outage rate is a measure of time that the unit was able to run at any level. So, in a non-leap year, it would be the number of hours the unit could run divided by 8,760, the number of hours in a year. Hausman Test., Tr. Vol. 4-B, 53:2–6.

327. The partial outage rate is the model's input for deratings. It is the percentage of actual available generation divided by the total available generation from the unit assuming

every available hour could have been loaded at full power. Hausman Test., Tr. Vol. 4-B, 53:9–15.

328. Adding the forced and partial outage rates of a unit together gives you the "effective unit outage rate." To determine a unit's equivalent availability factor, one subtracts the effective unit outage rate from 1. Hausman Test., Tr. Vol. 4-B, 53:16–54:9.

2. Dr. Hausman's sensitivity analyses

329. After investigating Ameren's modeling files, Dr. Hausman identified several performance improvements that Ameren modeled at its Rush Island plants concurrent with the boiler upgrade work at issue in this case. Hausman Test., Tr. Vol. 4-B, 47:19–48:2.

330. Dr. Hausman executed "sensitivity analyses" using Ameren's production cost modeling files to determine how the performance improvements at the Rush Island Units were impacting the modeling projections for those units' operations. Hausman Test., Tr. Vol. 4-B, 47:19–48:2.

331. A sensitivity test is a standard modeling technique whereby a modeler runs a computer simulation multiple times, varying only one input or parameter a little bit each time in order to investigate how that single element interacts with the rest of the system being modeled. Hausman Test., Tr. Vol. 4-B 46:24–47:8.

332. Dr. Hausman's sensitivity analyses revealed straightforward, linear relationships between unit capacity or unit availability and the unit's projected fuel use—and, accordingly, pollution levels. Hausman Test., Tr. Vol. 4-B, 55:20-56:19, 63:20-64:20, 65:22-66:7, 71:7-25, 72:12-21.

333. As shown below, any one of the performance improvements that Ameren modeled at the Rush Island units following the boiler upgrades would result in a concomitant

increase in fuel use that would translate into a pollution increase well above the 40 tons-per-year threshold for SO_2 to trigger New Source Review. Hausman Test., Tr. Vol. 4-B, 73:11–21.

a. Unit 1 sensitivity analysis

334. For Unit 1, Dr. Hausman reviewed a credible fuel budgeting modeling run performed in 2006 in order to evaluate how performance improvements following the 2007 projects at Unit 1 would be projected to affect operations and pollution. The model run he used was contemporaneously performed by the company when Ameren was planning the Unit 1 work, the modeling files were complete (allowing for replication and verification of the results), and the inputs presented credible, long-term forecasts without "red flags" such as artificial constraints or other indications that would suggest the model run was used for a different purpose or did not reasonably reflect company expectations. Hausman Test., Tr. Vol. 4-B, 68:4-16 & 97:15–98:1; *see also* Finnell Test., Tr. Vol. 10-A, 5:23–8:23 (discussing Plaintiff's Exhibit 892 and updates to Ameren's 2006 fuel budget modeling).

335. Comparing the year before the work was performed to the year after it was completed, Ameren modeled a 4% increase in equivalent availability following the boiler upgrades—a 2.2% improvement in the unit's forced outage rate and a 1.8% improvement in the unit's partial outage rate. Hausman Test., Tr. Vol. 4-B, 69:16–22.

336. Dr. Hausman determined that a one percentage point improvement in Unit 1's forced outage rate would translate into an additional 481 billion BTUs of fuel consumption per year and an additional 162 tons of SO_2 per year. Hausman Test., Tr. Vol. 4-B, 71:19-23.

337. Dr. Hausman also found that reducing Unit 1's partial outage rate (deratings) by one percentage point would result in an additional 408 billion BTUs of fuel consumption per year and an additional 138 tons of SO_2 per year. Hausman Test., Tr. Vol. 4-B, 72:12–21.

b. Unit 2 sensitivity analysis

338. For Unit 2, Dr. Hausman reviewed Ameren's "Original" 2010 Fuel Budget modeling run performed in early 2010 in order to evaluate how performance improvements following the 2010 projects at Unit 2 would be projected to affect operations and pollution following that work. That model run was used by Ameren's environmental services department to perform its "reasonable possibility analysis" for that work. Hausman Test., Tr. Vol. 4B, 49:6–10; Hutcheson Test., Vol. 11-A, 38:22-39:1.

339. Dr. Hausman determined that each additional megawatt of increased unit capacity at Unit 2 will result in that unit burning an additional 69 billion BTUs per year and an additional 23 tons of SO_2 per year. Hausman Test., Tr. Vol. 4-B, 59:24–60:2.

340. Dr. Hausman also found that a one percentage point improvement in the unit's forced outage rate would translate into an additional 566 billion BTUs per year and, as a result, an additional 189 tons of SO_2 per year. Hausman Test., Tr. Vol. 4-B, 64:15–20.

341. A one percentage point improvement in Unit 2's partial outage rate would translate into an additional 466 billion BTUs per year and, as a result, an additional 156 tons of SO_2 per year. Hausman Test., Tr. Vol. 4-B, 64:15–20.

3. Dr. Hausman's "with and without" analyses

342. In addition to his sensitivity analyses, Dr. Hausman also performed a "with and without" analysis using Ameren's ProSym model. A "with and without" analysis is a standard modeling technique used throughout the industry and in many fields that employ computer modeling. It compares two scenarios—one in which the performance improvements Ameren expected were realized (the scenario Ameren itself modeled), and another scenario in which the

units simply continued operating as they had in the past, without realizing any performance improvements as a result of the modifications. Hausman Test., Tr. Vol. 4-B, 25:12–18, 74:5–7.

343. This technique allows the modeler to look at the impact of one change (or set of changes) in the system while holding all else constant. Hausman Test., Tr. Vol. 4-B, 25:16–19 & 74:7–12.

344. Ameren's experts conceded that utilities often run a production cost model twice, changing just one variable, in order to see how changing that variable would impact the output of the model. King Test., Tr. Vol. 6-B, 67:14-19; Chupka Test., Vol. 8-B, 79:18-81:2. As Ameren expert Marc Chupka testified, the type of with-and-without modeling analysis that Dr. Hausman did in this case is a "standard tool" in utility modeling practice. Chupka Test., Tr. Vol. 8-B, 80:18-22.

345. Ameren expert Michael King agreed that the difference between two estimates of future emissions – one of which accounted for the project and one of which did not – would show the impact of the project. King Test. Tr. Vol. 6-B 69:7-71:23.

346. In his testimony in a prior NSR enforcement case, Ameren expert Michael King performed two modeling runs to identify the emissions that he testified were unrelated to the project and should be excluded from an NSR calculation under the demand growth exclusion. King Test. Tr. Vol. 6-B 65:17-21. In other words, Mr. King used the same technique in that case that Dr. Hausman did here (except Mr. King set out to identify the emissions that were *unrelated* to the project, while Dr. Hausman identified the emissions *related* to the project).

347. Similarly, Ameren expert Marc Chupka testified that one way to perform an NSR emissions analysis would be to (1) start with a contemporaneous emissions projection that

incorporates the effect of the project; (2) compare that projection to the baseline period; and then (3) address any unrelated factors. Chupka Test., Tr. Vol. 8-B, 81:3-24.

a. Unit 1 analysis

348. For Unit 1, Dr. Hausman's with-and-without analysis compared the ProSym modeling forecasts performed by Ameren in 2006 to another version in which the unit did not increase its availability by 4% following the work.

349. The comparison revealed that, but for the performance improvements modeled at the unit, Rush Island Unit 1 would have operated 192 fewer hours, the unit would have burned over 1,600 billion BTUs less coal, and it would have emitted 562 fewer tons in the year he examined. Hausman Test., Tr. Vol. 4-B, 79:23–80:7.

350. Based on Ameren's updated 2006 fuel budget modeling, the company projected that it would emit as much as 15,561 tons per year of SO_2 in the five years after the project, a 687-ton increase above baseline levels. Of that projected increase in emissions, 562 tons would not have been projected were it not for the availability improvements modeled at Unit 1. Hausman Test., Tr. Vol. 4-B, 80:10–21.

351. Dr. Hausman also used Ameren's Plant Information data to develop inputs based on the putative performance improvements in the company's Plant Information data. Dr. Hausman accepted the data at face value and gave Ameren credit for a 3.0% efficiency improvement (more than Ameren reasonably should have or did expect) and also incorporated a 20-MW increase in Unit 1's capacity. Hausman Test., Tr. Vol. 4-B, 81:1–3.

352. Using these inputs from the company's Plant Information data and re-running his with-and-without analysis, Dr. Hausman found that Ameren would have projected a 716-ton

increase above baseline pollution levels, of which 591 tons would not have been projected but for the performance improvements at the unit. Hausman Test., Tr. Vol. 4-B, 81:3–6.

b. Unit 2 analysis

353. For Unit 2, Dr. Hausman compared the ProSym modeling forecasts performed by Ameren to another version in which the unit did not increase its capacity by 18 MW and improve its availability by 2% following the work. The performance improvements represented by Ameren in this model are consistent with the performance improvements that Mr. Koppe independently determined the company should have expected to result from the boiler work. Hausman Test., Tr. Vol. 4-B, 82:21–24. The comparison revealed that, without the performance improvements modeled at the unit, Rush Island Unit 2 would have operated 96 fewer hours, the unit would have burned nearly 1,600 billion BTUs less in coal, and it would have emitted 746 fewer tons of SO_2 in the year he examined. Hausman Test., Tr. Vol. 4-B, 75:18–76:5.

354. Based on Ameren's "original" 2010 fuel budget modeling, the company projected as much as 16,816 tons per year of SO_2 in the five years after the project, a 2,528-ton increase above baseline levels. Of that projected increase in emissions, 746 tons would not have been projected were it not for the performance enhancements modeled at Unit 2. Hausman Test., Tr. Vol. 4-B, 76:22–77:6.

355. As with Unit 1, Dr. Hausman reviewed Ameren's Plant Information data to develop inputs based on the putative performance improvements contained in the company's data. Once again, Dr. Hausman accepted the Plant Information data at face value. Thus, Dr. Hausman gave Ameren credit for an efficiency improvement (4.2%) that exceeded what it reasonably should have or did expect, and also incorporated a 34 MW increase in capacity (a 5.75% increase). Hausman Test., Vol. 4-B, 79:6–8.

356. Using these PI-inputs and re-running his with-and-without analysis, Dr. Hausman concluded that Ameren still would have projected a 1,905-ton per year increase above baseline pollution levels, of which 696 tons would not have been projected but for the performance improvements at the unit. Hausman Test., Tr. Vol. 4-B, 78:21–79:2.

IV. AMEREN HAS FAILED TO MEET ITS BURDEN TO ESTABLISH THE APPLICABILITY OF THE DEMAND GROWTH EXCLUSION

357. Ameren pled as its Twenty-Sixth Affirmative Defense that any emissions increases following the 2007 and 2010 outages at Rush Island Unit 1 or Unit 2 were the result of increased demand and not the projects at issue. Answer (ECF No. 250), at 31.

A. Background about the Market for Rush Island's Generation

358. The Midcontinent Independent System Operator ("MISO") serves as the dispatch operator for Ameren's Rush Island units. Hausman Test., Tr. Vol. 4-B, 33:24–34:1.

359. As a dispatch operator, MISO aims to meet system demand with the lowest-cost—though still reliable—portfolio of electricity generation it can. "[G]eneration owners tell the dispatch operator what's available and at what price. And then the dispatch operator uses a computer algorithm to find the lowest cost way of meeting load." Hausman Test., Tr. Vol. 4-B, 33:19–23, 34:2–9.

360. "MISO's job is to find the lowest cost way of meeting that demand. And the way they do that is they start by turning on the lowest cost sources of energy first. Those are often nuclear or coal units like the Rush Island units. And then they progressively turn on more and more costly generators to run until at every moment the energy being generated is balanced with the load required by the system." Hausman Test., Tr. Vol. 4-B, 31:14–21.

361. As a general matter, electricity cannot be stored, so—at least when considering the system as a whole—electricity production and demand must be constantly balanced. Hamal Test., Tr. Vol. 9-A, 98:11–13. That does not mean, though, that electricity production and demand are the same thing. As with every market, the electricity market has a demand side and a supply side—and just because demand for electricity may be rising does not mean that any specific generating unit will be used to serve that rising demand. Hamal Test., Tr. Vol. 9-A 41:24–42:8.

362. The Rush Island units cannot generate—and so cannot serve demand—if they are unavailable. And Ameren cannot offer generation it does not have to the market: if a Rush Island unit was forced offline because of some mechanical failure, Ameren would not be able to offer Rush Island generation into the MISO market. Similarly, when Rush Island units are load limited or derated for some reason, Ameren cannot offer the unavailable portion of its generating capacity to the MISO market. Hamal Test., Tr. Vol. 9-A, 40:21–41:7; Naslund Test., Tr. Vol. 6-B, 13:24-14:5; King Test., Tr. Vol. 6-B, 52:24-53:6 (demand and availability are both necessary in order for a unit to operate).

363. Furthermore, in general, MISO cannot call on Ameren's units to provide more electricity than Ameren has offered into the market. Hamal Test., Tr. Vol. 9-A, 41:10–14; Hausman Test., Tr. Vol. 4-B, 35:6–9.

364. Ameren does not need MISO's permission to bring a unit offline if it has experienced a tube leak or other failure at the unit. Hamal Test., Tr. Vol. 9-A, 41:17–20; Hausman Test., Tr. Vol. 4-B, 35:10–12.

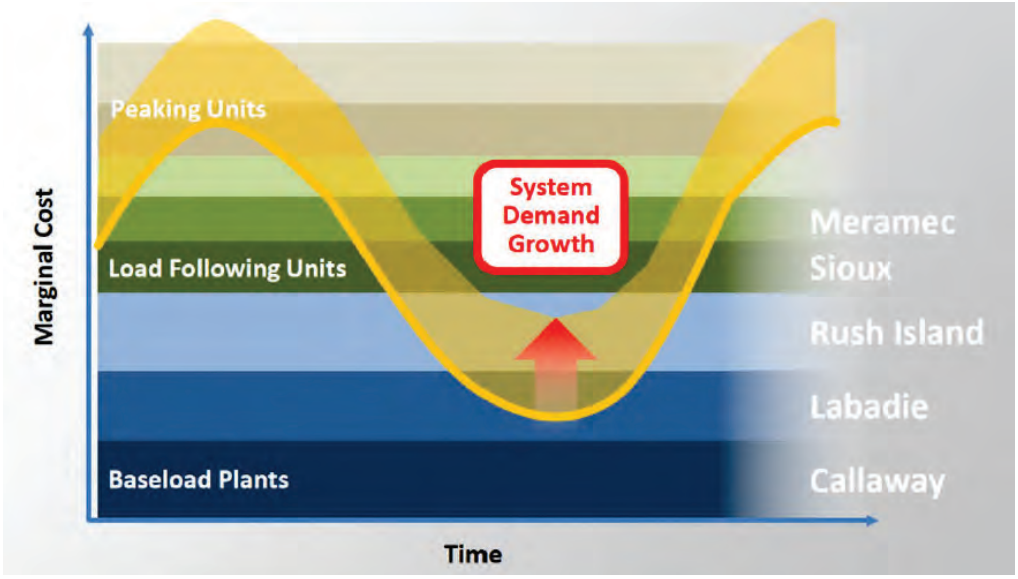
365. MISO does not tell generation owners like Ameren how to spend their capital improvement budgets or how to improve their generation services. Hamal Test., Tr. Vol. 9-A,

41:21–23; Hausman, Tr. Vol. 4-B, 35:13–19; Meiners Test., Tr. Vol. 7-B, 57:17-58:13. Ameren controls the engineering of its units and decides what maintenance work needs to be performed and when to perform that work. Hausman Test., Tr. Vol. 4-B, 36:3–6; Meiners Test., Tr. Vol. 7-B, 57:17-58:13. By controlling the maintenance of and investment in the Rush Island generating units, Ameren manages those supply assets to ensure that they can serve as much market demand as they can. Hausman Test., Vol. 4-B, 35:23–36:21.

366. MISO does not pay bonuses to generation owners when their units perform well or reliably. Hausman Test., Tr. Vol. 4-B, 35:20–22.

367. "Rush Island has low operating cost[s]. MISO's job is to run the system as efficiently as possible, and that translates into MISO doing what it can to get Rush Island to run more." Hamal Test., Tr. Vol. 9-A, 37:20–23. As a natural corollary, if Ameren is able to make the Rush Island units able to operate more hours or at higher loads, then MISO would call on them to make use of that new-found capability. Hamal Test., Tr. Vol. 9-A, 51:22–52:17.

368. Jaime Haro, Senior Director of the Ameren's Enterprise and Commodity Risk Management Department, described how the Rush Island units compare to other units in Ameren's generating portfolio by providing a generalized schematic of the "merit order" or "dispatch order" of its various plants. Haro Test., Tr. Vol. 9-A, 130:14 – 132:9; Hausman Test., Tr. Vol. 4-B, 31:14–32:22. At the bottom of the schematic are units that cannot shut down and are the cheapest to run, such as Ameren's Callaway nuclear plant. Next up to be dispatched are other baseload coal units such as the Rush Island generating units that run basically whenever they are available. Haro Test, Vol. 9-A, 65:1–66:1; Tr. Vol. 6-A, 55:4-7.



[Ameren Demonstrative WC_2]

369. Coal units like Rush Island are expensive to shut down, and it takes hours—sometimes as much as a day—to start them back up. Hamal Test., Tr. Vol. 9-A, 45:10–15. As such, the Rush Island units may ramp down their generation through the night or during other periods of low system load, but they generally do not turn off. Hamal Test., Tr. Vol. 9-A, 46:7–23; Haro Test., Tr. Vol. 9-A, 131:7–12.

370. As illustrated by Ameren's schematic, the general impact of an increase in system demand is that the Rush Island units might ramp down a little later at night than they otherwise would, or ramp up to high loads a little earlier in the mornings than they otherwise would. Haro Test., Tr. Vol. 132:2–9.

371. As Mr. Haro testified, though, when load is up, as it often is during the "on peak" hours shown with relatively high prices at the left and right hand side of the graphic, the Rush Island units are typically generating as much as they can. Haro Test., Tr. Vol. 9-A, 131:1–15.

Obviously, if the unit is already fully loaded, it cannot increase its output in order to serve more of the market's demand for electricity. Hamal Test., Vol. 9-A, 58:16–17.

372. In general, the Rush Island units are more likely to be running fully-loaded during "on peak" hours than "off peak" hours. Hamal Test., Tr. Vol. 9-A, 59:3–5, 59:17–19. Even according to Ameren's expert's analysis, only a third of the hours the Rush Island Unit 2 operated with some available capacity to spare were "on peak" hours. Thus, according to Ameren's expert, Unit 2 was at maximum capacity for more than half of all hours in the baseline period—and more than two-thirds of all "on peak" hours in the baseline period. Ringelstetter Test., Vol. 11-B, 40:10 – 15; Def. Demonstrative TK-15.[3]

373. This relationship is borne out in Ameren's modeling files. For example, as is evident in Ameren's modeling efforts performed in 2006, even when the company forecast system load to increase each year, the Rush Island units were projected to generate at essentially flat levels throughout the forecast period. As Dr. Hausman explained, this clearly indicates the Rush Island Units are baseload units, and they are more or less insensitive to variations in system load. Hausman Test., Tr. Vol. 4-B, 45:20–22.

B. Ameren's Failure of Proof Regarding Demand Growth as a Cause of Increased Emissions

374. In the company's 2011 Corporate Social Responsibility Report, Ameren characterized the projects at issue in this case as "necessary to respond" to increased demand. Naslund Test., Tr. Vol. 6-B, 16:12-15, 18:3-5; Corporate Social Responsibility Report (Pl. Ex.

---

[3] Even this number appears to understate how often the units were run at their "available capacity." Ms. Ringelstetter's analysis does not accurately reflect those hours when the unit was ramping up after coming offline. She counted those hours as having "available capacity" even though the units would have been physically incapable of generating more during that time. Ringelstetter Test., Vol. 11-B, 69:3–70:15.

431) at AM-00510618. In other words, Rush Island could not have served at least some of the increasing system demand *without* the Rush Island upgrade projects.

375. To the extent that system demand was growing, as of 2008, Ameren expected that its purchase of three combustion turbines (natural gas units), would satisfy that demand growth until at least 2018. Naslund Test., Tr. Vol. 6-B, 15:14-16:11.

376. To the extent that system demand was growing, Ameren did not offer any evidence at trial to show how changes in system demand, if any, would or did specifically impact the operation of and emissions from the Rush Island units. For example, Ameren utility market expert Cliff Hamal admitted that he did not quantify "how demand would change Rush Island's operations in any way." Hamal Test., Tr. Vol. 9-A, 39:23–40:5.

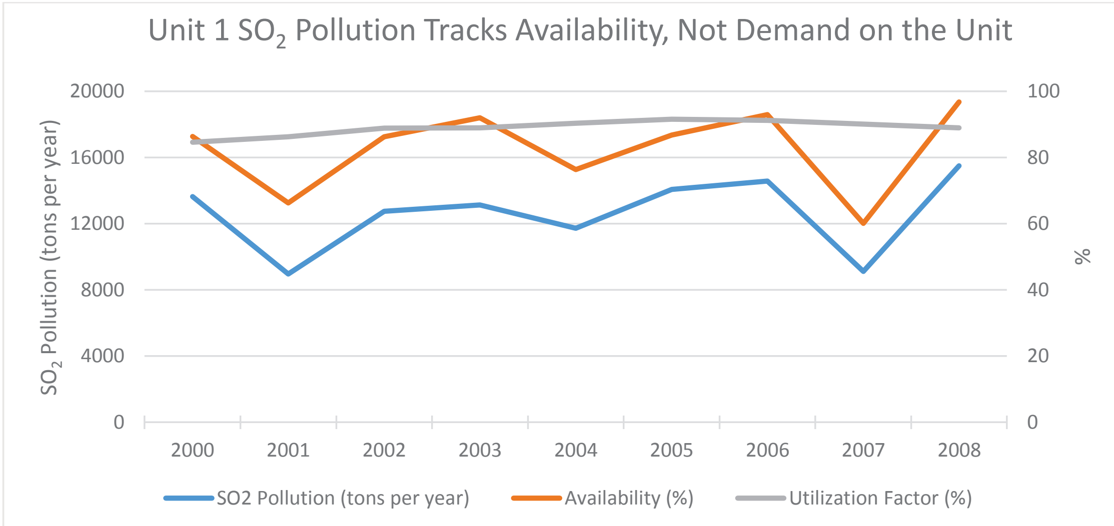
377. The industry does have a standard measure that isolates demand for the output of individual generating units. That metric is known as the "utilization factor," and Ameren itself uses it during the course of its business. Sahu Test., Tr. Vol. 5, 56:18-57:3, 76:15-22; Ringelstetter Test., Tr. Vol. 11-B, 80:18-81:6; Economic Evaluation of Plant-upgrading Investments (Pl. Ex. 241), at AME_RHK000011-12 ("loading order [is] reflected in the utilization factor") (EPRI Report, Vol. 1); Availability Worksheet (Pl. Ex. 250), at Spreadsheet Tab "Instructions" (utilization factor is the "percent of mwhrs used after outages and derates").

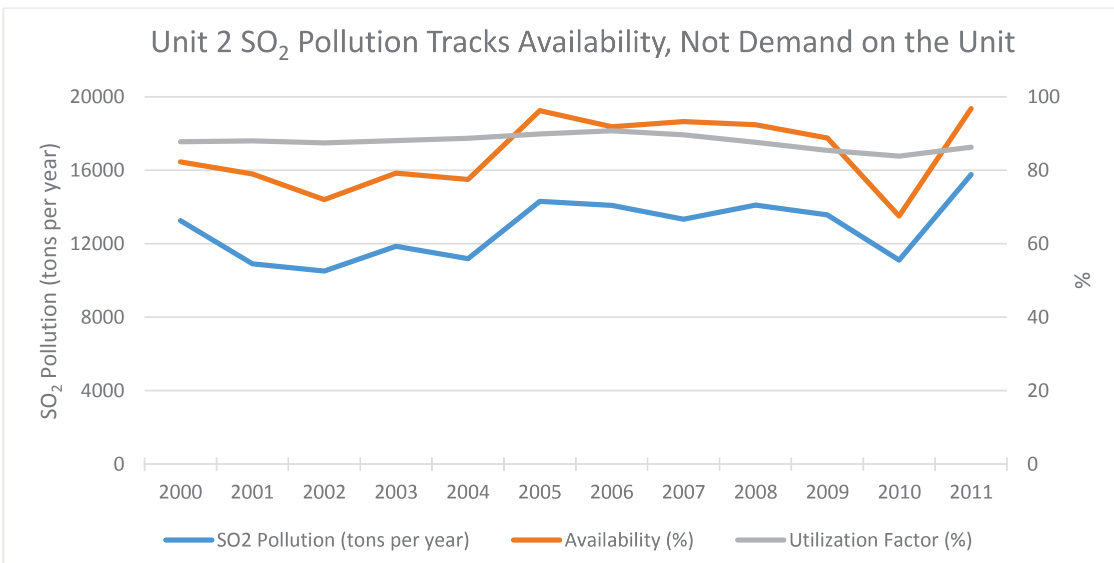
378. Ameren expert Michael King testified that demand for the generation of coal units had been decreasing since 2007 due to falling natural gas prices. King Test., Tr. Vol. 6-B, 34:20-35:3, 35:8-16. Mr. King also testified that the utilization factors for the Rush Island units have been declining since around 2007. King Test., Tr. Vol. 6-B, 87:13-24. Mr. King further explained that if the utilization factor is decreasing, any emissions increases during that time period cannot be the result of increased demand. King Test., Tr. Vol. 6-B, 88:3-6, 89:9-12.

379. Ameren expert Sandra Ringelstetter calculated utilization factors in this case and found that the utilization factor for Unit 1 was projected to remain basically constant and in fact decreased from 91.18% in the baseline period to 89.66% in the applicable post-project period. Ringelstetter Test., Tr. Vol. 11-B, 83:4–15; Def. Ex. NE, at "RI U1 2007 Summary" tab. As a result, any increase in generation that was projected to occur and was in fact realized at Unit 1 following the 2007 outage cannot be attributed to increased demand.

380. For Unit 2, Ms. Ringelstetter calculated that Unit 2's utilization was projected to increase slightly (about 2%), but that it in fact decreased from 91.45 in the baseline period to 89.37 in the relevant post-project period. Ringelstetter Test., Tr. Vol. 11-B 81:7-83:3; Def. Ex. NE, at "RI U2 2010 Summary" tab. As a result, the more than 15% increase in emissions that was projected to occur and that was in fact realized at Unit 2 following the 2010 boiler upgrades cannot be attributed to increased demand.

381. At Rush Island, emissions of SO_2 track availability of the units more closely than demand. Sahu Test., Tr. Vol. 5, 103:5-107:19; *see also* King Test., Tr. Vol. 6-B, 86:2-23 (Ameren expert conceding the relationship between availability and SO_2 pollution at Rush Island).





382. Ameren did not offer any evidence to explain how an increase in emissions associated with an increase in capacity at Rush Island can be caused by demand growth.

V. AMEREN'S NSR EMISSION ANALYSES

383. Ameren called two witnesses at trial from its Environmental Services Department: Steven Whitworth and Michael Hutcheson. Mr. Whitworth was the Supervisor of the Air

Quality section within Ameren's Environmental Services Department from 2002 to 2007. In 2007, Mr. Whitworth became Department manager, which meant that he has ultimate responsibility over the entire Environmental Services group. Whitworth Test., Tr. Vol. 11-A, 90:4-9. Mr. Hutcheson works for Mr. Whitworth and was the Ameren employee responsible for performing the NSR emissions calculations that Ameren presented at trial. Hutcheson Test., Tr. Vol. 11-A, 34:2-35:2, 54:20-55:11, 63:9-15.

384. Ameren does not have any internal guidelines for performing a New Source Review analysis. Hutcheson Test, Tr. Vol. 11-A, 65:21-24.

385. The Environmental Services Department at Ameren is responsible for determining New Source Review applicability. Environmental Services does not have any role in Ameren's capital project justification process. Naslund Test., Tr. Vol. 6-B, 19:20-23, 20:7-18.

386. Project justification packages include a document called the Project Risk Management Plan. Schweppe Dep., May 20, 2014, Tr. 112:2-7.

387. Robert Schweppe was Director and later Managing Supervisor of the Project Engineering group at Ameren. Prefatory Statement to Depo Designation, Vol. 6-A, 19:9-11; Project Approval Package (Pl. Ex. 1), at AM-0072586. Mr. Schweppe signed off on the Project Risk Management Plan for the major component replacements at issue for both Unit 1 and Unit 2. Project Approval Package (Pl. Ex. 1), at AM-00072606 (Unit 1 boiler components); Project Approval Package (Pl. Ex. 3), at AM-00072841 (Unit 2 boiler components); Project Approval Package (Pl. Ex. 4), at AM-00072864 (Unit 1 air preheater); Project Approval Package (Pl. Ex. 6), at AM-00072923 (Unit 2 air preheater).

388. Each Project Risk Management Plan lists whether certain risk factors have been addressed, followed by a series of check boxes. One of the check boxes is for

"Legal/Environmental." For each of the projects at issue, the Legal/Environmental box was not checked. Pl. Ex. 1 at AM-00072606; Pl. Ex. 3 at AM-00072841; Pl. Ex. 4 at AM-00072864; Pl. Ex. 6 at AM-00072923.

389. Mr. Schweppe testified that he did not know why the Legal/Environmental box was not checked, and that he did not "recall that box ever being checked" for "any project risk plan." Mr. Schweppe continued that he did not know what the box meant and that he had never asked anyone to understand what it meant. Schweppe Dep., May 20, 2014 Tr., 112:14-114:5.

A. Ameren Performed No Pre-Project NSR Analysis for Either Project

1. Rush Island Unit 1

390. Ameren has admitted that it performed no emission calculations for purposes of determining PSD applicability prior to undertaking the 2007 project at Unit 1. Whitworth Test., Tr. Vol. 11-A, 94:23-25; Boll Test., Tr. Vol. 8-B, 38:3-5; Birk Dep., Sept. 24, 2013, Tr. 220:14-21; *see also* Knodel Test., Tr. Vol. 1-A, 88:10-12; Ameren Closing Arg., Vol. 12, 51:18-20.

391. Mr. Whitworth, the Head of Ameren's Environmental Services department, testified at trial that the only pre-project emission evaluation he did for Unit 1 was a non-numerical analysis that considered only whether the Unit 1 project would increase the unit's potential to emit. Mr. Whitworth also admitted that he relied on an inapplicable provision of the Missouri regulations. Whitworth Test., Tr. Vol. 11-A, 88:16-25, 90:12-15, 90:20-92:19; *see also* Boll Test., Tr. Vol. 8-B, 9:7-13:25 (company relied on non-numerical evaluation of whether project would have an impact on maximum continuous rating), 38:3-14.

392. Ameren's Environmental Services Department did not communicate with project engineer David Boll at any time prior to the Unit 1 project completion in 2007. Boll Test., Vol. 8-B, 39:17-21, 40:6-9.

393. The Rush Island Plant Manager at the time of the 2007 outage was Robert Meiners. As plant manager, he was accountable for making sure the plant complied with environmental regulations. Meiners Test., Tr. Vol. 7-B, 64:2-5. However, Mr. Meiners had no communications with anyone about whether to seek a New Source Review permit for the Unit 1 project. When asked whether he understands that PSD requires utilit[ies] to make a prediction of future emissions in order to do [] emissions analys[es], Mr. Meiners replied "That's not – not my responsibility. I'm not involved with it." Meiners Dep., April 8, 2014, Tr. 342:11-17. In fact, Mr. Meiners testified that throughout his more than 40-year career at Ameren, he never had a single discussion with anyone about whether or not to seek an NSR permit for any capital project at all. Meiners Test., Tr. Vol. 7-A, 68:2-18 and Vol. 7-B, 64:2-20. Similarly, Mr. Strubberg testified that he was not involved in any assessment of whether the projects triggered PSD. Strubberg Test., Tr. Vol. 8-A, 73:17-74:5.

394. Prior to undertaking the Unit 1 project, Ameren did not communicate with permitting authorities about whether a New Source Review permit would be required. Whitworth Test., Tr. Vol. 11-A, 106:3-7.

2. Rush Island Unit 2

395. The Head of Ameren's Environmental Services department, Mr. Whitworth, testified at trial that the only pre-project emission evaluation he did for Unit 2 was a non-numerical analysis that considered only whether the Unit 2 project would increase the unit's potential to emit. Mr. Whitworth also admitted that he relied on an inapplicable provision of the Missouri regulations. Whitworth Test., Tr. Vol. 11-A, 88:16-25, 90:12-15, 90:20-92:19.

396. The Ameren employee who was responsible for doing NSR calculations for Unit 2 was Michael Hutcheson. Mr. Hutcheson testified that he did not review any EPA or

Missouri Department of Natural Resources guidance specifically as part of his work for the project at issue. Hutcheson Test., Tr. Vol. 11-A, 65:25-66:2.

397. Mr. Hutcheson admitted he had no personal knowledge of the project or whether the effects of the project were included in the projections he relied upon.

a. Mr. Hutcheson testified that in performing the company's NSR analysis, he did not speak to any of the engineers who planned and developed the project. He received information from his superiors in the Environmental Services Department, but he did not know the source of that information. Hutcheson Test., Tr. Vol. 11-A, 63:5-19.

b. Mr. Hutcheson also testified that he did not review any of the project justification documents for the work. Hutcheson Test., Tr. Vol. 11-A 63:20-25.

c. Mr. Hutcheson did not know whether the modeling runs that he relied on for his analysis included any projected improvements in capacity or availability. Mr. Hutcheson did nothing to check the validity of the modeling runs he received, but simply "took them on their face." Hutcheson Test., Tr. Vol. 11-A, 65:4-20; Hutcheson Dep., April 24, 2014, Tr. 118:20-119:5.

d. Mr. Hutcheson testified that he did not consider whether availability was expected to improve as a result of the projects because he did not think that information was "relevant" or "necessary." Hutcheson Test., Tr. Vol. 11-A, 82:16-25.

398. Mr. Hutcheson performed two purported NSR analyses for the Rush Island Unit 2 project – the "Original" Reasonable Possibility Analysis and the "Amended" Reasonable Possibility Analysis. Neither analysis was completed before the project work started. Knodel Test., Tr. Vol. 1-A, 88:13-18; Whitworth Test., Tr. Vol. 11-A, 96:12-23, 97:2-15; Hutcheson

Test., Tr. Vol. 11-A, 84:15-17, 85:3-8. Mr. Hutcheson's analysis relied on a ProSym model run the company performed that had been completed in January 2010, after the outage had begun. Hutcheson Test., Vol. 11-A, 38:22-24. The Original Reasonable Possibility analysis was not completed until after the project had begun. Mr. Hutcheson admitted that the analysis *should* be completed before beginning construction. Hutcheson Test., Tr. Vol. 11-A, 56:1-7; 84:15-85:2; *see also* Knodel Test., Tr. Vol. 1-A, 88:24-89:3.

399. Mr. Hutcheson began working on the Original Reasonable Possibility Analysis only after Ameren's legal department requested analyses of about 20 projects, including the Rush Island Unit 2 project. Some of the projects he was asked to analyze had already occurred and some were planned for the future. Hutcheson Test., Tr. Vol. 11-A, 34:2-23.

400. Although the Unit 2 project was originally approved in 2005 and re-approved by Ameren's Board of Directors and CEO on August 14, 2009 (FOF 136, 137), Mr. Hutcheson did not even begin collecting information relevant to his NSR analysis until November or December 2009. Hutcheson Test., Tr. Vol. 11-A, 84:11-14.

401. Ameren's "Original" ProSym modeling run was not completed until January 2010, after the 2010 outage had begun. The original case was used to develop the corporate budget for 2010. Finnell Dep., Nov. 22, 2013, Tr. 79:2-8. After the 2010 outage was complete, Ameren ran two other modeling cases, including the "EDF" case. Finnell Test., Tr. Vol. 10-A, 9:25-10:5. The EDF case was completed in early 2011. Finnell Test., Tr. Vol. 10-A, 10:3-5. The EDF case was the same as the "Original" case, but was modified to include efficiency improvements. Finnell Dep., Nov. 22, 2013, Tr. 77:12-20. The EDF case was used by environmental services to perform the Amended Reasonable Possibility Analysis. Finnell Dep., Nov. 22, 2013, Tr. 76:4-79:8; Hausman Test., Tr. Vol. 4-B, 87:11-14.

402. Ameren's Original Reasonable Possibility analysis "projected" that Unit 2's emissions of SO_2 would increase by 2,531.15 tons per year, from 14,287.73 in the baseline period to 16,818.88 tons per year in the highest projected post-project period. Hutcheson Test., Tr. Vol. 11-A, 40:22-41:2; Knodel Test., Tr. Vol. 1-A, 91:10-17; Def. Ex. C at Tab Net Emissions Change; *see also* Pl. Ex. 493, at AM-02231873, at "projected Emissions" tab (showing even higher projected SO_2 emissions of 17,018 for Unit 2 in 2012).

403. Ameren excluded every ton of the projected emissions increase on the basis that Unit 2 was capable of accommodating all of the increases in the baseline. Ameren provided no other reason for excluding the projected emissions increases in its Original Reasonable Possibility Analysis. Knodel Test., Tr. Vol. 1-A, 91:10-17. Mr. Hutcheson stated that there was no mechanism in his spreadsheet (Def. Ex. C and D) to account for whether the projected increase was related to the project. He testified that the relatedness question was a "qualitative" one not a "quantitative" one. Hutcheson Test., Tr. Vol. 11-A, 80:22-81:3.

404. Ameren did not rely on any guidance or applicability determinations in making their capable of accommodating determination. Whitworth Test., Tr. Vol. 11-A, 102:3-8, 103:24-104:3.

405. In late 2010, well after Ameren had completed the Unit 2 boiler upgrade, Mr. Hutcheson was asked by Ameren's in-house counsel, Susan Knowles, to revise his analysis. Hutcheson Test., Tr. Vol. 11-A, 85:3-11; Naslund Test., Tr. Vol. 6-B, 18:14-19; Hutcheson Dep., April 24, 2014, Tr. 115:2-12. Mr. Hutcheson used the EDF case to perform the Amended Reasonable Possibility Analysis. Hutcheson Dep., April 24, 2014, Tr. 117:10-20; Hausman Test., Tr. Vol. 4-B, 87:11-14.

406. Mr. Hutcheson completed the Amended Reasonable Possibility Analysis in early 2011, almost a year after the Unit 2 project had begun, and then only after EPA had issued a Notice of Violation to Ameren and after this lawsuit had been filed. Knodel Test., Tr. Vol. 1-A, 92:14-24, 93:15-19; Hutcheson Test., Tr. Vol. 11-A, 55:2-56:9, Def. Ex. D; RFA No. 7.

407. Mr. Hutcheson was asked to perform the Amended Reasonable Possibility analysis in order to incorporate a 2.4% efficiency improvement expected from the 2010 outage. No efficiency improvement had been incorporated into the Original Analysis. Mr. Hutcheson was not asked to make any other changes to the inputs into the analysis, such as changes that reflected the full extent of the capacity or availability improvements at Unit 2. Hutcheson Dep., April 24, 2014, Tr. 115:13-23; 117:10-20.

408. Ameren's expert, Mr. King, testified that he would not perform an NSR analysis based on a modeling run that was created just for NSR purposes. Mr. King agreed that in using such a run, a source runs the risk of looking like it is "cooking the forecast" to project no emissions increase. King Test., Tr. Vol. 6-B, 67:20-68:13.

409. Even with the changes made to the efficiency input, Ameren's Amended Reasonable Possibility Analysis still "projected" an increase of SO_2 emissions of 2,059.30 tons per year. Knodel Test., Tr. Vol. 1-A, 93:3-5; Def. Ex. D. As with its original analysis, Ameren excluded every ton of the projected emissions increase on the basis that the unit was capable of accommodating those emissions in the baseline period. Ameren provided no other basis for excluding those emissions increases. Knodel Test., Tr. Vol. 1-A, 93:6-14.

B. Ameren's Post Hoc Reasonable Possibility Analysis is Substantively Flawed

1. Ameren's calculations fail to model all of the performance improvements expected from the boiler upgrades

410. Ameren's Reasonable Possibility Analysis was based on its computer simulations performed for fuel budgeting purposes in January 2010. Those simulations include an 18 MW increase in Unit 2 capacity and a 2% improvement in unit availability—resulting in a 95% EAF—for the unit following the boiler work at issue in this case. *See* FOF 338, 353.

411. But project justification documents developed in 2009 projected significantly better performance at Unit 2 following the work. The CPOC report relied on a 22.5 MW increase in unit capacity as a result of the boiler work, as well as a 4.2% improvement in availability—resulting in a nearly 97% EAF—for the unit following the upgrades. *See* FOF 157, 158, 253.

2. Ameren's capable of accommodating approach

412. Ameren calculated the emissions the unit was capable of accommodating before the project by using the amount of time the unit was available to operate and multiplying that by the 95th percentile emissions rate (in pounds per hour). Hutcheson Test., Tr. Vol. 11-A, 41:3-17, 47:20-48:6, 68:16-24. Mr. Hutcheson calculated the 95th percentile emissions rate in Def. Ex. C, Tab Sheet1 and the results are shown in columns X and Y of the tab. Hutcheson Test., Vol. 11-A, 46:18-47:1.

413. Mr. Hutcheson's use of the 95 percentile emissions rate was not based on anything in the New Source Review rules. Hutcheson Test., Tr. Vol. 11-A, 69:13-70:5. Nor was it a standardized practice within Ameren. In fact, he used a 97th percentile emissions rate for nitrogen oxides for the same project. Hutcheson Test., Tr. Vol. 11-A, 78:3-22; Def. Ex. C at Tab RI U2 W2010 Detail.

414. In selecting the emissions rate for the capable of accommodating analysis, Mr. Hutcheson wanted to pick a rate that was "representative of what the unit could accommodate in

the baseline." The value he picked was in the top five percent of emissions rates that the unit achieved during the baseline period and that the median value would have been the 50th percentile. He also testified that he "would have no doubt" that there could be a big difference between the 95th percentile value and the 50th percentile value. Hutcheson Test., Tr. Vol. 11-A, 70:12-71:11.

415. Mr. Hutcheson did not look to see whether Unit 2 actually ran at the 95th percentile value for even 24 hours. Hutcheson Test., Tr. Vol. 11-A, 73:8-11.

416. The 95th percentile calculation that Mr. Hutcheson said was a representative emissions rate for Unit 2 actually included several hours in which Unit 2 was emitting at a rate well over what is allowed by its permit. Def. Ex. C at Tab Sheet1 (Column L, Rows 4563-4574 and 4590-4591); Hutcheson Test., Tr. Vol. 11-A, 73:12-21.

417. By using the 95th percentile emissions rate, Ameren calculated it would have accommodated about 17,550 tons of SO_2. Hutcheson Test., Tr. Vol. 11-A, 67:5-16. That much annual pollution would be more than Unit 2 had emitted since 1995, when the units were required to make reductions under the Acid Rain program. Declaration of Steven Whitworth (Pl. Ex. 926), at p. 10; Hutcheson Test., Tr. Vol. 11-A, 67:20-68:6; Knodel Test., Tr. Vol. 1-A, 56:1-4.

418. Mr. Hutcheson testified that had he used an average SO_2 emissions rate rather than the 95th percentile rate, it would "essentially be recalculating the baseline." Hutcheson Test., Vol. 11-A, 47:12-14. This is incorrect. Ameren's capable-of-accommodating calculation is based on the unit's *availability*, not on the actual operation. It calculates the additional emissions impact from running every hour the unit was available.

419. Had Mr. Hutcheson used the 50th percentile value for the SO_2 rate, even Ameren's flawed analysis would show the project triggered New Source Review. This can be seen from Def. Ex. C. Column Y on Sheet1, which has the results of the 95th percentile calculation. The calculation is linked to the ultimate emissions calculation set forth in Tab Net Emissions Change. Hutcheson Test., Vol. 11-A, 76:8-24; Def. Ex. C.

420. When clicking on the interactive formula bar for Cell Y8 in Tab Sheet1, the user can change .95 to .5 and thus run the calculation using the 50th percentile. After doing so, the Net Emissions Change tab automatically changes: the capable-of-accommodating number becomes 197 tons, the net change (the emissions increase) becomes 2,334 tons, and the spreadsheet indicates that the project triggers New Source Review. Def. Ex. C at Tab Net Emissions Change (Columns E, G, and I).

3. No analysis of relatedness

421. Mr. Hutcheson testified that to assess whether the increase was related to the project he talked to several people including his boss, Ken Anderson, and Steven Whitworth, the

head of the Environmental Services Department. None of the engineers who planned the outage were involved. Hutcheson Test., Tr. Vol. 11-A, 81:4-16.

422. Mr. Hutcheson testified that they discussed the heat rate, maximum design rate of the boiler, and SO_2 emissions rate. They concluded that those characteristics would not change due to the projects and thus any increase was not related to the projects. Hutcheson Test., Vol. 11-A, 49:17-50:21.

423. In performing the New Source Review analysis for Unit 2, Mr. Hutcheson did not look at whether availability was expected to increase as a result of the project. He testified that if the unit was capable of accommodating additional demand, "the availability is not necessarily relevant" and that it "wasn't necessary" to look at availability for his analysis. Hutcheson Test., Vol. 11-A, 82:16-25.

424. In contrast to Mr. Hutcheon's trial testimony, Ameren in fact uses availability predictions as part of its process to determine how much coal to buy. The company does so because the more available a unit like Rush Island is, the more it will generate and the more coal it will need. Naslund Test., Tr. Vol. 6-B, 11:6-16.

425. Ameren also used availability in the *baseline* as the basis for its capable of accommodating calculations. As Mr. Hutcheson explained, the company looked to availability to determine what the unit was capable of generating before the project. Hutcheson Test., Tr. Vol. 11-A, 44:9-14, 87:4-12.

426. In Rule 30(b)(6) testimony, Steven Whitworth, the head of Ameren's Environmental Services Department, testified as Ameren's corporate representative. Mr. Whitworth testified that he believed emissions that a unit was capable of accommodating are per se unrelated. In the Rule 30(b)(6) deposition, Whitworth testified that, "The emissions that the

unit was capable of accommodating prior to the outage would be totally unrelated to . . . any activities that occurred on the outage. So just by the nature of the scope, the emissions are unrelated." Whitworth Rule 30(b)(6) Dep., Dec. 4, 2013, Tr. 38:4-12; Whitworth Test., Tr. Vol. 11-A, 101:19 – 102:2.

C. Nothing in Ms. Ringelstetter's Analyses Excuses Ameren's Failure to Perform Appropriate NSR Projections

1. Ms. Ringelstetter failed to address relatedness for either unit

427. Changes in availability would affect how much the unit was projected to generate. Ringelstetter Test., Tr. Vol. 11-B, 78:3–9.

428. Changes in unit capacity would affect how much the unit was projected to generate. Finnell Test., Tr. Vol. 10-A, 9:7–10.

429. Ms. Ringelstetter examined selected ProSym modeling files and observed that Ameren projected changes in the Rush Island units' availability and capacity following the boiler work at issue in this case, but testified that those changes had nothing to do with the boiler work. *See*, *e.g.*, Ringelstetter Test., Vol. 11-B, 56:10–15.

430. Ms. Ringelstetter noted that the maximum capacity at Rush Island Unit 2 was projected to be 11 MW above baseline levels following the boiler upgrades, but she attributes the capacity increase entirely to the LP turbine work performed in 2010. Ringelstetter, Vol. 11-B, 17:20–24 & Ameren's Summary Exhibit XF_2 (indicating 11 megawatt increase).

431. However, her baseline capacity number is not a measure of the unit's actual performance based on operating data; rather it is a reported number that tracks Ameren's Capability Tables. Ringelstetter Test., Tr. Vol. 11-B, 73:12–74:9.

432. Ameren's documents and witnesses stated that the company's 2005 Capability Tables were "unrealistically high" and were later adjusted downward significantly in February, 2006. Finnell Test., Tr. Vol. 10-A, 5:23–8:23 (discussing Plaintiff's Exhibit 892 and updates to Ameren's 2006 fuel budget modeling which show adjustments from the "unrealistically high" 610 MW to values between 581-596 MW). Since Ameren's selected baselines for both units include substantial amounts of 2005, Ms. Ringelstetter's 11 MW number significantly understates the projected capacity increase at Unit 2 compared to Ameren's documents and data. FOF 157, 289, 299, 300, 301.

433. Ms. Ringelstetter further testified that Ameren's ProSym models projected an increase in availability at each unit following the boiler upgrades, but stated that the increase is not substantial enough to appear to be a meaningful difference, and so discounts it entirely for her emissions assessment. Ringelstetter Test., TR. Vol. 11-B, 17:4–12.

434. Ms. Ringelstetter discounted these increases even though the availability forecast for Ameren's economic justification of the work at Unit 2 was fine-tuned to the tenth of a percent, and even that tiny variation meant hundreds of thousands of dollars dropped out of the analysis. June 15, 2009 Email (Pl. Ex. 895), Meiners Test., Tr. Vol. 7-B, 34:9-35:25.

435. Ms. Ringelstetter offered no opinion on how—if at all—the projects at issue in this case would have been expected to change the operations of the Rush Island units. Ringelstetter Test., Tr. Vol. 11-B, 59:23–60:3.

436. Nor did Ms. Ringelstetter offer any independent opinion on whether or to what extent the low pressure turbine replacement that occurred at Rush Island Unit 2 alongside the boiler modifications had any impact on unit operations or performance. Ringelstetter Test., Tr. Vol. 11-B, 60:4–9.

437. As such, all of her emissions analyses—and all of the emissions she concludes should be excluded from the emissions projection—rest on the assumption that *none* of the projected emissions increases were caused or enabled by the projects at issue in this case. Ringelstetter, Tr. Vol. 11-B, 18:9–11 & 22:2–9.

438. When she developed her calculations for her expert report, Ms. Ringelstetter believed it was *irrelevant* whether the projects at issue in this case resulted in performance improvements. Rather, by her calculations, the only thing that mattered for the demand growth exclusion was whether the unit "could have accommodated" the projected emissions levels during the baseline. Ringelstetter Test., Tr. Vol. 11-B, 77:2–17.

2. Ms. Ringelstetter's Unit 1 analysis relies on faulty assumptions

a. Background regarding ancillary services

439. Ancillary services are things other than simple electric generation that utilities provide to keep the electric grid operating reliably. Generally they involve promises that certain amounts of generation will be held in reserve or would be dedicated to real-time adjustments in response to market fluctuations. When a unit was providing some ancillary services, it would typically not be operating at its full capabilities. Hamal Test., Tr. Vol. 9-A, 23:4–6; Haro Test., Tr. Vol. 9-A, 99:21–100:13.

440. On January 1, 2007, Ameren Missouri entered into a short term contract to provide ancillary services to its Illinois affiliates. Def. Ex. HX. That contract was to last "from January 1, 2007 until the earlier of (i) December 31, 2007, or (ii) the date during calendar year 2007 on which the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") ancillary services market for Ancillary Services is operational." Def. Ex. HX at 1.

441. The short-term contract was later renewed when the launch of MISO's ancillary service market was further delayed. Haro Test., Tr. Vol. 9-A, 133:24–134:7.

442. The contract did not specify how much of the ancillary services described in the contract would be provided by Rush Island units or how often the units would be assigned to provide those services. Def. Ex. HX at Article 3, § 3.1.1 and Schedule A.

443. As of January 2009, ancillary services such as regulation hours and spinning reserves were offered into—and cleared through—MISO's ancillary services market. Hamal Test., Tr. Vol. 9-A, 43:10–12; Ringelstetter Test., Tr. Vol. 11-B, 95:10–14.

444. As Mr. Hamal explained: "In order to provide [ancillary services], you can't be at full load. You have to back off. You have to be at partial load. And so when prices are really high, I'd rather have a high-cost unit at partial load than a low-cost unit." Hamal Test., Vol. 9-A, 24:11–15.

445. The Rush Island units would not be expected to provide ancillary services once MISO's ancillary service market was implemented. Ameren's contract for ancillary services was never intended to extend beyond when MISO's ancillary services market started up in 2009. Haro Test., Vol. 9-A, 102:1-14, 134:4-7.

446. The MISO ancillary services market helped optimize the provision of ancillary services like regulation and spinning reserves: "it allow[ed] MISO to look at the fact that not only is that unit providing regulations, but it's not providing energy. So if that's a low-cost unit providing regulation, there may be a high-cost unit that could provide that regulation and save the system money overall." Hamal Test., Tr. Vol. 9-A, 24:5–10.

447. Since the Rush Island units are relatively-low cost units that run all the time, (Hamal, Tr. Vol. 9-A, 26:16–17), the implementation of the MISO ancillary services market

meant they would be "held back" little if any to provide ancillary services once those services were cleared through the market system. Hamal Test., Tr. Vol. 9-A, 24:20–24.

448. Ameren's chief modeler, Mr. Timothy Finnell, explained that in order to model ancillary services like regulation hours or spinning reserves in ProSym, Ameren would inflate a unit's partial outage rate, thereby depressing the unit's availability in the model. That would, in effect, lower the output of the units that were assigned to regulation in the model. Finnell Test., Tr. Vol. 9-B, 99:3–7; *see also* Ringelstetter Test., Tr. Vol. 11-B, 62:4–63:17.

449. Mr. Finnell admitted that assigning units regulation hours or ancillary services in the model would affect how much generation they were expected to produce and how much coal they were expected to burn in the forecast years. Ameren modeled ancillary services by increasing a unit's partial forced outage rate. Increasing the forced outage rate results in reduced generation and coal burned in the model. Finnell Test., Tr. Vol. 9-B, 99:3–100:19.

450. In 2008, Mr. Finnell, then head of Operations Analysis in Ameren's Corporate Planning Department and in charge of the company's ProSym modeling, testified before the Missouri Public Service Commission about how the sale of ancillary services impacted the company's business forecasts:

> Q. Is AmerenUE selling ancillary services to the utility operating subsidiaries owned by Ameren Corporation in Illinois?
>
> A. Yes, for 2008, AmerenUE is selling 39 MW of spinning reserves and 68 MW of supplemental reserves to Illinois affiliates.
>
> Q. Does the PROSYM model include the sales of ancillary services to these Illinois utilities?
>
> A. No. The sales of these ancillary services were not included because they are based on a short-term contract that will end when the MISO ancillary service market begins.

Finnell MPSC Test. (Pl. Ex. 439), at 12:16–23.

451. Neither of Ameren's two experts hired to discuss dispatch and market issues quantified how the provision of ancillary services influenced Rush Island operations before the projects were performed or once the modifications were completed. Mr. Hamal "didn't get into the details and quantify how much regulation Rush Island did," focusing instead on the general market structure. Hamal Test., Tr. Vol. 9-A, 44:3-5. Ms. Ringelstetter, despite offering an opinion that Ameren's modeling of ancillary services was "entirely appropriate," (Ringelstetter Test., Tr. Vol. 11-B, 66:4–6), did not mention ancillary services, regulation hours, or spinning reserves in her expert report, nor was she aware of any "specifics" regarding Ameren's short-term ancillary service agreements. Ringelstetter Test., Tr. Vol. 11-B, 66:10–67:10.

b. Ms. Ringelstetter's modeling choice

452. For the analysis in which she concludes that projected emissions would not increase following the Unit 1 modification work, Ms. Ringelstetter uses a ProSym modeling effort that includes two artificial adjustments.

453. First, the ProSym modeling run that Ms. Ringelstetter used when assessing the 2007 project at Rush Island 1 included an input for that unit which was intended to reflect its provision of ancillary services. Despite the short-term nature of the services as described above, she used a run where Unit 1 was modeled as holding back 15 MW for regulation hours for *every year* of the model forecast, 2007 through 2012. Ringelstetter Test., Tr. Vol. 11-B, 63:18–64:2; *see* Hausman Test., Tr. Vol 4-B, 97:3-9.

454. Second, Ms. Ringelstetter claims the modeling effort suffered from what she calls a bias in the inputs which requires a downward adjustment to the model's projections. However,

Ameren never performed such an adjustment when it did its own analyses, and in fact other modeling efforts did not suffer from this bias. Hausman Test., Tr. Vol. 4-B, 98:9–99:12.

455. Without either of these adjustments, Ms. Ringelstetter's analysis would show a significant projected increase in Rush Island 1 operations and pollution above baseline levels. Hausman Test., Tr. Vol. 4-B, 99:13–23.

VI. THE 2007 AND 2010 BOILER UPGRADES TRIGGERED TITLE V REQUIREMENTS

456. The Clean Air Act Title V permit for the Rush Island Plant contains a condition restating the requirement that Ameren was prohibited from performing any unpermitted major modifications of Rush Island Units 1 or 2. Declaration of Steven Whitworth (Pl. Ex. 926), at attached Title V Permit, AM-02511339-2511393, at 2511362.

457. Ameren has not obtained a permit for its major modifications, and the Rush Island Title V permit does not incorporate PSD requirements for its major modifications. Pl. Ex. 926, at attached Title V Permit, AM-02511339-2511393, at 2511348-350 (Listing no Unit Specific Emission Limitations for SO_2).

CONCLUSIONS OF LAW

I. OVERVIEW

Under the Clean Air Act's PSD program, an existing source of pollution must obtain a permit and install state-of-the-art emissions controls when the source makes a "major modification." *Ameren SJ Decision*, 2016 WL 728234, at *4. The United States claims Ameren violated the PSD program's requirements by making major modifications to Units 1 and 2 at Rush Island without obtaining applicable permits or installing required emissions controls. The only disputed element of proof is whether the projects performed on Units 1 and 2 were "major modifications" under the law. *See* Subsection II.A (other elements of proof undisputed). To prove a major modification, the United States must show the work at issue was (1) "a physical change or change in method of operation that (2) would result in a significant net emissions increase." *Ameren SJ Decision*, 2016 WL 728234, at *2 (citing 40 C.F.R. §52.21(b)(2)).

For the purposes of the first prong of the test, the term "physical change" is extremely broad, and there is no dispute that the projects were physical changes. *Id.* at *4. But not all physical changes trigger PSD permitting requirements. Routine maintenance, repair, and replacement projects are excluded from the definition of "major modification." *Id.* Ameren argues the challenged Rush Island projects were routine maintenance projects and as a result exempt from being considered "physical changes." Subsection III.A below explains why the challenged projects are not routine maintenance.

For the purposes of analyzing the second prong of the test, Subsection II.B below explains that the projects would be expected to result in—and did result in—a significant net emissions increase. Because the projects were physical changes that would result and did result in a significant net emissions increase, they were major modifications under PSD.

Because the United States has proved the Rush Island projects were major modifications, Ameren violated the PSD provisions of the Clean Air Act because it did not obtain the required permits or meet other PSD requirements before beginning construction. In addition, as explained in Subsection II.C below, Ameren also violated the Title V provisions of the Clean Air Act.

II. THE UNITED STATES PROVED THAT AMEREN VIOLATED THE PREVENTION OF SIGNIFICANT DETERIORATION AND TITLE V PROVISIONS OF THE CLEAN AIR ACT

A. Undisputed Elements of Proof

The only disputed element of proof is whether the projects were major modifications under the law.

There is no dispute that:

- Ameren is a "person" under the applicable law and the owner and operator of the Rush Island facility. 42 U.S.C. 7602(e) and 10 C.S.R. 10-6.020(2); FOF 2.
- Rush Island Units 1 and 2 are each a "major emitting facility," a "major stationary source," and an "electric steam generating unit" under the applicable PSD and Title V provisions. 42 U.S.C. § 7479(1), 40 C.F.R. § 52.21(b)(1) and (b)(31); FOF 13.
- EPA provided sufficient pre-filing notice of the violations to Ameren and the State of Missouri and provided notice of the filing of this case to the State. 42 U.S.C. § 7413(a), (b); FOF 18-21.
- At the time of the projects, Rush Island was in an area designated as attainment for SO_2. 42 U.S.C. § 7471; FOF 11. Therefore the PSD program applies.

B. The Projects Should Have Been Expected to Cause—and Did Cause—Emissions Increases

1. **Legal standard**

There are two ways to establish PSD liability. The United States can satisfy its burden by proving either that: (1) the source should have expected an emissions increase related to the project (the expectations approach); or (2) an emissions increase related to the project actually occurred (the actual emissions approach). *Ameren SJ Decision*, 2016 WL 728234, at *16; *see also* 40 C.F.R. § 52.21(a)(2)(iv)(*b*), (*c*).

Regulations establish how to compare pre- and post-project emissions. The pre-project "baseline" is any 24 consecutive months in the 5 years before the project. 40 C.F.R. §52.21(b)(48)(i). The post-project period is the maximum annual emissions in any one of the five years after the project. 40 C.F.R. §52.21(b)(41)(i). The difference between the baseline and post-project high emissions year is the emissions increase for PSD purposes. An increase of 40 tons or more of SO_2 per year is "significant" under the regulations. 40 C.F.R. §52.21(b)(23)(i). In this case, there is no evidence of any creditable emissions decreases, so any emissions increase proven is the same as the net emissions increase. *See* 40 C.F.R. § 52.21(b)(3).

Under the expectations approach, courts must determine what a source should have expected at the time of the project. To prevail, the United States "must show that at the time of the projects [defendant] expected, or should have expected, that its modifications would result in a significant net emissions increase." *Ameren SJ Decision*, 2016 WL 728234, at *13 (citing cases and quoting *United States v. Ala. Power Co.*, 730 F.3d 1278, 1282 (11th Cir. 2013) (internal quotations omitted)).

Ameren's internal documents are relevant to what the company expected or should have expected. *See*, *e.g.*, *Ala. Power*, 730 F.3d. at 1286-87; *United States v. La. Generating LLC*, 929 F. Supp. 2d 591, 593-594 (M.D. La. 2012) ("The documents clearly show outages were a problem and the company planned to work on the reheaters in order to fix those problems."); *Ohio Edison*, 276 F. Supp. 2d at 834 ("The documents prepared to justify the expenditures described the various purposes of the projects to include replacement of major components to increase the life and the reliability of the units.").

Under the actual emissions approach, the question is simply whether SO_2 emissions actually increased by more than 40 tons per year as a result of the project.

Under either approach, additional operations made possible by a project must be attributed to that project. As EPA has explained, "where the proposed change will increase reliability, lower operating costs, or improve other operational characteristics of the unit, increases in utilization that are projected to follow can and should be attributable to the change." 61 Fed. Reg. 38,250, 38,268 (1996). A series of court decisions have echoed this requirement.

"If an increase in hours of operation is caused or enabled by a physical change, the increased hours must be included" in the projection. *Duke Energy 2010*, 2010 WL 3023517, at *5; *see also Duke Energy 2007*, 549 U.S. at 577-78 (noting regulatory provision that requires assessing number of hours the unit is or probably will be running); *Ala. Power*, 730 F.3d at 1281; *United States v. Cinergy Corp.*, 458 F.3d 705, 710 (7th Cir. 2006) (revitalizing a plant to operate more hours may trigger PSD obligations); *Ohio Edison*, 276 F. Supp. 2d at 834-35 (finding PSD liability for projects that were "intended to result in increased hours of operation as a result of a reduction in . . . forced outages").

Even when there is evidence that emissions will or did increase after a project, a source may demonstrate that the increased emissions should be excluded from PSD review under the "demand growth exclusion." Under the demand growth exclusion, a source must exclude from its calculations:

> any emissions increases that "an existing unit could have accommodated during the consecutive 24–month period used to establish the baseline actual emissions . . . and that are also unrelated to the particular project, including any increased utilization due to product demand growth." 67 Fed.Reg. at 80,277 (codified at 40 C.F.R. § 52.21(b)(41)(ii)(c)).

New York v. U.S. E.P.A., 413 F.3d 3, 31 (D.C. Cir. 2005) ("*New York I*"). After substantial argument about the application of the demand growth exclusion at summary judgment, I explained its application as follows:

> if emissions increase because a project enables the unit to meet previously unmet demand during peak hours, for example, those emissions increases are likely related to the project and therefore do not qualify for the demand growth exemption. . . if the unit undergoes modifications that allow it to run more during the daytime hours tha[n] it could before, it cannot be said that the increased emissions were merely a coincidence or unrelated to the modification.

Ameren SJ Decision, 2016 WL 728234, at *10.

Finally, Congress intended for the PSD rules to "have broad application." *Id*. (citing *Ala. Power Co. v. Costle*, 636 F.2d 323, 399-400 (D.C. Cir. 1979)).

2. **The evidence shows that Ameren should have expected an emissions increase related to each project, and such an emissions increase occurred**

The core facts of this case show that before Ameren performed the challenged projects, problems with the components at issue were limiting the units' performance. Replacing those components would improve performance and result in additional use and pollution. That was what Ameren should have expected before the work began. The evidence shows that is what Ameren *did* expect. The evidence also shows that is exactly what happened.

Two key—and undisputed—characteristics of the Rush Island units underlie the entire discussion of emissions increases. First, the Rush Island units are big sources of pollution. That means even small performance improvements can enable a 40-ton increase in SO_2. For example, there is no dispute that it only takes an additional 21 hours of operations at full power for a Rush Island unit to emit more than 40 tons of SO_2. FOF 190.

Second, the Rush Island units are "baseload" units. FOF 6. They are relatively cheap sources of electricity. FOF 50. The market for electricity, which puts a premium on price, drives these baseload units to operate as much as they can. *Id*. That means the Rush Island units run every hour they are available—and at high or even maximum levels during hours of "peak" demand. FOF 6, 371-372. Moreover, Rush Island's baseload status means that if the units improve their performance in any way that allows them to generate more electricity, the market will call on the units to generate more electricity. FOF 50, 215. As Ameren's retired executive Charles Naslund explained at trial, Ameren plans its coal purchases based in part on availability projections because the company knows that the more available the Rush Island units are, the more they will run. FOF 424. That additional generation requires additional coal—and means additional pollution. FOF 205.

These two facts lead to a logical conclusion: if the Rush Island units are upgraded so they *can* generate more electricity, they *will*. Performance improvements have a direct impact on annual generation and pollution levels. Ameren's witnesses and documents recognize this simple relationship. FOF 424, 427-428, 448. And using Ameren's computer modeling software, United States' expert Ezra Hausman illustrated that a mere one-megawatt improvement in unit capacity would lead to an additional 23 tons per year of SO_2 pollution and that a one percent improvement in unit availability would result in about 150 extra tons of SO_2 per year. FOF 336-337, 339-41. Ameren should have expected the Rush Island boiler upgrades to result in at least an additional 40 tons of SO_2 pollution—and that is exactly what happened.

a. The Koppe-Sahu emissions calculations show a predicted increase at Unit 1 and were confirmed by an actual increase

Before the projects, the components at issue were causing outages and deratings at Unit 1. FOF 47-88. Ameren's availability data showed that the economizer, reheater, lower slope tubes, and air preheater were the predominant cause of availability losses at the unit, so Ameren decided to replace them with redesigned components. FOF 136, 138-139, 222-223. The decision to replace these components was the result of a lengthy and deliberate process and was ultimately approved by a series of managers and executives, culminating with the Ameren parent company CEO. FOF 136, 177. One of the bases of that approval was the expectation that the replaced components would cause *no* outage time for *20 years* following the projects. FOF 38, 145-149. Looking at the unit as a whole, Ameren expected that Unit 1's long-term availability would increase to 95% after the work was done, about a 3% increase compared to the PSD baseline. FOF 228.

The United States' expert Robert Koppe did his own analysis of how the project would affect Unit 1's performance. Mr. Koppe is a power plant engineer who has spent much of his career analyzing the performance of generating units on behalf of utilities and public service commissions using methodologies that courts have consistently found to be reliable. FOF 90-91; *see, e.g., United States v. Cinergy Corp.*, 623 F.3d 455, 459 (7th Cir. 2010); *United States v. Ohio Edison Co.*, 276 F. Supp. 2d 829, 877 (S.D. Ohio 2003). Mr. Koppe analyzed the problems affecting Rush Island during the baseline period and determined what Ameren should have expected to result from the work it did in the 2007 and 2010 outages. FOF 195.

Mr. Koppe started by identifying all the outage hours and deratings attributed to the components at issue during the baseline. He found that the equivalent availability losses due to the four components at issue totaled 336 hours in the baseline period, about half the unit's total outage time.[4] FOF 197, 222. Importantly, Mr. Koppe also looked at the condition of the unit as a whole and the other work performed during the 2007 outage. FOF 197-198. As Mr. Naslund explained at trial, Ameren was working hard to address any potential future problems during the outage. FOF 199. Mr. Koppe concluded that the other work performed during the 2007 outage would prevent availability from declining due to other potential issues. FOF 255. He also

[4] Ameren claims that Mr. Koppe and Dr. Sahu should have accounted for derates differently. This portion of Ameren's criticism has to do with what is known in the industry as a "utilization factor" and whether Mr. Koppe and Dr. Sahu should have used a different utilization factor for deratings than they did for outages, as Ameren's expert Marc Chupka testified he would have done. But Mr. Chupka is an economist, not a power plant engineer, and Dr. Sahu's use of a single utilization factor for both outages and deratings is exactly what the Electric Power Research Institute ("EPRI") has recommended since the 1980s. FOF 210. In fact, except for the purposes of this litigation, Ameren instructs its engineers to do the very same thing. FOF 210.

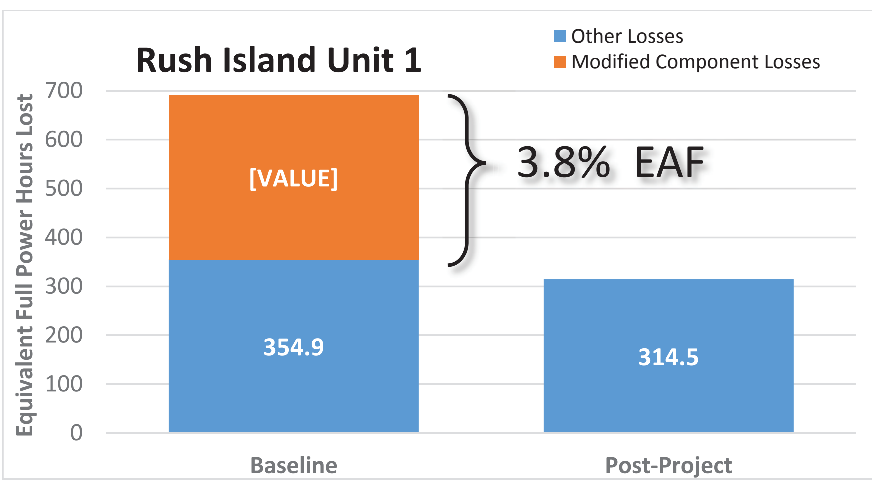
concluded that the project would completely eliminate availability losses from the components at issue and result in an availability improvement of 3.8% from the baseline, bringing Unit 1's availability to about 96% post-project.[5] FOF 224-225, 227. Mr. Koppe concluded—and Ameren witnesses and documents confirm—that availability would not have increased at all if these problematic components had not been replaced. Rather, it would have gotten worse. FOF 227, 231, 239, 255.

Dr. Ranajit Sahu, a permitting engineer and expert for the United States, took Mr. Koppe's findings on expected improved availability and used them to calculate the expected additional pollution that would result from the improvements, using a methodology that has been recognized as industry-standard by several courts. *See, e.g.*, *Ala. Power*, 730 F.3d at 1284-85; *La. Generating*, 929 F. Supp. 2d at 596. Dr. Sahu concluded, as Ameren did, that the company would utilize the regained hours at the same proportion as it had in the past. FOF 206, 208. Based on his and Mr. Koppe's analyses, Dr. Sahu calculated an expected increase in emissions of 608 tons of SO_2 post-project for Unit 1. FOF 232. Because Dr. Sahu's calculation was based on

[5] Ameren argues in its post-trial brief that Mr. Koppe testified that it would not be reasonable to expect the units could achieve over 95% availability post-project because "things happen" and "other components can fail." Ameren then argues that an increase to 95% at Unit 1 is no significant increase at all because Unit 1 had a baseline availability of 94.7%. There are two major flaws with this argument. First, Mr. Koppe did not testify that the units would not be expected to achieve over 95% availability; in fact, he testified that Ameren should have expected "the fairly long-term average equivalent availability" to reach about 95%, but "the best performance post-project" (which is the relevant measure) "would be more like 97 or 98 percent." Koppe Test., Tr. Vol. 3-A, 79:7-14. Second, Ameren's argument that there was no expected significant availability increase only works if its suggested baseline availability figure of 94.7% is accepted. That figure is at odds with Mr. Koppe's well-supported calculation that Unit 1's baseline availability was actually 92.1%. Ameren's calculations appear to be based on the exclusion of certain GADS events from its performance data, but Ameren offered no testimony at trial to support that approach.

the additional operation allowed by the project, the entire predicted increase is related to the work. *Id.*

Post-project results confirm Mr. Koppe and Dr. Sahu's calculations. In 2008, Unit 1 set its record availability with the best availability in the entire Ameren system. FOF 234; *see also* FOF 236. As Mr. Koppe and Ameren both expected, all the outages and deratings due to the replaced components were eliminated. FOF 237. Availability during the highest post-project emissions year reached 96.4%, which is 4.3% higher than the baseline. FOF 238. The entire expected improvement related to the project (3.8%) was realized. That improvement was an order of magnitude more than the 0.3% increase needed to result in 40 additional tons of SO_2. FOF 191. The chart below shows the baseline availability losses caused by the components at issue (orange) and caused by all other factors (blue). After the work was completed, Unit 1's actual availability climbed to 96.4% and it did not experience any losses due to the new components and actual availability. FOF 237–38.



EAF: 92.1% 96.4% (+ 4.3%)

With the availability improvement came an actual increase in emissions of 665 tons of SO_2. FOF 664. Those additional tons were made possible by the availability improvement and are related to the project. FOF 239.

At trial, Ameren sought to exclude any testimony from Mr. Koppe and Dr. Sahu on the cause of the actual increase. As discussed below (*see* Subsection I.A on Evidentiary Issues), I am denying Ameren's motions to strike this testimony because I find that the challenged opinions were properly disclosed. But even without the challenged testimony, the evidence shows an actual and significant net increase of emissions related to the project for both units. Ameren has *not* challenged the admissibility of the testimony by Mr. Koppe and Dr. Sahu that:

- An availability improvement of just 0.3% or an additional 21 hours of operation would cause a more than 40 ton-increase in pollution.
- The work would eliminate all availability losses due to the components, increase overall availability by far more than 0.3%, and increase pollution.[6]
- Post-project data shows those predictions came true: there were no component losses of any kind in the post-project year, availability improved by much more than 0.3%, the unit operated hundreds of hours more, and pollution increased.

FOF 267. Mr. Koppe and Dr. Sahu made a prediction based on improved unit performance, and the actual data confirmed those predictions. As Mr. Koppe explained at trial:

> [If] half of all the outage time that's occurring is eliminated by the projects and the effect of all the other equipment in the unit stays the same . . . then the availability of the unit as a whole increases, and it increases specifically because the projects have eliminated boiler tube leaks in these sections and have eliminated the effects of pluggage.
>
> ***
>
> The causation of what actually happened is obvious from the—from the data.

Koppe Test., Tr. Vol. 4-A, 115:18-25, 4-B, 18:1-4.

[6] Ameren concedes that Unit 1 availability was projected to increase by 1.3%. Ameren Br. at 5 (Doc. 835).

Here, based on the substantial and credible evidence presented showing how the project would cause improvements in availability and, as a result, increase emissions, I am able to find, even without explicit expert testimony, that the predicted cause of the increase was the cause of the actual emissions increases. *See, e.g.*, *United States v. Crenshaw*, 359 F.3d 977, 988 (8th Cir. 2004) (citing *Jackson v. Virginia*, 443 U.S. 307, 319 (1979) (noting court authority "to draw reasonable inferences from basic facts to ultimate facts").

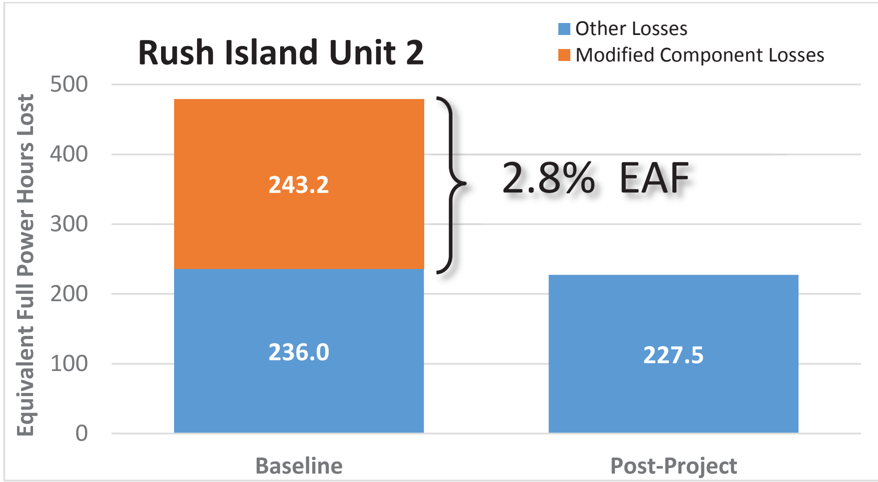
b. The Koppe-Sahu emissions calculations show a predicted increase at Unit 2 and were confirmed by an actual increase

The background story of Unit 2 is the same as Unit 1. Unit 2 had the same problems with the components at issue limiting the unit's availability in the time leading up to the outage. As with Unit 1, Mr. Koppe analyzed the expected impact of the 2010 project on Unit 2's availability. FOF 47–88, 145–47, 197–98. Mr. Koppe found that the outages and deratings at Unit 2 caused by the economizer, reheater, and air preheater resulted in about 245 equivalent lost hours during the baseline, slightly more than half the total lost operating time. FOF 247. As with Unit 1, Mr. Koppe examined the overall condition of Unit 2 and found that other work performed during the outage would prevent availability from getting worse and that the component replacements would result in an availability improvement. FOF 251. For Unit 2, he predicted that the project would completely eliminate all of the losses due to the three components at issue and, by itself, would improve Unit 2's availability by 2.8%. FOF 248, 251. None of these improvements would be possible if Ameren had not replaced the reheater, economizer, and air preheater. Rather, without the project, availability at Unit 2 would have decreased, not increased. FOF 255.

Ameren argued at trial that availability could *never* increase beyond 95%. But former plant manager Robert Meiners agreed with Mr. Koppe and Dr. Hausman that the long-term availability forecast of 95% meant individual years would be as high as 97% or 98%. FOF 257. As noted above, the relevant PSD inquiry compares the baseline emissions to the year with the highest amount of projected emissions in the five-year post-project period. Tellingly, Ameren already knew that Unit 1 set an availability record after the 2007 project of nearly 97% in 2008. FOF 254. When seeking re-approval of the Unit 2 project in 2009, Ameren's engineers explicitly stated they expected Unit 2 to perform "at least equal to, if not better than," Unit 1 and expected a 3–4% availability improvement. FOF 256. Mr. Meiners confirmed this at trial, testifying that the availability input used in financially justifying the Unit 2 outage to senior company executives was almost 97%. FOF 253.

The post-project data shows that Unit 2's availability actually reached 97.4% in the highest year after the project. FOF 260. As Ameren's trial witness Scott Anderson testified after reviewing Unit 2's historic availability statistics, the difference between the pre- and post-project performance was "night and day." FOF 261. Comparing the baseline to the post-project year, Mr. Koppe predicted an availability improvement of 2.8% due to the project alone, and Ameren actually got an improvement of 2.9%. FOF 259. The components at issue caused no availability losses after the project, as Mr. Koppe predicted. *Id.* As with Unit 1, the availability improvements far exceeded the small changes that would cause Unit 2 to emit 40 additional tons of SO_2.

The chart below shows the baseline availability losses caused by the components at issue (orange) and caused by all other factors (blue). After the work, there were no losses due to the new components and actual availability climbed to 97.4%. FOF 259–60.



EAF:	94.5%	97.4% (+ 2.9%)

Based on Mr. Koppe's prediction of regained availability, and using the method described above, Dr. Sahu calculated an expected increase of 415 tons per year of SO_2 in Unit 2 that would result from the availability improvement alone. FOF 258.

Separate from the expected increase in emissions based on availability improvements, Ameren also should have expected an emissions increase at Unit 2 based on capacity improvements. After the Unit 1 outage, Ameren saw a significant *capacity* gain as a result of the project. FOF 269. Ameren and Mr. Koppe both analyzed how a similar capacity gain would affect Unit 2's post-project operation.[7] [8]

There is no dispute that Ameren realized a gain in capacity, measured in megawatts ("MW"), at Unit 1. FOF 269–70, 274. Ameren expected similar improvement at Unit 2. *Id.* In

[7] In addition, Ameren replaced the low pressure turbine during the 2010 outage, which would also be expected to affect performance.

[8] Ameren argues that Mr. Koppe and Dr. Sahu's analyses double count the effect of deratings already accounted for in its availability analysis in its capacity analysis, but Dr. Sahu clearly presented separate emissions calculations for the availability and capacity increases. FOF 258, 302-303. *See also* US Br. at 26 n.16 (Doc. 838).

a series of company documents from Fall 2007 until the time of the overhaul, Ameren engineers repeatedly stated that significant capacity increases (of up to 30 MW) would result from the boiler work. FOF 269–78. That expectation was included in the documents presented to corporate executives seeking approval of the Unit 2 project. That expectation was even used to calculate how the project would impact Ameren's shareholders and ratepayers. FOF 158, 276. For instance, in the justification for the outage work that was presented to Ameren's executives, the company's engineers explained exactly what benefits they assessed in determining the projected value of the project. The first benefit listed is "30 MW gain in summer (3 mos), 20 MW gain balance of year *from reheater, economizer and APH [air preheater] investment*." Pl. Ex. 110 at AM-02465690 (emphasis added); FOF 277.

As he did for availability, Mr. Koppe independently studied the data and information produced by Ameren and reached a conclusion similar to what Ameren's engineers found before the Unit 2 outage. Mr. Koppe confirmed that pluggage had limited Unit 2's capability during the pre-project period and that Ameren should have expected at least 22 MW of increased capability due to the boiler work. FOF 279. Another 12-15 MW of capability would result from the new LP turbine. FOF 280. Dr. Sahu calculated that an 18 MW capacity increase due to the boiler project alone would increase emissions by 417 tons of SO_2. FOF 303.

The post-project data confirmed the results of Mr. Koppe's analysis. In fact, Ameren reported its improved capacity to MISO, the North American Electric Reliability Council, and the Missouri Public Service Commission, among other outside entities, each time attributing a major portion of the unit's capacity increase to the boiler work at issue. For example, Ameren responded to an inquiry from the Missouri Public Service Commission in a rate case related to the Unit 2 2010 outage. In defending its requested rate increase, Ameren stated that unit capability improved by 34 MW, of which 22 MW were restored capacity. FOF 288–89. Similarly, Ameren reported that Unit 2's *summertime* peak capability had increased to nearly 650 MW gross "due to work completed during the 2010 major outage (replacement of lower pressure turbines and *numerous boiler modifications*)." FOF 287 (emphasis added).

Ameren's post-project reports are quite similar to what Mr. Koppe found in reviewing the post-project data. Mr. Koppe first analyzed Ameren's "Plant Information" database and determined that Unit 2's capability had increased by 38 MW, from 615 MW during the pre-project period[9] to 653 MW afterwards. FOF 296–99. An almost identical increase is observed by comparing Ameren's "full load" test reports. The average capability reported by Ameren in those reports increased by 37 MW, when comparing baseline (620 MW) and post-project (657 MW) periods. FOF 295, 301.

Of the overall increase in capability, Mr. Koppe determined that about 23 MW of the increase were due solely to the component replacements and would require more coal to be burned. FOF 300. Ameren's documents show that it had reached the same conclusion. The predicted and actual capability increases Mr. Koppe reports are right in line with what Ameren used in its financial justification for Unit 2 (22.5 MW) and far more than the 1.7 MW that would result in 40 additional tons of SO_2.

Based on the performance improvements predicted by Mr. Koppe, Dr. Sahu calculated increases of more than 400 tons of SO_2 due to either the availability increase or the capacity increase alone. FOF 258, 303. Both the availability and capacity improvements Mr. Koppe predicted were borne out by actual data. FOF 237–38, 259–60. After the 2010 project, overall

[9] Because Ameren did not produce complete Plant Information data from before 2006, Mr. Koppe used January 2006-December 2007 for the pre-project period, since that was closest in time to Ameren's baseline.

emissions of SO_2 from Unit 2 increased by 2,171 tons per year. FOF 266. As a result, the actual emissions increase includes increases resulting from the availability increase and the capacity increase. Each is an order of magnitude larger than the PSD significance threshold.[10]

3. **Dr. Hausman used Ameren's modeling to quantify the emissions impact from the projects**

The conclusions of Mr. Koppe and Dr. Sahu are further supported by Dr. Hausman's analysis of Ameren's computer modeling efforts. Dr. Hausman is a modeler and market consultant with nearly 20 years of experience focused on the electric industry.

Ameren uses a sophisticated computer modeling program called ProSym to predict the operations of its generating fleet—including the Rush Island units—so it can plan accordingly. FOF 314–15. Ameren uses ProSym modeling for a number of things, including rate recovery proceedings before the Missouri Public Service Commission, fuel purchasing and planning, and informing capital investment decisions. FOF 315. Ameren has testified to the public service commission that its use of ProSym is "very well calibrated" and gives reliable projections of future unit performance. Plaintiff's Exhibit 439.

In the lead-up to the Rush Island overhaul projects—and in the normal course of its business—Ameren used ProSym to model and predict the Rush Island units' fuel needs ("heat input" in the industry parlance) for the years after the 2007 and 2010 major boiler outages. FOF 318–19, 329. Dr. Hausman performed two types of analysis based on Ameren's modeling. First, Dr. Hausman examined how varying specific inputs, such as the units' availability parameters or

[10] As noted in the discussion of Unit 1, even if I were to exclude testimony on actual emissions causation from Mr. Koppe and Dr. Sahu, which I will not, I can connect the dots myself to find the predicted—and realized—improvements caused the predicted—and realized—emissions increase.

maximum capacity values, would affect the model's projections for that unit's future performance. FOF 330–31. In effect, he investigated whether, and to what extent, the Rush Island units would actually use extra operating hours or extra capacity if the units were improved. The model that Ameren used routinely to simulate its units' operations showed that if Ameren increased the number of hours its Rush Island units were able to run, or if the company enabled the units to operate at higher output levels during those hours, then the units would take advantage of those performance enhancements, burning more coal and, as a result, emitting more pollution. FOF 332. In fact, the models showed that both a unit's capacity level and its availability are linearly related to the unit's projected coal consumption. *Id*.

The results of the ProSym runs confirm the admissions by Ameren's witnesses: performance improvements like capacity increases or availability gains would lead to additional operations and additional pollution. FOF 427–28. Dr. Hausman's sensitivity analyses quantify those relationships.

The following chart provides the results of Dr. Hausman's sensitivity analyses. Dr. Hausman ran several iterations of Ameren's ProSym model to identify what changes in forced outage rates, partial outage rates, and capacity would mean for coal consumption and pollution. FOF 334–41.

	Performance Measure	Δ Coal Consumption (Billion BTU)	Δ SO_2 Pollution (tons per year)
Rush 1	Forced Outage Rate (per 1%)	481	162
	Partial Outage Rate (per 1%)	408	138
Rush 2	Maximum Capacity (per 1 MW)	69	23
	Forced Outage Rate (per 1%)	566	189
	Partial Outage Rate (per 1%)	466	156

The demonstrated relationship between availability and capacity and emissions mean that a mere 0.3% improvement in availability[11] or a 1.7 MW increase in capacity is enough to cause the Rush Island units—modeled by Ameren in its regular business—to emit 40 additional tons of SO_2 pollution. FOF 333.

Dr. Hausman's second set of analyses compared the results of Ameren's modeling efforts, which included assumptions about improved unit availability and capacity beginning the year after the projects were performed, to model runs in which the Rush Island Units were not improved—that is, a scenario in which the outages that included the projects at issue in this case were never undertaken. FOF 342. These "with and without" analyses served to isolate the amount of the projected increase in unit operations and air pollution that was caused or enabled by Ameren's 2007 and 2010 outage work. FOF 343, 345. In other words, even though other factors contributed to unit operations and pollution, the comparison reveals how much of those emissions would not have been emitted "but for" the Rush Island performance improvements. Ameren—not Dr. Hausman—performed the engineering assessments of their outage work and folded those expected operational benefits into the company's modeling.[12] Dr. Hausman simply examined the result of those operational benefits on the units' projected operations. The

[11] These figures were based on Unit 1's partial outage rate results. Looking at Unit 2 or the forced outage rates would yield a smaller percentage triggering 40 tons of $S0_2$.

[12] Ameren argues that Dr. Hausman's with-and-without analyses are irrelevant because they do not compare baseline performance to projected performance. Rather, his analyses compare two future scenarios: the projected performance with the project to projected performance without the project. Although the comparison Dr. Hausman did is not the same as what is required of sources doing PSD calculations, Dr. Hausman's comparisons are relevant to this case, which requires a determination about causation. The purpose of Dr. Hausman's analysis was to examine the relationship between capacity and availability and that of generation and emissions. Conducting a with-and-without analysis provides useful causation information and is a standard industry method.

performance improvements Dr. Hausman identified in Ameren's ProSym input files are consistent with the performance improvements Mr. Koppe expected the Rush Island units would see over baseline levels based on his engineering analysis. The results of Dr. Hausman's analyses are summarized in the table below:

	Baseline Emissions	Modeled Performance Improvements	Projected Emissions	Total Increase	Result of Improvements
Rush 1	14,874 tpy	4.0% EAF	15,561 tpy	687 tons	562 tons
Rush 2	14,288 tpy	18 MW and 2.0% EAF	16,816 tpy	2,528 tons	746 tons

FOF 348–50, 353–54. These results show that Ameren's modeling would predict significant emissions increases at the Rush Island units as a result of the projects.

Ameren's expert witnesses confirmed at trial that the technique Dr. Hausman used is commonly used in the industry. FOF 344. Ameren's experts Michael King and Marc Chupka testified that they had done or recommended similar analyses in prior PSD enforcement cases—but did not do them here. *Id*.

4. **The evidence shows that efficiency improvements would not prevent emissions from increasing as a result of the projects**

Ameren argued that it expected unit efficiency to improve at Unit 2[13] and that this efficiency improvement would offset any overall increase in emissions. Before this litigation, however, Ameren made clear that it expected the improved efficiency to result in *more*

[13] Ameren has also argued that efficiency was expected to prevent an emissions increase at Unit 1. However, the project was not justified based on any efficiency improvements. It was justified based on outages and load limitations. FOF 145–47, 212. Moreover, while Ameren has now claimed some improvements in the unit's *net* efficiency, such an improvement means more of the unit's generation can be sent to the grid (as opposed to be used to run the plant itself) but does not reduce the amount of coal burned. FOF 117, 213, 351.

generation (greater total capacity) rather than less coal burned. In justifying the projects to management, Ameren's engineers predicted a small improvement (0.5%) in auxiliary load due to the boiler component replacements and a 15 MW increase in capacity due to the low pressure turbine. FOF 280. The 15 MW Ameren attributed to the turbine was *separate* from the 22.5 MW improvement attributed to the boiler components. Pl. Ex. 110; FOF 281. Similar improvements were reported by Ameren to the Missouri Public Service Commission—a 0.5% improvement due to the boiler component replacements and a 1.9% (12 MW) improvement due to the turbine replacement. FOF 291. Both types of improvements would result in producing more generation, but *not* in burning less coal. FOF 117, 213, 214, 280. Consistent with these reported expectations, Ameren did not incorporate *any* efficiency change in the 2010 fuel budget model run that it used as the projection for its NSR emissions calculation. FOF 401, 407. While Ameren later revised that run to reflect changed efficiency at Unit 2, it only did so *after* the project was long complete and the United States had filed this lawsuit. FOF 401. These revisions, which were made after the completion of the project and even after this lawsuit was filed, lack credibility. And even the revised projection showed an emissions increase that would trigger NSR after the analysis is adjusted to disregard Ameren's inappropriate application of the demand growth exclusion. *See* Subsection III.C.

The United States' experts took these potential efficiency improvements into consideration in performing their analyses. FOF 213–15, 279, 280, 300. Mr. Koppe explained that auxiliary load reductions would not impact gross efficiency, which is what matters for purposes of determining how much sulfur dioxide a unit will emit. FOF 117, 213. In his analysis of the turbine replacement at Unit 2, Mr. Koppe concluded that because the capacity increase at Unit 2 exceeded the efficiency improvement, the unit would ultimately still burn more coal even with the turbine replacement. FOF 214, 215, 280, 281, 300. Separately, Dr. Hausman did a variant of his with-and-without analysis that incorporated an efficiency increase that was even greater than the 2.4% improvement Ameren reported to the Missouri Public Service Commission. Dr. Hausman's analysis found improving efficiency had only a small effect on the projected increase related to the project, which was 696 tons of SO_2—still more than 15 times the threshold requirement. FOF 356.

Ameren concedes that efficiency actually got *worse* after the project compared to the baseline. Ameren blames a portion of the actual increase in pollution on the realized decrease in efficiency. Regardless of the cause for the unit's decline in efficiency, each hour of operations or each extra MW that is generated at the plant requires that much more coal—and results in that much more pollution. Ameren's argument has no impact on the United States' actual emissions theory because blaming increased emissions on unexpectedly declining unit efficiency does not change the fact that the units burned more coal and emitted more pollution than they otherwise would have without the boiler upgrades—and some of the emissions increase would never have occurred had Ameren decided not to perform those overhauls. Ameren did not claim that the efficiency decrease accounts for the entire post-project emissions increase. So even if some of the post-project actual increase was due to worsening efficiency, there was still an increase of emissions due to the projects.

Ameren argues that efficiency was *expected* to improve, so it was reasonable to expect less pollution, and then it argues that efficiency *actually* got worse, so the increase in pollution is unrelated to the projects. The evidence shows that the efficiency increase that Ameren claims to have expected would result in more MW, not less fuel burned. FOF 214, 215, 280, 281, 291, 300. And while the efficiency decrease that came after the project could explain part of the actual increase, it does not alter the fact that a substantial portion of the increase (far more than 40 tons) was related to the increased availability and capacity caused by the project. FOF 216.

5. **Conclusion: The emissions evidence shows an increase related to the projects should have been expected and actually occurred**

Ameren expected the projects to cause its highest period of post-project availability to rise well above the baseline availability for both units. The projects caused substantial availability increases. Ameren also expected and realized a post-project increase in capacity at Unit 2 from the challenged boiler work. Those expected and actual performance improvements were significantly larger than the small changes (an additional 21 full power hours or 1.7 MW) needed to cause a 40-ton increase in emissions.

The United States' experts approached the question of estimating the projected increases from different perspectives. Mr. Koppe and Dr. Sahu first focused on the expected incremental availability (and, for Unit 2, capacity) improvement, determined whether those improvements would be realized for the unit as a whole, and then directly calculated the tons of emissions associated just with those project-related improvements. Dr. Hausman took another approach. Using Ameren's modeling, he began with a projection that accounted for *everything* that Ameren expected at the units in the future, and then he isolated the amount of generation and pollution related to the project. Ameren criticized both approaches but never did its own calculation to show which of the additional tons of emissions were related to the projects.

Using these different approaches, Mr. Koppe and Dr. Sahu reached very similar conclusions to Dr. Hausman. Additionally, these experts' calculations were confirmed by the actual results, as shown in the two charts below:

UNIT 1	Koppe/Sahu	Hausman	Ameren's Documents	Actual Emissions
Δ EAF	3.8%	4.0%	4.0%	4.3%
Δ SO_2	608 tons	562 tons	[No PSD Analysis]	665 tons
FOF	227, 232	348 – 350	228 – 231	238, 243

UNIT 2	Koppe/Sahu	Hausman	Ameren's Documents	Actual Emissions
Δ EAF	2.8%	2.0%	3-4%	2.9%
Δ Capacity	18.1 MW	18 MW	22.5 MW	23 MW
Δ SO_2	415 (EAF) 417 (MW)	746 tons	2,531	2,170 tons
FOFs	251, 258, 303	353, 354	256, 276, 277, 402	260, 266, 300

The Koppe-Sahu results, Dr. Hausman's analyses, and the actual post-project data all establish that there is a significant net SO_2 increase of more than 40 tons that was caused by the projects. Based on the known facts that the Rush Island units are low-cost, baseload units, common sense compels the same conclusion: improving availability or capacity at baseload units like Rush Island will result in additional operations and pollution. Ameren's model confirms that relationship, as Dr. Hausman showed and Ameren's chief modeler confirmed in his testimony. FOF 329–41, 448. Other courts have recognized this relationship. *See* Subsection II.B.1 above (citing cases). Ameren should have expected a significant net emissions increase and should have obtained a permit before beginning work.

C. Ameren Also Violated Title V

Because I conclude the projects were major modifications, I also find that Ameren has violated Title V of the Clean Air Act.

Title V creates an operating permit program designed to collect all of a source's applicable requirements under the Clean Air Act in a single place. 42 U.S.C. § 7661c(a); *Ameren SJ Decision*, 2016 WL 728234, at *3 (quoting *Sierra Club v. Otter Tail Power Co.*, 615 F.3d. 1008, 1012 (8th Cir. 2010)).

Missouri's Title V program requires sources to obtain a permit with "all applicable requirements." 10 C.S.R. § 10-6.065(6)(C)1.A; *see also* 42 U.S.C. §§ 7661 - 7661c(a). By definition, applicable requirements include requirements under the New Source Review program. 10 C.S.R. § 10-6.020(2)(A)23; *see also Ameren SJ Decision*, 2016 WL 728234, at *24. In addition, Ameren's Title V permit prohibits major modifications without Ameren first obtaining a permit. FOF 456.

By performing major modifications without obtaining an NSR permit (and satisfying the associated requirements, including the requirement to operate best availability control technology to reduce emissions), Ameren violated both the requirement to obtain a permit with all applicable requirements and the permit prohibition against unpermitted major modifications.

III. AMEREN'S DEFENSES AND CRITIQUES OF THE UNITED STATES' EVIDENCE FAIL

A. The Projects were not Routine Maintenance

Ameren has asserted the routine maintenance, repair, and replacement defense. The routine maintenance exemption provides that projects do not constitute "major modifications" if they merely consist of routine maintenance, repair, or replacement activities. *See* 40 C.F.R. § 52.21(b)(2)(iii)(a); 10 C.S.R. 10-6.060(8).

Based on the evidence presented at trial, I conclude that the projects cannot be considered routine maintenance under the law. The Rush Island boiler refurbishments at issue were the most expensive boiler projects ever performed on an Ameren boiler. FOF 182, 183. They involved the redesign and replacement of major boiler components that were intended to improve the performance of the units and enable them to burn coal they were not originally intended to burn. FOF 47, 53, 62, 134, 138–47. They were the first such replacements in the history of each unit, are rarely done at any unit in the industry, and the combination of boiler replacements has rarely, if ever, been done in the industry. FOF 172, 174–76. Under the appropriate legal standards, every factor of the routine maintenance test weighs heavily against classifying the work as routine maintenance, repair, and replacement. Even Ameren's designated expert on routine maintenance, Jerry Golden, acknowledged at trial that these projects were not *de minimis*. FOF 164.

1. Legal standard

The standard for the routine maintenance, repair and replacement exemption in the NSR rules "is a narrow one and is generally limited to *de minimis* circumstances." *Ameren SJ Decision*, 2016 WL 728234, at *5. Ameren has the burden of proving the routine maintenance exemption applies. *Id.*

As I explained at summary judgment, to determine whether a defendant has met its burden of proving the routine maintenance exemption, courts examine the projects, taking into account the 1) nature and extent, 2) purpose, 3) frequency, and 4) cost of the activity to arrive at a common-sense finding. *Id.* at *4, *5 (citing *Wisconsin Elec. Power Co. v. Reilly*, 893 F.2d 901, 910-11 (7th Cir. 1990)). "Frequency [is] evaluated by considering the work conducted at the particular unit, work conducted by others in the industry, and work conducted at other individual units within the industry. In evaluating frequency, the most relevant inquiry is how often similar projects have been undertaken at particular units in the industry, not how many similar projects have been implemented industry wide." *Id*. at *5.

EPA has consistently interpreted the routine maintenance exemption as requiring review based on the "principle that a non-routine collection of activities, considered 'as a whole,' is not exempt under routine exclusion, even if individual activities could be characterized as routine." *Id.* at *8. For these reasons, as I stated at summary judgment:

> separate equipment or component replacements should be taken as a whole, i.e., multiple component replacements may constitute one 'project,' for purposes of the RMRR analysis, if . . . it appears that the work was done as part of one project. Under this common sense framework, I agree with EPA that whether the challenged work was planned for together, budgeted together, performed together, and undertaken for the same purpose are relevant to the inquiry.

Id.

2. The boiler refurbishments at each Rush Island unit constitute one project for routine maintenance purposes

All of the boiler component replacements were related in that they were planned together, budgeted together as capital projects, performed at the same time, and undertaken for the same purpose. As a result, I find that the work should be viewed together in determining whether it qualifies for the routine maintenance exemption.[14]

<u>The work was planned together.</u> There is no question that Ameren planned the component replacements together. When Ameren issued the contract documents to qualified bidders for the project, it consolidated all of the work in its contract specifications. FOF 133, 134. Ameren noted that the projects were combined to "gain efficiencies in procurement, design and installation" and described the air preheater replacement as "part of a Major Mechanical

[14] Even if I were to consider each major component replacement separately, I would still conclude that the projects were not routine maintenance under the weight of the evidence.

Work Package to include the Economizer, Reheater and Lower Slope portion of the boiler." FOF 132. Ameren described the "major boiler modifications for Rush Island 1 and 2" as follows:

> For several years we have been planning major refurbishment of the Rush Island 1 and 2 boilers, which have operated for nearly 30 years without replacing any of the major components. The major scope elements include the following major components which are experiencing an increase in tube leaks and fatigue issues, and have been redesigned to improve future operation and maintenance:
>
> - Reheater—redesigned for PRB coal
> - Economizer—redesigned for PRB coal
> - Lower Slope—ruggedized design to better withstand slag falls
> - Air Preheater—redesigned for ease of future basket replacement.

P. Ex. 6; FOF 139.

<u>The work was budgeted together.</u> As of December 2004, Ameren had created a preliminary capital budget for the replacement of the Unit 1 economizer, reheater, lower slopes, and air preheater as part of a single project. FOF 126. Even though Ameren prepared separate work orders for the two air preheater replacements, all the work was from Ameren's capital budget—not the operations and maintenance budget—and was budgeted for the same outage to be performed at the same time. FOF 130, 131, 181. Likewise, at Unit 2, Ameren consolidated the replacement of the challenged components when it sought bids from outside engineering firms to design, fabricate, and install those components. FOF 133.

<u>The work was performed at the same time.</u> It is undisputed that the components at issue were performed together during the same outages at Unit 1 and Unit 2. FOF 25, 169, 170.

<u>The work was undertaken for the same purpose.</u> Ameren's routine maintenance expert, Mr. Golden, agreed that the purpose of the work at each unit was the same. FOF 150–51. Mr. Golden confirmed Mr. Stevens' testimony that the purpose of the work at each unit was to eliminate pluggage and fouling of the economizers and reheaters and to eliminate future forced

and maintenance outages caused by tube leaks.[15] FOF 56–69, 145–47, 149. The United States' expert Mr. Koppe also explained that Ameren could completely resolve the capability restraints caused by pluggage only by replacing each of the components at issue during the same outage. FOF 53, 63, 196. Ameren's Jeff Shelton agreed. FOF 64.

3. The projects do not qualify for the routine maintenance exemption

a. Nature and extent

The 2007 and 2010 projects involved the replacement of major boiler components that are integral to the operation of the Rush Island Unit 1 and 2 boilers. The 2007 and 2010 projects took years to design and plan and required the special fabrication of components that were not otherwise available at the Rush Island plant. FOF 139, 164. The projects were far more extensive than the type of maintenance, repair, and replacement routinely performed at Rush Island and other coal-fired power plants. FOF 165–72. And it is clear from Ameren's documents that the company itself never considered these projects to be just "routine maintenance," as that term is understood in the industry; it considered them to be "major boiler modifications" or "major boiler refurbishments." FOF 50, 130, 139, 171.

Each of the boiler components was redesigned to eliminate the recurring problems associated with Ameren's switch to PRB coal. FOF 53, 134, 138–49. These design changes were intended to upgrade and improve the performance of the boilers. FOF 145–60.

Given the complexity of the replacements, the components were designed, engineered, and constructed by outside contractors, such as Alstom Power, the original manufacturer of the boilers. The work was well beyond the capacity of Ameren's own staff. FOF 128, 166.

[15] On Unit 1, the lower slopes were replaced to eliminate tube leaks and repair damage resulting from slag falls and erosion following the switch to PRB coal. FOF 52, 53, 56–59.

In contrast with routine maintenance, repairs, and replacements undertaken at utility plants, the projects required approvals of executives at the very highest level of the company, including Ameren's CEO. FOF 135–37.

The economizers, reheaters, and air preheaters each weigh hundreds of thousands of pounds and required construction of heavy equipment such as monorails and cranes. FOF 162, 167–68.

The 2007 outage for Unit 1 lasted 100 days and required more than 1,000 workers and 448,539 total hours of labor, of which 402,109 hours were performed by contractors. FOF 169. Ninety-one percent of the work done during the Unit 1 outage was performed by contractors. *Id*.

The 2010 outage at Unit 2 lasted approximately 100 days and required more than 350,000 hours of labor, of which 290,953 hours were performed by contractors. FOF 170. An average of 360 contractor staff worked two 10-hour shifts six days a week during the outage. *Id*.

The 2007 and 2010 overhauls were considered capital projects and were funded out of Ameren's capital budget rather than the operations and maintenance budget. FOF 181. As capital projects, these component replacements improved the value of the generating unit. FOF 180.

As a result, the nature and extent of these projects weighs heavily against a finding that these projects qualify for the narrow routine maintenance exemption.

b. Purpose

As noted above, the consistent purpose of the projects was to eliminate pluggage, fouling, and tube leaks. Ameren expected that tube leaks in the economizers and reheaters would be eliminated for at least 20 years. FOF 38, 145–47. By contrast, routine maintenance, repair, and replacement is performed to allow a unit or plant to continue to operate in its present condition.

See Doc. 227-2, Memorandum from Don Clay, Acting EPA Ass't Admin. (Sept. 9, 1988), at 3-4; Doc. 227-3, 2000 DTE Applicability Determination Detailed Analysis, at 11.

The replacement of these major boiler components allowed the units to operate hundreds more hours than they could in the baseline period at a higher capacity by eliminating tube leaks, load limitations, and operational constraints. The purpose of these projects indicates that the work was far from routine.

c. Frequency

Even though the most relevant inquiry is how often similar projects have been undertaken at particular units in the industry, for each of the three inquiries under the frequency factor, the inquiry weighs heavily against a finding of routineness.

<u>Frequency at the unit.</u> None of the components at issue had been replaced at these units before. FOF 173. The components were replaced after 31 years of service at Unit 1 and 33 years of service at Unit 2. FOF 4, 174.

<u>Frequency at individual units within the industry.</u> The components at issue are very rarely replaced at any plant. FOF 174–76. Ameren's expert confirmed this point. Mr. Golden agreed that the typical life of a reheater is about 30 years, the typical life of a primary economizer is about 35 years, and the typical life of the lower furnace is about 40 years. FOF 174. Mr. Golden also testified that complete air heater replacements (including the rotor and all baskets), like the ones done at Rush Island, are not done frequently at any unit. *Id*. This evidence, coming from Ameren's expert, demonstrates that replacing the components at issue is rarely done at individual units within the industry.

<u>Work conducted by others in the industry.</u> Mr. Golden testified about a list he has complied of 18,300 projects undertaken at coal-fired power plants. The list includes projects that

Mr. Golden identifies as capital projects costing more than $100,000. *Id*. As an initial matter, the relevance of Mr. Golden's list to this case is weak because Mr. Golden has been unable to identify *any* coal-fired unit in the electric utility industry that has replaced the economizer, the reheater, the lower slopes, and the air preheater together. *Id*. Boiler refurbishments like the ones at Rush Island are not common in the industry.

Regarding air preheater replacements, Mr. Golden identified 35 replacements of regenerative air preheaters going back to the 1970s.[16] FOF 176. By his count, that is less than 2 percent of the coal-fired units in the country. However, Mr. Golden was unable to say whether those 35 instances were complete replacements or similar to those at Rush Island. *Id*. Even if they were, a replacement that takes place at less than 2 percent of the units going back to the 1970s is not common in the industry.

As a result, the frequency factor weighs heavily against these projects being routine.

d. Cost

The projects at issue were the most expensive capital projects ever done at Rush Island. Each project cost substantially more than the entire operations and maintenance budget for the plant for an entire year. FOF 177, 178, 182. Grouping the replacements at each unit together, the two projects were among the most expensive boiler projects ever undertaken at any of Ameren's plants. FOF 183.

Based on the undisputed facts regarding the costs of these projects, the cost factor also weighs heavily against these projects being routine.

4. Conclusion: the projects cannot be considered routine

[16] Even for the claimed 35 air preheater replacements, Mr. Golden was unable to testify that all were complete replacements or that all the replacements were comparable to the air preheater replacements at Rush Island. FOF 177.

Ameren has not satisfied its burden of proving that the Rush Island projects fall within the narrow routine maintenance exemption. The 2007 and 2010 major boiler outages were unprecedented events for Rush Island Units 1 and 2—they were the centerpieces of the "most significant" outages in plant history. FOF 172. A common sense finding weighing the nature and extent, purpose, frequency and cost of the projects reveal them to be far from *de minimis* activities contemplated by the exemption. Ameren's expert agreed and testified at trial that these projects were not *de minimis* activities. As a result, Ameren's routine maintenance defense fails.

B. The Emissions Increases Cannot Be Set Aside Based on the Demand Growth Exclusion

Ameren also asserts the "demand growth exclusion," set forth at 40 C.F.R. § 52.21(b)(41)(ii)(c), as a defense to liability. As the United States Court of Appeals for the District of Columbia explained in *New York v. EPA*, "the regulation establishes two criteria a source must meet before excluding emissions from its projection: (1) the unit could have achieved the necessary level of utilization during the [baseline period]; and (2) the increase is not related to the physical or operational change(s) made to the unit." 413 F.3d at 33 (quotations omitted). "The two prongs are distinct. Satisfying the 'could have accommodated' prong is necessary but not sufficient to justify application of the exclusion, and emissions that 'could have been accommodated' at baseline are not per se 'unrelated.'" *Ameren SJ Decision*, 2016 WL 728234, at *21.

Additionally, as stated at summary judgment, "the burden is Ameren's to prove that the demand growth exclusion applies." *Id*.

1. Ameren's experts confirm that demand was not projected to—and did not—cause the pollution increases at Rush Island

Fundamental to an invocation of the demand growth exemption is that demand *on the unit* increases. But in this case just the opposite happened, as the data shows—and Ameren's expert witnesses conceded.

A unit's "utilization" is a measure of how much of its available capacity the unit is called on to use. The measure serves to reflect market demand on a specific unit. FOF 377. As Mr. King explained, a declining utilization factor means demand on the unit is decreasing. FOF 378. As a result, when the utilization factor is declining, an increase in pollution *cannot* be the result of demand. *Id.*

As far as the actual emissions case is concerned, Mr. King and Ms. Ringelstetter both testified that the utilization factor for the Rush Island units actually *decreased* after the projects. FOF 378–80. The declining demand that the units actually experienced after the projects prevents Ameren from asserting a successful demand growth argument for the actual emissions increase shown in the data.

Ameren's application of the demand growth exclusion also fails for the expectations case. Ameren's testifying expert Marc Chupka looked at the utilization factor data leading up to each project and concluded that "[i]t would be reasonable to assume a constant utilization factor for projecting future emissions" following the boiler upgrades at issue in this case. FOF 208. Ms. Ringelstetter agreed. She testified that the utilization of Unit 1 was projected to remain basically constant, and, though utilization of Unit 2 was projected to increase somewhat (about 2%), the increase paled in comparison to the projected increase in emissions (over 15%). FOF 380. A constant utilization factor means static demand on the units. If that demand is constant, it cannot be the cause of an emissions increase. Regardless, even the marginal projected increase in Unit 2's utilization factor cannot account for the substantial emissions increase that Ameren's modeling and calculations projected. *Id*.

2. Ameren's evidence does not address what portion of the units' projected or actual emissions increases were "unrelated" to the projects

The evidence Ameren presented in support of the demand growth defense generally falls into two categories: (1) evidence that regional demand for electricity was generally going up during the years surrounding the Rush Island projects, and (2) calculations regarding how much generation (and pollution) the units "could have accommodated" during the baseline periods. The central problem for Ameren's defense is that these showings, while necessary to the company's proof, are insufficient to establish that the demand growth exclusion applies to any specific "portion" of its projected emissions increases, as required by the rule. *Cf.* 40 C.F.R. § 52.21(b)(41)(ii)(*c*); *see also* 40 C.F.R. § 52.21(r)(6)(i)(*c*) (requiring operators to document and describe certain PSD analyses, including "the amount of emissions excluded under [the demand growth exclusion] and an explanation for why such amount was excluded"). Ameren has failed to establish a correlation between rising regional demand and any specific impact on unit performance in order to show what portion of its projected emissions increases are "unrelated" to the projects at issue in this case.[17]

[17] Ameren's theory on demand growth appears to be that, if it can prove emissions were related to demand, then the emissions cannot be related to the projects. This rests on the false assumption that an effect can only have one cause. Because pollution, like any effect, can have more than one "but for" cause, it is not enough for Ameren to simply point out that some of its projected and actual increases in emissions are related to the presence of sufficient market demand for Rush Island power. Ameren disputes the relevance of the restaurant analogy argued by the United States and used by the Court at summary judgment. *See Ameren SJ Decision,* 2016 WL 728234 at *10 n.17. But the restaurant analogy remains useful. To be sure, a meal

The first category of Ameren's evidence—its various system load forecasts—fails to connect meaningfully to projections of unit operations because increases in system demand do not necessarily translate into increases in unit operations. As Ameren's witnesses testified, during the baseline period, the units operated as baseload units and operated whenever they were available. As a result, they were usually fully-loaded during "on peak" hours when system demand was at its highest. FOF 371–72. If the units were generally maxed out anyway, increases in system demand would have little effect on unit operations.[18] That is reflected in Ameren's expert testimony on unit utilization, discussed above. Moreover, as Dr. Hausman testified, Ameren's ProSym modeling efforts showed just how disconnected unit operations were from system level demand. Ameren's load forecasts were inputs into its modeling runs, and they reflected the company's expectation that system load was growing on the order of 1% a year. But the output files from those very same runs reveal Ameren's computer simulations projected that generation from the Rush Island units would increase immediately following the outage and then remain relatively flat. FOF 373. Ameren seems to suggest that rising regional demand for electricity—like a rising tide—would lift operating levels at its units. The evidence clearly establishes otherwise.

---

served to a restaurant customer is "related" to the customer's decision to order it (customer demand); but that does not mean that the meal is "unrelated" to the restaurant having an open table or the chef's preparation of the food.

[18] Ameren witness Jaime Haro noted that, for baseload units like Rush Island, increases in system demand would mean the units still ran at high levels most of the day, but they might ramp down a little later each day or turn up to full load a little earlier each morning. FOF 370. The marginal increases in demand on the "shoulder" hours may have been attributable to system level demand, but Ameren made no attempt to quantify just what portion of its emissions projections were made up of these marginal shifts. As a result, Ameren cannot meet its burden of proof on this defense.

Ameren's second category of evidence, presented through its expert Sandra Ringelstetter, is a series of calculations describing how much SO_2 pollution the Rush Island units "could have accommodated" during their respective baseline periods. This, too, fails to address how any specific portion of its projected emissions increases is unrelated to the projects at issue. It does not address any portion of the units' projected emissions *at all*. While varying somewhat in the details, all of these calculations involve picking a pollution rate the units achieved at some limited point during the baseline period (sometimes a month, sometimes a week, sometimes a discontinuous set of hours taken from across the 24-month baseline period), and then multiplying that emissions rate by the unit's baseline equivalent availability levels. Since EAF is a measure of available hours, and since its emissions rate is related to a unit's load levels,[19] these calculations essentially assume that the unit would run flat out, at some very high level of operations, through day and night, for nearly two continuous years. Ameren then concludes that, since demand was going up and its "could have accommodated" calculations result in more emissions than any projected increase in this case, *all* projected emissions increases can and should be excluded from the NSR liability calculation.

Ameren's "could have accommodated" calculations are fundamentally flawed. For example, they employ unreasonably-high emissions rates and rely on applicability determinations divorced from the operational realities of electric utilities. But even if Ameren's "could have accommodated" calculations were reliable, the calculations cannot—as a structural matter—say anything about whether the projected emissions from the units are *related* to the projects at hand. Ameren's "could have accommodated" calculations consider neither the

[19] Despite Ms. Ringelstetter's testimony to the contrary, hourly emissions are directly related to hourly heat input in her own analysis, Ringelstetter Test., Vol. 11-B, 85:15–86:3, and the relationship between heat input and unit load level is "more or less linear." *Id.* at 85:9 – 11.

projects at issue nor the projected emissions in any way. At best, the calculations have something to say about only one prong of the demand growth exclusion, which is not sufficient to establish the exclusion applies.

3. Ameren's other demand growth arguments fail

Ameren made two additional arguments at trial in support of its demand growth defense. First, Ameren argued that "unit-level demand" is not the focus of the test, and that instead, the demand growth exclusion focuses directly on "systemwide demand." In other words, Ameren argues that the problem of translating system demand into demand on the unit and changes in unit operations is not required by the rule itself. For that proposition, Ameren cites the 1992 WEPCO Rule Preamble where the demand growth exclusion was first introduced. The passage does not support Ameren's argument; in fact, just the opposite:

> [W]here increased operations are in response to independent factors, such as system-wide demand growth, which would have occurred and *affected the unit's operations* even in the absence of the physical or operational change, such increases do not result from the change and shall be excluded from the projection of future actual emissions.

57 Fed Reg. 32,314, 32,326 (1992). As a result, the regulations themselves establish that EPA has always required an operator to show whether—and to what extent—demand would "affect the unit's operations" before the demand growth exclusion could be applied.[20]

---

[20] Ameren cites various other authorities in its post-trial brief to support its argument that evidence of increasing systemwide demand is sufficient to establish the demand growth exclusion. Ameren misreads each of these authorities, ignoring paired language clarifying that the relevant inquiry requires consideration of how demand affects the units at issue. The demand growth standard is clear. In situations like these, "where [a] proposed change will increase reliability, lower operating costs, or improve other operational characteristics of the unit, increases in utilization that are projected to follow can and should be attributable to the change." 61 Fed. Reg. 38,250, 38,268 (1996).

Ameren's second argument was presented through the testimony of Ms. Ringelstetter. Specifically, Ameren argued that any performance changes or any emissions increases following the Rush Island modifications would be unrelated to those boiler modifications. This conclusion is unsupported and was offered for the first time at trial.

Until the summary judgment ruling, Ameren and its experts declared that it did not really matter *what* the project was so long as the unit, during the baseline, "could have accommodated" the projected emissions. As the head of Ameren's Environmental Services Department testified in Rule 30(b)(6) deposition testimony, "The emissions that the unit was capable of accommodating prior to the outage would be totally unrelated to . . . any activities that occurred on the outage. So just by the nature of the scope, the emissions are unrelated." Whitworth Rule 30(b)(6) Depo. Test. 38:4-12; *see also Ameren SJ Decision*, 2016 WL 728234, at 9 (describing Ameren's argument that "'unrelated' means any emissions increases a unit could have accommodated at baseline"). And when Ms. Ringelstetter originally performed her "could have accommodated" calculations, she declared that was the only step necessary to establish that the exclusion applied. She testified at her deposition that even assuming the performance improvements she recognized in Ameren's modeling files were the result of the boiler upgrades, it would not have changed her analysis, her calculations, her considerations, or her conclusions in any way. FOF 438.

Ameren's theory is inconsistent with the plain language of the regulations, the case law, and my summary judgment decision holding that the two prongs of the exclusion are distinct. *See Ameren SJ Decision*, 2016 WL 728234, at *11. After my summary judgment ruling, Ameren adjusted its theory and attempted to show that neither the capacity increase experienced at Unit 2 nor the availability increase experienced at either unit was related to the boiler upgrade work at issue in this case. Not only is such a conclusion contrary to the Ameren's internal engineering and economic documents, the pre- and post-project analyses provided by Ms. Ringelstetter, on which Ameren bases its relatedness arguments, are flawed.

Ms. Ringelstetter's capacity analysis begins by relying on inapplicable pre-project values. Instead of comparing projected future operations to actual, past operations, she looks at modeling inputs from previous years. Though those earlier modeling efforts might generally be expected to reflect the unit's actual operations around that time, the capacity values used here present a particular problem: Ameren uses its capability tables to develop unit capacity inputs, and for half of the baseline at each unit, the capacity tables were "unrealistically high."[21] FOF 431–32. That means the capacity increase Ameren expected to see and did see following the Unit 2 work was about twice what Ms. Ringelstetter saw. That increase cannot be attributable to turbine work alone, as Ms. Ringelstetter claims. FOF 431–32; *cf.*, *e.g.*, FOF 304.

Ms. Ringelstetter's analysis also discounts the observed availability increases post-project as being too small to be meaningful. Essentially, Ms. Ringelstetter argues that the increases are "in the noise," so there is no increase at all. But the evidence shows that just a 0.3% availability improvement could result in 40 additional tons of SO_2 at Rush Island. FOF 191. Ameren's

[21] In January and February of 2006—and in middle of the baseline periods—Ameren decided to update its capability tables to come up with more accurate predictions. Pl. Ex. 157 at AM-02743289. For the Rush Island units, that meant substantially reducing the projected unit capabilities as operating data showed that the units were struggling to perform as expected for many months of the year. U.S. FOF 119. Recognizing this, and using "historical operating data along with design criteria," Ameren updated its capability tables and substantially reduced the Rush Island numbers in order to "generate more realistic capability ratings for all of [the company's] fossil units." Pl. Ex. 260 at AM-00091465. The new numbers dropped the average annual capability ratings for the units by about 12 MW. Compare Pl. Ex. 157 with Pl. Ex. 260. So Ms. Ringelstetter's baseline capability number is substantially inflated since almost half of the numbers there were "unrealistically high." U.S. FOF 432.

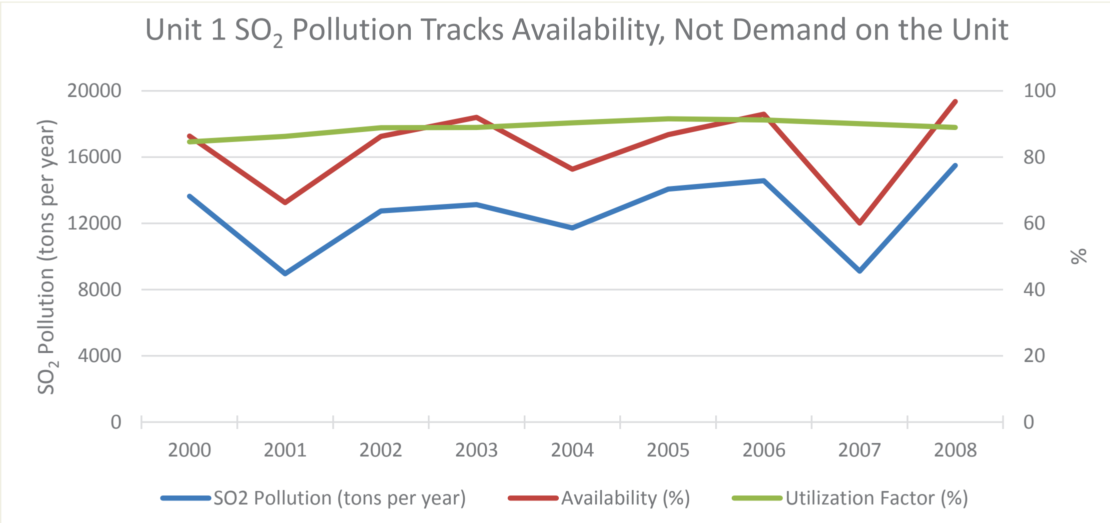
economic justifications were calculated to a tenth of a percent. FOF 104, 148. Ms. Ringelstetter's opinion also disregards the fact that Ameren projected long-term averages in its computer modeling and that specific years, as is relevant under the PSD analysis, might be as much as 2% or 3% higher than the inputs presented in the ProSym inputs. FOF 257. The important inquiry here is the size of the availability gain, which the evidence noted in Subsection II.B has shown to be about 3–4%. As Dr. Hausman testified, that kind of gain would lead to additional operations and pollution. To the extent Ms. Ringelstetter's testimony disregards these gains, her testimony is simply not credible.

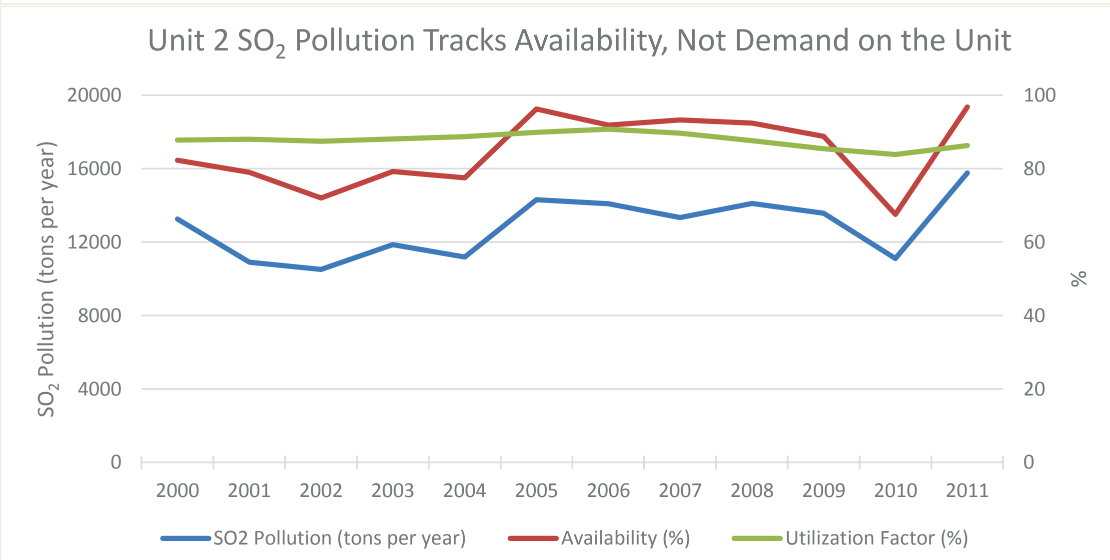
4. Emissions resulting from operations that would not have been possible but for the boiler upgrades cannot be considered "unrelated" to those boiler upgrades

Ameren's demand growth defense fails to address whether projected emission increases are related to the projects at issue. No matter how Ameren calculates the quantity of emissions it could have emitted had demand for electricity stayed high through the night, it does not address the reality that the units' real opportunities to sell more (and emit more) came by expanding their ability to operate when the demand is high—and when their units are generally maxed out—during the day. FOF 370–71. If there were baseline hours where the unit could not operate because of outages caused by the components at issue, any post-project recovery of those hours would be related to the project. Mr. Koppe found there were 246 outage hours for Unit 1 and 146 outage hours for Unit 2 caused by the projects in the baseline. FOF 240, 263. As described in Subsection II.B of my Conclusions of Law, both Mr. Koppe and Ameren concluded that those hours would be recovered and used in the post-project period. For those hours, the units went from unable to operate to able to operate. Demand did not cause that change; the units already operated every hour they could. That change resulted from $70 million of capital work. As I explained at summary judgment, when a unit "undergoes modifications that allow it to run more during the daytime hours tha[n] it could before, it cannot be said that the increased emissions were merely a coincidence or unrelated to the modification." *Ameren SJ Decision*, 2016 WL 728234, at *10.

Ameren's witness admitted that changes in unit capacity or availability would lead to changes in operations and pollution, FOF 427–28, and the company justified the cost of the projects on precisely those kinds of performance improvements. FOF 146, 277. Dr. Hausman specifically examined how performance improvements at the units translate into coal consumption and pollution, and the result is predictable: when the units are better able to supply electricity, they do so, and they burn more coal in the process, emitting more pollution. *See* Subsection II.B.2.c.

Moreover, the company's data reflects the straightforward relationship between the Rush Island units' performance abilities and their pollution levels. As discussed earlier, "[u]tilization is a variable that describes how much of the [unit's] available capacity the unit utilizes," and that in turn reflects the influence of all of the "market considerations" like system demand and market price that can impact unit operations. FOF 377. A unit's equivalent availability factor, on the other hand, reflects the engineering condition of the unit—how well it has been maintained and whether it stands ready to generate whenever needed. FOF 94. The graphs below show that Ameren's historical emissions data reflects the reality that Rush Island operations were driven by its engineering condition (measured by its availability) more than any market fluctuations (measured in its utilization). These graphs show SO_2 emissions, availability, and utilization factor at Units 1 and 2, respectively. They were the subject of testimony by Dr. Sahu and Mr. King and are based on data compiled by Dr. Sahu and Ms. Ringelstetter.[22]





[22] Ameren moved to exclude the graphs as not properly disclosed. For reasons I discuss below (*see* Section on Evidentiary Issues), I will deny Ameren's motion as it relates to these graphs. Notably, the charts were also used in the United States' summary judgment briefing, Doc. 609 at p. 20, and Ameren's David Strubberg presented a similar chart, comparing availability and generation, at the 2008 State of the System Meeting. FOF 202.

Reviewing these charts at trial, Ameren's testifying expert Michael King conceded that there was a relationship between availability and pollution. FOF 381.

Ameren argued that being forced to translate system level demand into an effect on unit operations would turn the analysis from an annual emissions focus to an hour-by-hour assessment, which is not contemplated by the regulations. That argument fails for two reasons.

First, just as a restaurant owner knows the ebb and flow of customers throughout the lunch and dinner rushes, Ameren knew that Rush Island generally ran hard throughout the day and ramped down somewhat at night. In this context, Ameren's employees noted that derates resulting from pluggage in the units' boiler components were costing the company as much as $25,000 a day. FOF 112. A company does not lose earnings when it has available capacity that it could dip into at a moment's notice; it loses earnings when it cannot provide the generation it would otherwise be able to sell for a profit. *See, e.g.*, FOF 112, 274 (Williamson email). And when Ameren justified the substantial expense of the boiler overhauls at the Rush Island units, the company quantified the benefit of recovering availability and capacity. Again, those benefits can only be considered "benefits" of the projects if the units would not have otherwise been able to operate that often or at those levels. *See*, *e.g.*, FOF 146. Documents like these reflect the general truth—without necessitating an hour-by-hour data review—that the units were limited, the problems were expected to be fixed, and the units would operate more as a result.

Ameren's argument that NSR cannot require sources to perform an hour-by-hour look at operations is disingenuous when its own ProSym software—which it uses regularly in the course of its business and runs hundreds if not thousands of times each year—solves the dispatch problem on an hour-by-hour basis for every year it is told to do so. FOF 317. That model makes it easy to isolate how performance improvements would interact with other market constraints to determine unit operations on an hour-by-hour basis and further determine how those hourly operations translate into annual generation and pollution numbers. Dr. Hausman did just that, and the results showed a straightforward relationship: more capacity or more availability led to more generation and more pollution. PSD requires sources to consider "all relevant information" in analyzing whether emissions will increase; it does not contemplate sources ignoring known, relevant information just because it might be unfavorable. Section 52.21(b)(41)(ii)(a). Ameren had the relevant information, and that information showed that the Rush Island units' performance would improve, resulting in increased generation and emissions.

As I have previously ruled, increases made possible by performance improvements must be attributed to the project and cannot be covered by the demand growth exclusion. *See* Subsection II.B.1.

C. Ameren's New Source Review Analyses Are Fatally Flawed and Cannot Provide Safe Harbor from Liability

Ameren's emissions calculations are not reasonable analyses under the PSD rules and therefore do not show that Ameren should not have expected an emissions increase.

1. Ameren does not have a legitimate process for assessing PSD applicability

First, Ameren's position relies on a fundamental misunderstanding of the PSD program. Ameren offered the testimony of Mr. Boll and Mr. Whitworth at trial to describe how Ameren determined whether a project might cause an emissions increase. Both witnesses testified that the company looked to whether the unit's *potential* emissions were expected to increase.[23] FOF 391. The company employee actually charged with performing the PSD analysis for Unit 2

[23] Mr. Boll used the term maximum continuous rating. FOF 391. As Ameren explained in its earlier briefing, that term is a measure of a unit's potential emissions. Doc. 542 at 5-6.

confirmed Ameren's reliance on the wrong metrics when he testified that any improvements in availability were "irrelevant." FOF 396, 397(d).

Ameren's method of assessing PSD does not comply with the rules, EPA's instructions, or case law. The rules explicitly direct a source to compare projected emissions to baseline emissions, both measured in tons per year. 40 C.F.R. § 52.21(b)(41), (48). As noted above, both EPA and the courts that have interpreted the PSD program have explained that "[i]f an increase in hours of operation is caused or enabled by a physical change, the increased hours must be included" in the projection. *Duke Energy 2010*, 2010 WL 3023517, at *5. EPA has brought enforcement actions since 1999 based on improvements in availability that lead to increases in annual pollution. Ameren's testifying expert conceded that EPA's enforcement approach has been "well-known in the industry" since 1999. FOF 219.

By focusing on potential emissions, Ameren ignores my ruling on Ameren's first motion for summary judgment. In motions practice, Ameren argued that the United States had to show a "modification" under the Missouri SIP before turning to the issue of whether the projects were "major modifications." Doc. 542 at 1-2. Ameren argued that modification status was controlled by *potential* emissions. *Id*. I rejected that argument. Doc. 711. As Ameren argued at summary judgment, "'modification' and 'major modification' are distinct terms with separate characteristics under the SIP." Doc. 542 at 5. At trial, however, Ameren described its internal analysis as focused solely on the first test, not the major modification test actually before the Court.

For the reasons described in Subsection II.B.2 of my Conclusions of Law, if Ameren had considered how the actual performance changes would affect generation, it would have expected and found emissions increases related to the project.

Second, Ameren failed to coordinate between the engineers who planned and performed the projects and the environmental services employees charged with assessing NSR applicability. Michael Hutcheson, who performed the NSR analysis for the Unit 2 project, reported that he learned about the project from his boss and his boss's boss but never talked to the engineers working on the project. FOF 397(a).

On the other side of this divide, engineering leaders at Ameren like Robert Meiners and David Strubberg testified that they had no involvement in assessing whether the projects triggered PSD. FOF 393. Mr. Meiners testified that as plant manager, he was "accountable" for ensuring that Rush Island complied with environmental regulations. *Id.* Despite that accountability, Mr. Meiners testified that he had never been involved in a single discussion about whether to seek a New Source Review permit for any project:

> Q. Even though you were plant manager, though, you had no involvement at all in the decision of whether to seek a New Source Review permit for either of the projects at issue in this case, right?
>
> A. I was not involved with that. We had an environmental department that took care of those kind of items. I was not involved.
>
> Q. And by "not involved," I mean, you didn't have a single discussion with anyone about the decision of whether to seek a New Source Review permit?
>
> A. No, I did not.
>
> Q. And, in fact, throughout your career at Ameren you've never had a single discussion with anybody about whether to seek a New Source Review permit for any project, right?
>
> A. No, I have not.

Tr. Vol. 7-B, 64:6-20.

The project justification packages that Ameren regularly put together as part of the work approval process included a checkbox asking whether the proponent had assessed

"Legal/Environmental" risks. FOF 388. But as one engineering manager testified, he could not "recall that box ever being checked" and had no idea what it meant. FOF 389. Each project had to be approved by a series of managers and executives, even the company CEO and board of directors. FOF 135–37. But the Environmental Services Department, charged with assessing NSR applicability, was not asked to approve the projects.

As a result, Ameren's PSD process suffered from two major flaws: the employees charged with assessing applicability started with an incorrect understanding of the law and lacked a meaningful understanding of the facts of the projects. In addition to these procedural flaws, for the reasons that follow, the actual analyses Ameren did "conduct" (for Unit 2 only) provide no basis for finding that Ameren could have reasonably expected the project would not significantly increase net emissions.

2. Unit 1

Ameren concedes that it performed no numerical calculation for the Unit 1 project.[24] FOF 391. Whatever qualitative analysis may have been done at the time cannot shield Ameren from liability now. Nor can the post-hoc analysis offered at trial by testifying expert Sandra

[24] Ameren argued for the first time in its post-trial brief that it was not required to perform a numerical calculation at Unit 1 because the provision of the 2002 Reform Rules requiring such calculations be performed was on remand at the relevant time. Ameren's argument fails. Even though a portion of the rule was on remand at the time, the Missouri SIP and EPA still required sources to maintain these records. *See* 71 Fed. Reg. 36,486, 36,487-88 (June 27, 2006); *see also* US Resp. Br. (Doc. 838) at 47-48. Moreover, as Ameren itself points out, the United States has not brought a record-keeping case and is not seeking judgment that Ameren failed to maintain the necessary records. Rather, the relevant issue is whether Ameren reasonably should have expected emissions to increase because of the projects. Whether Ameren performed a numerical calculation at all is certainly relevant to that inquiry and will, accordingly, be considered.

Ringelstetter, who used an inapt modeling run and incorrect application of the demand growth exclusion.

As an initial matter, there is no contemporaneous evidence that Ameren performed any assessment of the Unit 1 project. Mr. Boll testified that Ameren performed a qualitative emissions analysis for the projects in 2005. FOF 390, 391. But this analysis did not even rise to the back-of-an-envelope level—there is no written record of any such analysis. Moreover, because Mr. Boll and Mr. Whitworth made clear they only considered the maximum continuous rating of the unit, any qualitative analysis they did "conduct" did not comply with NSR requirements and therefore was not reasonable under the law. *Id.*

The post-hoc analysis performed by Ms. Ringelstetter does nothing to support Ameren's belief that emissions would not increase at Unit 1. Despite presumably having access to scores of ProSym modeling runs that projected Unit 1's post-project operations, Ms. Ringelstetter selected a run with two key flaws. First, according to her trial testimony, the run actually overstated emissions, so she adjusted it downward. FOF 454. Notably, other runs had no such issue, and Ameren itself never saw the need to adjust the run. FOF 454. Second, the run intentionally depressed output from Unit 1 for the full five years following the project based on the potential for the unit to provide ancillary services.[25] FOF 448, 449, 453. Ameren did not provide any evidence to support this assumption other than the testimony of Ms. Ringelstetter herself. Ms. Ringelstetter testified the modeling assumption was "entirely appropriate" and yet did not offer any document or specific fact to support that conclusion. She never even

[25] Ancillary services are services other than simple electric generation that utilities provide to keep the electric grid operating reliability. FOF 439.

mentioned ancillary services, spinning reserves, or regulation hours in her expert report. FOF 451. Moreover, the limited evidence in the record contradicts her opinion:

1. The only evidence that Ameren may have expected to provide some ancillary services with the Rush Island units around the time the boiler upgrades were performed is a short-term contract between Ameren Missouri and its Illinois affiliates. But that contract does not require anything specific of the Rush Island units in particular; in fact, it gave Ameren Missouri flexibility to provide the services from a number of different units. FOF 442.

2. Whatever effect the contract may have had on operations of the Rush Island units, the effect was never expected to last. The contract was never intended to extend beyond the inauguration of MISO's regional ancillary services market (originally scheduled in 2008 and then delayed to January 2009). FOF 440. Ameren's witnesses all agreed that once MISO implemented its ancillary services market the Rush Island units would not be providing such services at it does not make economic sense to hold back such cheap, reliable sources of generation. In fact, Ameren's head modeler told the Missouri Public Service Commission in that it did not make sense to model those services because they were based on a "short-term contract that will end when the MISO ancillary service market begins." FOF 445.

Selecting a run which depressed output for five years by modeling ancillary services at the Rush Island Unit 1 that—if ever they had an impact on operations—would last no more than two years after the project runs afoul of the regulations' requirement to "consider all relevant information" and use the highest year of post-project emissions. 40 C.F.R. § 52.21(b)(41)(ii)(*a*).[26]

3. Unit 2

While Ameren did at least perform numerical analyses for Unit 2, these analyses are no more compelling than its qualitative analysis for Unit 1.

As an initial matter, even though PSD analyses should be completed before beginning construction, Ameren did not complete any numerical analysis for Unit 2 until after the project work started. FOF 398-401. Ameren began its "Original" analysis at the end of 2009, which

[26] After using an inappropriate modeling run to obtain projected emissions, Ms. Ringelstetter misapplied the demand growth exclusion, as described in Subsection III.B of my Conclusions of Law.

relied on a January 2010 modeling run. By the time that analysis was done, the project was underway and it was too late for Ameren to comply with the law if a permit was required. Moreover, the work had been *approved* for four years at that point. The work was first approved in 2005 and then reassessed in a process that culminated with the final approval from the Board of Directors in August 2009. FOF 400.

Mr. Hutcheson testified at trial that the Original Unit 2 emissions calculation was one of about two dozen requested at the same time by Ameren's legal department. FOF 399. The projects to be assessed were a mix of past and future projects. *Id.* For Unit 2, the request came well after the project had been fully approved. FOF 400. This type of afterthought analysis (even if it had been finished just before the start of construction instead of just after) does not serve as a reasonable emissions calculation or prevent a finding of liability, particularly where the analysis fails to account for the company's actual expectations of performance improvements, as discussed below.

Ameren's "Amended" Unit 2 analysis is not helpful because it was not performed until even later and was only performed well after the project was completed, after Ameren received the Notice of Violation from EPA, after this lawsuit was filed, and only upon the request of Ameren's in-house counsel. FOF 401, 405-406. Ameren's in-house counsel asked the Environmental Services Department to perform this post-project amended "expectations" analysis to include the results of the amended EDF case that counsel had previously asked Mr. Hutcheson to run. That case was modeled to include additional efficiency improvements that had been left off from the Original run. FOF 401-407. Because the Amended analysis was performed under these circumstances and presumably for the purpose of this litigation, any credibility the analysis might otherwise have is severely diminished. Ameren's expert, Mr.

King, testified that he would not perform an NSR analysis based on a modeling run that was created just for NSR purposes, agreeing that in using such a run, a source runs the risk of looking like it was "cooking the forecast" to project no emissions increase. FOF 408.

In addition to these procedural flaws, the analyses Ameren actually did conduct suffered from considerable substantive flaws. Ameren's Original analysis failed to fully incorporate the improved availability the company expected after the project. The modeling run used for the projection assumed 95% availability for Unit 2 after the project. FOF 257, 410. But, as discussed in Subsection II.B.2 above, Ameren expected that the best years after the project would be 2–3% higher than that, based on its experience with Unit 1's record availability in 2008. The justification seeking ultimate approval for the project was based on an availability of nearly 97%. The regulations require Ameren to consider the highest year of emissions. 40 C.F.R. § 52.21(b)(41)(i). By limiting availability to 95%, Ameren failed to perform a reasonable analysis under the PSD rules.

Even without fully accounting for the project's effects, Ameren's analysis would have shown an NSR-triggering increase except for what Ameren excluded based on its capable of accommodating analysis. In calculating the capable of accommodating number, however, Ameren posited that the unit could have run all available hours *and* that it could have polluted at its 95th percentile emissions rate. FOF 412. The effect was that the total capable of accommodating number was more SO_2 per year than Ameren had emitted since 1995 (when Acid Rain rules were taking effect). FOF 417. Had Ameren used a more realistic emissions rate, its own analysis would have shown that it was *not* capable of accommodating the projected increase. FOF 413–16, 419, 420.

The post-hoc analysis by Ms. Ringelstetter begins with the same flaw as Mr. Hutcheson's calculation. Ms. Ringelstetter also failed to properly account for the project. She used the same modeling run as Mr. Hutcheson and as a result did not account for Ameren's actual, expected highest year of availability and "business activity." In addition, she attributed the entire capacity gain modeled in that run to the turbine, despite the fact that Ameren expected increased capacity resulting from the boiler work as well, as described in Subsection II.B.2 above. FOF 430.

Finally, Ms. Ringelstetter did not do her own analysis of whether the increased emissions projected by the model were related to the project.[27] FOF 437. She simply assumed they were not. FOF 437–38. Because her assumptions are incorrect, Ms. Ringelstetter's analysis is not persuasive.

EVIDENTIARY ISSUES FROM TRIAL

At trial and in post-trial briefing, both parties moved to exclude, strike, or deem irrelevant certain testimony or exhibits. For the reasons stated below, to the extent I have relied on evidence and testimony challenged by either party in my findings of fact and conclusions of law set out above, the parties' motions are denied. To the extent I have not relied on the challenged evidence and testimony, the parties' motions are denied as moot.

I. AMEREN'S MOTIONS TO STRIKE TESTIMONY AND EVIDENCE

A. Ameren's Motions to Strike Mr. Koppe and Dr. Sahu's Testimony and Evidence Concerning the Causation of Actual Emissions Increases

In two motions filed during trial (Doc. 787 and 793), and in a motion filed along with its post-trial briefs (Doc. 832), Ameren moved to exclude certain testimony of Mr. Koppe and Dr. Sahu, along with related exhibits that were admitted into evidence during trial concerning

[27] Ms. Ringelstetter's analysis of the emissions that unit was capable of accommodating is also flawed, for the reasons described in Subsection III.B of my Conclusions of Law.

causation of the actual emissions increases. Ameren argues the testimony concerning the causation of the actual emissions increases are new, undisclosed opinions.

While Ameren argues that Mr. Koppe and Dr. Sahu's opinions are new, there is no dispute that both Mr. Koppe and Dr. Sahu (1) analyzed the actual post-project data in their reports, the attachments, and their work papers, and (2) stated that the projected increases actually materialized. Both Mr. Koppe and Dr. Sahu disclosed in their reports that they analyzed post-project actual data. Likewise, their opinions about how the projects enable increased availability and contribute to increases in emissions were discussed in their reports and at their depositions. Ameren argues that because neither expert's report states their opinions in the precise words that Ameren thinks they should have used, the reports did not give notice that the projects at issue actually caused increases in emissions. But the notice required of expert opinions is not so formulaic. While undisclosed expert opinions are inadmissible, Rule 26(a)(2)(B) "contemplates that the expert will supplement, elaborate upon, explain and subject himself to cross-examination upon his report." *Thompson v. Doane Pet Care Co.*, 470 F.3d 1201, 1202-1203 (6th Cir. 2006) (holding the district court erred in excluding the testimony of an expert accounting witness because he failed to recite in his report that his opinion was based on "generally accepted accounting principles," the phrase used in the contract at issue in the case; further holding there was no authority for the "mechanical and formalistic ruling" that an expert's opinion must state such "magic words"); *see also Wood v. Robert Bosch Tool Corp.*, No. 4:13 CV 01888 TCM, 2015 WL 5638040, at *8 (E.D. Mo. 2015) (denying in part a motion to strike new expert opinion statements because the offered statement "clarifies [the expert witness's] earlier information, does not contradict it, and should not be surprising to Defendant or its experts"). For these reasons, and those set out in the United States' post-trial brief (*see*

Doc. 831 at 50-56) and its opposition to Ameren's motion to strike (*see* Doc. 836), Mr. Koppe and Dr. Sahu's challenged opinions are not "new opinions." Ameren had sufficient notice of both the United States' actual emissions case and of Mr. Koppe and Dr. Sahu's opinions.

Moreover, Ameren cannot show that it was prejudiced by the challenged testimony or the admission of the exhibits. The evidence the United States presented to show that the actual emissions increases were caused by the projects was also presented in the context of its expectations case regarding the expected causes of projected emissions increases, so the challenged testimony is in part cumulative evidence. Additionally, Ameren had the opportunity both during pre-trial discovery and during cross-examination at trial to test those opinions. *See* Doc. 831 at 50-56. Finally, Mr. Koppe's testimony regarding Ameren's full load tests and related exhibit 928 do not prejudice Ameren. Exhibit 928 is merely a summary exhibit of Ameren's own capability data. Ameren itself argued at summary judgment that such summary evidence containing simple mathematic calculations (averaging pre-project and post-project data and comparing them) is admissible. Moreover, Mr. Koppe considered the full load tests along with numerous other materials to reach his conclusion that the capacity increase was due to the projects, making the exhibit cumulative evidence.

Accordingly, I find that the opinions were sufficiently disclosed and that Ameren has not suffered any prejudice from the admission of that testimony because it had notice and opportunity to test it and because it is in part cumulative evidence. As a result, I will not strike Mr. Koppe and Dr. Sahu's testimony on the causation of the actual emissions, Mr. Koppe's testimony concerning the increased MW capability at Unit 2, or the related challenged exhibits.

B. Ameren's Motion to Strike Dr. Hausman's Testimony Criticizing Ms. Ringelstetter's Opinions

Ameren has also moved to strike certain testimony of Dr. Hausman, arguing that he offered new opinion testimony at trial when he criticized Ms. Ringelstetter's analysis. Ameren asks me to strike Dr. Hausman's testimony from the record per Fed. R. Civ. P. 26. In the challenged testimony, Dr. Hausman testified about the different ProSym runs he and Ms. Ringelstetter analyzed, which included a discussion of why he chose the particular run selected. This testimony is not a new opinion that should be stricken under Rule 26. Rather, as Rule 26 contemplates, Dr. Hausman's testimony merely clarified his previously disclosed opinion, explaining why he chose the ProSym run he used and how the different runs he and Ms. Ringelstetter used factored into the different conclusions each expert drew. *Thompson*, 470 F.3d at 1202-1203. Moreover, Ameren has not shown it was prejudiced by this testimony, as it had always had the opportunity to test the basis of Dr. Hausman's analysis. *See also* Doc. 836 at 17 (discussing the lack of prejudice to Ameren).

As a result, I will not strike Dr. Hausman's testimony concerning the differences between his and Ms. Ringelstetter's analyses because it is not undisclosed testimony and Ameren cannot show it was prejudiced by the testimony.

II. THE UNITED STATES' MOTION TO CURTAIL RE-LITIGATION OF THE LAW OF THE CASE

In its post-trial brief, the United States also raised an evidentiary issue, renewing its motion in limine to curtail Ameren's re-litigation of the law of the case. *See* Doc. 757; Doc. 758 at Section IV.B. The United States argues that three categories of evidence Ameren presented at trial are irrelevant and should be excluded:[28] (1) applicability analyses or permitting documents that were generated after the projects at issue in this case and involving different facilities operating under separate state implementation plans at different types of sources, (2) testimony from EPA or state agency staff regarding the operation and application of regulatory provisions, and (3) PowerPoint presentations and other pamphlets discussing NSR regulations.

Ameren argues that these categories of evidence are relevant, not to establish the reasonableness of any legal interpretation, but to establish the reasonableness of its engineering judgments, emissions analyses, and predictions of the future.

To the extent I rely on the challenged evidence in my findings and conclusions above, I will deny the United States' motion. To the extent I have not relied on the challenged evidence, the motion is denied is moot.

CONCLUSION

For the reasons set out above, I find that the United States has established by a preponderance of the evidence that Ameren violated the PSD and Title V provisions of the Clean Air Act. The 2007 project at Rush Island Unit 1 and the 2010 project at Rush Island Unit 2 were each major modifications under the PSD provisions of the Clean Air Act. Ameren violated the requirements of the PSD program by failing to obtain a preconstruction permit and install best available pollution control technology, among other requirements. Ameren also violated Title V of the Clean Air Act and its operating permit by performing a major modification without obtaining the required permit and by not including applicable requirements in its operating

[28] The United States seeks to exclude the following exhibits and testimony: Ameren exhibits BQ, PQ, PV, QJ, QS, RB, RC, RD, RE, RG, RH, RN, OY, OZ, PA, PF, and deposition testimony from David Campbell, Trial Tr. Vol. 12, 9:10-11:8; Gregg Worley, Trial Tr. Vol. 12, 4:2-5:22; and James Stewart, Trial Tr. Vol. 12, 11:4-13:2.

permit applications. As a result, I will enter a finding of liability against Ameren. A status conference will be set to address remedies.

Accordingly,

IT IS HEREBY ORDERED that Defendant Ameren Missouri is found liable under the Clean Air Act, 42 U.S.C. § 7401 *et seq*.

IT IS FURTHER ORDERED that a status conference to address remedies is set for **Wednesday, February 15, 2017 at 11:00 a.m.** in courtroom 16-South.

IT IS FURTHER ORDERED that the United States' Motion in Limine to Curtail Ameren's Re-Litigation of the Law of the Case #[757] is **DENIED** per my rulings above.

IT IS FURTHER ORDERED that Ameren's Motion to Treat Certain KDHE Produced Documents as Highly Confidential During Trial #[778] is **DENIED** as moot.

IT IS FURTHER ORDERED that Ameren's Motion to Bar Robert Koppe's New Causation Opinions #[787] is **DENIED** as moot.

IT IS FURTHER ORDERED that Ameren's Motion to Bar Dr. Ranajit Sahu's New Opinions #[793] is **DENIED** as moot.

IT IS FURTHER ORDERED that Ameren's Motion to Strike EPA's New Expert Opinion Evidence and Related Trial Exhibits #[832] is **DENIED** per my rulings above.

IT IS FURTHER ORDERED that the Parties' Joint Motion to Correct Clerk's Exhibit List #[829] is **GRANTED**.

RODNEY W. SIPPEL
UNITED STATES DISTRICT JUDGE

Dated this 23rd day of January, 2017.

United States Court of Appeals
For the Eighth Circuit

No. 19-3220

United States of America

Plaintiff - Appellee

Sierra Club

Intervenor - Appellee

v.

Ameren Missouri

Defendant - Appellant

Chamber of Commerce of the United States of America; American Chemistry Council; America's Power; Missouri Chamber of Commerce and Industry; National Association of Manufacturers; National Mining Association

Amici on Behalf of Appellant(s)

Appeal from United States District Court
for the Eastern District of Missouri - St. Louis

Submitted: December 16, 2020
Filed: August 20, 2021

Case No. EF-2024-0021
Schedule KM-r3

Before SMITH, Chief Judge, LOKEN and MELLOY, Circuit Judges.

SMITH, Chief Judge.

Ameren Missouri ("Ameren") appeals an adverse judgment of the district court in a Clean Air Act (CAA) enforcement action brought by the United States of America, acting at the request of the Administrator of the United States Environmental Protection Agency (EPA) (hereinafter, EPA or "government"). Ameren argues that the district court erroneously found it liable for not obtaining permits for projects at its Rush Island Energy Center ("Rush Island") and, as a result, assessed liability under the applicable federal regulations. In addition, Ameren maintains that the district court ordered legally flawed injunctions at both Rush Island and at a different plant, Labadie Energy Center ("Labadie"). We affirm the district court's liability determination, but we reverse in part the remedial portion of its order concerning the Labadie plant and remand for further proceedings consistent with this opinion.

I. *Background*

A. *Statutory and Regulatory Background of the CAA*

"Congress enacted the Clean Air Act Amendments of 1970 seeking to guarantee the prompt attainment and maintenance of specified air quality standards." *Sierra Club v. Otter Tail Power Co.*, 615 F.3d 1008, 1011 (8th Cir. 2010) (quotations omitted). In enacting the CAA amendments, Congress "directed EPA to devise National Ambient Air Quality Standards (NAAQS) limiting various pollutants, which the States were obliged to implement and enforce." *Id.* (quotation omitted). The New Source Performance Standards (NSPS) program was a key part of the CAA's regulatory scheme. *Id.* The NSPS program "required EPA to develop technology-based performance standards designed to limit emissions from major new sources of pollution." *Id.* (quotation omitted). Both newly constructed facilities and modified facilities with increased emissions constitute "[n]ew sources." *Id.* "It is 'unlawful for any owner or operator of any new source to operate such source in violation of' applicable performance standards." *Id.* (quoting 42 U.S.C. § 7411(e)).

The NSPS program, however, "did too little to 'achieve the ambitious goals of the 1970 amendments.'" *Id.* (quoting *Env't Def. v. Duke Energy Corp.*, 549 U.S. 561, 567 (2007)). "Merely setting emissions limits failed to improve air quality in those areas that had already attained the minimum standards of the NAAQS because polluters had no incentive to diminish emissions below the established limits." *Id.* As a result, in 1977, Congress amended the CAA "to add the 'Prevention of Significant Deterioration' (PSD) program, which seeks to ensure that the 'air quality floor' established by the NAAQS does not 'in effect become a ceiling.'" *Id.* (quoting *Sierra Club v. Thomas*, 828 F.2d 783, 785 (D.C. Cir. 1987)).

The PSD program limited construction of major emitting facilities with specified preconditions. 42 U.S.C. § 7475(a). "The term 'construction' when used in connection with any source or facility, includes the *modification* . . . of any source or facility." *Id.* § 7479(2)(C) (emphasis added). "The term 'modification' means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." *Id.* § 7411(a)(4).

The PSD program prohibits the construction of a major emitting facility unless preconditions are satisfied. One precondition is that the proposed facility obtain a permit setting forth applicable emission limitations. *Id.* § 7475(a)(1). Another precondition is that "the owner or operator of such facility demonstrates . . . that emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of" prescribed air quality standards. *Id.* § 7475(a)(3). The PSD program also requires the owner or operator to install "the best available control technology for each pollutant subject to regulation . . . emitted from, or which results from, [the proposed] facility." *Id.* § 7475(a)(4). The "'best available control technology' (BACT) . . . . is not a particular type of technology." *Otter Tail*, 615 F.3d at 1011 (quoting 42 U.S.C. § 7475(a)(4)). Instead, the BACT "is an 'emission limitation based on the maximum degree of reduction of each pollutant subject to regulation . . . which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable' for the facility in question." *Id.* (alteration in original) (quoting 42 U.S.C. § 7479(3)).

Only *major* modifications to emitting sources are subject to PSD review. *Ala. Power Co. v. Costle*, 636 F.2d 323, 399 (D.C. Cir. 1979). "Major modification means any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase . . . of a regulated NSR [New Source Review] pollutant . . . ; and a significant net emissions increase of that pollutant from the major stationary source." 40 C.F.R. § 52.21(b)(2)(i).

For projects that only involve "existing emissions units," the EPA applies what it calls the actual-to-projected-actual applicability test. *Id.* § 52.21(a)(2)(iv)(c).[1] To apply this test, the "baseline actual emissions" must first be calculated. "Baseline actual emissions means the rate of emissions, in tons per year, of a regulated NSR pollutant . . . ." *Id.* § 52.21(b)(48).

---

[1]This test provides: "A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions . . . and the baseline actual emissions . . . , for each existing emissions unit, equals or exceeds the significant amount for that pollutant . . . ." *Id.*

> Next, the "projected actual emissions" must be calculated by determining the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12–month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source.

Id. § 52.21(b)(41)(i). An "owner or operator of the major stationary source . . . [must] consider all relevant information" to calculate "the projected actual emissions." *Id.* § 52.21(b)(41)(ii)(a). "[A]ll relevant information . . . include[s] . . . historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans under the approved State Implementation Plan . . . ." *Id.* But the owner or operator "[s]hall exclude" from the projected actual emissions "that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions . . . and that are also unrelated to the particular project, including any increased utilization due to product demand growth." *Id.* § 52.21(b)(41)(ii)(c). The "exclu[sion] [of] increases stemming from unrelated demand growth" is referred to as "the 'demand growth exclusion.'" *New York v. EPA*, 413 F.3d 3, 16 (D.C. Cir. 2005).

Finally, the baseline actual emissions calculation is subtracted from the projected actual emissions calculation to determine if the difference between the numbers is "significant." 40 C.F.R. § 52.21(a)(2)(iv)(c). A table in the regulations sets forth the numeric thresholds that are considered "significant" for each regulated pollutant. *Id.* § 52.21(b)(23)(i). If the difference in the projected actual emissions and the baseline actual emissions is significant, *see id.*, then a permit is required before beginning construction on the project. *Id.* § 52.21(a)(2)(iii).

The actual-to-projected-actual test is distinguishable from "a potential-to-potential test," which "compare[s] past potential emissions with future potential emissions." *New York*, 413 F.3d at 17. "[T]he plain language of the CAA indicates that Congress intended to apply NSR to changes that increase actual emissions instead of potential or allowable emissions . . . ." *Id.* at 40.

B. *Missouri's State Implementation Plan*

"The PSD program is primarily implemented by the states through 'state implementation plans' (SIPs)." *Otter Tail*, 615 F.3d at 1011 (citing 42 U.S.C. § 7471). While "[s]tates have broad discretion in designing their SIPs," their "plans must include certain federal standards." *Id.* The EPA reviews and approves States' SIPs. *Id.* at 1011–12.

Missouri expressly incorporated the EPA's PSD regulations into its SIP ("Missouri SIP"). *See* Mo. Code Regs. Ann. tit. 10, § 6.060(8)(A) (2007) ("All of the subsections of 40 CFR 52.21, other than [certain subsections], are hereby incorporated by reference."). The EPA approved Missouri's SIP, explaining that "the provisions of § 52.21 supersede the state provisions for purposes of the PSD program." Approval and Promulgation of Implementation Plans; State of Missouri, 71 Fed. Reg. 36,486-02, 36,487 (June 27, 2006); *see also id.* at 36,489 ("This revision also incorporates by reference the other provisions of 40 CFR 52.21 as in effect on July 1, 2003, which supersedes any conflicting provisions in the Missouri rule. Section 9, pertaining to hazardous air pollutants, is not SIP approved.").

C. *Title V Program*

In addition to the CAA's PSD program, "the CAA . . . require[s] each covered facility to obtain a comprehensive operating permit setting forth all CAA standards applicable to that facility." *Otter Tail*, 615 F.3d at 1012 (citing 42 U.S.C. § 7661a(a)). The operating permits "incorporate into a single document all of the CAA requirements governing a facility. Similar to other CAA programs, Title V is implemented primarily by the states under EPA oversight. In states with EPA approved programs," the state permitting authority issues the Title V permits. *Id.* (citations omitted). These permits "are subject to EPA review and veto." *Id.* The EPA has approved Missouri's operating permit program under Title V of the CAA. This program is incorporated into the Missouri SIP. *See* Mo. Code. Regs. Ann. tit. 10, § 6.065 (2007).

D. *Factual Background and Procedural History*

This case involves Ameren's Rush Island power plant, which includes two coal-fired electric generating units, Units 1 and 2. These units began service in 1976 and 1977. They were grandfathered into the PSD program. They do not have air pollution control devices for sulfur dioxide. Rush Island currently emits approximately 18,000 tons of sulfur dioxide per year. Small performance improvements or increases in unit availability can result in a 40-ton increase in sulfur dioxide. For the Rush Island units to emit more than 40 tons of sulfur dioxide, it takes only an availability of 0.3 percent or an additional 21 hours of operation at full power.

By 2005, problems with Units 1's and 2's major boiler components forced Ameren to frequently take the units out of service. This made the units underperform and reduced the amount of electricity Ameren could generate and sell from the units. Ameren decided to replace the problem components with new, redesigned components. Ameren, however, did not do any quantitative PSD review for Unit 1's project and belatedly performed PSD review for Unit 2's project. Ameren proceeded with the projects without reporting its planned modifications to the EPA, obtaining the necessary permits, or installing pollution controls. To replace the major boiler components, Ameren took Unit 1 offline in 2007 and Unit 2 offline in 2010. Each unit was completely offline for three to four months to complete the projects. Ameren spent more than $20 million per project.

By replacing the failing components with new, redesigned components, Ameren expected unit availability to improve by much more than 0.3 percent, allowing the units to operate hundreds of hours more per year after the projects. Ameren expected to use that increased availability (and increased capacity for Unit 2) to burn more coal and generate more electricity. Unavoidably, the units would also emit more sulfur dioxide pollution.

As Ameren expected, its replacement of the failing components resulted in increased availability at Units 1 and 2 by eliminating hundreds of outage hours per year. And, Unit 2's capacity increased. The units ran more, burned more coal, and consequently emitted hundreds of tons more sulfur dioxide per year because of the operational increases.

The government filed suit against Ameren in response to the projects. It alleged that Ameren violated the CAA, the Missouri SIP, and Ameren's Rush Island Plant Title V Permit by performing major modifications on Units 1 and 2 without obtaining the necessary permits, installing pollution control technology, or otherwise complying with all applicable requirements.

1. *Liability Phase*

a. *Summary Judgment*

The district court bifurcated the proceedings into a liability phase and a remedy phase. During the liability phase, the district court issued two summary-judgment orders. In the first summary-judgment order, the district court rejected Ameren's argument that the major-modification test set forth in the federal regulations did not provide the relevant PSD liability test because the Missouri SIP elsewhere separately defined *modification* to mean that "the source's *potential* emissions would significantly increase." *United States v. Missouri (Ameren I)*, 158 F. Supp. 3d 802, 808 (E.D. Mo. 2016) (emphasis added). According to Ameren, the government could not establish liability because it never alleged that "the [Rush Island] projects increased the units' *potential* emissions." *Id.* (emphasis added). In rejecting this argument, the court first explained that "the PSD rules impose their own independent, stand-alone applicability provisions in Section (8) of the Missouri SIP (incorporating EPA's PSD rules set out at 40 C.F.R. 52.21)." *Id.* at 809. The court reasoned that "the PSD-specific applicability language should trump the general applicability language in Section (1) of the [Missouri] SIP." *Id.*

The court next cited the "well-established" "regulatory and statutory history of the PSD rules" as leaving "no doubt that the federal PSD rules are focused on 'major modifications' which are based on actual emissions determinations," not potential emissions. *Id.* at 810. The court found "most persuasive[] [that the] EPA's approval of the SIP provided that the CAA and the program requirements as set out in 40 C.F.R. § 52.21 would supersede any conflicting provisions in the state SIP." *Id.* (citing Approval and Promulgation of Implementation Plans; State of Missouri, 71 Fed. Reg. at 36,489).

Finally, the district court concluded that Ameren urged an interpretation of the SIP that would conflict with the PSD rules and, in the court's view, "render a portion of the PSD rules superfluous." *Id.*

In its second summary-judgment order, the district court addressed causation and "the PSD program's demand growth exclusion." *United States v. Ameren Mo. (Ameren II)*, No. 4:11-cv-77-RWS, 2016 WL 728234, at *9 (E.D. Mo. Feb. 24, 2016). According to the district court, "two main criteria . . . determine whether a major source of pollution must obtain a PSD permit. First, there must be a physical change, and second, that change would be expected to cause a significant net increase in actual emissions." *Id.* The demand growth exclusion is relevant to the second criteria—"how to determine whether the physical changes would have caused a significant net emissions increase, and if so, whether any of the increased emissions may be excluded from review under the 'demand growth exclusion.'" *Id.* The district court rejected Ameren's proposed interpretation of the exclusion as applying to "any emissions increases a unit could have accommodated at baseline." *Id.* Instead, the court held "that the demand growth exclusion requires a showing that the unit 'could have accommodated' the emissions at baseline *and* that . . . those increases were unrelated to the project." *Id.* at *11. The court also held that "while it remains the EPA's burden to prove that Ameren should have expected the projects to cause an increase in emissions, the burden is Ameren's to prove that the demand growth exclusion applies." *Id.*

Also in the second summary-judgment order, the district court addressed Ameren's argument that "because EPA brought suit *after* the challenged projects' completion," it was "limited to an 'actual increase' theory." *Id.* at *13. Under Ameren's actual-increase theory, the EPA would have to show that "the Projects actually caused emissions to increase" to establish Ameren's liability. *Id.* By contrast, under "an 'expectations' theory," the EPA could establish liability by showing "that Ameren 'should have expected' the Projects to increase emissions." *Id.* The court held that the government could proceed on the expectations theory. *Id.* at *13–16.

Additionally, the court considered Ameren's argument that the government had to "come forward with admissible evidence of what a reasonable power plant operator or owner would expect, and its failure to do so [was] fatal to EPA's expectations theory case." *Id.* at *18. But the court agreed with the government "that no special standard of care evidence is required for the factfinder to be able to determine whether a reasonable power plant operator or owner would have expected the projects to cause a significant emissions increase"; instead, "the PSD regulations themselves . . . guide the factfinder's determination." *Id.*

Finally, the court rejected Ameren's argument that the court "lack[ed] subject matter jurisdiction to hear EPA's [Title V] claim that Ameren [was] operating under an inadequate or deficient permit." *Id.* at *24.

b. *Trial*

Subsequently, the district court held a trial on the merits. After trial, the district court entered an order setting forth its factual findings and legal conclusions. *See United States v. Ameren Mo. (Ameren III)*, 229 F. Supp. 3d 906 (E.D. Mo. 2017). The court concluded that Ameren's Rush Island overhauls were major modifications that triggered PSD pollution-control requirements. The district court found that "[t]he emissions evidence show[ed] [that] an increase related to the projects should have been expected and actually occurred." *Id.* at 997 (emphasis omitted). The court identified categories of evidence that "all establish that there is a significant net [sulfur dioxide] increase of more than 40 tons that was caused by the projects." *Id.* at 998.

First, the court identified "[t]wo key—and undisputed—characteristics of the Rush Island units." *Id.* at 988. The first characteristic was that "the Rush Island units are big sources of pollution." *Id.* The second characteristic was that "the Rush Island units are 'baseload' units" that are "cheap sources of electricity" and "operate as much as they can." *Id.* According to the court, "[t]hese two facts lead to a logical conclusion [that] if the Rush Island units are upgraded so they *can* generate more electricity, they *will*. Performance improvements have a direct impact on annual generation and pollution levels." *Id.*

Second, Robert Koppe, a power plant performance expert, opined that the Rush Island's plant availability increased because it replaced "these problematic components." *Id.* at 989. Thereafter, "Dr. Ranajit Sahu, a permitting engineer and expert for the United States, took Mr. Koppe's findings on expected improved availability and used them to calculate the expected additional pollution that would result from the improvements." *Id.* at 990. He "calculated an expected increase in emissions of 608 tons of [sulfur dioxide] post-project for Unit 1." *Id.* And, "[b]ased on Mr. Koppe's prediction of regained availability, . . . Dr. Sahu calculated an expected increase of 415 tons per year of [sulfur dioxide] in Unit 2 that would result from the availability improvement alone." *Id.* at 992.

Third, Dr. Ezra Hausman, a modeler and market consultant with 20 years' experience in the electric industry, explained that the "sophisticated computer modeling program" that Ameren used "to model and predict the Rush Island units' fuel needs . . . for the years after the 2007 and 2010 major boiler outages" "showed that both a unit's capacity level and its availability are linearly related to the unit's projected coal consumption." *Id.* at 994, 995. Thus, "if Ameren increased the number of hours its Rush Island units were able to run, or if the company enabled the units to operate at higher output levels during those hours, then the units would . . . burn[] more coal and, as a result, emit[] more pollution." *Id.* at 994–95. Dr. Hausman's "results show[ed] that Ameren's modeling would predict significant emissions increases at the Rush Island units as a result of the projects." *Id.* at 996.

Finally, "the actual post-project data" showed "a significant net [sulfur dioxide] increase of more than 40 tons that was caused by the projects." *Id.* at 998. Both units were available more and operated every hour that they were available. Both units also increased their maximum generating levels. This resulted in both units increasing their sulfur dioxide pollution.

In summary, the court determined that "[b]ased on the known facts that the Rush Island units are low-cost, baseload units, common sense compels the same conclusion: improving availability or capacity at baseload units like Rush Island will result in additional operations and pollution." *Id.*

Regarding liability, the district court also rejected Ameren's defenses. First, the district court concluded that Ameren failed to satisfy "its burden of proving that the Rush Island projects fall within the narrow routine maintenance exemption." *Id.* at 1003. The court characterized "[t]he 2007 and 2010 major boiler outages [as] unprecedented events for Rush Island Units 1 and 2—they were the centerpieces of the 'most significant' outages in plant history." *Id.* (citation omitted).

Second, the court rejected Ameren's argument that any increases in production and pollution were merely the result of demand growth that should be excluded from the liability assessment. According to the court, the "relevant information" that Ameren had "showed that the Rush Island units' performance would improve, resulting in increased generation and emissions." *Id.* at 1010.

In summary, the district court "enter[ed] a finding of liability against Ameren," concluding that the Rush Island Unit 1 and 2 projects described above were major modifications under the CAA, Ameren violated the PSD program's requirements "by failing to obtain a preconstruction permit and install best available pollution control technology," and Ameren violated Title V of the CAA. *Id.* at 1017.

2. *Remedy Phase*

a. *Summary Judgment*

After entering its post-trial order on liability, the district court proceeded to the remedy phase. The court addressed the parties' summary-judgment motions. First, the court rejected Ameren's argument "that the Clean Air Act does not authorize injunctions as a remedy for past violations." *United States v. Ameren Mo. (Ameren IV)*, 372 F. Supp. 3d 868, 871 (E.D. Mo. 2019). According to the court, "[t]he plain language of § 7413(b) gives the EPA authority to 'commence a civil action' for injunctive relief or civil penalties, 'or both,' whenever a person '*has* violated or is in violation of any requirement or prohibition of' EPA air quality control programs." *Id.* (quoting 42 U.S.C. § 7413(b)). The court reasoned that § 7413(b)'s plain "language places no restriction on injunctive relief for past violations" and instead "authorizes the EPA to seek injunctive relief whenever a person *has violated* the Clean Air Act." *Id.*

In addition, the district court rejected Ameren's argument that the court could not "order injunctive relief that includes emissions reductions or control technology at the Labadie Energy Center (Labadie) coal-fired power plant." *Id.* at 874.

b. *Trial*

The district court subsequently held a remedy trial. Following the trial, the court issued an order imposing a two-pronged remedy with the purpose of "[(1)] bring[ing] Ameren's Rush Island facility into compliance with the law and [(2)] . . . remediat[ing] the harm from the more than 162,000 tons—and counting—in excess [sulfur dioxide] that Rush Island emitted after Ameren failed to obtain a PSD permit there." *United States v. Ameren Mo. (Ameren V)*, 421 F. Supp. 3d 729, 802 (E.D. Mo. 2019).

As to compliance, the district court concluded that "Ameren must make Rush Island compliant by obtaining a PSD permit with emissions limitations based on wet FGD [flue gas desulfurization technology]" used as the BACT. *Id.* at 806 (emphasis omitted). The court determined that FGD technology is technically and economically feasible and "can remove 95% or more of [sulfur dioxide] emissions." *Id.* at 812.

As to remediation, the district court concluded that "Rush Island's excess pollution is best remediated by decreasing emissions at the nearby Labadie Energy Center." *Id.* at 789 (emphasis omitted). Labadie consists of four coal-burning units and is located 35 miles west of St. Louis. Ameren argued that imposition of the remedy was "extreme" and "constitute[d] a penalty" "because Labadie is 'totally innocent,' and Ameren has not violated the Clean Air Act there." *Id.* at 820. The district court rejected Ameren's argument, reasoning that its "remedy is based on straightforward equitable principles and the authority [it] ha[s] under the Clean Air Act 'to restrain' violations, 'to require compliance,' and 'to award any other appropriate relief.'" *Id.* (quoting 42 U.S.C. § 7413(b)). According to the court, its remedy was "narrowly tailored" because "a tight geographic nexus [exists] between the harms Rush Island caused and the benefits gained through reducing Labadie's emissions. Pollution from Labadie affects the same communities as those affected by Rush Island, and to the same degree." *Id.* at 820–21. The court reasoned that its remedy "achieve[d] the maximum possible environmental benefit": "When Ameren reduces emissions at Labadie commensurate with the excess emissions from Rush Island, Ameren will have put the public in the place it would have been absent Ameren's Clear Air Act violation." *Id.* at 821. The court explained that "Ameren's ton-for-ton reductions at Labadie will lower the risks of premature mortality and disease in the same communities impacted by Ameren's Rush Island violations." *Id.*

The court rejected Ameren's argument "that any injunction against its Labadie plant would constitute a penalty." *Id.* While the court acknowledged it could not "issue injunctive relief that would constitute a penalty," it concluded that "[b]y ordering emissions reductions up to, but not surpassing, the excess emissions from Rush Island, [the court was] ordering relief that goes exactly to 'remedying the damage caused to the harmed parties by the defendant's action.'" *Id.* (quoting *United States v. Ameren Mo.*, No. 4:11-cv-77-RWS, 2016 WL 468557, at *1 (E.D. Mo. Feb. 8, 2016)). The court "order[ed] Ameren to base its relief at Labadie on DSI [dry sorbent injection] control technology" "[t]o . . . ensure that any relief at Labadie does not surpass the damage caused by Rush Island." *Id.* Installation of DSI technology on Labadie's units would allow Ameren to "operate DSI for as many years as necessary to remediate Rush Island's excess emissions[] and terminate its use of DSI without suffering significant lost capital assets." *Id.* The court "order[ed] Ameren to begin operating Labadie with DSI, or a more effective pollution control, beginning no later than three years after [its] order." *Id.* at 822.

3. *Summary*

In summary, the district court found Ameren in violation of the CAA for "mak[ing] major modifications to expand Rush Island's capacity" without "apply[ing] for a PSD permit and meet[ing] reduced emissions requirements." *Id.* at 824. By failing to "apply for the required PSD permit," Ameren "skirted PSD's requirement to install the best available technology to control the pollution Rush Island emits." *Id.*

"To remedy [Ameren's] violation of the Clean Air Act," the district court ordered Ameren to "apply for a PSD permit for Rush Island within ninety days, propose wet FGD as BACT in its permit application, and implement BACT no later than four and one-half years from [the] order." *Id.* "In addition to the relief [the court] order[ed] at Rush Island, [it] also order[ed] Ameren to reduce its pollution at Labadie in an amount equal to Ameren's excess emissions at Rush Island." *Id.* It left Ameren the option whether to "install[] DSI or some other more effective pollution control at Labadie." *Id.*

II. *Discussion*

Ameren appeals the district court's orders. It raises five arguments: (1) the Rush Island projects did not require permits under the Missouri SIP; (2) the Rush Island projects did not constitute major modifications; (3) the district court lacked jurisdiction under Article III and statutory authority under the CAA to enter the injunctions; (4) the injunctive relief ordered at Labadie is punitive, not remedial, and therefore prohibited; and (5) the district court lacked jurisdiction over the Title V claims. We address each in turn.

A. *Missouri SIP*

Ameren first argues that "under the plain language of Missouri's SIP, permits are required only for increases in potential emissions" and "it [is] undisputed that the [Rush Island] Projects would not, and did not, increase potential emissions." Appellant's Br. at 30. According to Ameren, the district court erroneously "substituted the federal regulations' applicability standard," which "nullified the SIP Permit Rule's Applicability Provision." *Id.* at 30–31.

The Missouri SIP identifies which construction or modification projects at emission sources require prior construction permits. Mo. Code Regs. Ann. tit. 10, § 6.060 (2007). Ameren cites to § 6.060(1) of the Missouri SIP, entitled "Applicability" ("Applicability Section"). This section governs Missouri's air quality construction permit programs. The Applicability Section provides, in relevant part, that

> [n]o owner or operator shall commence construction[2] or *modification* of any installation subject to this rule, begin operation after that construction or *modification*, or begin operation of any installation which has been shut down longer than five (5) years without first obtaining a permit from the permitting authority under this rule.

Mo. Code Regs. Ann. tit. 10, § 6.060(1)(C) (2007) (emphases added).

In turn, the Missouri SIP offers two definitions of *modification*. First, it generally defines "[m]odification" as "[a]ny physical change, or change in method of operation of, a source operation or attendant air pollution control equipment which would cause an increase in *potential emissions* of any air pollutant emitted by the source operation." *Id.* § 6.020(2)(M)(10) (emphasis added). "Potential to emit" means

[2]"It is undisputed that the projects at issue were not 'construction' as defined by the Missouri SIP or the PSD rules." *Ameren I*, 158 F. Supp. 3d at 809 n.5.

the unit's ability to emit at full design capacity "assuming continuous year-round operation." *Id.* at § 6.020(2)(P)(19).

Second, the Missouri SIP separately defines "Title I modification." *Id.* § 6.020(2)(M)(11). A "Title I modification" is "[a]ny modification that requires a permit under *10 CSR 10-6.060 section (7) or (8)*, or that is subject to any requirement under 10 CSR 10-6.070 or 10 CSR 10-6.080." *Id.* § 6.020(2)(T)(3) (emphasis added).[3]

Ameren maintains that the Missouri SIP limits PSD applicability to only projects increasing both actual *and* potential emissions. According to Ameren, the Missouri SIP's Applicability Section and definitional sections mean that "[i]f a project would *not* increase a unit's potential emissions, it is *not* a modification and does *not* trigger permitting under the Applicability Provision." Appellant's Br. at 35. Because the government "never alleged that the projects increased the units' potential emissions, Ameren argues that it [was] entitled to full summary judgment." *Ameren I*, 158 F. Supp. 3d at 808–09.

Ameren, however, overlooks that, in contrast to the general definition of *modification* in § 6.020(2)(M)(10), § 6.060(8)(A) of the Missouri SIP contains "*PSD-specific* applicability language." *Id.* at 809 (emphasis added) (citing *RadLAX Gateway Hotel, LLC v. Amalgamated Bank*, 566 U.S. 639, 645 (2012)). That section—expressly referenced in the Missouri SIP's definition of "Title I modification"—provides, in relevant part:

---

[3]In addition to defining *modification*, the Missouri SIP independently defines "[m]ajor modification" as "[a]ny physical change or change in the method of operation at an installation or in the attendant air pollution control equipment that would result in a significant net emissions increase of any pollutant." *Id.* § 6.020(2)(M)(3). The Missouri SIP uses the term *major modification* in a section concerning BACT. *See id.* § 6.020(2)(B)(5).

(8) Attainment and Unclassified Area Permits.

(A) *All of the subsections of 40 CFR 52.21* other than (a) Plan disapproval, (q) Public participation, (s) Environmental impact statements and (u) Delegation of authority *are incorporated by reference*. 40 CFR 52.21 as used in this rule refers to 40 CFR 52.21 promulgated as of July 1, 2003 as published by the Office of the Federal Register, U.S. National Archives and Records, 700 Pennsylvania Avenue NW, Washington, D.C. 20408. This rule does not incorporate any subsequent amendments or additions.

Mo. Code Regs. Ann. tit. 10, § 6.060(8)(A) (2007) (emphases added).

In turn, the federal regulation referenced in § 6.060(8)(A) of the Missouri SIP provides that the PSD's "[a]pplicability procedures" "apply to the construction of any new major stationary source or the *major modification of* any existing major stationary source" located in a PSD area. 40 C.F.R. § 52.21(a)(2)(ii) (emphasis added). The regulations explicitly define major modification. "*Major modification* means any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase . . . of a regulated NSR pollutant . . . ; and a significant net emissions increase of that pollutant from the major stationary source." *Id.* § 52.21(b)(2)(i) (emphasis added). "A . . . major modification shall meet each applicable emissions limitation under the [SIP] and each applicable emissions standard and standard of performance under 40 CFR parts 60 and 61." *Id.* § 52.21(j)(1).

The federal regulation establishes that a *major modification* triggers the PSD requirements. According to the regulation, "[n]o . . . major modification . . . shall begin actual construction without a permit that states that the . . . major modification will meet those requirements." *Id.* § 52.21(a)(2)(iii). To assess whether a major modification occurred, the federal regulation states that an "*[a]ctual-to-projected-actual applicability test* [applies] for projects that only involve existing emissions units." *Id.* § 52.21(a)(2)(iv)(c) (emphasis added). Under that test,

> [a] significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions . . . and the baseline actual emissions . . . , for each existing emissions unit, equals or exceeds the significant amount for that pollutant . . . .

Id.

As the district court observed, "EPA's approval of the [Missouri] SIP illustrates why the specific PSD rules control." *Ameren I*, 158 F. Supp. 3d at 810. In approving the Missouri SIP, the EPA stated, "[W]e are approving most of the revisions to the Construction Permits Required rule because the revisions incorporate, by reference, the Federal New Source Review reforms . . . . " Approval and Promulgation of Implementation Plans; State of Missouri, 71 Fed. Reg. at 36,486. More specifically, it stated that it was "approving revisions to Missouri rule, 10 CSR 10-6.060, Construction Permits Required, into the SIP. This rule incorporates by reference the . . . PSD . . . program in 40 CFR 52.21 . . . ." *Id.* at 36,487.

Importantly, the "EPA's approval of the SIP provided that the CAA and the program requirements as set out in 40 C.F.R. 52.21 would supersede any conflicting provisions in the state SIP." *Ameren I*, 158 F. Supp. 3d at 810 (quoting 71 Fed. Reg. at 36,486 ("This revision incorporates by reference the other provisions of 40 C.F.R. 52.21 as in effect on July 1, 2003, *which supersedes any conflicting provisions in the Missouri rule.*" (emphasis added in *Ameren I*))).

Furthermore, as the district court pointed out, Ameren's argument that "the [Missouri] SIP first requires . . . that a threshold determination be made that a project is a 'modification'" under § 6.020(2)(M)(1), "would render a portion of the PSD rules superfluous." *Id.* at 810. The Supreme Court rejected a similar argument in *Duke Energy*. In that case, the Court held that the EPA is not required "to conform its PSD regulations on 'modification' to their NSPS counterparts." 549 U.S. at 565. According to the Court, aligning the PSD regulations with the NSPS regulations "was inconsistent with their terms and effectively invalidated them." *Id.* Relevant to the present case, the Court rejected the defendant power company's argument that, "before a project can become a 'major modification' under the PSD regulations, it must meet the definition of 'modification' under the NSPS regulations." *Id.* at 581 n.8 (citations omitted). According to the Court, "the language of the regulations [did] not support" such a reading because it would render portions of the PSD regulations superfluous. *Id.* ("[I]t would be superfluous for PSD regulations to require a 'major modification' to be a 'physical change in or change in the method of operation,' if they presupposed that the NSPS definition of 'modification,' which contains the same prerequisite, had already been satisfied." (citations omitted)).

Finally, *United States v. Cinergy Corp.*, 623 F.3d 455 (7th Cir. 2010), upon which Ameren relies, is distinguishable. There, the EPA brought an enforcement action against several coal-fired power plants. *Id.* at 456. As in the present case, the EPA alleged that the plants' projects were major modifications requiring a PSD permit. *Id.* The plants argued that no permit was required because the projects did not increase the units' potential emissions under the Indiana SIP, which based applicability on increases in potential emissions instead of actual emissions. *Id.* at 458. On appeal, the Seventh Circuit held that "[t]he Clean Air Act does not authorize the imposition of sanctions for conduct that complies with a [SIP] that the EPA has approved." *Id.* (citing 42 U.S.C. § 7413(a)(1)).

Like the power plants in *Cinergy*, Ameren maintains that it lacked notice "that EPA would treat its approval of Sections 10–6.060(1)(C) (Applicability) and 10–6.020(2)(M)(10) (definition of 'modification') as a rejection of them"; furthermore, it asserts that "allowing EPA to impose liability when it is undisputed no modification has occurred would violate basic principles of due process and fair notice." *Ameren I*, 158 F. Supp. 3d at 812. But *Cinergy* is distinguishable from the present case because (1) the Indiana SIP did not incorporate the PSD rules into the State's plan; (2) the "EPA's approval of the Indiana SIP did not expressly provide that the PSD rules as set out in the Code of Federal Regulations supersede any conflicting provisions in the state SIP"; and (3) the power plants in *Cinergy* had "actual notice" of the Indiana SIP provision, whereas "it is not clear that Ameren had actual notice of the SIP provision." *Id.* Furthermore, *Cinergy* is merely persuasive authority and not binding on this court. *See Duluth, Winnipeg & Pac. Ry. Co. v. City of Orr*, 529 F.3d 794, 798 (8th Cir. 2008).

Accordingly, we hold that the district court did not err in holding that the Rush Island projects required permits through application of the actual-to-projected-actual applicability test under 40 C.F.R. § 52.21(a)(2)(iv)(c), incorporated by reference in § 6.060(8)(A) of the Missouri SIP.

B. *Major Modification*

Alternatively, Ameren argues that "even if federal regulations governed applicability, Ameren was held liable under the wrong legal standards, independently requiring reversal." Appellant's Br. at 45. Ameren maintains that the district court erred in concluding the Rush Island projects constituted *major modifications*. Specifically, Ameren contends that the district court erroneously (1) shifted the burden of proof on causation; (2) "applied new interpretations of the federal regulations' causation provision"; and (3) applied a "'reasonable power plant operator' standard the regulations do not require." *Id.* at 45–46. In addition, Ameren asserts that the district court erred by permitting the government to use expert opinions on actual post-project emissions that were not disclosed. *Id.* at 56.

A "[m]ajor modification" at emission sources occurs when a physical change in the facility would result in "a significant emissions increase." 40 C.F.R.

§ 52.21(b)(2)(i). "To satisfy its burden under the [CAA], the government ha[s] to show that at the time of the projects [Ameren] expected, or should have expected, that its modifications would result in a 'significant net emissions increase' . . . ." *United States v. Ala. Power Co.*, 730 F.3d 1278, 1282 (11th Cir. 2013).

1. *Burden of Proof*

One feature of the federal regulation's "projected-actual-emissions methodology [is] the exclusion from the emissions projection of any emissions due to increased demand." *New York*, 413 F.3d at 31. This demand-growth exclusion functions as a type of defense for the source to avoid triggering PSD requirements. The federal regulation "allow[s] exclusion of emissions that could have been accommodated during the baseline period and 'that are also unrelated to the particular project.'" *Id.* at 33 (quoting 40 C.F.R. § 52.21(b)(41)(ii)(c)). Emissions "unrelated to the particular project . . . include[] any increased utilization due to product demand growth." *Id.* (quoting 40 C.F.R. § 52.21(b)(41)(ii)(c)).

Thus, under the regulation, "a source must"

> establish[] two criteria . . . before excluding emissions from its projection: "(1) [t]he unit could have achieved the necessary level of utilization during the consecutive 24-month period [the source] selected to establish the baseline actual emissions; and (2) the increase is not related to the physical or operational change(s) made to the unit."

Id. (alterations in original) (emphasis added) (quoting Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Baseline Emissions Determination, Actual-to-Future-Actual Methodology, Plantwide Applicability Limitations, Clean Units, Pollution Control Projects, 67 Fed. Reg. 80,186-01, 80,203 (Dec. 31, 2002)); *see also United States v. DTE Energy Co.*, 845 F.3d 735, 737 (6th Cir. 2017).

Ameren argues that "the [d]istrict [c]ourt improperly shifted the burden of proving causation to Ameren." Appellant's Br. at 46. Before the district court, the parties disputed who bore the burden of proving "that any increases in emissions were caused by demand growth." *Ameren II*, 2016 WL 728234, at *11. Ameren argued that the EPA bore the burden of proving demand growth "because under the definition of 'projected actual emissions,' the regulations require that unrelated emissions be exempted from the calculation." *Id.* By contrast, the EPA maintained that Ameren bore the burden of proof on demand growth as "the party seeking to benefit from an exemption." *Id.* The district court held that "*while it remains EPA's burden to prove that Ameren should have expected the projects to cause an increase in emissions*, the burden is Ameren's to prove that the demand growth exclusion applies." *Id.* (emphasis added).

The district court is correct. As recognized in *New York* and *DTE Energy*, it is the source's burden to prove the applicability of the demand-growth exclusion. This is in accordance with the Supreme Court precedent that the party asserting the exception bears the burden of proving its applicability. *NLRB v. Ky. River Cmty. Care, Inc.*, 532 U.S. 706, 711 (2001) ("The burden of proving the applicability of the supervisory exception . . . should thus fall on the party asserting it."); *FTC v. Morton Salt Co.*, 334 U.S. 37, 44–45 (1948) ("[T]he general rule of statutory construction that the burden of proving justification or exemption under a special exception to the prohibitions of a statute generally rests on one who claims its benefits . . . .").

As a result, we hold that the district court did not impermissibly shift the burden of proof to Ameren in proving the applicability of the demand-growth exclusion.

2. *Causation*

According to Ameren, in post-trial briefing, the government switched theories on how the district court should analyze increased demand to satisfy the demand-growth exclusion. Ameren also asserts that the government, in effect, promulgated a new causation standard without following notice-and-comment rulemaking. Specifically, Ameren contends, the government persuaded the district court that Ameren had to show "demand growth for a specific unit's generation." Appellant's Br. at 47. Ameren argues that this causation standard is "the exact opposite of EPA's prior statements [that] '[d]emand growth refers to what the utility expects to be required to produce in the way of energy system wide, *not for a single unit*, but system wide.'" *Id.* (citation omitted).

We hold that the district court did not apply an improper causation standard. Citing *New York*, the district court expressly acknowledged that Ameren had to satisfy "two criteria . . . before excluding emissions from its projection." *Ameren III*, 229 F. Supp. 3d at 1003 (quoting *New York*, 413 F.3d at 33). The first requirement is that "*the unit* could have achieved the necessary level of utilization during the [baseline period]." *Id.* (emphasis added) (alteration in original) (quoting *New York*, 413 F.3d at 33). The second requirement is that "the increase is not related to the physical or operational change(s) made to *the unit*." *Id.* (emphasis added) (quoting *New York*, 413 F.3d at 33). This accurately states the appropriate causation standard. As a result, the district court did not err in holding that to prove the applicability of the demand-growth exclusion, Ameren had to establish "that demand *on the unit* increases." *Id.* at 1003.

3. *Reasonable Power Plant Operator*

"In order to be deemed a major modification, [the government] . . . [must] show (1) a physical change to the plant; (2) a significant net emissions increase; and (3) a causal link between the two." *United States v. La. Generating, LLC*, 929 F. Supp. 2d 591, 593 (M.D. La. 2012). As explained *supra*, "the government had to show that at the time of the projects [Ameren] expected, or should have expected, that its modifications would result in a 'significant net emissions increase' . . . ." *Ala. Power Co.*, 730 F.3d at 1282.[4]

"[T]he [federal] regulations do not require a utility to be prescient, rather they require the company to undertake a *reasonable estimate* of what post-project emissions would be." *United States v. Duke Energy Corp.*, No. 1:00-cv-1262, 2010 WL 3023517, at *6 (M.D.N.C. July 28, 2010) (emphasis added) (citing *United States v. Cinergy Corp.*, 458 F.3d 705, 709 (7th Cir. 2006)). "[T]he question [is] whether the owner of the facility at the time of the work . . . expected or *reasonably should have expected*, the work to increase emissions . . . ." *La. Generating*, 929 F. Supp. 2d at 593 (emphasis added).

In its motion for summary judgment at the liability phase, Ameren argued that "under an expectations theory," the EPA had to "come forward with admissible evidence of what a reasonable power plant operator or owner would expect, and its failure to do so is fatal to EPA's expectations theory case, warranting a grant of partial summary judgment." *Ameren II*, 2016 WL 728234, at *18. While "Ameren acknowledge[d] that the determination of whether a party acted reasonably is generally a question for the factfinder," it maintained that "when the touchstone for objective reasonableness requires a technical understanding of the subject matter that is beyond a layperson's normal understanding, the factfinder must have guidance to make that determination." *Id.*

The district court, however, determined "that no special standard of care evidence is required for the factfinder to be able to determine whether a reasonable power plant operator or owner would have expected the projects to cause a significant emissions increase." *Id.* The court reasoned that (1) "[t]he legal standards supplied

[4]Alternatively, the government can prove a project actually resulted in a significant increase in emissions. *See* 40 C.F.R. § 52.21(a)(2)(iv)(b).

by the PSD rules are sufficient to guide the analysis," and (2) "the parties . . . submitted mountains of evidence regarding what they believe a reasonable power plant operator or owner would have concluded." *Id.* Specifically, the parties' experts would "testify about what Ameren did to make its projections, what information Ameren considered or did not consider, and why, and what the projections showed." *Id.* The court noted that other "courts that have considered expectations theory enforcement actions" have applied "[t]his method." *Id.* (first citing *United States v. Duke Energy Corp.*, 981 F. Supp. 2d 435, 439 (M.D.N.C. 2013); then citing *Cinergy*, 623 F.3d at 459; and then citing *La. Generating*, 929 F. Supp. 2d at 593).

On appeal, Ameren now asserts that the district court erroneously denied "[s]tandard-of-care evidence [in] defining the specific boundaries of reasonableness." Appellant's Br. at 50. According to Ameren, "the written requirements of the regulations," as opposed to the "expert witnesses' subjective views," "should have governed liability." *Id.* Ameren maintains that "[b]y superimposing a[] [reasonable power plant operator] standard, the [d]istrict [c]ourt allowed EPA's experts to second-guess Ameren's conclusions even though Ameren followed the regulations' written requirements." *Id.* at 51.

We conclude that the district court did not err in holding that "no special standard of care evidence is required for the factfinder to be able to determine whether a reasonable power plant operator or owner would have expected the projects to cause a significant emissions increase." *Ameren II*, 2016 WL 728234, at *18. Instead, the district court, as the factfinder, was entitled to "consider all relevant information available to [Ameren] at the time of the project, including prior operating data and [Ameren's] own statements and documents" in determining whether Ameren "should have predicted that a project would have caused a [significant] net increase." *Id.* at *19 (quoting Jury Instr. No. 23, *United States v. Cinergy*, 1:99-cv-1693-LJM-JMS (S.D. Ind. 2008), ECF No. 1335).

4. *Expert Testimony*

Ameren argues that the district court abused its discretion in admitting and relying on undisclosed expert opinions. *See Ryan v. Bd. of Police Comm'rs of St. Louis*, 96 F.3d 1076, 1081 (8th Cir. 1996) ("We review the district court's decision to admit evidence over a party's objection for abuse of discretion.").

In two motions filed during the trial on the liability phase and in post-trial briefs, Ameren moved to exclude the expert testimony of Koppe and Dr. Sahu "concerning causation of the actual emissions increases." *Ameren III*, 229 F. Supp. 3d at 1015. Ameren argued to the district court that "the testimony concerning the causation of the actual emissions increases are new, undisclosed opinions." *Id.*

The district court denied Ameren's motions to exclude Koppe's and Dr. Sahu's testimony. First, it rejected Ameren's argument that the experts' opinions were "new" and concluded that Ameren had "sufficient notice of both the United States' actual emissions case and of Mr. Koppe and Dr. Sahu's opinions." *Id.* at 1016. The court highlighted that the experts "(1) analyzed the actual post-project data in their reports, the attachments, and their work papers, and (2) stated that the projected increases actually materialized." *Id.* at 1015. Additionally, the court noted that the experts discussed in their reports and depositions "how the projects enable increased availability and contribute to increases in emissions." *Id.* The court explained that the experts were not required to "state[] their opinions in the precise words that Ameren thinks they should have used" because the "notice required of expert opinions is not so formulaic." *Id.*; *see also Thompson v. Doane Pet Care Co.*, 470 F.3d 1201, 1202–03 (6th Cir. 2006) (explaining that Federal Rule of Evidence 26(a)(2)(B) "contemplates that the expert will supplement, elaborate upon, explain and subject himself to cross-examination upon his report")).

Second, the district court concluded that even if it erroneously admitted the expert testimony, Ameren was unable to "show that it was prejudiced by the challenged testimony or the admission of the exhibits." *Ameren III*, 229 F. Supp. 3d at 1016. This was because "[t]he evidence the United States presented to show that the actual emissions increases were caused by the projects was also presented in the context of its expectations case regarding the expected causes of projected emissions increases, so the challenged testimony is in part cumulative evidence." *Id.* The court also noted Ameren's "opportunity both during pre-trial discovery and during cross-examination at trial to test those opinions." *Id.*

Here, even assuming that the district court abused its discretion by admitting the expert testimony, "any error would be harmless." *Smith v. Tenet Healthsystem SL, Inc.*, 436 F.3d 879, 889 (8th Cir. 2006). Harmless error applies here because the district court, as the factfinder, expressly stated that had the expert testimony on actual emissions not been admitted, the result would not be different.

C. *Injunctive Relief*

Ameren argues generally that the district court lacked Article III jurisdiction and statutory jurisdiction to issue injunctive relief "based on Rush Island's *operation*." Appellant's Br. at 66. According to Ameren, the district court found during the liability phase "that the Rush Island Projects were major modifications requiring permits before Ameren could commence construction." *Id.* at 67. But, during the remedy phase, the government "did not seek to prove any injury from the violation it proved" and "[i]nstead . . . sought to obtain relief based on the harm from Rush Island's operation without a PSD permit." *Id.* Ameren maintains that "[o]perations do not cause an injury that the PSD program recognizes." *Id.* Ameren further argues that the district court lacked jurisdiction to impose injunctive relief redressing "excess emissions." *Id.* at 69. Ameren asserts that the government waived "penal relief, including civil penalties; an injunction to prevent construction; an injunction to obtain information about future planned projects; and declaratory relief." *Id.* at 71 (citations omitted). Finally, Ameren argues that the CAA "does not authorize injunctions for wholly past violations" and that "[o]nly past violations are at issue here." *Id.* at 72.

"We review a district court's grant of a permanent injunction for abuse of discretion." *Kittle-Aikeley v. Strong*, 844 F.3d 727, 735 (8th Cir. 2016). An abuse of discretion occurs when a district court "reaches its conclusion by applying erroneous legal principles or relying on clearly erroneous factual findings." *Id.* (citation omitted). "Where the determinative question is purely legal, our review is more accurately characterized as *de novo*." *Id.* (quotation omitted).

"Whenever . . . the [government] finds that any person *has violated* or is in violation of any requirement . . . of an applicable implementation plan or permit, [the government] [must] notify the person . . . of such finding." 42 U.S.C. § 7413(a)(1) (emphasis added). Only after the "expiration of 30 days following the date on which such notice of a violation [was] issued" may the government "bring a civil [enforcement] action." *Id.* § 7413(a)(1)(C). The government is authorized to "commence a civil action for a permanent or temporary injunction, or to assess and recover a civil penalty . . . , or both," "[w]henever such person *has violated*, or is in violation of" a requirement of Title I of the CAA. *Id.* § 7413(b)(1) (emphasis added). A civil enforcement action

> may be brought in the district court of the United States for the district in which the *violation* is alleged to have occurred, or is occurring, or in which the defendant resides, or where the defendant's principal place of business is located, and such *court shall have jurisdiction to restrain such violation, to require compliance, to assess such civil penalty, to collect any fees owed* the United States under this chapter (other than subchapter II) *and any noncompliance assessment and nonpayment penalty owed* under section 7420 of this title, *and to award any other appropriate relief.*

Id. § 7413(b) (emphases added).

In summary,

> [t]he Clean Air Act authorizes the EPA to bring a civil enforcement action when any person *has violated* a permit or SIP, *has violated* any requirement in certain subchapters of the Clean Air Act (including the PSD program), or "attempts to construct or modify a major stationary source" in any state that the EPA Administrator has found out of compliance with the New Source Review program.

United States v. EME Homer City Generation, L.P., 727 F.3d 274, 291–92 (3d Cir. 2013) (emphases added).

Section 7413(b) "limits a district court's jurisdiction to awarding certain kinds of relief." *Id.* at 292. "Each type of relief in [§ 7413(b)] (except for civil penalties) is necessarily forward-looking." *Id.* (footnote omitted). The remaining term —"[a]ny other appropriate relief"—is merely a "catch-all" provision that "follows 'a list of specific items separated by commas.'" *Id.* at 293 (quoting *Ali v. Fed. Bureau of Prisons*, 552 U.S. 214, 225 (2008)). "As the word 'other' demonstrates, this general phrase is a residual category of the same type as the preceding items (namely, kinds of relief)." *Id.* "[T]he canon of *ejusdem generis* requires us to interpret this catch-all as permitting forward-looking relief, consistent with the preceding types of relief in the list." *Id.* at 295.

In *Homer City*, the Third Circuit held that "[t]he text of the Clean Air Act does not authorize an injunction against *former* owners and operators for a *wholly past PSD violation*, even if that violation causes *ongoing harm*." *Id.* at 291 (emphases added). But the court "express[ed] no opinion" on whether injunctions are "available in general to remedy *ongoing harm* from *wholly past violations*." *Id.* at 291 n.19 (emphases added). Indeed, as against the current owners, the court explained that the government could, after "*completion* of a facility's modification, . . . still obtain an *injunction* requiring the owner or operator to comply with the PSD requirements." *Id.*

at 289 (emphases added); *see also United States v. U.S. Steel Corp.*, 16 F. Supp. 3d 944, 950 (N.D. Ind. 2014) ("Requiring a company to do 'a further round of modifications to get the permit' could only be done through injunctive relief." (quoting *United States v. Midwest Generation, LLC*, 720 F.3d 644, 646 (7th Cir. 2013)).

Homer City is distinguishable from the present case because it concerned injunctive relief against a facility's *former* owners. *United States v. Luminant Generation Co., L.L.C.*, 905 F.3d 874, 888 (5th Cir. 2018), *reh'g en banc granted*, 929 F.3d 316 (5th Cir. 2019).[5] It does not detract from the plain language of § 7413(b), which "plainly gives district courts jurisdiction to restrain a violation, require compliance, and award any other appropriate relief whenever a person has committed a . . . violation" *Id.*

Here, however, Ameren also specifically challenges the district court's injunction against its Labadie plant, which committed no violations of the CAA. According to Ameren, neither the CAA nor the regulations authorize such relief.

Under § 7413, a district court "has the authority to order [a defendant] to take appropriate actions that remedy, mitigate and offset harms to the public and the environment *caused by the [defendant's] proven violations* of the CAA." *United States v. Cinergy Corp.*, 582 F. Supp. 2d 1055, 1060 (S.D. Ind. 2008) (emphasis added); *see also United States v. Oliver*, No. 3:06-CV-196-JWS, 2009 WL 10671371, at *13 (D. Alaska June 25, 2009) ("Section 113(b) of the Clean Air Act, 42 U.S.C. § 7413(b), expressly provides for injunctive relief to *redress violations* of the Act." (emphasis added)), *aff'd*, 394 F. App'x 376 (9th Cir. 2010).

---

[5]The Fifth Circuit ultimately dismissed the appeal in *Luminant* on the parties' motion.

Here, the government never provided notice of or alleged that the Ameren's Labadie plant committed a *violation* of the CAA. The plain language of § 7413(b) and caselaw make clear that the injunctive relief a district court may award must redress a *violation* of the CAA. *See* 42 U.S.C. § 7413(b)(1)–(3) (permitting civil enforcement actions "[w]henever such person has violated, or is in violation of" certain requirements and noting that the district "court shall have jurisdiction to restrain such violation"). Because Ameren committed no violation of the CAA at its Labadie plant, the district court lacked authority to authorize injunctive relief as to it. *Cf. United States v. Cinergy Corp.*, 618 F. Supp. 2d 942, 967 (S.D. Ind. 2009) (denying government's requested relief because the remedy would be punitive as the government proved no violation at the non-source unit against which it was sought.), *rev'd on other grounds*, 623 F.3d 455 (7th Cir. 2010); *United States v. Westvaco Corp.*, No. MJG-00-2602, 2015 WL 10323214, at *12 & n.27 (D. Md. Feb. 26, 2015) (rejecting government's request for the district court to order the defendant "to install control technology on a totally 'innocent' boiler" that the government never alleged "violated PSD regulations" (footnote omitted)).

Accordingly, we reverse the Labadie injunction and remand for further proceedings consistent with this opinion.

E. *Jurisdiction over Title V Claims*

Finally, Ameren challenges the district court's jurisdiction over the Title V claims.

Ameren operates Rush Island under a Title V permit issued by the Missouri Department of Natural Resources. This permit "restat[ed] the requirement that Ameren was prohibited from performing any unpermitted major modifications of Rush Island Units 1 or 2." *Ameren III*, 229 F. Supp. 3d at 985.

The government brought Title V claims against Ameren, and Ameren challenged the district court's subject matter jurisdiction to hear those claims. It argued—as it does here—that the Title V violation "is reviewable exclusively by the courts of appeals, not collaterally in civil . . . enforcement actions in the district courts." Appellant's Br. at 73 (alteration in original) (quoting *Homer City*, 727 F.3d at 296–97).

Ameren's jurisdictional argument lacks merit. "The EPA has authority to bring a civil enforcement action against a person who, among other things, 'has violated, or is in violation of, any other requirement or prohibition of [various subchapters, including Title V].'" *Homer City*, 727 F.3d at 298 (alteration in original) (quoting 42 U.S.C. § 7413(b)(2)). In turn, Title V's plain text "lists only two ways in which it can be violated: operating without a Title V permit or *violating the terms of a Title V permit while operating a source*." *Id.* (emphasis added) (citing 42 U.S.C.§ 7661a(a)).

The district court expressly found that Ameren violated an express permit term prohibiting it from performing unpermitted major modifications. *Cf. Otter Tail*, 615 F.3d at 1020. Under § 7413(b), the district court had jurisdiction to consider whether Ameren violated the express terms of its Title V permit.

III. *Conclusion*

Accordingly, we affirm the judgment of the district court in all respects *except* as to the injunctive relief entered against Ameren's Labadie plant. We remand for further proceedings consistent with this opinion.

____

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

UNITED STATES OF AMERICA,	)	
Plaintiff,	)	
and	)	
SIERRA CLUB,	)	No. 4:11 CV 77 RWS
Plaintiff-Intervenor,	)	
vs.	)	
AMEREN MISSOURI,	)	
Defendant.	)	

MEMORANDUM OPINION & ORDER

TABLE OF CONTENTS

INTRODUCTION

I. Summary

In 1970, Congress enacted the modern Clean Air Act to protect the nation's air resources and "promote the public health and welfare and the productive capacity" of the people. 42 U.S.C. § 7401(b)(1). Not satisfied with the results achieved under the 1970 statute, Congress amended the Clean Air Act in 1977 to add protections for areas meeting existing federal air quality standards. The 1977 amendments require newly-constructed power plants to install pollution controls. These pollution controls decreased the pollution coming from new plants. Acknowledging the cost of retrofitting old facilities, the 1977 amendments allowed existing plants to continue operating for their natural lifespan without pollution controls. Existing plants retained this "grandfathered" status until they were modified in any way beyond routine maintenance that increased emissions.

Ameren Missouri's (Ameren) Rush Island Energy Center (Rush Island) started operating in 1976, one year before the Clean Air Act Amendments. In the mid-2000's, as Rush Island was reaching the end of its natural lifespan, Ameren decided to conduct the most significant outage in Rush Island history to redesign and rebuild essential parts of Rush Island's boilers. To increase Rush Island's capacity and lengthen its life, Ameren reconstructed Rush Island's Unit 1 in 2007 and Unit 2 in 2010. Collectively, these construction outages lasted about 200 days and required more than 1,360 workers and almost 800,000 hours of labor. Rush Island's generating capacity and pollution emissions both increased as a result of these major modifications.

Before making these major modifications, Ameren should have obtained a Clean Air Act permit and installed the best pollution controls available, which were required after 1977 for all new and rebuilt power plants. Ameren did not apply for a permit. Forty-three years after it first came on-line, Rush Island is still operating without any pollution controls. It is now the tenth-highest source of sulfur dioxide pollution in the United States. More than two and a half years ago, I determined that Ameren had violated the Clean Air Act. During the last two and a half years, the parties have prepared and presented evidence to determine how to bring Ameren into compliance with the 1977 Clean Air Act. I held a trial in April 2019 on this issue.

In this memorandum order and opinion, I provide my findings of fact and conclusions of law from that trial. As a remedy, I will order Rush Island to come into compliance with the Clean Air Act by obtaining a permit under the Prevention of Significant Deterioration (PSD) program. I will also order Ameren to remedy Rush Island's excess pollution with ton-for-ton reductions at its nearby Labadie Energy Center. This remedy will satisfy the purpose of the Clean Air Act to "promote the public health and welfare and the productive capacity" of the people, and it is narrowly tailored to address the harms created by Ameren's violations.

II. Case History

In this Clean Air Act case, Plaintiff United States of America claims that Defendant Ameren increased the risk of negative health impacts and premature deaths by releasing excess pollution from Rush Island. Plaintiff is acting at the request of the United States Environmental Protection Agency (EPA). According to the EPA, Rush Island has released more than 162,000 excess tons of sulfur dioxide into the air because Ameren failed to apply for a permit that would require it to install pollution control technology when it redesigned and rebuilt its boilers at Rush Island. That sulfur dioxide transformed into fine particulate matter ($PM_{2.5}$) that can cause heart attacks, asthma attacks, strokes, and premature death. Had Ameren installed the required pollution control technology, it would have reduced its Rush Island pollution by 95% or more. To remedy these harms, the EPA seeks an order requiring Ameren to (1) obtain the required

Clean Air Act permit (2) install sulfur dioxide "scrubbers" at Rush Island, and (3) install pollution control technology at a second coal-fired power plant to account for the excess emissions Rush Island continues to release while it operates without pollution controls.

I separated the liability and remedies phases of this case to more orderly conduct discovery and presentation of arguments. In August and September 2016, the liability phase concluded with a 12-day bench trial. On January 23, 2017, I issued my memorandum opinion and order on the liability phase. I found that Ameren violated the Clean Air Act, 42 U.S.C. § 7470 et seq., by overhauling its coal-fired boilers at Rush Island without obtaining the required permits. On February 16, 2017, I granted the Sierra Club's motion to intervene in this suit as a matter of right. [ECF No. 863].[1]

In April 2019, I held a six-day bench trial to determine the appropriate remedy in this case. In this memorandum order and opinion, I set forth findings of fact and conclusions of law from the remedies phase trial. These findings and conclusions depend in significant part on the evidence presented and conclusions made during the liability phase. Accordingly, I will summarize aspects of the liability phase trial as follows.

III. Liability Phase Findings of Fact and Conclusions of Law

Rush Island is a pulverized coal-fired power plant in Jefferson County, Missouri, directly adjacent to the Mississippi River. Rush Island's two units went into service in 1976 and 1977, immediately before the 1977 Clean Air Act Amendments. Because of this timing, Rush Island is one of many power plants that were grandfathered into the Clean Air Act's permitting scheme.

[1] Throughout this memorandum opinion and order, I sometimes refer to the Plaintiffs jointly. Frequently, I refer to the EPA's arguments, experts, and evidence without mentioning Sierra Club. These references reflect that the EPA presented much of the evidence at trial. Sierra Club was also present for the entire remedies trial, and independently has standing to seek the injunctive relief I order in this case.

The Rush Island plant currently emits about 18,000 tons of SO_2 per year. Neither of Rush Island's units has air pollution control devices for SO_2.

Under the Clean Air Act, every new or modified major pollution source must obtain one of two permits: a Non-Attainment Area permit when they are built in areas more polluted than the National Ambient Air Quality Standards (NAAQS), or a Prevention of Significant Deterioration (PSD) permit when they are built in attainment areas, which are less polluted than the NAAQS. 42 U.S.C. § 7470 et seq. The EPA sets NAAQS for six criteria pollutants at levels "requisite to protect the public health." 42 U.S.C. § 7409(b). However, NAAQS alone are insufficient to meet the goals of the Clean Air Act: Congress determined that even in attainment areas, air pollution control was necessary "to ensure that the air quality in . . . areas that are already 'clean' will not degrade." Alaska Dep't of Envtl. Conservation v. E.P.A., 540 U.S. 461, 470 (2004) (quoting R. Belden, Clean Air Act 6 (2001) at 43).

Congress has made some exceptions to blunt the impact of the Clean Air Act. Specifically, the Act does not require existing facilities to immediately install pollution controls. Instead, the Act allows these facilities to continue operating through their normal lifespans. This grandfathering only lasts until these plants cease operating or undergo major modifications. Any plant that is retired but reactivated loses its grandfathered status and must obtain a permit. A plant that is rebuilt in any significant way must obtain a permit as well.

Accordingly, the Clean Air Act represents a compromise: by limiting the duration of grandfathering to facilities' natural life, Congress prevented existing polluters from maintaining in perpetuity their *advantage* over new plants.

> [O]ld plants [are treated] more leniently than new ones because of the expense of retrofitting pollution-control equipment. But there is an expectation that old plants will wear out and be replaced by new ones that will be subject to the more stringent pollution controls that the Clean Air Act imposes on new plants. One

> thing that stimulates replacement of an old plant is that aging produces more frequent breakdowns and so reduces a plant's hours of operation and hence its output.

United States v. Cinergy Corp., 458 F.3d 705, 709 (7th Cir. 2006). Through the "major modification" exception to grandfathering, Congress memorialized this compromise as a matter of law.

Major modifications occur when there is a "physical change" or change in the method of operation of a major stationary source that would significantly increase net emissions. See United States v. Ameren Missouri, 2016 WL 728234, at *4 (citing 40 C.F.R. § 52.21(b)(2)(i)). An increase of 40 tons or more per year of sulfur dioxide ("SO_2"), the pollutant discussed in this case, is "significant" under the regulations. 40 C.F.R. § 52.21(b)(23)(i).

Under the Clean Air Act, if a grandfathered polluter ever modifies its facilities, it must do four things: (1) calculate the impact of those modifications, (2) report the planned modifications to the EPA, (3) obtain the requisite permits, and (4) install the required pollution control technologies at that time. This process ensures that any "major modifications" are identified, reported, and permitted. Ameren made major modifications to Rush Island without reporting those modifications and obtaining a permit.

The natural life of many of Rush Island's component parts is 30 to 40 years. Consistent with those lifespans, by 2005, major boiler components at Rush Island were experiencing performance problems including leaks, slagging, fouling, plugging, gas flow resistance, erosion, and mechanical failure. These problems forced Ameren to take the units offline with increasing frequency so that they could be unplugged, repaired, and otherwise serviced. These aging problems also reduced the capacity of the Rush Island boilers by slowing gas flow and reducing the gas volume moving through each boiler. See United States v. Ameren Missouri, 229 F. Supp.

3d 906, 922-936 (E.D. Mo. 2017).

Ameren sought to increase its plant capacity by redesigning and replacing essential components of both boilers, specifically the economizer, reheater, air preheater, and the "lower slope" panels surrounding the boiler. Ameren overhauled Unit 1 and Unit 2 in this manner in 2007 and 2010, respectively. After Ameren replaced these components at each unit, that unit's electric generating capacity increased immediately to levels that had not been seen in years. To achieve this improved capacity, Ameren employed more than 1,000 workers over several years. For example, "[t]he 2010 major boiler outage at Rush Island Unit 2 lasted approximately 100 days and required more than 350,000 hours of labor, of which 290,953 hours were performed by contractors. An average of 360 contractor staff worked two 10-hour shifts six days a week during the outage." United States v. Ameren Missouri, 229 F. Supp. 3d 906, 943 (E.D. Mo. 2017). The outage at Unit 1 was similar in scope and length, and both units' projects required years of planning.

Additional evidence presented at trial established that Ameren's work at both units did not constitute "routine maintenance." The new components in each boiler were designed, engineered, and constructed by outside contractors, and the complexity of the replacements was beyond the capacity of Ameren's in-house staff. Id. at 1001. The replaced equipment was so large and heavy that monorails had to be built to transport it at the construction site. Id. Ameren budgeted and paid for these projects out of its capital budget instead of its operations and maintenance budget. Id. at 1002. The Rush Island modifications required approval from high-level Ameren executives, which is unnecessary for routine maintenance. Id. at 1001. Ameren's Vice President called the 2007 modifications the "most significant outage in Rush Island history" and referred to the replacement of the economizer, reheater, air preheater, and lower slopes as distinct from other "routine maintenance that had to be performed" during the outage. Id. at 943.

Ameren's own internal metrics demonstrated an actual increase in emissions at Rush Island. Specifically, Ameren recorded outages and "derate" events, where Rush Island's maximum output was reduced. Ameren recorded these events contemporaneously in its Generating Availability Data System (GADS), and based staff bonuses in part on availability data. Id. at 931-933. Between 1997 and 2007, Unit 1's availability fluctuated between 70% and 90%. Id. at 949. Following its upgrade, Unit 1's availability increased to 96.77% in 2008. Id. at 954. This value was higher than any 12-month period at Unit 1 since 1990. Id. Unit 2's availability increased from 94.5% during a five-year baseline to 97.4% after the modifications. Id. at 958. This value was higher than any 12-month period at Unit 2 since 1987. Id. Ameren's employees have admitted that those availability increases would not have happened but for the projects.

Courts recognize these availability improvements as leading to emissions increases. "A significant decrease in outages results in a significant increase in both production and emissions." United States v. Ohio Edison Co., 276 F. Supp. 2d 829, 834-35 (S.D. Ohio 2003). "If the repair or replacement of a problematic component renders a plant more reliable and less susceptible to future shut-downs, the plant will be able to run consistently for a longer period of time," emitting more pollution as the plant is operated. United States v. Ala. Power Co., 730 F.3d 1278, 1281 (11th Cir. 2013).

With the facts presented at trial, the preponderance of evidence demonstrated that (1) Ameren conducted a "major modification" when it used more than 1,000 workers to design and replace essential components of Rush Islands boiler units in 2007 and 2010; (2) Ameren should have expected those modifications to increase emissions by more than forty tons of sulfur dioxide per year; (3) those modifications actually increased emissions by reducing future stoppages, increasing plant capacity, and extending the life of the plant; and (4) those modifications were, in Ameren's expert's words, not de minimis or routine modifications, nor did emissions increase because of demand alone.

Ameren should have obtained a Clean Air Act permit before beginning its major boiler modification. Ameren did not seek that permit. As a part of the permitting process, major pollution sources like Rush Island are required to have the Best Available Control Technology (BACT) when they undergo major modifications. Rush Island did not have any pollution control technology. Twelve and nine years since Ameren overhauled Unit 1 and Unit 2, respectively, Rush Island still does not have any pollution control technology. Through the end of 2016, Rush Island emitted 162,000 tons of sulfur dioxide more than it would have had Ameren complied with its obligations under the Clean Air Act.

Now, in the remedy phase of the trial, Ameren and the EPA dispute whether I should order injunctive relief in this case and what injunctive relief is appropriate. In September 2018, the parties filed five separate motions for summary judgment, three from Ameren, one from the EPA, and one from Plaintiff-Intervenor Sierra Club on the subject of standing. I granted the Sierra Club's motion for summary judgment on standing with respect to relief requested at Rush Island. [ECF No. 1055] There was no dispute of material fact that Sierra Club's members were injured in fact, their injuries were traceable to Ameren's excess emissions, and pollution reductions at Rush Island would redress their injuries.

I denied the parties' other motions for summary judgment. Neither the EPA nor Ameren demonstrated that there was no dispute of material fact concerning the appropriate remedy. I must evaluate injunctive relief relying on the "well-established principles of equity" the Supreme

Court articulated in eBay Inc. v. MercExchange, L.L.C., 547 U.S. 388, 391 (2006).[2] Based on the parties' filings, I could not say as a matter of law what injunctive relief was required pursuant to the eBay factors.

In April 2019, the EPA and Ameren presented their arguments concerning remedies over six days of trial. The EPA requests an order requiring Ameren to obtain a PSD permit for Rush Island, (2) propose Flue Gas Desulfurization (FGD) scrubbers as the appropriate permit technology, (3) meet an emissions limitation based on FGD scrubbers, and (4) address ton-for-ton excess emissions from Rush Island by installing pollution control technology on Ameren's Labadie Energy Center. Based on the extensive testimony provided by its experts, the EPA argues that the eBay factors support this relief.

Ameren argues that it did not have fair notice of the EPA's legal interpretations, that there is no evidence of harm created by its SO_2 emissions, that Ameren has already decreased its emissions, that it should have had the opportunity to apply for a much less stringent "minor permit," and that the expense of installing scrubbers is unduly burdensome.

In addressing these arguments, I note that by making major modifications without satisfying the requirements of the Clean Air Act, Ameren reaped significant financial benefits. According to Ameren's 2011 estimates, installing wet FGDs at Rush Island would cost between $650 million and $960 million. September 19, 2011 Project Plan (Pl. Ex. 1102), at AM-REM-00294509. Ameren deferred these costs for more than ten years at the expense of downwind communities that it will never have to fully repay. Instead, I may only order remediation enough to account for the total amount of excess emission released by Ameren, a remedy that is more

[2] Though the eBay case did not establish the governing standard for a permanent injunction, I will rely on the eBay Court's presentation of the "familiar principles" as a four-factor test. eBay, 547 U.S. at 391. In this memorandum opinion and order, I refer to the factors as the "eBay factors" or "eBay standard."

than a decade late, but which is closely tailored to the harm suffered by these communities.

Accordingly, and based on the evidence presented at trial, I conclude that the following injunctive relief is necessary to remedy the harm created by the more than 162,000 tons of excess pollution Ameren released from Rush Island: Ameren must (1) apply for and obtain the applicable Clean Air Act permit from the Missouri Department of Natural Resources (MDNR) for its Rush Island Plant, (2) propose wet flue gas desulfurization (FGD) as the required control technology for Rush Island, (3) meet an emissions limitation of 0.05 lb/mmBTU at Rush Island and (4) install and use dry sorbent injection (DSI) technology, or another more effective control technology, at its Labadie Energy Center (Labadie), until it reduces pollution from Labadie in an amount equal to the excess emissions from Rush Island.

This remedy results from the following findings of fact and conclusions of law. In summary, I find that the EPA's experts convincingly and credibly testified that wet FGD is the most effective control technology that could be used at Rush Island. Additionally, when considering the energy, environmental, and economic impacts, wet FGD is achievable at Rush Island. As a result, wet FGD is the Best Available Control Technology (BACT) for Rush Island. The EPA's experts also convincingly and credibly testified that Ameren's failure to install BACT at Rush Island has led to more than 162,000 tons of excess SO_2 emissions and increased the risk of health problems and premature mortality in the exposed population. Considering this evidence, I conclude that ordering commensurate reductions at Labadie is a remedy that is closely tailored to the harm suffered, addresses irreparable injury that could not be compensated through legal remedies, serves the public interest, and is warranted when considering the balance of hardships in this case.

FINDINGS OF FACT

I. BACKGROUND: RUSH ISLAND'S MAJOR MODIFICATIONS

a. Ameren Redesigned and Rebuilt Units 1 and 2 Near the End of Their Design Life

1. Rush Island Units 1 and 2 began operating in 1976 and 1977. They were originally grandfathered into compliance with the Clean Air Act without needing to install BACT emission limitations imposed by the Prevention of Significant Deterioration (PSD) program. Ameren Missouri, 229 F.Supp.3d at 915.

2. Neither Rush Island Unit 1 nor Rush Island Unit 2 has installed any air pollution control devices for SO_2 emissions. Id.; see also id. at 917 (Liability Findings ¶ 8).

3. Rush Island Units 1 and 2 were originally designed to have an approximately 30-year life, with components typically lasting 30 to 40 years. Id. at 917 (Liability Findings ¶ 5). By 2007 and 2010, when Ameren modified Rush Island Units 1 and 2, they had already been operating for 30 years. Ameren has already run the Rush Island plant ten years longer than it expected at the time the plant was constructed.

4. The 2007 and 2010 modifications ended Rush Island's grandfathered status under the PSD program. The modifications were made during the most significant outage in Rush Island plant history and were justified based on increasing plant operations and revenue. Id. at 915; see also id. at 940 (Liability Findings ¶¶ 155-160), 943 (Liability Findings ¶ 172).

b. Modifications at Rush Island Led to Actual Emissions Increases

5. At trial, Ameren argued that it had reduced both its fleetwide SO_2 emissions and its emissions from Rush Island. In 2010, Ameren began operating pollution control equipment, specifically Flue Gas Desulfurization (FGD) scrubbers, at its Sioux pulverized coal-fired power plant northeast of Rush Island. Knodel, Tr. Vol. 1-A, 88:16-89:2. Ameren also converted two of

its four units at the Meramec Energy Center to natural gas combustion. Michels, Tr. Vol. 5-B at 5:22-6:7. These changes decreased emissions from the Sioux and Meramec plants. (Ex. UU).

6. Ameren did not install pollution control equipment at Rush Island or its Labadie Energy Center, although it began using lower sulfur coal at these two plants. Michels, Tr. Vol. 5-B, 5:22-6:7.

7. Ameren has not submitted evidence demonstrating that Rush Island's emissions have decreased or stayed the same after its major modifications. At the remedies phase trial, and in its proposed findings of fact, Ameren did not present any data demonstrating Rush Island's emission rate before 2007. Without that information, Ameren cannot demonstrate that its emissions decreased or stayed the same after its major modifications.

8. After the liability trial, I found that Ameren's modifications at Rush Island had increased emissions from Unit 1 by about 665 tons per year and from Unit 2 by about 2,171 tons per year. Ameren Missouri, 229 F. Supp. 3d 906, 955, 959.

c. Rush Island Is One of a Small Minority of Similar Plants That Continue to Operate Without SO_2 Scrubbers

i. SO_2 Scrubbers Are Widely Used in the Electric Utility Industry

9. There are two ways to reduce the amount of SO_2 emitted from a pulverized coal-fired electric generating unit: (1) reduce the sulfur content of the source coal, and (2) use a control system to capture SO_2 before it is released to the atmosphere. The main types of control technology used to capture SO_2 are FGD scrubbers and dry sorbent injection (DSI) technology. Staudt Test., Tr. Vol. 1-B, 12:20-13:14; Callahan Dep., Nov. 8, 2017, Tr. 44:3-10 (testimony of Ameren supervisor of environmental projects).

10. FGD scrubbers have been widely used to reduce SO_2 from coal-fired electricity generating units for decades. Staudt Test., Tr. Vol. 1-B, 15:2-4; Mar. 2009 Rush Island FGD

Project Technology Selection Report (Pl. Ex. 1029), at AM-02638262 and AM-02638283; Missouri Department of Natural Resources (MDNR) Rule 30(b)(6) Dep., Aug. 10, 2018, Tr. 141:23-142:3.

11. Scrubbers can either be "wet" or "dry," depending on the amount of moisture introduced into the gas stream. Wet FGD systems introduce more moisture, reducing the temperature of the gas stream and keeping some water in the form of droplets, rather than vapor. Water droplets create a more reactive environment, increasing the amount of SO_2 "scrubbed" from the exhaust. Additionally, the lower temperatures in a wet FGD system are compatible with using limestone as the "scrubbing reagent." Limestone is cheap and readily available in Missouri. Staudt Test., Tr. Vol. 1-B, 13:4-14:12; see also Mar. 2009 Rush Island FGD Project Technology Selection Report (Pl. Ex. 1029), at AM-02638262 and AM-02638283.

12. Dry FGD systems cool the gas stream less than wet FGD systems do. They use hydrated lime as a reagent, remove less SO_2 than dry systems do, and produce a dry waste product that must be disposed of at cost. Staudt Test., Tr. Vol. 1-B, 13:4-14:12; see also Mar. 2009 Rush Island FGD Project Technology Selection Report (Pl. Ex. 1029), at AM-02638262 and AM-02638283.

13. Wet FGD scrubbers are the most effective SO_2 control technology. They can remove more than 99% of a plant's SO_2 emissions. Dry FGD scrubbers are slightly less effective, but they can still remove more than 95% of a plant's SO_2 emissions, depending on the type of coal being burned. Staudt Test., Tr. Vol. 1-B, 14:13-15:1; Snell Test., Tr. Vol. 4-B, 50:8-22; Harley Dep., Apr. 11, 2018, Tr. 100:17-101:6 (testimony of Ameren Director of Project Engineering); see also March 2008 EPRI Report: Flue Gas Desulfurization Performance Capability (Pl. Ex. 1045), at AM-02699777 ("plants designed for 99% removal are scheduled to

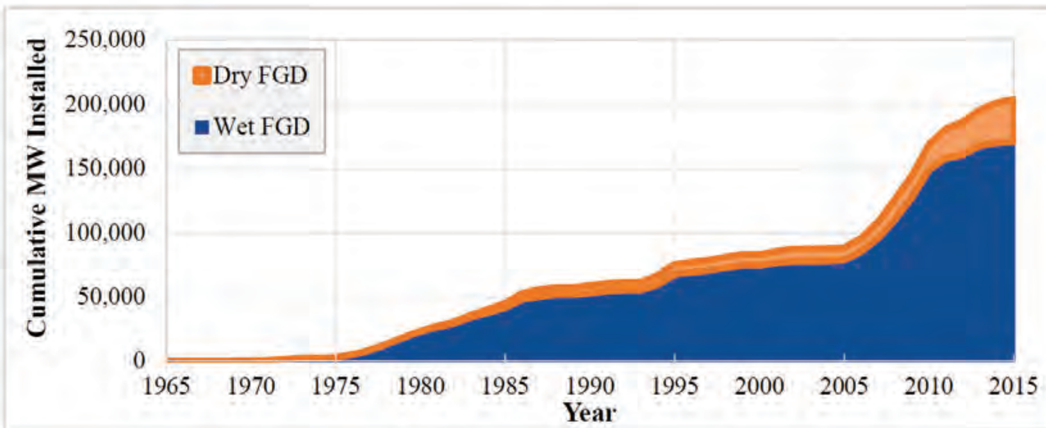
be operating in late 2008 or early 2009”).[3]

14. As illustrated by Figure 1, scrubbers have been used at pulverized coal-fired power plants dating back to the early 1970s. As of 2016, most of the coal-fired generating capacity operating in the United States was produced by power plants with scrubbers. Specifically, 200,000 megawatts of capacity was available at scrubbed coal-fired units out of 250,000 megawatts of capacity at all coal-fired electric generating units. Staudt Test., Tr. Vol. 1-B, 15:2-25; Black & Veatch Rush Island FGD Technology Selection Report (Pl. Ex. 1029), at AM-02638262.

15. Of that 200,000 megawatts, wet scrubbers account for about 170,000 megawatts, while dry scrubbers account for the other 30,000 megawatts. Staudt Test., Tr. Vol. 1-B, 15:2-25, 19:9-21:15; see also Black & Veatch Rush Island FGD Technology Selection Report (Pl. Ex. 1029), at AM-02638262. Wet scrubbers are by far the dominant SO_2 control technology for power plants.

[3] The Electric Power Research Institute (EPRI) is a research arm of the electric utility industry. Ameren and other utilities fund EPRI to research and provide reports on the best practices on a variety of issues, including the performance and cost of pollution controls. Callahan Dep., Nov. 8, 2017, Tr. 58:15-21, 59:8-18; Harley Dep., Apr. 11, 2018, Tr. 38:22-40:3.

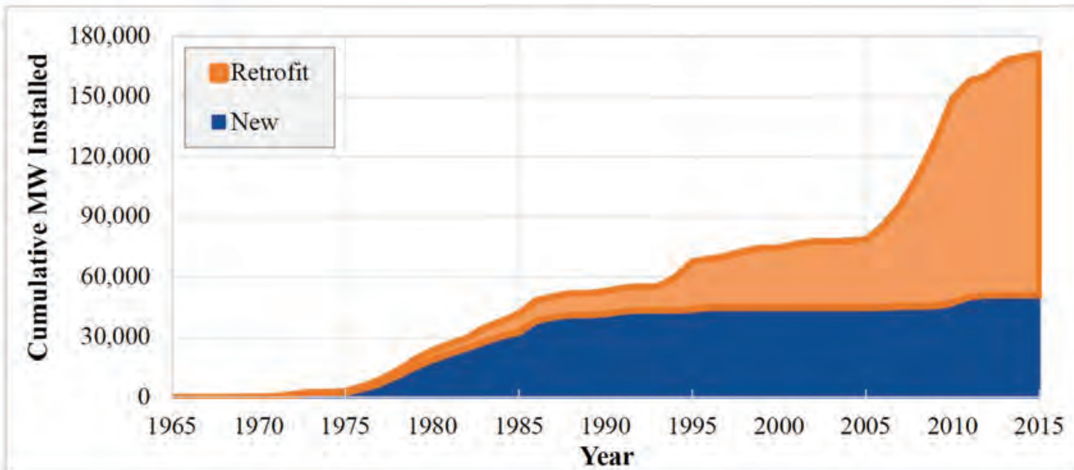
Figure 1



16. Scrubbers are currently installed on hundreds of coal-fired electric generating units, including approximately 84% of coal-fired power plants in the United States, weighted by generating capacity. Knodel Test., Tr. Vol. 1-A, 77:6-9; Staudt Test., Tr. Vol. 1-B, 15:17-16:10; see also Stumpf Dep., Mar. 27, 2018, Tr. 48:18-25 (Ameren project manager testifying that FGDs have become prevalent in the utility industry); Harley Dep., 51:1-52:25 (Ameren senior director testifying about scrubber "boom" in the utility industry); Mitchell Dep., May 30, 2018, Tr. 39:14-18 (Ameren project engineer testifying that scrubbers were well-established at the time of the FGD engineering studies for Rush Island).

17. The vast majority of wet scrubbers operating at power plants today were installed on existing plants, as illustrated by Figure 2. About 120,000 megawatts of the total 170,000 megawatts of wet scrubber capacity operating in 2015 was installed on existing plants. Most of that scrubbed capacity was installed between 2005 and 2015. Staudt Test., Tr. Vol. 1-B, 65:13-66:16.

Figure 2



18. Rush Island's continued operation without pollution controls has made it one of the largest sources of SO_2 pollution in the United States. Between 1997 and 2017, Rush Island moved from being the 154th to the 10th highest man-made source of SO_2 emissions in the country. Knodel Test., Tr. Vol. 1-A, 73:6-74:5.[4]

ii. DSI Controls Are Not Commonly Installed on Units of Rush Island's Size

19. Unlike FGD control technology, dry sorbent injection does not require a reaction vessel or added moisture. Instead DSI involves blowing reagent directly into the duct work downstream of the coal-fired boiler. A fabric filter or baghouse (hereinafter referred to as DSI-FF) can be added to remove particulate matter and increase overall removal efficiency of sulfate and other pollutants. Without a baghouse, an ordinary DSI system can remove 50% of SO_2 emissions. With a baghouse, a DSI-FF can remove 70% SO_2 reductions. Staudt Test., Tr. Vol. 1-B, 16:11-17:22; Snell Test., Tr. Vol. 4-B, 10:18-11:9; Harley Dep., Apr. 11, 2018, Tr. 163:2-19

[4] In that same year, Ameren's Labadie plant ranked as the fourth highest SO_2 emitter in the United States, and Missouri as a whole had become the second highest SO_2 emitting state in the country, behind only Texas. Knodel Test., Tr. Vol. 1-A, 74:6-15.

(testifying that DSI typically can achieve 40 to 50% reductions).

20. There are only a handful of units the size of Rush Island that currently use DSI for SO_2 control. None of those systems were in operation prior to 2007 when Ameren undertook the major modifications at issue in this case. Neither party presented testimony identifying the source category to which those large units with DSI belong. Staudt Test., Tr. Vol. 1-B, 52:10-17; Tr. Vol. 2-A, 33:1-11.

21. Ameren's expert Colin Campbell admitted that Rush Island would be the first power plant to have BACT determined based on the use of DSI, Test., Tr. Vol. 4-A, 98:3-7.

d. Ameren Evaluated FGD Installation at Rush Island

22. Although Ameren did not install control technology at Rush Island, Ameren spent about $8 million between 2008 and 2011 evaluating what control technology it should install. Staudt Test., Tr. Vol. 1-B, 17:23-19:7; Campbell Test., Tr. Vol. 4-A, 93:12-17; September 19, 2011 Project Plan (Pl. Ex. 1102), at AM-REM-00294508.

23. Ameren completed two phases of its evaluation. "[T]he first phase evaluated the various . . . technologies and the second phase utilized the selected technology (Wet FGD system) to develop a design basis, scope and detailed cost estimate." June 2, 2010 Request for Preliminary Work Order Authorization (Pl. Ex. 1095), at AM-REM-00288486.

24. The consulting firms Black & Veatch and Shaw prepared independent feasibility studies during these phases. Staudt Test., Tr. Vol. 1-B, 17:23-20:22; AmerenUE Rush Island Power Plant Technology Selection Report (Pl. Ex. 1029); Shaw Technology Evaluation (Pl. Ex. 1069); Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 134:13-135:2, 135:22-136:11, 138:16-138:20, 138:25-139:6 (identifying Pl. Exs. 1029 and 1069 as the final Phase 1 reports, which were the best estimates available at the time concerning the feasibility of using wet scrubbers at

Rush Island); Callahan Dep., Nov. 8, 2017, Tr. 119:17-120:9 (supervisor of the Phase 1 and 2 studies testifying Ameren hired multiple independent engineering firms to get a "better handle on potential cost as well as schedule").

25. Ameren's internal presentations indicate that these studies were designed to evaluate business planning and compliance options for a number of regulations, including the Cross-State Air Pollution Rule, rules for Hazardous Air Pollutants, and the New Source Review Program, the regulatory program at issue in this case. See June 1, 2010 CPOC Presentation, Scrubber Technology Assessment, Rush Island Plant (Pl. Ex. 1099), at AM-REM-00288980.

26. In Phase 1, Shaw solicited bids from six vendors with extensive experience installing FGDs. Shaw Technology Evaluation (Pl. Ex. 1069), at AM-REM-00191161; Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 138:25-139:12. After reviewing this and other information, Shaw recommended wet FGD for further review and eventual installation at Rush Island. This decision was "[b]ased on the overall evaluation of experience, performance, arrangement, operating flexibility, constructability, modularization, site impacts, capital costs, operating costs, maintenance and repair costs, and other attributes such as permitting, social-economic costs and public relations." Shaw Technology Evaluation (Pl. Ex. 1069), at AM-REM-00191196; Staudt Test., Tr. Vol. 1-B, 20:9-22:9.

27. Black & Veatch also recommended wet FGD for further review in Phase 1.

28. Ameren accepted the consulting firms' recommendations, selecting wet FGD for further evaluation in Phase 2. In Phase 2, Ameren requested more detailed cost estimates, engineering designs, and project execution plans for Rush Island. The Phase 2 reports were thousands of pages long, included bid information from FGD suppliers, and laid out a detailed schedule for installing FGD at Rush Island. Staudt Test., Tr. Vol. 1-B, 33:17-36:7; Callahan

Dep., Nov. 7, 2017, Tr. 165:16-166:20; May 2010 Shaw Final Report (Pl. Ex. 1071); August 2010 Black & Veatch Execution Plan and Report (Pl. Ex. 1115).

i. Ameren's Studies Recommended Wet FGD at Rush Island

29. As part of its efforts, Ameren evaluated the technical and economic feasibility of installing FGDs at Rush Island. These evaluations were summarized in several presentations given to Ameren management. February 5, 2010 Project Review Board Presentation-Rush Island FGD (Pl. Ex. 1100), at AM-REM-00288998 to 289000; June 1, 2010 Corporate Project Oversight Committee (CPOC) Presentation, Scrubber Technology Assessment, Rush Island Plant (Pl. Ex. 1099), at AM-REM-00288981 to 288987; March 2, 2009 Economic Value Analysis for Rush Island FGD Project Plan (Pl. Ex. 1023), at AM-02634859 to 2634860.

30. Based on its evaluations, Ameren's corporate project oversight committee agreed that wet FGD technology (1) was technically and economically feasible at Rush Island, (2) was the right choice for complying with, among other things, New Source Review, and (3) should be pursued further in contract development. Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 58:24-59:12, 59:25-60:22, 82:3-83:17.

31. Ameren explained in one of its management presentations that wet FGD was its "technology choice for SO_2 removal at Rush Island" because of its "advantages in cost, capability and flexibility" over other options. June 1, 2010 CPOC Presentation, Scrubber Technology Assessment, Rush Island Plant (Pl. Ex. 1099), at AM-REM-00288987.

32. For coal-fired power plants, the emission limitation is typically stated in terms of pounds of pollutant per million BTU of heat input (lb/mmBTU). This unit represents the amount of pollution emitted per unit of fuel put into the boiler. Knodel Test., Tr. Vol. 1-A, 39:1-6. The emission limitation is always accompanied by an averaging time; for coal-fired power plants,

typically the averaging time used is a 30-day rolling average to help address variability on a day-to-day basis. Knodel Test., Tr. Vol. 1-A, 39:7-11.

33. Ameren concluded that the wet FGD systems have the advantage of "[d]emonstrated performance" to meet an SO_2 emission rate guarantee of 0.06 lb/mmBTU. June 1, 2010 CPOC Presentation (Pl. Ex. 1099), at AM-REM-00288984; Callahan Dep., Nov. 8, 2017, Tr. 201:13-21 (agreeing that 0.06 pounds per million BTU was a demonstrated number that could be achieved).

34. Ameren rejected the less-effective DSI technology because it was "[n]ot commercially demonstrated" and "not proven to meet low emissions requirements." June 1, 2010 CPOC Presentation (Pl. Ex. 1099), at AM-REM-00288984.

35. Ameren concluded that wet FGD also had advantages with respect to other environmental impacts, including the removal of Hazardous Air Pollutants (HAPs). Staudt Test., Tr. Vol. 1-B, 40:12-41:7. For example, wet FGD helps remove other acid gases. June 1, 2010 CPOC Presentation, Scrubber Technology Assessment, Rush Island Plant (Pl. Ex. 1099), at AM-REM-00288985. Wet FGD also helps remove organic HAPs, in part due to lower flue gas temperatures. Id. Specifically, wet FGD helps remove oxidized mercury, sulfur trioxide, particulate matter, hydrogen chloride, and hydrogen fluoride. Direct Testimony of Mark Birk, Missouri Public Service Commission Case No. ER-2011-0028 ("Birk PSC Testimony"), Sept. 3, 2010 Tr. 3:20-4:2 (Pl. Ex. 1003); see also Callahan Dep., Nov. 8, 2017, Tr. 25:14-23. Wet FGD also eliminates landfill impacts because the gypsum byproduct can be sold to nearby cement plants. Id. at AM-REM-00288986.

36. Ameren concluded that wet FGD was an economically viable option as well. In Ameren's words "[e]conomic evaluation supported" the use of wet FGD at Rush Island. March

2, 2009 Economic Value Analysis for Rush Island FGD Project Plan (Pl. Ex. 1023), at AM-02634859; February 5, 2010 Project Review Board Presentation-Rush Island FGD (Pl. Ex. 1100), at AM-REM-00288999; June 1, 2010 CPOC Presentation: Scrubber Technology Assessment Rush Island Plant (Pl. Ex. 1099), at AM-REM-00288984 to 288986; August 20, 2010 Rush Island Progress Overview (Pl. Ex. 1101), at AM-REM-00289177; Staudt Test., Tr. Vol. 1-B, 23:2-7; Callahan Dep., Nov. 8, 2017, Tr. 186:7-10.

37. Wet FGD has a less expensive reagent than dry FGD or DSI. The wet FGD limestone reagent costs $28/ton; the dry FGD lime reagent costs $75/ton; and the DSI trona reagent costs $150/ton. Shaw Technology Evaluation (Pl. Ex. 1069), at AM-REM-00191180.

38. Ameren also determined that wet FGDs would not require the new induced draft booster fans that dry FGD would require. Instead, the existing fans would only need to be upgraded. Foregoing the new fans would reduce capital costs at Rush island by $37 to $50 million and would result in lower plant energy consumption. An additional $20 million could be saved by using limestone milling equipment at Ameren's Sioux power plant. June 1, 2010 CPOC Presentation, Scrubber Technology Assessment, Rush Island Plant (Pl. Ex. 1099), at AM-REM-00288983; Staudt Test., Tr. Vol. 1-B, 36:20-38:7, 55:5-15.

39. Wet FGD also provides greater fuel flexibility for Rush Island. Because wet FGD removes more SO_2 per ton of coal, Ameren could use higher sulfur coal in some circumstances while still meeting emissions limitations. Staudt Test., Tr. Vol. 1-B, 21:16-22:9; Callahan Dep., Nov. 8, 2017, Tr. 203:13-204:3; see also Birk PSC Testimony (Pl. Ex. 1003) Tr. 4:8-15 (describing fuel flexibility as advantage for wet FGDs in Sioux rate case).

40. Ameren's final project plan estimated that the total cost of installing wet FGDs at Rush Island would range from $650 million to $960 million, based on estimates provided by

multiple engineering firms. September 19, 2011 Project Plan (Pl. Ex. 1102), at AM-REM-00294509; see also February 5, 2010 Project Review Board Presentation-Rush Island FGD (Pl. Ex. 1100), at AM-REM-00289005; Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 87:11-88:1 (identifying these costs as the best estimates available to Ameren at the time of the cost of scrubbing Rush Island).

41. As part of its economic evaluation, Ameren also compared the estimated costs of installing wet FGDs at Rush Island to the costs incurred by other electric utilities for wet FGD installations. Ameren concluded that the costs of installing FGDs at Rush Island would be consistent with the costs borne by the rest of the industry to install scrubbers. See February 5, 2010 Project Review Board Presentation-Rush Island FGD (Pl. Ex. 1100), at AM-REM-00289006; Staudt Test. Tr. Vol. 1-B, 23:10-25:16, 56:20-57:6; Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 90:6-91:3.

42. Ameren also told the Missouri Public Service Commission in a formal planning document that it planned to install scrubbers on Rush Island and Labadie. Michels Test., Tr. Vol. 5-B, 17:6-18:19.

43. Wet FGD is an economically and technically feasible control technology for Rush Island. Staudt Test., Tr. Vol. 1-B, 42:19-24, 48:22-49:11.

ii. Ameren's Studies Confirmed the SO_2 Emission Rates Achievable at Rush Island

44. To design an FGD system cost estimate, a study must define the emission rate requirements of the proposed system. Staudt Test., Tr. Vol. 1-B, 6:19-7:12, 25:19-26:4; Callahan Dep., Nov. 8, 2017, Tr. 92:12-93:3, 129:8-130:9.

45. During the first two phases of Ameren's FGD study efforts, Ameren's engineering firms based their design work and cost estimates on an SO_2 emission rate target of

0.06 lb/mmBTU. May 2010 Shaw Final Report (Pl. Ex. 1071), at AM-REM-00194954 to 194955; August 2010 Black & Veatch Execution Plan and Report (Pl. Ex. 1115), at AM-REM-00324205 to 324206; Staudt Test., Tr. Vol. 1-B, 26:5-27:4; Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 145:21-146:3, 147:21-147:24, 158:13-21, 161:2-21; Callahan Dep., Nov. 8, 2017, Tr. 51:9-15, 123:8-124:14.

46. Ameren initially transmitted this 0.06 lb/mmBTU design rate to its outside engineering firms on October 3, 2008. When it did so, Ameren requested that the engineers assess whether FGDs could be designed to achieve even greater SO_2 reductions. Oct. 3, 2008 Letter to Black & Veatch (Pl. Ex. 1086) (requesting an assessment of "maximum achievable design basis" for SO_2 removal, "even if greater than the design values"); Oct. 3, 2008 Letter to Stone & Webster (Shaw) (Pl. Ex. 1085) (same). Concurrently, Ameren instructed its engineering firms to use a slightly higher "operating" value of 0.08 lb/mmBTU, which would "represent permit requirements" for the FGDs. Id.; Callahan Dep., Nov. 8, 2017, Tr. 93:20-94:5, 123:8-124:14.

47. Depending on the fuel being burned, Ameren estimated that these emission rate targets would reflect removal efficiencies of up to 99%. If Rush Island continued to burn lower sulfur PRB coal, then a design emission rate of 0.06 lb/mmBTU would reflect a 95% SO_2 reduction, while an operating rate of 0.08 lb/mmBTU would reflect a 90% reduction. Mar. 2, 2009 Economic Value Analysis for Rush Island FGD Project Plan (Pl. Ex. 1023), at AM-02634848.

48. As part of its FGD study efforts, Ameren also obtained FGD proposals from all of the major FGD suppliers in the United States, all of whom indicated that they could supply an FGD system capable of meeting Ameren's emission targets. Staudt Test., Tr. Vol. 1-B, 72:19-

73:24.

49. For example, the company Alstom submitted a wet FGD proposal to Ameren in May 2009. May 21, 2009 Alstom WFGD Indicative Submittal (Pl. Ex. 1068). At that time, Alstom had over 50,000 MW of wet FGD systems either operating or under contract. Id. at AM-REM-00191035. Alstom confirmed it could meet Ameren's emission requirements, id., and highlighted its experience with several relevant wet FGD projects for Rush Island:

- A wet FGD installed for a new 750-MW unit at the JK Spruce plant in 2009. The plant burns PRB coal and was provided an emission guarantee of 0.06 lb/mmBTU or 96% removal.
- Wet FGDs contracted to be installed on two existing 450-MW units at the Coronado plant. The plant burns PRB and was provided an emission guarantee of 0.04 lb/mmBTU or 97% removal.
- A wet FGD installed on an existing 720-MW unit at the Iatan plant in 2008. The Iatan plant is located in Missouri, burns PRB coal, and was provided an emission guarantee of 0.021 lb/mmBTU or 98% removal.

Id. at AM-REM-00191071-73; see also Staudt Test., Tr. Vol. 1-B, 74:4-76:9.

50. After the Phase 2 reports were finalized, Ameren began the specification development process for wet FGD at Rush Island. Aug. 5, 2010 Conference Mem. (Pl. Ex. 1088). The final specification was thousands of pages long and extremely detailed. Staudt Test., Tr. Vol. 1-B, 42:25-44:13; Construction Specification Section 1600—Design Basis (Pl. Ex. 1144).

51. As part of the specification development process, Ameren tasked a team of its engineers to confirm the emission rate targets for the FGDs and prepare the specification in coordination with Ameren's outside engineers. Stumpf Dep., Mar. 27, 2008, Tr. 63:21-64:15, 151:6-153:22, 154:11-17, 158:22-159:20.

52. As a result of the specification development process, on September 23, 2010, Ameren lowered its SO_2 emission rate requirements for the Rush Island FGDs to 0.04

lb/mmBTU. Sept. 23, 2010 Letter to Black & Veatch (Pl. Ex. 1076); Nov. 1, 2010 Conference Mem. (Pl. Ex. 1091), at AM-REM-00286756; Stumpf Dep., Mar. 27, 2008, Tr. 190:12-22, 198:2-8, 218:17-219:9, 238:11-19.

53. The 0.04 lb/mmBTU SO_2 emission rate was the same emission rate guarantee that Ameren obtained for the FGD installed in late 2010 at its Sioux plant. Staudt Test., Tr. Vol. 1-B, 71:13-20; Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 206:10-207:11, 208:6-9.

54. Based on the coal expected to be used at Rush Island, the 0.04 lb/mmBTU emission rate reflects SO_2 removal efficiencies of 95 to 97 percent. Nov. 17, 2010 Letter from BV to Ameren (Pl. Ex. 1174) at BV2_0204414-15; Staudt Test. Tr. Vol. 1-B, 44:14-46:4.

55. Ultimately, an emission rate of 0.04 lb/mmBTU was used as the design basis in the construction specification. Staudt Test., Tr. Vol. 1-B, 42:25-44:13; Construction Specification Section 1600—Design Basis (Pl. Ex. 1144), at AM-REM-00538825; see also Stumpf Dep., Mar. 27, 2008, Tr. 252:6-253:10, 254:9-23, 286:20-287:5. This rate was retained as the design basis until Ameren suspended the FGD project in September 2011. September 19, 2011 Project Plan (Pl. Ex. 1102), at AM-REM-00294511; Staudt Test., Tr. Vol. 1-B, 44:14-46:4; Stumpf Dep., Mar. 27, 2008, Tr. 286:20-287:5.

56. The pollution control experts in this case agree that an SO_2 emission rate of 0.04 lb/mmBTU would be an achievable design emission rate for a wet FGD at Rush Island. Staudt Test., Tr. Vol. 1-B, 46:5-8; Snell Test., Tr. Vol. 4-B, 51:13-52:16.

iii. Ameren's Studies Demonstrate How Quickly Wet FGD Can Be Installed

57. When Ameren suspended the Rush Island FGD project in September 2011, its engineers put into place a "reactivation plan" in case FGDs later became required. September 9, 2011 Project Plan (Pl. Ex. 1102) at AM-REM-00294510 ("The following link is to a document

that outlines instructions for reactivating the project including … an estimated schedule . . . [:] WFGD Specification Reactivation."); see also Staudt Test., Tr. Vol. 1-B, 46:9-47:23; Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 228:6-15.

58. Ameren's reactivation plan provided that the "Complete WFGD Specification turn-over from Shaw" should be "considered the starting point for picking up where the original [FGD] team left off." WFGD Specification Reactivation Instructions (Pl. Ex. 1141).

59. The reactivation plan also included a schedule for completing the project upon reactivation. The plan provided that, upon reactivation, engineers would need two weeks to verify the chosen SO_2 technology (wet FGD). If the technology selection changed, engineers would need an additional ten weeks to create a new specification. After management approval, Ameren could send the project to FGD suppliers for bid within six months from re-activation (which was May 2016, under the then-proposed schedule). September 19, 2011 Project Plan (Pl. Ex. 1102), at AM-REM-00294512, AM-REM-00294580. Based on that schedule, the FGD could have been "on-line" by the end of 2020, representing a four and one-half-year process from the time of reactivation. Id.

60. This reactivation plan allows Ameren to install FGD controls more quickly by taking advantage of all the resources already invested in engineering wet FGDs for Rush Island. Staudt Test., Tr. Vol. 1-B, 46:18-48:6. By the time the project was suspended, Ameren had invested 3 years of engineering work and approximately $8 million on the project. September 19, 2011 Project Plan (Pl. Ex. 1102), at AM-REM-00294508; see also Stumpf Dep., Mar. 27, 2008, Tr. 64:21-65:2, 291:18-292:19.

61. Company documents refer to the "[e]ngineering activities for Rush Island FGD" as "a significant risk mitigation strategy in terms of cost and schedule." 2010 Project Review

Board Presentation—Rush Island FGD (Pl. Ex. 1100), at AM-REM-00289019; see also, e.g., Ex. 1095, at AM-REM-00288487 ("Continuing with engineering activities for Rush Island FGD is a risk mitigation strategy for both cost and schedule."). The "risk" was the possibility that FGDs could be required by various drivers. Ameren's "response" was to "[g]et an early start on engineering in order to act as quickly as possible." Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 44:21-45:10, 47:24-48:13, 48:16-49:12, 101:18-103:1.

62. In light of the extensive amount of engineering work already completed, I find that Ameren would be able to install FGDs at Rush Island within four and one-half years from the date of the requirement to do so. September 19, 2011 Project Plan (Pl. Ex. 1102), at AM-REM-00294512, AM-REM-00294580 (May 2016 reactivation date and December 2020 online date).

II. RUSH ISLAND'S VIOLATIONS HAVE LED TO MORE THAN 162,000 TONS OF EXCESS SULFUR DIOXIDE POLLUTION

63. At the time Rush Island's boilers were modified, the surrounding airshed had attained the NAAQS for fine particulate matter, a key by-product of SO_2. Morris Test., Tr. Vol. 4-B, 69:4-24. Although part of Jefferson County is currently a non-attainment area for SO_2 itself, at the time of the modifications at Rush Island, it was in attainment of the SO_2 NAAQS. Therefore, the requirement to obtain a PSD permit and meet BACT emissions limitations applied to Rush Island. Ameren Missouri, 229 F.Supp.3d at 986; 42 U.S.C. §§ 7471, 7475.

64. Missouri is the PSD permitting authority for facilities in Missouri, pursuant to an EPA-approved State Implementation Plan, and is subject to EPA oversight. Knodel Test., Tr. Vol. 1-A, 45:2-23, 79:10-17; MDNR Rule 30(b)(6) Dep., Aug, 10, 2018, Tr. 101:13-15.

a. PSD Requires the Best Available Control Technology

i. BACT Determination Is a Five-Step Process

65. Missouri and the EPA use the same definition of BACT, which applies to both new and modified sources. Campbell Test., Tr. Vol. 4-A, 90:24-91:6.

66. BACT is "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation . . . which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility . . . ." 42 U.S.C. § 7479(3); Knodel Test., Tr. Vol. 1-A, 38:11-41:13.

67. An applicant for a PSD permit bears the responsibility when submitting its application of addressing all the steps in the BACT analysis. Knodel Test., Tr. Vol. 1-A, 51:19-23.

68. The permitting authority reviews each submission and determines if the analysis is correct. If the applicant's BACT analysis is incorrect, the permitting authority modifies the analysis to arrive at the appropriate BACT emissions limitation. In this case, Ameren should have prepared the initial BACT analysis, but the final BACT determination would have been made by MDNR with EPA oversight. Knodel Test., Tr. Vol. 1-A, 44:18-45:23, 53:11-54:18; Dec. 1, 1987 Memo on Improving NSR Implementation (Pl. Ex. 1320) at Campbell_EXP_0039928.

69. Because BACT requires "the maximum degree of reduction," BACT rates tend to get more stringent over time as pollution control technologies improve. Staudt Test., Tr. Vol. 1-B, 70:10-14, 80:23-81:3.

70. The EPA's Draft NSR Workshop Manual ("NSR Manual") outlines the BACT analysis process used by most permitting authorities, including MDNR. Knodel Test., Tr. Vol.

1-A, 48:12-20, 49:23-26, 50:2-6; MDNR Rule 30(b)(6) Dep., Aug. 10, 2018, Tr. 140:3-21.

71. The NSR Manual is the most commonly-referenced, commonly used guidance document for BACT analyses in the country. It is the most widely-distributed guidance relating to NSR that is not the regulations themselves. Campbell Test., Tr. Vol. 4-A, 90:4-10; see also id. at 88:17-89:19 (Ameren expert explaining that he provides a copy of the NSR Manual to participants in his BACT course, which focuses on the top-down method).

72. MDNR permit engineers rely on the NSR Manual in doing PSD reviews. MDNR Rule 30(b)(6) Dep., Aug. 10, 2018, Tr. 140:3-21.

73. Determining BACT involves a five-step, top-down process. Knodel Test., Tr. Vol. 1-A, 50:2-6; NSR Manual (Pl. Ex. 1190), at AM-REM-00544123-MDNR; MDNR Rule 30(b)(6) Dep., Aug. 10, 2018, Tr. 101:25-102:24, 106:4-7.

74. As part of the five-step process, the permit applicant

a. [Step One] Identifies all relevant control technologies for reducing the pollutant at issue, Knodel Test., Tr. Vol. 1-A, 50:7-16; NSR Manual (Pl. Ex. 1190), at AM-REM-00544123-MDNR.

b. [Step Two] Removes any technologies that are not technically feasible for the project in question, Knodel Test., Tr. Vol. 1-A, 50:17-24; NSR Manual (Pl. Ex. 1190), at AM-REM-00544123-MDNR,

c. [Step Three] Ranks the remaining technologies in order of control effectiveness, Knodel Test., Tr. Vol. 1-A, 50:25-51:10; NSR Manual (Pl. Ex. 1190), at AM-REM-00544123-MDNR,

d. [Step Four] Evaluates the technologies in sequence, from most effective to least effective, and selects the most effective technology that is achievable based on energy, environmental, and economic impacts and other costs, Knodel Test., Tr. Vol. 1-A, 51:11-13, 80:8-81:3; NSR Manual (Pl. Ex. 1190), at AM-REM-00544123-MDNR, and

e. [Step Five] Selects an emissions limitation rate based on the design and performance of other pollution sources that have already installed the control technology. Knodel Test., Tr. Vol. 1-A, 51:14-18; NSR Manual (Pl. Ex. 1190), at AM-REM-00544123-MDNR.

75. Step Four of the method gives the BACT determination a “top-down” character, because it starts with the top control option and moves in sequence to lesser options. If the energy, environmental, and economic impacts of the top option indicate that the technology is “achievable,” then the analysis stops: the top control is the BACT technology. If the top control is not achievable, the next most-stringent control options are considered in sequence, until an achievable technology is settled on. Staudt Test., Tr. Vol. 1-B, 53:16-54:21; Campbell Test., Tr. Vol. 4-A, 92:20-25; NSR Manual (Pl. Ex. 1190), at AM-REM-00544119-MDNR. Again, as soon as an achievable technology is found in this sequence, the analysis stops, and that technology determines BACT.

76. The top-down approach applies regardless of whether a plant is new or is undergoing a modification. Knodel Test., Tr. Vol. 1-A, 106:20-25. Under the top-down approach, the burden of proof is on the applicant to justify why the proposed source is unable to apply the best technology available. Dec. 1, 1987 Memo on Improving NSR Implementation (Pl. Ex. 1320) at Campbell_EXP_0039928; Knodel Test., Tr. Vol. 1-A, 44:5-17.

77. Almost all Clean Air Act permitting agencies, including the Missouri Department of Natural Resources (MDNR), use the top-down method that is set forth in the

EPA's 1990 New Source Review Workshop Manual. Campbell Test., Tr. Vol. 4-A, 48:7-16, 90:20-23; Knodel Test., Tr. Vol. 1-A, 49:21-50:1, 79:22-80:2.

Cost-Effectiveness Calculations in a Top-Down BACT Analysis

78. Cost is one of several criteria considered in Step 4 of the BACT process, where applicants determine whether each control technology is achievable. Knodel Test., Tr. Vol. 1-A, 80:8-81:3.

79. However, step four of the BACT process is not a search for the most cost-effective controls; nor is it a cost-benefit analysis. Id.; Staudt Test., Tr. Vol. 1-B, 58:5-16. Rather, cost considerations are measured by what is achievable. 42 U.S.C. § 7479(3). "In the absence of unusual circumstance, the presumption is that sources within the same source category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category." NSR Manual (Pl. Ex. 1190), at AM-REM-00544146-MDNR; Staudt Test. Vol. 1-B, at 63:14-64:6.

80. Similar language is found elsewhere in the NSR Manual: "BACT is required by law. Its costs are integral to the overall cost of doing business . . . Thus, where a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant costs differences, if any, between the application of the control technology on those other sources and the particular source under review." NSR Manual (Pl. Ex. 1190) at AM-REM-00544148-MDNR.

81. MDNR specifically relies on the NSR Manual's guidance in considering the economic impacts of pollution controls under a BACT analysis. Staudt Test., Tr. Vol. 1-B, 64:7-10; Norborne PSD Permit (Pl. Ex. 1180), at AM-REM-00503313-MDNR (quoting NSR Manual); see also MDNR Rule 30(b)(6) Dep., at 138:20-139:6, 140:22-141:22) (MDNR witness

testifying that "when a permit writer looks at a permit application from, for example, a coal-fired utility, [] they would look towards other coal-fired utilities to determine the appropriate controls and what controls are already being used"). The focus is on other sources in the same source category, because they would face similar technical and economic circumstances. Staudt Test., Tr. Vol. 1-B, 64:11-19.

ii. Cost-Effectiveness Does Not Determine BACT

82. As one criterion under step four of the top-down method, applicants can also prepare calculations of cost-effectiveness. Average (or total) cost-effectiveness measures the cost of a control option in annualized costs per ton of pollution that it would reduce in a year. Staudt Test., Tr. Vol. 1-B, 57:19-58:4; NSR Manual (Pl. Ex. 1190), at AM-REM-00544153-MDNR to 544154-MDNR.

83. In contrast, incremental cost-effectiveness compares how much each additional ton of reduction costs as compared to another control option. Campbell Test., Tr. Vol. 4-A, 114:19-115:7. Staudt Test., Tr. Vol. 1-B, 92:1-14; NSR Manual (Pl. Ex. 1190), at AM-REM-00544158. Incremental cost-effectiveness is useful when comparing technologies "next" to each other in the effectiveness rankings, provided those controls result in similar emission rates. Staudt Test., Tr. Vol. 1-B, 92:15-23, NSR Manual (Pl. Ex. 1190), at AM-REM-00544158-MDNR ("The incremental cost effectiveness calculation compares the costs and emissions performance level of a control option to those of the next most stringent control option …") (emphasis added).

84. The NSR Manual cautions against over-reliance on incremental cost-effectiveness in eliminating a control under Step Four of the top-down method. Pl. Ex. 1190, at AM-REM-00544163-MDNR ("[U]ndue focus on incremental cost effectiveness can give an impression that

the cost of a control alternative is unreasonably high, when, in fact, the cost effectiveness, in terms of dollars per total ton removed, is well within the normal range of acceptable BACT costs."); see also In re General Motors, Inc., PSD Appeal No. 01-30, 10 E.A.D 360, 371 (E.A.B. Mar. 6, 2002) (the NSR Manual "places primary stress on the average cost measure").

iii. NSPS Do Not Fundamentally Alter the BACT Process

85. Alongside BACT requirements, all new major sources of pollution must meet "New Source Performance Standards" (NSPS). Pursuant to Section 111 of the Clean Air Act, the EPA establishes NSPS for different source categories. See 42 U.S.C. § 7411.

86. Ameren's expert admitted that the EPA sets the NSPS at rates that can be reasonably met by all new and modified sources in a source category, even though individual sources might be capable of lower emission rates. Campbell Test., Tr. Vol. 4-A, 98:14-18.

87. An applicable NSPS serves as a "floor" for the emission limit established as BACT. The BACT limit cannot be less stringent than the NSPS. 42 U.S.C. § 7479(3); In re Columbia Gulf Transm'n Co., PSD Appeal No. 88-11, 2 E.A.D. 824, 1989 WL 266361, at *4 (EPA 1989).

88. As the NSR Manual explains: "[T]he only reason for comparing control options to an NSPS is to determine whether the control option would result in an emission level less stringent than the NSPS. If so, the option is unacceptable." Ex. 1190, at AM-REM-00544129-MDNR (emphasis added).

89. "Simply meeting or exceeding the NSPS does not attest to the correctness of a BACT determination." Columbia Gulf, 1989 WL 266361, at *4. That NSPS sets "a 'floor' on emissions does not fundamentally change the BACT process of determining the 'best' available technology." United States v. Ameren Missouri, No. 4:11 CV 77 RWS, 2019 WL 1384631, at *3 (E.D. Mo. Mar. 27, 2019) (citing Columbia Gulf at *4).

90. The top-down method was originally developed in response to concerns that BACT analyses were inappropriately defaulting to the less-stringent and generally-applicable NSPS standards, without giving enough consideration to more stringent control options required for BACT. Knodel Test., Tr. Vol. 1-A, 47:14-48:9; June 13, 1989 Statement on Top Down BACT (Pl. Ex. 1321), at Campbell_EXP_0040089.

b. FGD Scrubbers Constitute BACT for the Vast Majority of Pulverized Coal-Fired Power Plants

i. The Electric Power Utility Industry Recognizes That FGD Constitutes BACT

91. BACT for a pulverized coal-fired power plant generally requires either wet or dry FGD scrubbers. Staudt Test., Tr. Vol. 1-B, 95:1-12. This trend results from the top-down process: scrubbers are the most-effective pollution controls. As the industry has progressed, an increasing number of plants have used scrubbers, demonstrating their achievability in different circumstances. See, e.g., supra Figure 1; ¶ 14.

92. As Ameren's Senior Director of Engineering and Project Management, Duane Harley, explained: "There's lots of different types of scrubbers in the market. Any one of those could be considered BACT. … Could be wet. Could be dry." According to Harley, dry scrubbers would be preferred in arid locations such as the West and wet scrubbers would typically be installed on plants that are larger than 300 MW. Harley Dep. Tr., Apr. 11, 2018, 97:5-98:8.

93. The electric power utility industry recognizes that FGD constitutes BACT for coal-fired units. In March 2008, the Electric Power Research Institute published a report on the performance capability of FGD systems. Staudt Test., Tr. Vol. 1-B, 85:7-86:19; see also supra Footnote 3. The report noted: "Many coal-fired units must comply with the Clean Air Act

(through New Source Review), consent decrees, or the Clean Air Visibility rules. Operators of these units have or will have to commit to installing FGD systems that meet the regulatory requirements of best available control technology (BACT) … .” 2008 EPRI Report (Pl. Ex. 1045), at AM-02699795.

94. Ameren itself has acknowledged that BACT may require FGD at Rush Island. Specifically, an Ameren presentation prepared in 2011 for the Missouri Public Service Commission indicates: “New Source Review lawsuit by EPA may require flue gas desulfurization (FGD) systems or scrubbers at Rush Island.” April 2011 Presentation: Ameren Missouri Long Term Low Sulfur Coal Supply (Pl. Ex. 1009), at AM-02225205. It is well-understood that BACT at Rush Island would likely require installing scrubbers.

ii. During The Past Twenty Years, Every BACT SO_2 Determination for a Pulverized Coal-Fired Power Plant Has Required FGD

95. The prevalence of FGD at other plants is demonstrated by databases maintained by EPA Headquarters and Region 7. EPA Headquarters maintains a RACT BACT LAER Clearinghouse (RBLC) with a searchable database of BACT permit decisions made throughout the United States. The RBLC catalogues permitted technology and emissions limitations for individual facilities. Knodel Test., Tr. Vol. 1-A, 52:5-53:7.

96. From about 2002 until about 2015, EPA Region 7 also maintained a New Source Review Electricity Generating Unit Coal-Fired Spreadsheet on its website. The spreadsheet was designed to include every NSR application that had been submitted across the United States. It included information such as unit size, type of controls, and BACT limits. Knodel Test., Tr. Vol. 1-A, 34:20-35:8, 52:24-53:10.

97. Every BACT determination for SO_2 emissions from pulverized coal-fired power plants during the past twenty years has required wet or dry FGD as the required pollution control

technology. Staudt Test., Tr. Vol. 1-B, 77:20-78:2.

98. During this period, MDNR determined that BACT at a coal-fired power plant in Southwest Missouri requires the use of FGD controls for SO_2. Chipperfield v. Mo. Air Conservation Comm'n, 229 S.W.3d 226, 240 (Mo. Ct. App. 2007). As noted by the Missouri Court of Appeals in a decision upholding MDNR's BACT determination: "In general, pulverized coal-fired boilers burning low-sulfur coal, such as Powder River Basin ('PRB') coal, may use dry FGD, while boilers burning high-sulfur coals, such as eastern bituminous coal, must use wet FGD." Id.

99. EPA expert Jon Knodel is an environmental engineer with EPA Region VII who reviews permits for coal-fired power plants in Missouri. Id. at 32:17-20, 54:3-55:3. Based on Knodel's count, between 1999 and 2008, MDNR issued four air permits for coal-fired power plants. Knodel Test., Tr. Vol. 1-A, 54:22-55:3. All of these required either wet or dry FGD as the SO_2 control technology. Id. at 57:23-58:2, 59:10-15, 59:18-60:21, 60:24-61:3.

100. In 1999, MDNR issued a PSD permit to Kansas City Power and Light's Hawthorn plant with a 30-day SO_2 BACT limit of 0.12 lb/mmBTU, based on the use of a dry FGD. Knodel Test., Tr. Vol. 1-A, 59:10-17.

101. In 2004, MDNR issued a PSD permit for City Utilities' proposed Southwest power plant with a 30-day SO_2 limit of 0.095 lb/mmBTU, based on the use of dry FGD. Knodel Test., Tr. Vol. 1-A, 55:4-58:2; Dec. 15, 2004 Permit to Construct (Pl. Ex. 1004), AM-00134223-EPA, AM-00134224-EPA; see also Chipperfield, 229 S.W.3d at 240 (describing determination of BACT rate). In doing so, MDNR explicitly found that the costs of both wet and dry FGD were reasonable. Staudt Test., Tr. Vol. 1-B, 67:3-68:13; In the Matter of Appeal of City Utilities PSD Permit, 10/11/05 Hr'g Tr. (Pl. Ex. 1177) at 16:18-17:16.

102. In 2006, MDNR issued a permit for Kansas City Power and Light's Iatan power plant with 30-day SO_2 limits of 0.1 lb/mmBTU for the existing unit (Unit 1) and 0.09 lb/mmBTU for the new unit (Unit 2), based on the use of wet FGD at both units. Knodel Test., Tr. Vol. 1-A, 59:18-60:9; Jan. 31, 2006 Permit to Construct (Pl. Ex. 1034), at AM-02693650-53. After these permit limits were challenged by a third party, an amended permit was issued in 2007 with lower SO_2 limits of 0.07 lb/mmBTU for Unit 1 and 0.06 lb/mmBTU for Unit 2. Knodel Test., Tr. Vol. 1-A, 60:10-21; July 13, 2007 Amendment to Permit (Pl. Ex. 1283), at AMEREM_JES0007121-25; Staudt Test., Tr. Vol. 1-B, 81:20-82:13.

103. In 2008, MDNR issued a PSD permit to Associated Electric Cooperative, Inc. (AECI) for the proposed Norborne plant with 30-day SO_2 limits of 0.07 to 0.08 lb/mmBTU, based on the use of dry FGD. Knodel Test., Tr. Vol. 1-A, 60:22-61:3; Feb. 22, 2008 Letter Enclosing Permit to Construct (Pl. Ex. 1180), at AM-REM-00503274-MDNR to 3275-MDNR.

104. These Missouri permit limits are consistent with those issued by other permitting authorities for coal-fired power plants during the same period, all of which also required the use of wet or dry FGD. Staudt Test., Tr. Vol. 1-B, 77:20-78:2.

105. For example, Ameren's expert Colin Campbell testified about a PSD permit issued for the following non-Missouri plants: (1) In 2005, Newmont's TS power plant was permitted for an SO_2 limit of 0.065 lb/mmBTU; (2) in 2007, LS Power's Longleaf power plant was permitted for the same emission rate (0.065 lb/mmBTU); and (3) also in 2007, Basin Electric's Dry Fork power plant in Wyoming was permitted for an SO_2 limit of 0.07 lb/mmBTU. <u>See</u> Campbell Test., Tr. Vol. 4-A, 107:13-108:4, 131:17-132:1.

c. The Parties' Competing BACT Analyses

106. During trial, the parties each presented expert testimony concerning what BACT

would have been at the time that Ameren modified Rush Island. Based on what BACT would have been, I can determine how much SO_2 Ameren would have emitted had it complied with the law. Then, I can subtract that lower pollution amount from the SO_2 emissions that were actually released to determine Rush Island's "excess emissions." For clarity, I refer to this determination as a "historic BACT analysis." According the correct historic BACT analysis, Ameren's failure to install scrubbers at Rush Island resulted in 162,000 tons of excess SO_2 emissions through the end of 2016. The excess emissions are a measure of the harm suffered by Plaintiffs because of Ameren's violation of the Clean Air Act.

107. In support of their proposed historic BACT analysis, Plaintiffs presented the expert testimony of Dr. James Staudt. Dr. Staudt has a bachelor's degree in mechanical engineering from the Naval Academy and a Ph.D in mechanical engineering from Massachusetts Institute of Technology. Staudt Test., Tr. Vol. 1-B, 4:25-5:6. Dr. Staudt has decades of experience in the air pollution control industry, first working for supply companies and then later as a consultant on control technology issues for government agencies and industry clients. Id. at 5:20-11:14. Because of his work, Dr. Staudt has been familiar with the BACT requirements for decades, and has previously been accepted as an expert on SO_2 BACT issues in United States v. Westvaco, No. MGJ-00-2602 Trial Transcript, ECF No. 985-4 at 8:19-9:23; id. at 10:12-11:14.

108. Dr. Staudt conducted two BACT analyses using the five-step process: one to determine historic BACT and a second to determine current BACT. Staudt Test., Tr. Vol. 1-B, 49:12-50:1.

109. In conducting his historic BACT analysis, Dr. Staudt considered (1) the engineering analyses and cost estimates prepared for Ameren's Rush Island FGD studies discussed above in Section I.d, (2) vendor proposals, (3) relevant BACT determinations reported

in the EPA Clearinghouse, (4) contemporaneous Missouri permits for coal-fired power plants, (5) industry performance data for scrubbers, and the (6) 0.04 lb/mmBTU SO_2 performance guarantee that Ameren obtained for the FGD system installed at its Sioux power plant. Staudt Test., Tr. Vol. 1-B, 35:23-36:6. 71:2-72:14, 76:10-77:19.

110. To challenge Dr. Staudt's testimony, Ameren presented the expert testimony of Colin Campbell. Campbell is a permit engineer with a bachelor's degree in mechanical engineering and economics from North Carolina State University. Campbell Test., Tr. Vol. 4-A, 39:12-16. Campbell teaches courses for agency employees and permit engineers on NSR issues, including a course on how to do a BACT analysis. Campbell Test., Tr. Vol. 4-A, 40:9-13, 40:24-41:25, 88:17-89:19.

111. Campbell performed an analysis of what BACT would be for Rush Island today. He did not conduct a historic BACT analysis. Instead, he assumed that historic BACT would have been the same as current day BACT. Campbell Test., Tr. Vol. 4-A, 94:12-95:5.

112. For both historic and current BACT, Campbell testified that Ameren could satisfy the law by installing DSI. According to Campbell, if Rush Island were permitted today, MDNR would set an emission rate of 0.275 lb/mmBTU, based on a DSI system with 50% SO_2 reduction. Campbell Test., Tr. Vol. 4-A, 69:10-22.

113. Campbell reached this determination by 1) ranking wet FGD, dry FGD, DSI with a fabric filter, and DSI without a fabric filter, in that order, 2) eliminating dry FGD and DSI with a fabric filter because they were too expensive, 3) calculating the incremental cost effectiveness between wet FGD with DSI without a fabric filter, 4) rejecting wet FGD because MDNR would find its incremental cost effectiveness too expensive, and 5) selecting the remaining option: DSI without a fabric filter.

114. I carefully observed and reviewed Campbell's and Dr. Staudt's conflicting testimony to determine their credibility. Based in part on the following credibility findings, I make factual findings concerning BACT for Rush Island in Section III.

d. Campbell's Testimony Rejecting Wet FGD and Choosing DSI Was Not Credible

115. Ameren primarily relies on Colin Campbell's expert testimony to argue that DSI constitutes BACT. Campbell testified that wet FGD's incremental cost effectiveness was too high for wet FGD to be BACT. Campbell Test., Tr. Vol. 4-A, at 97:21-98:7. Campbell further testified that Ameren should be able to come into compliance with the PSD program without obtaining a PSD permit. Id. at Tr. Vol. 4-A, 132:2-5.

116. Before trial, the EPA made a Daubert challenge to exclude these opinions. The EPA argued that Campbell's methods were unreliable because he did not follow the five-step process laid out in the NSR manual, among other arguments. I denied the EPA's motion because I could not say that Campbell's opinion was so unreliable as to be unhelpful to the trier of fact. United States v. Ameren Missouri, No. 4:11 CV 77 RWS, 2019 WL 1384580, at *3 (E.D. Mo. Mar. 27, 2019). However, I explained that Campbell's opinion would be more credible if he had completed and documented the five-step process used by permitting authorities across the country. Id. I noted that

> [Campbell's] methods depart significantly from the five-step process used in preparing a permit application or supporting documents. (Campbell deposition, filed under seal at ECF No. 968-5 at 196:11-18). Most importantly, Campbell eliminated the second-highest and third-highest ranking options before evaluating the first-highest ranking option. As a result, Campbell's incremental cost effectiveness compared the highest and lowest ranking options. This error violates Campbell's own advice to permit engineers. (BACT workshop presentation, filed under seal at ECF No. 970 at 3, 5-6). In his BACT workshop presentation, Campbell explained that incremental cost effectiveness should be performed between the "'dominant' control option [and] the next most stringent option." (Id. at 3). He cautioned that incremental cost is appropriate when "[D]ominant control

> options have similar average cost effectiveness numbers" or similar emission rate reductions. (Id. at 5).

Id. at *2.

117. Having now heard Campbell's testimony during trial, I will give little weight to his testimony because of flaws in his economic analysis, inconsistencies in his statements at trial, and his mischaracterization of how NSPS factors into the BACT process.

i. Campbell Overly Relied on Incremental Cost Effectiveness at Rush Island

118. Campbell's BACT determination hinges upon on his incremental cost effectiveness analysis. Campbell rejected wet FGD because it purportedly had an incremental cost effectiveness of $9,500/ton, well above the $6,800/ton limit he inferred from reviewing PSD permits issued by MDNR. Campbell Test., Tr. Vol. 4-A, 84:9-25.

119. Campbell did not reach any conclusions in this case about whether the average cost-effectiveness of wet FGD at Rush Island would represent unreasonable economic impacts for Ameren. Id. at 115:8-116:17.

120. As a general matter, Campbell's heavy reliance on incremental cost-effectiveness, without consideration of average cost-effectiveness, is inconsistent with BACT permitting practices. The NSR manual explains that "undue focus on incremental cost effectiveness can give an impression that the cost of a control alternative is unreasonably high, when, in fact, the cost effectiveness, in terms of dollars per total ton removed, is well within the normal range of acceptable BACT costs." NSR Manual (Pl. Ex. 1190), at AM-REM-00544163-MDNR.

121. Additionally, Campbell's testimony concerning incremental cost effectiveness was not credible for the following reasons: (1) he included non-comparable cost categories

when comparing wet FGD at Rush Island to MDNR's past permit decisions; (2) he compared the most effective with the least effective technology when calculating incremental cost effectiveness; (3) his cost thresholds are not supported by the MDNR permits he cites; and (4) he ignored the presumption that facilities in the same source category can bear the same costs.

122. Each of these flaws was necessary to Campbell's decision to reject wet FGD. Together they demonstrate that Campbell's cost analysis of wet FGD is not credible. Accordingly, I give little weight to Campbell's testimony rejecting wet FGD.

ii. Campbell's Cost Comparisons Include Cost Categories Not Included in Other Plants' BACT Determinations

123. To calculate incremental cost-effectiveness, Campbell relied on wet FGD cost estimates provided by Kenneth Snell, Ameren's control costs expert. Snell estimated that installing wet FGD at Rush Island would cost $896 million in 2016 dollars or $1 billion in 2025 dollars. Snell Test., Tr. Vol. 4-B, 28:1-9, 28:24-29:10.

124. In contrast, the EPA's expert Dr. Staudt estimated that installing wet FGDs at Rush Island would cost $582 million in 2016 dollars. Dr. Staudt based his estimate on costs included in Ameren's engineering studies, but he subtracted a set of variable costs normally excluded from comparative cost estimates. Under this "overnight" cost methodology, Dr. Staudt excluded the Allowance for Funds Used During Construction (or AFUDC), an inflation-like metric called escalation, overhead, and property taxes. Staudt Test., Tr. Vol. 1-B, 59:24-61:5; Tr. Vol. 2-A, 25:25-26:6, 28:18-30:18.

125. Snell's cost estimate differs from Dr. Staudt's estimate because Snell included $150 million for financing,[5] $64 million for escalation, $44 million for overhead, and $22 million for property taxes. Snell Test., Tr. Vol. 4-B, 57:19-59:25; Ex. HW, Ex. HX.

[5] Specifically, Snell calculated $150 million in AFUDC, the financing charge incurred over the time it takes to complete a project. Staudt Test., Tr. Vol. 1-B, 24:7-24; Vol. 2-A, 30:1-18.

126. Traditionally, these costs are excluded from cost comparisons across power plant and control technologies because they are extrinsic to the technologies themselves and vary dramatically. For example, different companies have different cost recovery rates and execute projects on different timelines. Excluding extrinsic costs allows for a more consistent way to compare costs across the industry. Staudt Test., Tr. Vol. 1-B, 24:7-24; Vol. 2-A, 30:1-18.

127. When Ameren conducted its own economic analysis comparing the costs of wet FGDs at Rush Island to others in the industry, it did not include AFUDC in its estimates. See February 5, 2010 Project Review Board Presentation—Rush Island FGD (Pl. Ex. 1100), at AM-REM-00289006.

128. Dr. Staudt's decision to remove the extrinsic expenses for the purpose of comparing project costs was not refuted by Snell or any of Ameren's other witnesses. Snell testified that he was "not offering an opinion as to whether or not it's appropriate to include [AFUDC or escalation] costs for the purposes of a BACT analysis." Snell Test., Tr. Vol. 4-B, 50:4-6. "[His] opinion is . . . the real costs that Ameren would incur if they were to install these technologies." Id. at 50:6-7.

129. Because Dr. Staudt's testimony concerning the appropriateness of excluding extrinsic expenses is uncontested, and I find Dr. Staudt's testimony to be credible, I also find that Dr. Staudt correctly excluded these extrinsic expenses from his BACT analysis.

130. In contrast, Snell used the total project costs, including the expenses Dr. Staudt excluded, to compare the cost of installing FGD at Rush Island to the costs at facilities featured in other permit determinations made by MDNR. In making this comparison, Snell should have instead relied on the cost calculating conventions normally used in BACT determinations.

131. When calculating incremental and average cost effectiveness between the various pollution control options for Rush Island, Campbell also should have excluded these variable costs.

132. Campbell did not ask Snell whether Snell's total cost estimates would be appropriate to use in conducting a BACT analysis. Snell Test., Tr. Vol. 4-B, 49:13-25.

133. I find that it was inappropriate for Campbell to rely on Snell's total cost estimates for purposes of doing a BACT analysis for Rush Island.

iii. Campbell's Incremental Cost Effectiveness Analysis Was Inconsistent With His Prior Trainings and Advice

134. To determine the incremental cost effectiveness at Rush Island, Campbell compared the per-ton cost of FGD with the per-ton cost of DSI.

135. Incremental cost effectiveness is appropriate for BACT determinations when the two compared technologies rank directly adjacent to each other in their effectiveness. See United States v. Ameren Missouri, No. 4:11 CV 77 RWS, 2019 WL 1384580, at *2 (E.D. Mo. Mar. 27, 2019), (citing In re General Motors, Inc., No. 27947, 10 E.A.D. 360, 2002 WL 373983 ,*9); see also Staudt Test., Tr. Vol. 1-B, 92:25-93:15; Campbell Test., Tr. Vol. 4-A, 119:16-18; NSR Manual (Pl. Ex. 1190), at AM-REM-00544158-MDNR ("The incremental cost effectiveness calculation compares the costs and emissions performance level of a control option to those of the next most stringent option") (emphasis added).

136. Additionally, the two compared technologies should have similar levels of effectiveness. Staudt Test, Tr. Vol. 1-B, 92:25-93:15. By following these rules, permit applicants can identify technologies that are unnecessarily expensive relative to similarly or equally effective technologies. Technologies with very different effectiveness should not be used for incremental cost effectiveness; the more effective technology is better. See id. at 92:15-23; NSR

Manual (Pl. Ex. 1190), at AM-REM-00544158-MDNR

137. Campbell ignored both of these conventions. First, he compared the most effective technology, wet FGD, with the least effective technology, DSI. The two are not ranked adjacent to each other. Second, wet FGD and DSI have do not have similar levels of effectiveness; the two have dramatically different levels of effectiveness. Staudt Test., Tr. Vol. 1-B, 92:25-93:15. Specifically, Campbell compared a wet FGD capable of achieving SO_2 reductions of more than 90% to a DSI system that can only achieve 50% reductions and an emission rate 5 ½ times higher than what could be achieved by the top controls. Campbell Test., Tr. Vol. 4-A, 118:24-119:15.

138. Campbell's comparison of wet FGD and DSI is inconsistent with his own guidelines used outside of litigation and the guidelines used by other practitioners. See Campbell Test., Tr. Vol. 4-A, 117:15-118:20 (discussing inconsistencies between Campbell's method in this case and his training materials).

139. Campbell now purportedly "vigorously" disagrees that incremental cost-effectiveness should be reserved for control technologies with similar reduction capabilities. Campbell Test., Tr. Vol. 4-A, 70:9-19.

140. Nonetheless, I find Campbell's testimony on the incremental cost comparison between wet FGD and DSI to be not credible, as it is inconsistent with established standards in the field and even his own past work.

iv. Campbell's Cost Threshold Opinion Is Unsupported

141. Campbell ultimately rejected wet FGD as BACT because its incremental cost effectiveness exceeded a threshold he inferred from MDNR and other permitting authorities' determinations. Campbell Test., Tr. Vol. 4-A, 119:19-120:3. Campbell's testimony on this point

was inconsistent, unsupported, and not credible.

142. Specifically, Campbell testified that permitting authorities across the country, and MDNR specifically, apply a "de facto line at $5,000" per ton for incremental cost-effectiveness. Campbell Test., Tr. Vol. 4-A, 61:8-9, 62:19-22, 67:4-12, 119:9-120:3, 121:14-17. Campbell testified on direct that permitting authorities will reject control technologies above this threshold.

143. On cross-examination, however, Campbell admitted that permitting authorities have accepted technologies with incremental cost-effectiveness values of $10,000/ton. Id. at 120:11-23.

144. Campbell also admitted he was only speculating when he said MDNR had a threshold at $5,000. He later testified that the limit in Missouri was actually $6,800/ton. Id. at 121:18-21.

145. According to Campbell, four Missouri permits supported his purported $6,800/ton threshold: Continental, Noranda, Norborne, and Southwest. Nothing in these permits actually establishes this limit. Staudt Test., Tr. Vol. 1-B, 93:16-22.

146. Two of these permits (Continental and Noranda) relate to, respectively, a cement plant and an aluminum smelter. Permits in these source categories are minimally relevant to a BACT determination at a pulverized coal-fired power plant. Campbell Test., Tr. Vol. 4-A, 111:5-113:9; Staudt Test., Tr. Vol. 1-B, 91:9-25; MDNR Rule 30(b)(6) Dep., Aug. 10, 2018, Tr. 137:24-142:3. Unlike power plants, it is "very unusual" for cement plants to use FGDs. Cement plants have "a great deal of intrinsic SO_2 capture" built into their process because SO_2 is a useful ingredient in their product. Staudt Test., Tr. Vol. 1-B, 91:9-25.

147. Additionally, the Noranda permit did not discuss incremental cost-effectiveness in its BACT analysis. Campbell admitted this fact on cross examination. Campbell Test., Tr. Vol.

4-A, 121:23-122:12. Therefore, the Noranda permit does not support Campbell's purported $6,800 threshold.

148. For the remaining two permits (Norborne and Southwest), Campbell admitted on cross-examination that the incremental cost-effectiveness values presented in those decisions "didn't much factor into the analysis." Campbell Test., Tr. Vol. 4-A, 122:14-123:12.

149. For the Norborne permit, Campbell admitted that MDNR's decision to select dry FGD over wet FGD was based largely on environmental and energy impacts and not costs. Campbell Test., Tr. Vol. 4-A, 123:25-125:20.

150. Even if the Norborne decision had been based on costs, it would not support a finding of a $6,800/ton threshold. The incremental cost effectiveness at Norborne was $20,218/ton, based on a 95% removal wet FGD with a 93% removal dry FGD. On cross-examination, Campbell admitted that Missouri's BACT determination at Norborne did not support the $6,800/ton threshold he claimed:

> Q. … So in terms of whether we can get a $6,800-per-ton incremental cost threshold out of the Norborne permit, we can't; right?
>
> A. That's right.

Id. at 125:23-126:1.

151. For the Southwest City Utilities permit, MDNR did not consider costs in its determination. MDNR Rule 30(b)(6) Dep., Aug. 10, 2018, Tr. 142:6-143:15, 144:18-24; Missouri Air Conservation 11/28/05 Decision (Pl. Ex. 1007) at AM-00151141 ("However, Hale agreed that dry FGD was BACT for this particular pulverized coal-fired boiler based on his review of the energy and environmental impacts of dry versus wet FGD. … Hale did not consider economic impacts of costs as part of his analysis of BACT for SO_2.").

152. Additionally, the applicant calculated an incremental cost-effectiveness of over

$10,000/ton when comparing wet and dry FGD, two adjacent technologies in the "top down" analysis. Staudt Test., Tr. Vol. 2-A, 7:1-9, 24:4-16. The Southwest City Utilities permit does not support the purported $6,800 threshold as Campbell applied it in this case.

153. Campbell pointed to only these four Missouri permits to support the purported $6,800/ton threshold. None of those permits actually support that threshold. I find that Campbell's testimony on this issue is not based on established criteria to evaluate cost-effectiveness and is not credible.

154. Ameren presents no credible evidence that MDNR or any permitting authority will reject technologies with incremental cost effectiveness above $6,800/ton.

v. Campbell Disregards MDNR Practice Concerning Sources in the Same Category

155. Campbell also undermines his credibility by contradicting the NSR's source category "cost presumption." This principal of NSR permitting holds that "in the absence of unusual circumstance, the presumption is that sources within the same category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category." NSR Manual (Pl. Ex. 1190), at AM-REM-00544146-MDNR.

156. MDNR included the same language in a PSD permit for the Norborne coal-fired power plant. In that permit, MDNR rejected an applicant's attempt to rely on incremental cost-effectiveness over the same source category cost presumption. MDNR stated the following:

> [A]s per the draft of NSR Workshop manual, "in the absence of unusual circumstance, the presumption is that sources within the same category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category." Since AECI has not provided any data which differentiates this project from previously permitted units which have limits of 0.05 lb/MMBTU on an annual basis, it is presumed that the costs these systems will

> incur can also be incurred by AECI. Therefore, the economic analysis provided by AECI was not considered in selecting the NO_x limit.

Norborne PSD Permit (Pl. Ex. 1180), at AM-REM-00503313-MDNR (quoting NSR Manual); see also MDNR Rule 30(b)(6) Dep., at 139:21-141:22) (testifying that "when a permit writer looks at a permit application from, for example, a coal-fired utility, [] they would look towards other coal-fired utilities to determine the appropriate controls and what controls are already being used").

157. Campbell claimed during his direct examination that "there is no such presumption" in the "real world." Campbell Test., Tr. Vol. 4-A, 58:8-59:4. But this testimony was not supported by any evidence.

158. Campbell's statement—that the same source category cost presumption does not apply in the real world—undermines his credibility.

vi. Campbell Incorrectly Rejects Information From Power Plants Subject to NSPS

159. Campbell testified that SO_2 BACT determinations for coal-fired power plants during the past couple decades are not informative for Rush Island in 2019 because they involved "new" plants subject to NSPS. Campbell Test., Tr. Vol. 4-A, 75:20-22, 100:5-102:11.

160. Campbell's decision to disregard new plants subject to NSPS is inconsistent with the design and function of NSPS and is unsupported by the evidence presented in this case. See FOF ¶ 85-90.

161. Despite these features, Campbell testified that sources subject to NSPS should not be compared to Rush Island, because the NSPS fundamentally altered the range of options available in a BACT determination. Campbell Test., Tr. Vol. 4-A, 75:20-22, 100:5-102:11.

162. There is no difference between the emissions rates that can be achieved through

use of FGDs at NSPS-subject new units and existing units. Campbell Test., Tr. Vol. 4-A, 105:9-13.

163. Instead of relying on recent BACT determinations, Campbell based his testimony on BACT determinations made in the late 1970s and early 1980s. He also considered a 1990 BACT determination for a CFB boiler in Hawaii to be relevant. Campbell Test., Tr. Vol. 4-A, 102:12-104:3.

164. Campbell's testimony on this point is inconsistent with the permit application he helped electric utility DTE prepare for its Monroe power plant. Campbell Test., Tr. Vol. 4-A, 104:4-19.

e. I Reject Campbell's Testimony That DSI Is BACT for Rush Island

165. In addition to the flaws in Campbell's testimony, the following facts contradict Campbell's claims that DSI is BACT for Rush Island.

166. In 2008, MDNR rejected DSI for a coal-fired power plant because it did not "represent the upper level of SO_2 controls" necessary to constitute BACT. Staudt Test., Tr. Vol. 1-B, 93:23-94:25; 2/22/08 Norborne PSD Permit (Pl. Ex. 1180) at AM-REM-00503315-MDNR to 3316-MDNR (rejecting control efficiencies of up to 85%).

167. No permitting authority anywhere in the country has ever determined SO_2 BACT for a pulverized coal-fired power plant based on DSI. If I were to accept Campbell's testimony, Rush Island would be the first pulverized coal-fired power plant to have BACT based on DSI. Staudt Test., Tr. Vol. 1-B, 89:7-9; Campbell Test., Tr. Vol. 4-A, 97:21-98:7; Knodel Test., Tr. Vol. 1-A, 63:22-25.

168. Under a top-down BACT analysis, to arrive at his BACT determination, Campbell would have had to evaluate and then eliminate wet FGD, dry FGD, and DSI-FF in that

order, before settling on the least effective control technology available for Rush Island. FOF ¶¶ 75, 113.

169. Campbell admitted he "gave dry FGD relatively little consideration in [his] analysis [and] didn't assess its impacts in any quantitative way in Step 4." Campbell Test., Tr. Vol. 4-A, 85:1-4. Similarly, he did not evaluate DSI with a fabric filter in "any quantitative way." Id. at 85:16-25.

170. Campbell then compared the very effective, more capital-intensive wet FGD with the least effective and least expensive option—DSI without a fabric filter. Id. at 119:7-11.

171. The flaws in Campbell's analysis affect the core of his testimony that DSI constitutes BACT at Rush Island. Campbell rejected wet FGD specifically because his calculated incremental cost effectiveness was higher than a threshold he allegedly derived from BACT permits. In doing so, Campbell (1) overly relied on incremental cost effectiveness, (2) considered extrinsic expenses not normally included in BACT cost comparisons, (3) inappropriately compared the most- and least-effective technology, (4) derived a cost threshold that is not supported by the evidence, and (5) disregarded consistency among pulverized coal-fired power plants installing FGD. Campbell also inappropriately disregarded BACT permits for power plants subject to NSPS. I reject Campbell's testimony that DSI is BACT for Rush island.

f. Dr. Staudt's Testimony Concerning BACT at Rush Island Was Credible

172. In contrast to Campbell, Dr. Staudt conducted the well-established five-step BACT determination as outlined in the NSR manual and as practiced by MDNR and other permitting authorities.

173. Specifically, Dr. Staudt started step four by analyzing the most effective control technology, wet FGD. Dr. Staudt evaluated the energy, environmental, and economic costs of

wet FGD and concluded that wet FGD was achievable.

174. In coming to these conclusions, Dr. Staudt relied on standards and practices outlined in the EPA's Draft NSR Manual, the EPA's Cost Control Manual, and in permits issued by MDNR. Dr. Staudt carefully explained his methods, provided consistent testimony, and supported his testimony with credible evidence.

175. Ameren attempted to challenge Dr. Staudt's credibility by arguing that Staudt 1) overly relied on plants that had to meet the NSPS, 2) evaluated natural gas conversion as a control technology throughout the five-step process, and 3) did not evaluate the incremental cost effectiveness of wet FGD.

176. These arguments do not demonstrate that Dr. Staudt's testimony is not credible. With respect to NSPS, Dr. Staudt convincingly testified that NSPS provides a floor that does not fundamentally alter the BACT determination. Staudt Test., Tr. Vol. 1-B, 89:21-91:8; Tr. Vol. 2-A, 7:10-8:1. With respect to the natural gas conversion, Dr. Staudt eliminated the natural gas option because it was a different kind of fuel, and its inclusion did not affect how wet FGD was analyzed in step four. Tr. Vol. 2-A, 21:6-17, 22:23-23:18.

177. Dr. Staudt's economic evaluation may have been more compelling if he had discussed incremental cost effectiveness, even if BACT determinations do not specifically require it.

178. Still, I find that Dr. Staudt's testimony is credible, helpful to the trier of fact, and instrumental to determining what BACT was at the time of Rush Island's modifications. I heavily rely on Dr. Staudt's testimony when discussing facts surrounding BACT determinations in this case.

g. BACT Requirements at Rush Island in 2007 and 2010

179. Staudt and Campbell—and ultimately the parties in this case—did not have any material disagreement over Steps 1 through 3 of BACT process. Campbell Test., Tr. Vol. 4-A, 97:9-20. The results of those analyses are identified below:

Step One: Identify Available Control Options

180. The available SO_2 control technologies for Rush Island Units 1 and 2 include wet FGD, dry FGD, DSI-FF, and ordinary DSI. Staudt Test., Tr. Vol. 1-B, 50:19-51:1; Campbell Test., Tr. Vol. 4-A, 50:16-51:13. I find that Dr. Staudt's and Campbell's testimony on this point is credible and that this is the appropriate ranking.

Step Two: Eliminate Technically Infeasible Options

181. None of these control technologies can be eliminated as technically infeasible for Rush Island. Staudt Test., Tr. Vol. 1-B, 51:24-52:5; Campbell Test., Tr. Vol. 4-A, 50:16-51:13, 93:1-8; Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 59:1-12.

Step Three: Rank Technically-Feasible Options by Effectiveness

182. Wet FGD is the most effective control technology (about 99% removal efficiency), followed by dry FGD (about 95%), DSI with a fabric filter (about 70%), and DSI without a fabric filter (about 50%). Staudt Test., Tr. Vol. 1-B, 14:13-15:1, 52:21-53:15, 16:11-17:14; Campbell Test., Tr. Vol. 4-A, 50:16-51:13; Snell Test., Tr. Vol. 4-B, 5:19-6:3, 18:19-19:7, 50:8-22.

Step Four: Evaluate Most Effective Controls

183. Dr. Staudt and Campbell disagreed about the results of the fourth and fifth steps.

184. Dr. Staudt concluded that wet FGD could not be eliminated because it was achievable, taking into account energy, environmental, and economic impacts and other costs. Staudt Test., Tr. Vol. 1-B, 54:22-55:4.

185. Campbell concluded that wet FGD could be eliminated because its incremental cost effectiveness was unacceptably costly when compared with DSI. As noted above, Campbell did not use the top-down method here. Instead Campbell eliminated the middle two options—because dry FGD and DSI-FF were not "dominant control options." Id. at 74:3-12.

186. Neither Campbell nor Ameren cites to any permitting authority, permitting applicant, permitting guide, or other authority supporting Campbell's method of excluding "non-dominant" control options before conducting the step four analysis.

187. In contrast, Dr. Staudt employed the top-down method, as practiced by MDNR and other permitting authorities. Dr. Staudt evaluated the energy, environmental, economic, and other costs associated with wet FGD.

188. Based on Dr. Staudt's credible, well-supported testimony, I find that the energy, environmental and economic impacts of wet FGD do not make wet FGD unachievable. Instead, these impacts are reasonable and comparable to the impacts experienced at other permitted pulverized coal-fired power plants.

Energy Impacts

189. The evidence does not show that wet FGD's energy impacts would be unreasonable for Rush Island. Staudt Test., Tr. Vol. 1-B, 54:22-55:4. Ameren's engineering studies determined that Ameren would not have to install power-intensive fans for wet FGD, but it would have to install them for dry FGD or DSI with a fabric filter. Staudt Test., Tr. Vol. 1-B, 55:5-19. These fans would decrease the overall power output of the plant.

190. Ameren presented evidence that wet FGD would reduce power output at Rush Island, due to the energy demands of the wet FGD controls. Snell Test., Tr. Vol. 4-B, 38:6-17. Ameren did not argue that this energy demand was different from the energy demand of

scrubbers at other pulverized coal-fired power plants. Additionally, Ameren did not present evidence that this energy demand would make wet FGD unachievable. As a result, the weight of the evidence demonstrates that the energy impacts of wet FGD do not make it unachievable for Rush Island.

Environmental Impacts

191. Relatedly, the evidence does not show that wet FGD would impose unreasonable environmental impacts at Rush Island. Instead, Ameren would have the environmental benefit of producing saleable gypsum instead of landfill waste. Staudt Test., Tr. Vol. 1-B, 40:12-41:24, 55:20-56:5; see FOF ¶¶ 35. Additionally, water limitations would not be an issue for Rush Island, because it is in close proximity to the Mississippi River. Staudt Test., Tr. Vol. 1-B, 56:6-14.

192. Ameren presented evidence at trial that wet FGD would require more wastewater treatment and new mercury controls, creating more costs for Ameren than DSI would impose. Snell Test., Tr. Vol. 4-B, 37:24-39:10. However, Ameren made no effort to explain how these environmental impacts made wet FGD unachievable. Nor did Ameren suggest that these environmental impacts are different from the kinds of impacts experienced at other pulverized coal-fired power plants. See NSR Manual (Pl. Ex. 1190), at AM-REM-00544146-MDNR; Staudt Test. Vol. 1-B, 63:14-64:6.

Economic Impacts

193. Finally, wet FGD would not impose unreasonable economic impacts at Rush Island. Staudt Test., Tr. Vol. 1-B, 56:15-19.

194. Ameren openly concedes that it can afford to install scrubbers at Rush Island. Ameren's contemporaneous studies confirmed that wet FGDs would be economically feasible.

The same studies show that, from a cost perspective, wet FGDs are preferable to dry FGDs at Rush Island. FOF ¶¶ 26, 31-33, 36, 38.

195. The large number of coal-fired electric generating units already equipped with wet FGDs provides strong evidence that the cost of wet FGD is achievable for a pulverized coal-fired power plant like Rush Island. Staudt Test., Tr. Vol. 1-B, at 62:8-21, 64:20-65:7, 66:17-67:2.

196. Ameren's engineering studies confirmed that the capital costs of installing wet scrubbers at Rush Island would be consistent with costs borne by other utilities. Staudt Test. Tr. Vol. 2-A, 56:20-57:6.

197. Rush Island does not have any unique characteristics that would make the typical costs of wet FGDs unreasonable in this context. Staudt Test., Tr. Vol. 1-B, 65:8-12; Snell Test., Tr. Vol. 4-B, 57:15-18. None of Ameren's experts have identified any circumstances at Rush Island that would make the costs to install wet FGDs at Rush Island unusual compared to other plants. Staudt Test., Tr. Vol. 1-B, 65:8-12; Snell Test., Tr. Vol. 4-B, 57:15-18.

198. On the contrary, Ameren's own engineers have admitted that there is nothing about Rush Island that makes it different from any of the other plants where FGDs have been installed. Mitchell Dep., May 30, 2018, Tr. 81:13-23, 192:2-10.

199. For purposes of historic BACT, Dr. Staudt calculated the average cost-effectiveness of wet FGD to be about $2800/ton for Rush Island Unit 1 and Unit 2. Staudt Test., Tr. Vol. 1-B, 57:7-58:22. Based on these figures, Dr. Staudt testified that wet FGD could not be eliminated as unachievable due to cost concerns. Id. at 62:3-7.[6]

---

[6] Dr. Staudt made conservative assumptions when calculating the average cost effectiveness for wet FGD. He based his baseline emission rate on low sulfur coal, leading to lower emissions reductions, a larger demoninator, and a higher per ton cost. Staudt Test., Tr. Vol. 1-B, 59:3-15, 61:16-62:2. Dr. Staudt also used a capacity factor of 80% rather than 100%. Staudt Test., Tr. Vol. 1-B, 61:16-62:2.

200. Wet FGD is achievable at Rush Island, taking into account the energy, environmental, economic impacts and other costs of this technology. I find no basis for eliminating the top control, wet FGD, at Step Four of the BACT analysis.

Step Five: Select BACT

201. In Step Five, the permit applicant and permitting authority determine what emissions limit can be achieved by installing the selected control technology.

202. For Rush Island Unit 1, Dr. Staudt testified that historic BACT would have been 0.08 lb/mmBTU, based on a 30-day rolling average. This corresponds to a design removal efficiency of 91.4%. Staudt Test., Tr. Vol. 1-B, 69:13-22.

203. For Rush Island Unit 2, Dr. Staudt testified that historic BACT would have been 0.06 lb/mmBTU, based on a 30-day rolling average. That would represent a 94% design removal efficiency. Staudt Test., Tr. Vol. 1-B, 69:23-70:2.

204. Dr. Staudt's historic BACT rates include a reasonable compliance margin and are consistent with the rates that Ameren's engineering studies confirmed would be achievable at Rush Island. FOF ¶ 30.

205. Dr. Staudt's historic BACT rates are consistent with permits issued by MDNR and other permitting authorities during the relevant period. Staudt Test., Tr. Vol. 1-B, 70:15-17, 79:6-18, 80:23-81:19. FOF ¶¶ 99-105.

206. Dr. Staudt's historic BACT rates are also consistent with the design specifications used for Ameren's engineering studies, and performance of FGDs at Ameren's other plants. By the time Rush Island Unit 2 was modified, Ameren already had a plant "perform[ing] at 0.06 pounds per million Btu, so [it] knew that number could be achieved." Callahan Dep., Nov. 8, 2017, Tr. 201:13-21; see also id. at 78:2-8, 84:8-23 (the FGDs at Ameren Illinois's Duck Creek

plant were achieving 99% removal or 0.06 lb/mmBTU).

207. Finally, Dr. Staudt's historic BACT rates are consistent with industry performance data. In 2008 and 2011, the years after each of the modifications at issue, the top 20% of performing scrubbers in the industry were achieving SO_2 rates, respectively, of 0.059 lb/mmBTU and 0.037 lb/mmBTU. Staudt Test., Tr. Vol. 1-B, 82:21-88:3.

208. For these reasons, I find that, at the time Ameren modified Rush Island, BACT required SO_2 emissions limitations at least as stringent as 0.08 lb/mmBTU for the 2007 modification of Rush Island Unit 1, and 0.06 lb/mmBTU for the 2010 modification of Rush Island Unit 2, based on 30-day rolling averages.

h. Rush Island's Excess Emissions Total More Than 162,000 Tons

209. Dr. Staudt calculated the excess emissions from Ameren's failure to install scrubbers in 2007 and 2010, based on Dr. Staudt's historic BACT determinations and Rush Island's actual emissions reported by Ameren to the EPA's Air Market Program. Staudt Test., Tr. Vol. 1-B, 99:17-101:4.

210. Based on Dr. Staudt's testimony and the evidence at trial, I find that Ameren's failure to install scrubbers at Rush Island resulted in 162,000 tons of excess SO_2 emissions through the end of 2016. These excess emissions continue at a rate of about 16,000 tons per year, and will be emitted each year that Rush Island operates without scrubbers. Staudt Test., Tr. Vol. 1-B, 101:5-9.

211. If Ameren finishes installation of wet FGD scrubbers at Rush Island in 2023, the excess emissions will total nearly 275,000 tons. Staudt Test., Tr. Vol. 1-B, 99:17-102:1. Obviously, the sooner Ameren installs scrubbers, the lower its excess emissions will be. Id. at 101:18-102:1.

III. CURRENT BACT ANALYSIS

212. While the historic BACT determination was necessary to calculate Rush Island's excess emissions between 2007 and the present day, a current BACT determination helps identify the appropriate relief in this case. The EPA has asked me to (1) determine what technology constitutes BACT for Rush Island and (2) order Ameren to propose that technology in its permit application. Without this relief, the EPA is concerned that Ameren will continue to delay and oppose the installation of the appropriate pollution control technology.

213. I find that wet FGD constitutes BACT for Rush Island today. I also find that BACT for Rush Island Units 1 and 2 is a 30-day rolling average of 0.05 lb SO_2/mmBTU. This emission limitation is lower than the historic BACT for Rush Island because BACT rates decrease over time due to the technology-forcing nature of the requirement.

a. Current BACT Requires Wet FGD

214. Ameren's and the EPA's expert testimony concerning current BACT is essentially identical to their expert testimony concerning historic BACT. On behalf of Ameren, Campbell conducted one BACT analysis used for historic and current BACT. On behalf of the EPA, Dr. Staudt conducted a current BACT analysis that had the same process and result as his historic BACT analysis, save an updated emissions limitation.

215. The parties agree on the results of steps one, two, and three. Additionally, Ameren's experts admitted that the rate the EPA determined in Step Five would be achievable with wet FGD. Campbell Test., Tr. Vol. 4-A, 93:18-94:3; see also Snell Test., Tr. Vol. 4-B, 51:13-52:16 (conceding that a design SO_2 emission rate of 0.04 lb/mmBTU is achievable at Rush Island).

216. For the same reasons as were applicable to the historic BACT analysis, I find that

wet FGD cannot be eliminated at Step Four of the top-down method based on unreasonable energy, environmental or economic impacts. FOF ¶ 189-200.

217. Between 2010 and the present day, scrubber technologies, including wet FGD, have become more prevalent at pulverized coal-fired power plants. Between 2005 and 2015, wet FGD technology was installed on nearly 100,000 megawatts of pulverized coal-fired electric generating capacity in the United States. FOF ¶ 17 and Figure 1. Almost all of that scrubbed generating capacity is at existing plants that installed scrubbers. FOF ¶ 17. Today, there are very few units the size of the Rush Island that continue to operate without any type of FGD controls. FOF ¶¶ 16, 18.

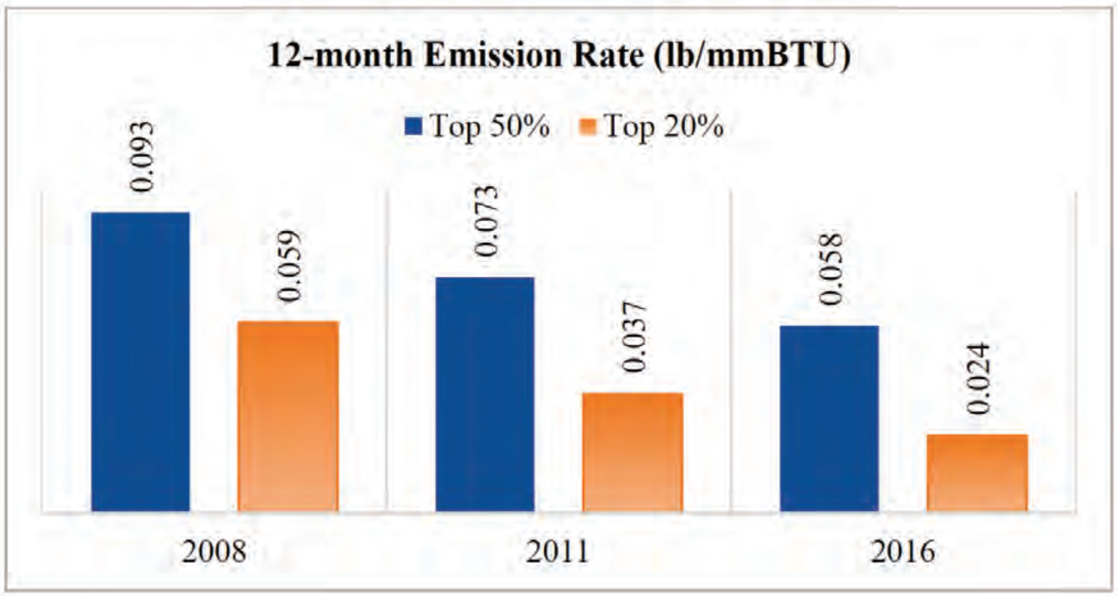
218. The more widespread use of FGD scrubbers at coal-fired power plants strengthens the argument that wet FGD is achievable today at Rush Island. As quoted by MDNR in its Norborne permit, "in the absence of unusual circumstance, the presumption is that sources within the same category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category." Norborne PSD Permit (Pl. Ex. 1180), at AM-REM-00503313-MDNR (quoting NSR Manual and emphasis added).

219. Ameren presented no evidence at trial to distinguish Rush Island from the other pulverized coal-fired power plants using scrubbers today. FOF ¶¶ 197-98. The only Ameren witness who attempted to do so was Campbell, who testified that the most unusual circumstance about Rush Island is that it is "not equipped with a scrubber and not otherwise required to install a scrubber . . ." Campbell Test., Tr. Vol. 4-A, 114:5-12.

220. The performance of scrubbers in the electric utility industry has continued to improve over the past decade, as illustrated in Figure 3. Figure 3 identifies the 12-month

averaged emission rate for the top performing 50% of plants and the top performing 20% of plants in 2008, 2011, and 2016.

Figure 3



221. As shown in Figure 3, the average emission rate achieved by the top 20% of units (57 units) in 2016 was 0.024 lb/mmBTU. In 2008 and 2011, the average emission rate being achieved by the top 20% of units was 0.059 and 0.037 lb/mmBTU, more than 100% and 50% higher than in 2016, respectively. These trends demonstrate a significant and sustained improvement in performance between 2008 and 2016. Staudt Test., Tr. Vol. 1-B, 82:21-83:20.

222. In Missouri, the Iatan plant reflects the low emissions rates that FGD can achieve today. Like Rush island, Iatan burns low-sulfur coal. Using wet FGDs since 2008, Iatan now achieves emission rates as low as 0.004 to 0.006 lb/mmBTU. Although similar in size to Rush Island, Iatan's total SO_2 emissions (250 tons) are a small fraction of Rush Island's (18,000 tons). Staudt Test., Tr. Vol. 1-B, 76:6-76:9, 84:10-84:25.

223. With respect to economic impacts, Ameren does not dispute that it can afford FGDs at Rush Island, and it presented no evidence that installing FGDs would otherwise impose an undue financial burden on the company. FOF ¶¶ 37-41, 194.

224. For his BACT analysis, Dr. Staudt estimated that the capital cost of installing wet FGDs at Rush Island would be about $582 million in 2016 dollars. This estimate was based on the costs calculated by Ameren's engineering studies, excluding AFUDC, escalation, corporate overhead, and property taxes consistent with the standard methodology for BACT cost calculations. Staudt Test., Tr. Vol. 1-B, 59:24-61:5; Tr. Vol. 2-A, 25:25-26:6, 28:18-30:18.

225. Based on those capital cost estimates, Dr. Staudt calculated the average cost-effectiveness of wet FGDs at Rush Island to be $3,854 per ton of SO_2 removed. Staudt Test., Tr. Vol. 1-B, 58:23:59-2. Dr. Staudt testified that wet FGD could not be eliminated based on these average cost-effectiveness figures, Staudt Test., Tr. Vol. 2-A, 26:17-27:5, and his testimony is unrebutted: Ameren's BACT expert reached no opinion on whether the average cost-effectiveness of wet FGDs at Rush Island would be considered unreasonable. Campbell Test., Tr. Vol. 4-A, 115:8-116:17.[7]

226. According to Ameren's engineering studies, this average cost effectiveness result is consistent with costs borne by other coal-fired power plants installing scrubbers. See February 5, 2010 Project Review Board Presentation-Rush Island FGD (Pl. Ex. 1100), at AM-REM-00289006; Staudt Test. Tr. Vol. 1-B, 23:10-25:16, 56:20-57:6; Ameren Rule 30(b)(6) Dep., Nov.

[7] On cross-examination, Campbell testified that permitting authorities generally use a $5000/ton threshold for average cost-effectiveness. Campbell Test., Tr. Vol. 4-A, at 115:8-14. While Campbell's testimony was inconsistent with his prior sworn deposition testimony that he knew of no "rule of thumb" limit for average cost-effectiveness, (id. at 115:8-116:17), I note that—if credited—Campbell's testimony would provide further support that $3,854/ton would be considered an acceptable average cost-effectiveness for purposes of BACT.

7, 2017, Tr. 90:6-91:3.

227. I find that the average cost-effectiveness of wet FGD at Rush Island is reasonable for a pulverized coal-fired power plant today. I also find that the economic costs of installing wet FGD at Rush Island do not make wet FGD unachievable.

228. Additionally, I find that neither the energy nor environmental costs of installing wet FGD at Rush Island make wet FGD unachievable. Ameren presents no evidence demonstrating, and I have no reason to find, that the energy and environmental costs for a current BACT determination at Rush Island are any greater or less reasonable than the energy and environmental costs for a historic BACT determination.

b. Current BACT Requires an Emissions Limitation of 0.05 lb/mmBTU

229. Dr. Staudt testified that, based on a selection of wet FGD, the appropriate emissions limitation for Rush Island is 0.05 lb/mmBTU. Staudt Test., Tr. Vol. 1-B, 70:3-17.

230. In 2011, Ameren accepted its consultants' recommendation that it solicit bids for a wet FGD system designed to meet an SO_2 emission rate of 0.04 lb/mmBTU, regardless of the type of coal burned. FOF ¶¶ 52-55.

231. Ameren's expert Campbell admitted that 0.05 lb/mmBTU would be an achievable emission rate at Rush Island and a good estimate of what MDNR would set as BACT if scrubbers were required. Campbell Test., Tr. Vol. 4-A, 93:18-94:3; see also Snell Test., Tr. Vol. 4-B, 51:13-52:16 (conceding that a design SO_2 emission rate of 0.04 lb/mmBTU is achievable at Rush Island).

232. An SO_2 emission rate of 0.05 lb/mmBTU could be achieved through use of either wet or dry scrubbers and does not represent the lowest achievable SO_2 emission rate at Rush Island. Staudt Test., Tr. Vol. 1-B, 70:18-25.

233. I find that wet FGD constitutes BACT today for Rush Island and the appropriate operating emissions limitation for this technology would be set at 0.05 lb/mmBTU, based on a 30-day rolling average.

IV. RUSH ISLAND'S EXCESS EMISSIONS CAUSED IRREPARABLE INJURY, INCLUDING INCREASED RISK OF PREMATURE MORTALITY

234. The EPA offered evidence to demonstrate that the excess SO_2 emissions resulting from Ameren's decision to ignore PSD requirements caused irreparable injury that could not be compensated through legal remedies. See eBay Inc. v. MercExchange, L.L.C., 547 U.S. 388, 391 (2006). The EPA also offered evidence to demonstrate that the balance of hardships and public interest favors injunctive relief. See id. Based on both parties' evidence, I make the following findings of fact concerning the result of Rush Island's excess pollution.

a. Rush Island's Excess Pollution Is Substantial

235. SO_2 is a regulated pollutant under the Clean Air Act. Any source that releases more than 100 tons of SO_2 yearly is considered a "major" source. 42 U.S.C. § 7479(1); see also 40 C.F.R. § 52.21(b)(1)(i) (same regulatory threshold).

236. Rush Island's annual SO_2 emissions and its excess emissions that should have been captured by BACT (16,000 tons per year) both far exceed this threshold. Compare Staudt Test., Tr. Vol. 1-B, 101:10-13 with 42 U.S.C. § 7479(1) and 40 C.F.R. § 52.21(b)(1)(i). The annual excess pollution from Rush Island alone is equivalent to the amount of pollution that would be emitted by more than 160 sources that each would be considered "major" sources of harmful air pollution under the Clean Air Act.

b. Rush Island's Excess SO_2 Emissions Created Harmful $PM_{2.5}$

237. SO_2 is directly emitted from Rush Island as a gas. However, SO_2 is not stable in the atmosphere. Over time, all the SO_2 released by Rush Island will convert to fine particulate

matter known as "$PM_{2.5}$." $PM_{2.5}$ includes all particles that are 2.5 micrometers in diameter or smaller. Chinkin Test., Tr. Vol. 2-A, 97:6-19.

238. On average, about five percent of the SO_2 emitted by a facility will convert into $PM_{2.5}$ each hour, with a range of one to ten percent depending on meteorological variables. Chinkin Test., Tr. Vol. 2-A, 97:20-98:21. $PM_{2.5}$ pollution resulting from Rush Island's excess SO_2 emissions travels hundreds of miles from Rush Island's smokestack. Chinkin Test., Tr. Vol. 2-B, 22:15-19.

239. $PM_{2.5}$ derived from burning coal and other fossil fuels is known as combustion-related $PM_{2.5}$ or combustion particles. These combustion particles are generally less than one micrometer in diameter, about the same size as a virus. By contrast, most naturally-occurring particles in the atmosphere are greater than ten micrometers in diameter.

240. Because of their size, combustion-related $PM_{2.5}$ particles have a better chance of getting past the body's natural defenses. $PM_{2.5}$ particles are more likely to get into deeper lung structures such as the alveoli, where they can do greater damage for more sustained periods of time. Schwartz Test., Tr. Vol. 3-A, 21:9-22:18, 59:5-11.

241. $PM_{2.5}$ is made up of different chemical constituents, which react with each other in the atmosphere. One of the constituents of combustion-related $PM_{2.5}$ is sulfate $PM_{2.5}$, which forms from SO_2 emissions. Sulfate $PM_{2.5}$ is one of the largest components of $PM_{2.5}$ in the atmosphere. Schwartz Test., Tr. Vol. 3-A, 22:19-23:10, 59:5-59:11.

242. Sulfate combustion particles are not pure, homogenous specimens. They chemically bind to other substances present in the outdoor air. Sulfate tends to combine with metals in the atmosphere, forming compounds that magnify the human health effects of $PM_{2.5}$. Schwartz Test., Tr. Vol. 3-A, 24:23-26:13, 27:5-28:24; see also Valberg Test., Tr. Vol. 5-A,

111:5-16 (conceding that the sulfate ion does not exist in the air by itself).

243. The available scientific evidence indicates that all constituents of $PM_{2.5}$ are toxic. Insufficient evidence exists to determine whether any particular constituent is more toxic than any other. Schwartz Test., Tr. Vol. 3-A, 23:11-13.

244. $PM_{2.5}$ is regulated in the United States and throughout the world on a mass basis, rather than on a constituent-by-constituent basis. Id. at 23:22-24:19, 58:23-59:24; see also Valberg Test., Tr. Vol. 5-A, 111:17-19, 113:2-5 (conceding that $PM_{2.5}$ is regulated on a mass basis, not a constituent basis).

i. Dr. Schwartz Presented Credible, Well-Supported, Expert Testimony Concerning the Health Impacts of $PM_{2.5}$

245. To demonstrate the health effects of $PM_{2.5}$, the EPA offered the expert testimony of Dr. Joel Schwartz. Dr. Schwartz is a tenured professor in the Department of Environmental Health and the Department of Epidemiology at the Harvard School of Public Health and is also a professor in the Department of Medicine at the Harvard Medical School. Schwartz Test., Tr. Vol. 3-A, 4:25-5:5, 8:17-20; see also Curriculum Vitae of Dr. Joel Schwartz (Pl. Ex. 1324).

246. Dr. Schwartz is one of the world's leading scientists on the health effects of air pollution. He has published about 790 peer-reviewed articles. Schwartz Test., Tr. Vol. 3-A, 12:8-11; Pl. 1324. His published research has been cited more than 60,000 times in the scientific literature. Id. at 12:18-19. Dr. Schwartz is not aware of any person who has published more articles than he has in the field of air pollution research. Id. at 13:1-4.

247. Dr. Schwartz performs extensive research on air pollution, teaches courses on epidemiology, and serves as the director of the Harvard Center for Risk Analysis. Schwartz Test., Tr. Vol. 3-A, 5:6-8, 7:13-10:10, 13:5-15:13. Dr. Schwartz's research has been cited by the EPA in its Integrated Science Assessments and has been relied upon by the World Health

Organization in setting standards for air pollution. Schwartz Test., Tr. Vol. 3-A, 15:14-16:1. Dr. Schwartz has also testified before Congress as to the health effects of air pollution, and recently provided a keynote presentation on $PM_{2.5}$ health effects to a World Health Organization conference of international public health ministers. Schwartz Test., Tr. Vol. 3-A, 16:2-25.

248. Dr. Schwartz has testified in federal court two times before this case. He was received as an expert in those cases. Id. at 18:2-5.

249. Dr. Schwartz's testimony is consistent with the scientific consensus that $PM_{2.5}$ harms public health and that there is no threshold below which $PM_{2.5}$ does not cause adverse health effects in exposed populations.

250. During his testimony and during cross-examination, Dr. Schwartz's answers were detailed, credible, and supported by an overwhelming amount of evidence. I find Dr. Schwartz's testimony concerning the health effects of $PM_{2.5}$ to be credible.

ii. $PM_{2.5}$ Causes Heart Attacks, Strokes, Asthma Attacks, and Premature Mortality

251. $PM_{2.5}$ is harmful to human health, causing numerous adverse health effects in exposed populations. Inhaling $PM_{2.5}$ leads to increased risk of high blood pressure, hardened arties, heart attacks, strokes, asthma attacks, and premature mortality. Schwartz Test., Tr. Vol. 3-A, 19:18-20:4, 49:6-50:13 (explaining the American Heart Association's official statement on health effects of $PM_{2.5}$ inhalation), 60:6-62:5 (explaining the EPA's Integrated Science Assessment on health effects of health effects of $PM_{2.5}$ inhalation).

252. The health effects from $PM_{2.5}$ are well-established, and the harmful mechanisms of $PM_{2.5}$ exposure have been demonstrated in many epidemiological, toxicology, and clinical studies. Schwartz Test., Tr. Vol. 3-A, 49:6-50:13, 60:6-62:5.

253. The effect of $PM_{2.5}$ exposure on life expectancy, heart attacks, and strokes is both

acute and chronic, based on short-term and long-term exposure, respectively. Schwartz Test., Tr. Vol. 3-A, 49:6-17, 60:18-61:11.

254. The harmful nature of $PM_{2.5}$ exposure is widely known and agreed upon. Schwartz Test., Tr. Vol. 3-A, 19:18-20:22, 47:6-24. Dr. Schwartz cited statements from the U.S. Centers for Disease Control, the U.S. Environmental Protection Agency, the American Heart Association, the American Thoracic Society, the American Medical Association, the National Academy of Sciences, the World Health Organization, the Royal College of Physicians of the United Kingdom, and the United Nations Environment Program to support his expert testimony on this point. Id.

255. The relationship between the concentration of $PM_{2.5}$ in the ambient air and resulting health effects is known as a concentration-response function. For premature mortality, the concentration-response function indicates the percent change in mortality that is expected from a given change in $PM_{2.5}$ exposure. Schwartz Test., Tr. Vol. 3-A, 36:4-38:2, 86:13-15.

256. The scientific consensus concerning ambient $PM_{2.5}$ concentrations is that there is no safe level below which $PM_{2.5}$ is not harmful. The $PM_{2.5}$ concentration-response relationship has been extensively analyzed in the scientific literature, and studies of both short- and long-term exposure to $PM_{2.5}$ have consistently found no evidence of a safe threshold. Schwartz Test., Tr. Vol. 3-A, 42:17-43:5, 43:22-45:17, 46:19-47:15, 57:16-58:10, 62:6-63:5, 64:11-24, 67:17-68:10.

257. The concentration-response relationship between $PM_{2.5}$ and mortality is linear. Researchers have *not* found a population threshold for ambient $PM_{2.5}$, including at the concentrations experienced in communities near Rush Island. Less data exists to determine the shape of the concentration-response relationship at annual ambient levels below 3 or 4 micrograms per cubic meter. However, the areas impacted by Rush Island's excess emissions are

all above those concentrations. Schwartz Test., Tr. Vol. 3-A, 38:6-39:16, 64:11-66:11, Schwartz Test., Tr. Vol. 3-B, 49:6-21.

258. Dr. Schwartz agrees with the World Health Organization that there is "no evidence of a safe level of exposure or a threshold below which no adverse health effects occur" from exposure to $PM_{2.5}$. Schwartz Test., Tr. Vol. 3-A, 57:16-58:10 (discussing statement on $PM_{2.5}$ health effects issued by World Health Organization).

259. Dr. Schwartz's testimony about the scientific consensus concerning the $PM_{2.5}$ concentration-response relationship was in part based on a 2009 Integrated Science Assessment published by the EPA. Schwartz Test., Tr. Vol. 3-A, 60:4-63:5; see generally 2009 Integrated Science Assessment for Particulate Matter (Pl. Ex. 1209) at 2-8 to 2-17 (evaluating "evidence from toxicological, controlled human exposure, and epidemiologic studies" and concluding that $PM_{2.5}$ causes premature mortality and other health effects); id. at 6-75 (explaining that short- and long-term studies of concentration-response relationships have "consistently found no evidence for deviations from linearity or a safe threshold"); id. at 6-158 to 6-201 and 7-82 to 7-96 (further summarizing evidence for causal determinations for short- and long-term exposure).

260. The evidence demonstrating that there is no safe threshold for $PM_{2.5}$ has only increased since the EPA's 2009 Integrated Science Assessment. Schwartz Test., Tr. Vol. 3-A, 64:11-66:11, 68:1-69:15; Schwartz Test., Tr. Vol. 3-B, 49:6-21.

261. Interpreting more recent studies, Dr. Schwartz testified that the linear concentration-response function between $PM_{2.5}$ and premature death has been demonstrated at lower concentrations than before. Schwartz Test., Tr. Vol. 3-A, 64:11-66:11, 68:1-69:15; Schwartz Test., Tr. Vol. 3-B, 49:6-21.

262. The concentration-response function cited by Dr. Schwartz is derived from

substantial sets of data that have been extensively analyzed in the peer-reviewed literature. In part, Dr. Schwartz relied on a recent study published in the New England Journal of Medicine that included approximately 500,000 unique $PM_{2.5}$ concentration data points at ambient levels between 6 and 16 micrograms per cubic meter, and 70,000 unique data points clustered between ambient $PM_{2.5}$ concentrations of 10 and 11 micrograms per cubic meter. The study found a linear relationship in these two ranges. Schwartz Test., Tr. Vol. 3-A, 36:10-37:12, 39:9-43:5.

263. Based on the no-threshold, linear concentration-response relationship for $PM_{2.5}$, any incremental increase in $PM_{2.5}$ exposure produces an incremental increased risk of mortality and other health effects in the population exposed to Rush Island's excess emissions. Similarly, any incremental decrease in exposure produces a positive impact on public health. Schwartz Test., Tr. Vol. 3-A, 39:9-16, 41:11-43:5, 46:19-47:5, 79:15-21.

264. Both of Ameren's toxicologists conceded that, if a substance is actually a no-threshold pollutant, any incremental increase in exposure produces an incremental increase in risk in the rate of mortality. Fraiser Test., Tr. Vol. 4-A, 28:9-15, Valberg Test., Tr. Vol. 5-A, 137:14-19.

265. Based on (1) the linear concentration-response function for $PM_{2.5}$, (2) the lack of a threshold for $PM_{2.5}$, (3) the conversion of 162,000 tons of excess SO_2 pollution into $PM_{2.5}$, and (4) the scientific consensus that $PM_{2.5}$ increases the risk of high blood pressure, heart attack, stroke, asthma attack, and premature mortality, I find that the pollution resulting from Ameren's failure to obtain a PSD permit has harmed—and continues to harm—public health. Schwartz Test., Tr. Vol. 3-A, 19:18-20:22, 42:17-43:5, 46:19-47:1, 65:17-66:11, 82:1-8.

iii. Dr. Fraiser's and Dr. Valberg's Testimonies Were Not Credible

266. In contrast with Dr. Schwartz, Defendants' testifying experts Dr. Lucy Fraiser and

Dr. Peter Valberg provided testimony that is inconsistent with and not supported by the scientific consensus on $PM_{2.5}$'s human health impacts.

Dr. Lucy Fraiser

267. Dr. Fraiser is a toxicological consultant who spends about 85% of her time on litigation support. Fraiser Test., Tr. Vol. 4-A, 23:3-7.

268. Dr. Frasier has not written any peer-reviewed publications or performed any original research on air pollution. Fraiser Test., Tr. Vol. 4-A, 22:21-23, 23:14-16. Dr. Fraiser has written five publications concerning the effects of cancer drugs based on her dissertation work, the last of which was published almost 25 years ago in 1995. Id. at 22:14-20.

269. At trial, Dr. Frasier testified that $PM_{2.5}$ concentrations below the NAAQS do not cause actual adverse health effects. Dr. Frasier's other opinions primarily flow from this assertion. This testimony contradicts the EPA statements and congressional reports regarding the NAAQS. Compare Fraiser Test., Tr. Vol. 4-A, 24:18-25:12 with, e.g., H.R. Rep. 95-294 at 112 (quoting National Academy of Sciences, Summary of Proceedings: Conference on Health Effects of Air Pollution (Nov. 1973); H.R. Rep. 95-294 at 111.

270. The House Report concerning the NAAQS states that "[i]n the absence of evidence to the contrary, for a population of various stages and initial states of health, no threshold should be stipulated below which exposure is harmless. Instead, the response to exposure should be assumed to be directly related to successively greater or lesser concentrations of the toxic materials and the level of resistance of those exposed." H.R. Rep. 95-294 at 111.

271. In the publication of the 2013 National Ambient Air Quality Standards, the EPA stated that "there is no discernible population-level threshold below which effects would not occur, such that it is reasonable to consider that health effects may occur over the full range of concentrations observed in the epidemiological studies, including the lower concentrations in the

latter years." 78 Fed. Reg. 3086, 3098, 3118-19, 3148 (Jan. 15, 2013).

272. Dr. Fraiser concedes that her opinions are contrary to the determinations of the World Health Organization, the American Heart Association, the EPA, and other mainstream scientific organizations that have concluded that $PM_{2.5}$ is a no-threshold pollutant that causes increased mortality. Fraiser Test., Tr. Vol. 4-A, 26:6-33:25.

273. Dr. Fraiser also admits that the NAAQS do not guarantee zero risk. Id. at 25:13-23. Instead, she argues that concentrations below the NAAQS "are not an unacceptable risk." Id.

274. Dr. Fraiser is not a statistician. Id. 21:18-22:6. Dr. Fraiser performs quantitative risk assessments, but she did not perform a quantitative risk assessment in this case. Id. at 24:6-9. Dr. Fraiser reviewed the EPA's health impacts modeling in this case, but her opinion is primarily based on her interpretation of the NAAQS. Id. at 24:10-22.

275. Dr. Fraiser's direct criticism of the EPA's health impacts testimony is outside of her area of expertise. For example, Dr. Fraiser criticized the epidemiological literature on health effects of $PM_{2.5}$, stating that confounding factors undermine these studies. However, Dr. Fraiser is not an epidemiologist and has never performed an epidemiological study. Fraiser Test., Tr. Vol. 4-A, 21:18-21. Dr. Fraiser's bare assertion that "innumerable potential confounding factors" mar these studies is not credible. Many $PM_{2.5}$ studies have analyzed the effects of confounders and found that they do not undermine the epidemiological results of these studies. Compare Fraiser Test., Tr. Vol. 3-B, 71:21-72:3 with Schwartz Test., Tr. Vol. 3-A, 69:16-76:15; see also 2009 Integrated Science Assessment for Particulate Matter (Pl. Ex. 1209) at 1-21 (explaining that that $PM_{2.5}$ "has been shown to result in health effects in studies in which chance, bias, and confounding could be ruled out with reasonable confidence"), 2-9 (summary of causal determinations for short-term $PM_{2.5}$ exposure), 2-11 (summary of causal determinations for long-

term $PM_{2.5}$ exposure).

276. Dr. Fraiser also testified that more recent epidemiological studies show uncertainty between $PM_{2.5}$ and mortality effects at levels below the NAAQS. Her testimony on this point is contradicted by the very studies she references. Explaining those studies, the EPA's 2018 draft Integrated Science Assessment states:

> A number of recent studies have conducted analyses to inform the shape of the concentration response relationship for the association between long-term exposure to $PM_{2.5}$ and mortality, and are summarized in Table 11-7. Generally, the results of these analyses continue to support a linear, no-threshold relationship for total, nonaccidental, mortality, especially at lower ambient concentrations of $PM_{2.5}$, i.e., less than or equal to 12 micrograms per meter cubed. Lepeule, et al. 2012; Di, et al. 2017 C; and Shi, et al. 2015 observed linear no-threshold concentration response relationships for total nonaccidental mortality with confidence in the relationship down to a concentration of 8, 5, and 6 micrograms respectively. Figure 1122.
>
> […]
>
> Similar linear no-threshold concentration response curves were observed for total nonaccidental mortality in other studies: Chen, et al. 2016; Hart, et al. 2015; Thurston, et al. 2015; Cesaroni, et al., 2013.

Fraiser Test., Tr. Vol. 4-A, 19:15-21:17 (quoting from the 2018 EPA Integrated Science Assessment for Particulate Matter (External Review Draft), Section 11.2.4, at 11-81). These contradictions make Dr. Fraiser's testimony less credible.

277. For all these reasons, I give little weight to Dr. Fraiser's testimony. Specifically, I find her testimony less credible because (1) she has no expertise in epidemiology and statistics, two areas on which she opines, (2) she has not published original research regarding the health impacts of air pollution, (3) her NAAQS opinion contradicts the scientific consensus about the lack of a human health population threshold for $PM_{2.5}$, and (4) she mischaracterizes the findings of recent epidemiological studies.

<u>Dr. Peter Valberg</u>

278. Dr. Valberg's opinions also conflict with the generally held scientific consensus

on $PM_{2.5}$.

279. Dr. Valberg is a toxicologist at Gradient Corporation, where he has provided litigation services as an expert witness since 1990. Litigation consulting constitutes between 40% and 60% of his time. Valberg Test., Tr. Vol. 5-A, 98:20-100:15.

280. As part of litigation consulting, Dr. Valberg has provided testimony on behalf Clean Air Act Defendants in which he has unsuccessfully offered the same opinions he offered in this case. In a Clean Air Act case concerning excess SO_2 emissions released by an illegally modified plant, Dr. Valberg testified that the resulting $PM_{2.5}$ caused no harm to human health based on his opinion that sulfate particles are harmless. Valberg Test., Tr. Vol. 5-A, 103:4-104:25 (referring to United States v Cinergy Corp., 618 F.Supp.2d 942, 950 (S.D. Ind. 2009).[8]

281. The Cinergy court found that Dr. Valberg's opinions were contrary to mainstream science. In rejecting Dr. Valberg's opinions, that court concluded his opinions were a "minority view" that is contrary to the "bulk of the scientific literature on the subject [that] concludes that $PM_{2.5}$ has significant effects on human health." United States v. Cinergy Corp., 618 F.Supp.2d 942, 950 (S.D. Ind. 2009).

282. Dr. Valberg has also provided expert witness testimony in tobacco litigation. His opinions in tobacco cases have departed from the scientific consensus as well. Valberg Test., Tr. Vol. 5-A, 102:9-103:3; Geanacopoulos v. Phillip Morris USA Inc., No. 98-6002, 33 Mass. L.Rptr. 308, 2016 WL 757536, at *9 (Mass. Dist. Ct. Feb. 24, 2016) ("Dr. Valberg's analysis of the data provided by the published studies was shown to be inconsistent and contrary to the consensus of the scientific community.").

[8] The Cinergy opinion at 618 F.Supp.2d 942 was reversed by the Seventh Circuit. See 623 F.3d 455 (7th Cir. 2010). I cite the Cinergy opinion at 618 F.Supp.2d 942 several times in this memorandum opinion. These citations are for propositions that did not form the grounds for the Seventh Circuit's reversal.

283. In addition to litigation consulting, Dr. Valberg also provides consulting services to parties who want to comment on EPA regulatory proceedings. Valberg Test., Tr. Vol. 5-A, 119:5-8.

284. Dr. Valberg submitted comments to the EPA on behalf of the Utility Air Regulatory Group (UARG), a group of electric generating utilities, as well as other industry trade associations. In those comments, Dr. Valberg argued against lowering $PM_{2.5}$ standards. Valberg Test., Tr. Vol. 5-A, 125:22-126:20; see 78 Fed. Reg. 3086, 3111 (Jan. 25, 2013) (Def. Ex. AS). These comments included the same views expressed by Dr. Valberg in this litigation. The EPA rejected the comments and extensively explained its reasons for rejecting them. See id. at 3111-3120.

285. The EPA specifically rejected Dr. Valberg's testimony on the following points: (1) that the causal relationship the EPA found between $PM_{2.5}$ and human health impacts is not credible, id. at 3112-13; (2) that toxicological and epidemiology studies indicate a lack of "coherence or biological plausibility" between $PM_{2.5}$ and human health effects, id. at 3114(3); (3) that observed health effects of $PM_{2.5}$ are due to "confounding" variables, id. at 3115, and are biased by exposure measurement error, id. at 3118; (4) that the EPA's no-threshold determination is not credible, id. at 3119; and (5) that $PM_{2.5}$ should be regulated on a constituent-by-constituent basis rather than on a mass basis, id. at 3119.

286. Dr. Valberg also previously submitted comments criticizing the EPA's 2009 Integrated Science Assessment. Valberg Test., Tr. Vol. 5-A, 119:9-20. In those comments, Dr. Valberg argued the evidence was too weak to support the conclusion that $PM_{2.5}$ is harmful. On that basis, he urged the EPA to reconsider its determination that $PM_{2.5}$ exposure causes adverse health effects. The EPA rejected these comments. Valberg Test., Tr. Vol. 5-A, 119:25-121:22.

iv. The Evidence Does Not Support Ameren's Argument that Rush Island's Excess Emissions Are Harmless

287. Based in part on Dr. Valberg's and Dr. Fraiser's flawed testimony, Ameren makes five arguments why Rush Island's Excess SO_2 emissions are harmless. Ameren argues (1) that $PM_{2.5}$ concentrations below NAAQS do not pose a risk to human health, (2) that sulfate $PM_{2.5}$ is not toxic, (3) that epidemiological studies have too much variation and uncertainty to show a linear, no-threshold concentration-response function for $PM_{2.5}$, (4) that incremental changes smaller than the EPA's Significant Impact Levels (SILs) are meaningless, and (5) that modeling performed on behalf of the EPA in this litigation is "[u]ncertain, [o]verstated, and [u]nreliable." I will discuss the first three arguments here and the fourth and fifth arguments when addressing facts about the EPA's modeling.[9]

<u>The EPA Does Not Guarantee No Human Health Impacts Due to $PM_{2.5}$ Concentrations Below the NAAQS</u>

288. Pursuant to the Clean Air Act, the EPA must set the NAAQS at levels "the attainment and maintenance of which in the judgment of the Administrator, . . . allowing an adequate margin of safety, are requisite to protect the public health." 42 U.S.C. § 7409(b)(2).

289. Based on this language, Ameren argued throughout the trial that the NAAQS are protective of human health, and that any $PM_{2.5}$ concentration below the NAAQS would not pose a meaningful risk of harm to human health.

290. The structure of the Clean Air Act, the EPA's statements concerning the NAAQS, and the scientific consensus concerning $PM_{2.5}$ refute this argument.

291. Pursuant to the Clean Air Act, pollution sources in areas with air quality meeting

[9] In its proposed findings of fact, Ameren also presents two other arguments that are really subsets of the first argument (concerning NAAQS) and the fourth argument (concerning SILs).

the NAAQS must obtain PSD permits and must install BACT. When Congress added the PSD elements of the Clean Air Act, it acknowledged that reducing pollution in non-attainment areas was insufficient to meet the lofty goals of the Clean Air Act. See Envtl. Def. v. Duke Energy Corp., 549 U.S. 561, 567-68 (2007). Under this framework, neither Congress nor the EPA has characterized the NAAQS as eliminating all risk or all human health impacts. In fact, Ameren's expert Dr. Fraiser admitted that the NAAQS do not establish a zero-risk threshold. FOF ¶ 264.

292. Instead of referring to the NAAQS as a zero-risk, zero-impact threshold, the EPA has repeatedly stated that $PM_{2.5}$ has no known threshold. See FOF ¶ 271. Dr. Schwartz relied on the EPA's statements when testifying that the linear concentration-response function for $PM_{2.5}$ extends to concentrations below NAAQS. Id.

293. NAAQS attainment does not negate all the other evidence demonstrating human health impacts of $PM_{2.5}$, as Ameren argues. If this argument were true, then no human health impacts would ever arise from ambient air pollution across the United States, except for limited parts of California.

294. For these reasons, the evidence does not demonstrate that the NAAQS establish a zero-risk, zero-impact threshold, below which no human health impacts are meaningful.

The Toxicity of Sulfate $PM_{2.5}$ Cannot be Differentiated from Other Constituents

295. The scientific community has not determined whether sulfates are any less or more harmful than any other constituent of $PM_{2.5}$. FOF ¶ 243. Nonetheless, Ameren argues that sulfate $PM_{2.5}$ is harmless. Dr. Valberg has unsuccessfully made this argument to the EPA on behalf of other clients. Valberg Test., Tr. Vol. 5-A, 122:23-123:19.

296. Neither the EPA nor Congress has determined that sulfate-based particulates should be excluded from the total $PM_{2.5}$ mass when evaluating the health effects of $PM_{2.5}$.

Valberg Test., Tr. Vol. 5-A, 111:17-19, 113:2-5.

297. The consensus scientific opinion is that all $PM_{2.5}$ particles are toxic, including $PM_{2.5}$ derived from power plant SO_2 emissions. Researchers have not been able to determine the precise relative toxicities of different $PM_{2.5}$ constituents. In the absence of consistent evidence that any constituent has a different impact, the scientific community treats particles from all sources, including sulfates, as having the same toxicity. Schwartz Test., Tr. Vol. 3-A, 23:11-13, 23:22-24:19, 58:23-59:24; Tr. Vol. 3-B, 34:22-35:13, 39:12-22.

298. The EPA's Federal Register Notices announcing the $PM_{2.5}$ NAAQS in 2013 and 2006 cite evidence of sulfate $PM_{2.5}$'s toxicity. See 78 Fed. Reg. 3086, 3122-23 (Jan. 25, 2013) (Def. Ex. AS); 71 Fed. Reg. 61,144, 61,163 (Oct. 17, 2006). The 2006 Federal Register Notice stated that "[i]n short, there is not sufficient evidence . . . to suggest that any component should be eliminated from the indicator for fine particles. The Staff Paper continued to recognize the importance of an indicator that not only captures all of the most harmful components of fine particles (i.e., an effective indicator), but also emphasizes control of those constituents or fractions, including sulfates, transition metals, and organics that have been associated with health effects." 71 Fed. Reg. 61,144, 61,163; see also 62 Fed. Reg. 36,652, 38,666 (July 18, 1997) (noting that "the available scientific information does not rule out any one of these components as contributing to fine particle effects").

299. The World Health Organization has singled out combustion-related $PM_{2.5}$ as consistently demonstrating toxicity. Combustion-related $PM_{2.5}$ includes the sulfate $PM_{2.5}$ created by Rush Island's excess emissions. Schwartz Test., Tr. Vol. 3-A, 58:23-59:24.

300. I find that sulfate $PM_{2.5}$ is harmful and contributes to the negative human health impacts of $PM_{2.5}$ noted above.

Dr. Schwartz's Testimony Concerning Health Impacts of $PM_{2.5}$, Based on Epidemiological Studies, is Credible

301. Ameren seeks to discredit Dr. Schwartz's testimony by pointing to variation in the results of epidemiological studies and meta-analyses of those studies. See Ameren's Proposed Findings of Fact, ECF No. 1110, at ¶¶ 166-69. For example, Ameren discusses the results of seven studies used to inform a Regulatory Impact Analysis in California. Id. Some of those studies found a positive, but statistically insignificant slope; one found a positive, insignificant slope; and some of the studies found a positive and statistically significant slope. Schwartz Test., Tr. Vol. 3-B, 22:18-26:14.

302. In his testimony, Dr. Schwartz's explained that variability among different studies' statistical significance does not thwart his analyses. Dr. Schwartz included studies such as these in his meta-analyses, because the meta-analyses incorporate the findings of vast amounts of data and publications to determine the overall trend. Dr. Schwartz used his most recent, most comprehensive meta-analysis when determining the concentration-response relationship for $PM_{2.5}$, as applied to this case. Id. at 23:19-24:8.

303. Schwartz also demonstrated a vast knowledge of these underlying publications, explaining the conditions and results of studies when questioned about them. Id. at 22:25-26:25.

304. For these reasons, the variation in some epidemiological studies does not undermine Dr. Schwartz's testimony concerning the health impacts of $PM_{2.5}$.

c. Rush Island's Excess Pollution Affects the Entire Eastern Half of the United States

i. Plaintiff's Experts Presented Detailed and Credible Modeling Results

305. To quantify the human health impacts of Rush Island's excess emissions, the EPA presented photochemical grid modeling results. Chinkin Test., Tr. Vol. 2-B, 17:23-30:16.

Photochemical grid modeling is a computer modeling technique that tracks the “fate and transport” of air pollution in the atmosphere, namely how pollutants chemically change and where those pollutants travel. Chinkin Test., Tr. Vol. 2-B, 25:15-17 (describing the “fate and transport” of pollution as an assessment of “how air pollution is formed and moves”).

306. Most SO_2 released from a power plant converts to $PM_{2.5}$ before being deposited in the environment. Chinkin Test., Tr. Vol. 2-A, 99:9-14. The rate at which SO_2 is converted into $PM_{2.5}$ varies between about 1 percent and 10 percent per hour and is faster in warmer and more humid weather and slower in cool and dry weather. Chinkin Test., Tr. Vol. 2-A, 97:20-98:16.

307. The variation in this rate does not substantially change the ultimate volume of $PM_{2.5}$ resulting from the SO_2 pollution. Under certain circumstances the conversion process may take longer. Slightly more SO_2 may be deposited if conversion rates are slower, but most of the SO_2 that remains in the atmosphere will be converted to $PM_{2.5}$. Chinkin Test., Tr. Vol. 2-A, 97:20-99:23; see also Chinkin Test., Tr. Vol. 2-B, 30:2-16. In general, the SO_2 emitted in the center of the country will transform into $PM_{2.5}$ before it is blown out to sea. Chinkin Test., Tr. Vol. 2-A, 100:6-9.

308. The EPA hired expert Lyle Chinkin to conduct atmospheric fate and transport modeling based on the facts in this case. Chinkin is an expert in atmospheric air quality modeling, air pollution fate and transport analysis, and air quality measurements. Chinkin has more than 40 years of experience working with photochemical models. He has used those models to analyze air quality issues ranging from single-source impacts for private clients to regulatory analyses for state and federal agencies. Chinkin Test., Tr. Vol. 2-A, 91:16-93:1, 94:14-20; Chinkin Resume (Pl. Ex. 1322).

309. Chinkin used a photochemical model called CAMx to estimate the impact of Rush

Island's excess pollution on downwind areas. CAMx is a reliable, state-of-the-science, peer-reviewed computer modeling program that is regularly used by both industry members and government regulators. Chinkin Test., Tr. Vol. 2-B, 4:12-5:20, 9:15-22.

310. Models like CAMx are used by air quality scientists, facility operators, and regulators to evaluate (1) the impact of a single source's pollution on the surrounding area, or (2) the downwind effect of an entire state's pollution portfolio. The EPA has long used air quality modeling like CAMx to assess the public health benefits associated with proposed rules and regulations. Chinkin Test., Tr. Vol. 2-B, 6:13-7:7.

311. To isolate the air quality impact from Rush Island's excess SO_2 pollution, Chinkin used a standard analytic technique known as a "with and without analysis." He ran the photochemical grid model twice, once in a "base case" and again in a "controlled case" scenario. In the base case, the inputs include the country's emissions profile and meteorology (wind, humidity, temperature, etc.), and the outputs are meant to replicate the ambient air quality. In the second controlled case scenario, the model setup remains unchanged except the emissions from one source—Rush Island—are reduced to account for the installation of pollution controls, specifically wet FGD. The differences in modeled $PM_{2.5}$ air quality concentrations between the two models are attributable to the difference in SO_2 contributed to the atmosphere from the examined source. Chinkin Test., Tr. Vol. 2-B, 8:3-9:9.

312. Photochemical modeling is time-consuming and expensive. CAMx divides the continental United States into 12-kilometer-square grids and then twenty-five planes of grid squares stacked upon each other, resulting in nearly 2.5 million cubic cells. In each of these cells, the model examines the concentration and influx of atmospheric constituents, calculates chemical reactions, and quantifies the resulting matter's transport into neighboring cells. The

model repeats these steps at five-minute intervals until it calculates an entire year's worth of reactions and physical transport. Because of the immense breadth of data and time-stepped calculations that are performed, modeling a year of pollution effects in CAMx can take weeks. Furthermore, developing the inputs for CAMx, including a verified and reliable emissions inventory, can take months. For these reasons, modeling more than a single year's worth of emissions is often impracticable. Chinkin Test., Tr. Vol. 2-B, 9:23-10:14.

313. A modeled year of results can be useful for estimating emissions impacts for other years, provided that year's weather and temperature data are fairly representative. In 2011, the weather and temperature data were representative of the weather and temperature data for the period Chinkin studied. Specifically, 2011's weather and temperature data were close to the median for years 2007 through 2016. For this reason, Chinkin chose to run the CAMx model for the 2011 emissions and meteorological data sets. Chinkin Test., Tr. Vol. 2-B, 29:9-30:16.

314. Although it is affected by temperature and other parameters, the relationship between the SO_2 concentrations and $PM_{2.5}$ formation is linear. As a result, the modeled $PM_{2.5}$ concentrations for 2011 can be scaled up or down on a percentage basis to estimate air quality impacts for other years. These estimates will not be perfectly accurate, but choosing a representative year such as 2011 decreases the overall bias and allows a larger timespan of emissions to be estimated without unnecessarily increasing litigation costs. Chinkin Test., Tr. Vol. 2-B, 29:18-24; see also id. Tr. Vol. 2-A, 98:22-99:8.

315. Modeling outputs will not perfectly match monitoring data. Any given monitor provides a point measurement of air quality at its location. In contrast, a photochemical grid model returns average air quality concentration values for a 12-square-kilometer area. Some of the locations within the modeled 12-kilometer grids will have higher concentrations, and others

will have lower concentrations. Nevertheless, comparing base case modeling results to monitors helps gauge whether the model is accurate. Chinkin Test., Tr. Vol. 2-B, 15:3-17:7.

316. Chinkin's base case model performed "exceptionally" well when compared with national monitoring networks, with error and bias measures well within industry standards for providing reliable results. Chinkin Test., Tr. Vol. 2-B, 17:8-18.

ii. The Model Predicts Rush Island's Excess Emissions Increased $PM_{2.5}$ Concentrations Across the Entire Eastern Half of the United States

317. The CAMx modeling Chinkin performed indicates that Rush Island's excess pollution impacts the entire Eastern United States. Chinkin Test., Tr. Vol. 2-B, 28:7-15. Ameren's own modeling expert, Ralph Morris, admitted that photochemical grid modeling showed excess pollution from Rush Island impacted $PM_{2.5}$ concentrations in Pennsylvania, Michigan, Louisiana, and even Florida. Morris Test., Tr. Vol. 5-A, 5:2-17.

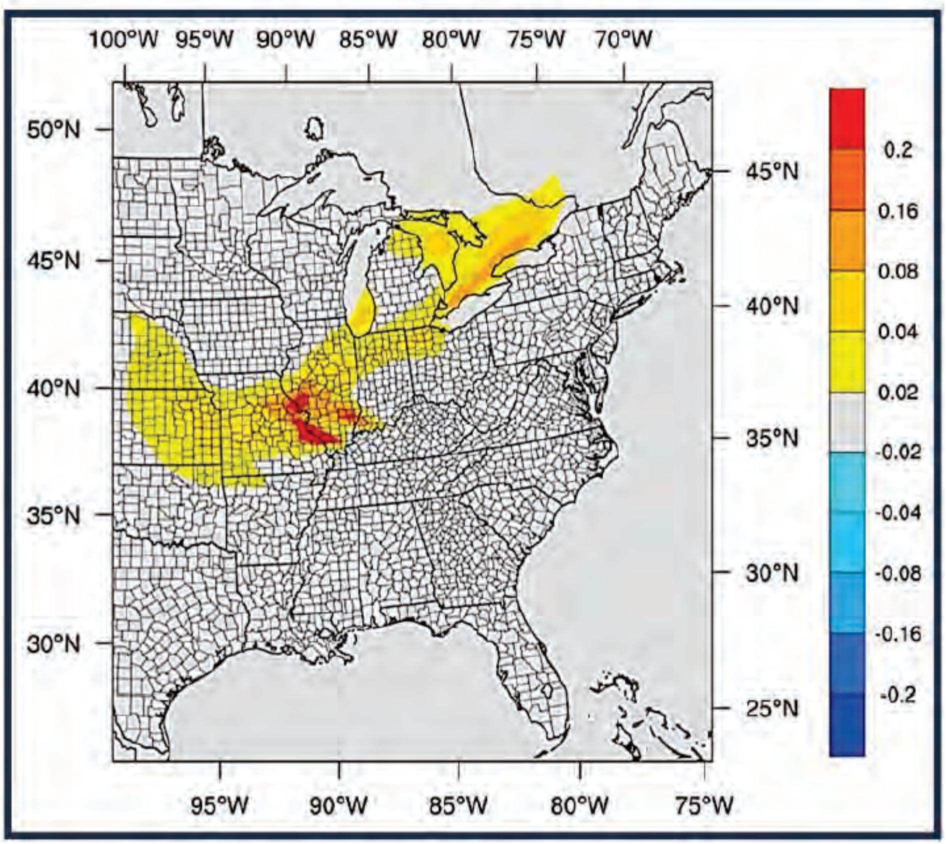
318. The impact of Rush Island's excess pollution depends in part on the wind and weather. See, e.g., Chinkin Test., Tr. Vol. 2-B, 23:18-25:7; Model Results Maps (Pl. Exs. 1373-76).

319. On some days, the pollution's largest impact on air quality occurs relatively close to the plant. For example, as shown in Figure 4, on August 18, 2011, CAMx modeling shows Rush Island's excess pollution contributed as much as 2.25 $\mu g/m^3$ to ambient $PM_{2.5}$ concentrations in the greater St. Louis area. At the same time, some of the excess pollution was predicted to extend hundreds of miles further in a band stretching from Kansas to north of the Great Lakes. When describing this result, Chinkin testified: "I've been doing this for 30 plus years. That is a very large impact. *It's one of the largest I've seen from a single source on a single day*." Pl. Ex. 1369; Chinkin Test., Tr. Vol. 2-B, 17:23-20:2 (emphasis added).

320. On other days, excess SO_2 pollution from Rush Island has its greatest air quality

impact hundreds of miles away. For example, as shown in Figure 5, on March 15, 2011, air quality modeling indicates Rush Island's excess SO_2 predominantly affected air quality to the southwest of the plant. The largest contributions for that day measured more than 0.02 $\mu g/m^3$ and occurring around Houston, Texas. <u>See</u> Pl. Ex. 1372. Regarding this result, Chinkin testified: "[C]onsidering it's one source and [the pollution has] now traveled hundreds if not a thousand miles away, that's a very large impact." Chinkin Test., Tr. Vol. 2-B, 22:2-19.

<u>Figure 4</u>



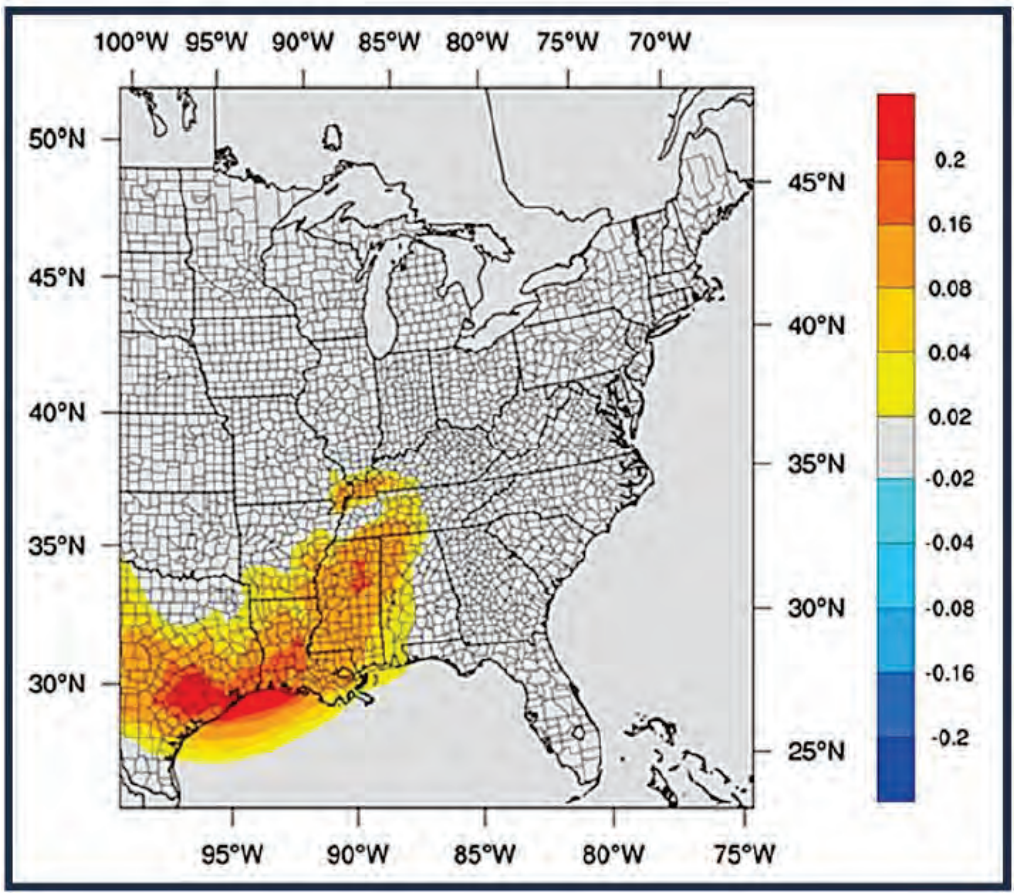
Pl. Ex. 1369 (described at Chinkin Test., Tr. Vol. 2-B, 17:23-20:2).

321. On more than 250 days in 2011 (70% of the days in the year), Rush Island's

excess SO_2 pollution contributed more than 0.1 μg/m^3 to downwind $PM_{2.5}$ concentrations. Chinkin Test., Tr. Vol. 2-B, 26:14-15.

322. During more than 90 days in 2011 (25% of the year)—and about half of summer days—Rush Island's excess pollution contributed more than 0.25 μg/ m^3 to downwind $PM_{2.5}$ concentrations. Chinkin Test., Tr. Vol. 2-B, 26:15-20.

Figure 5

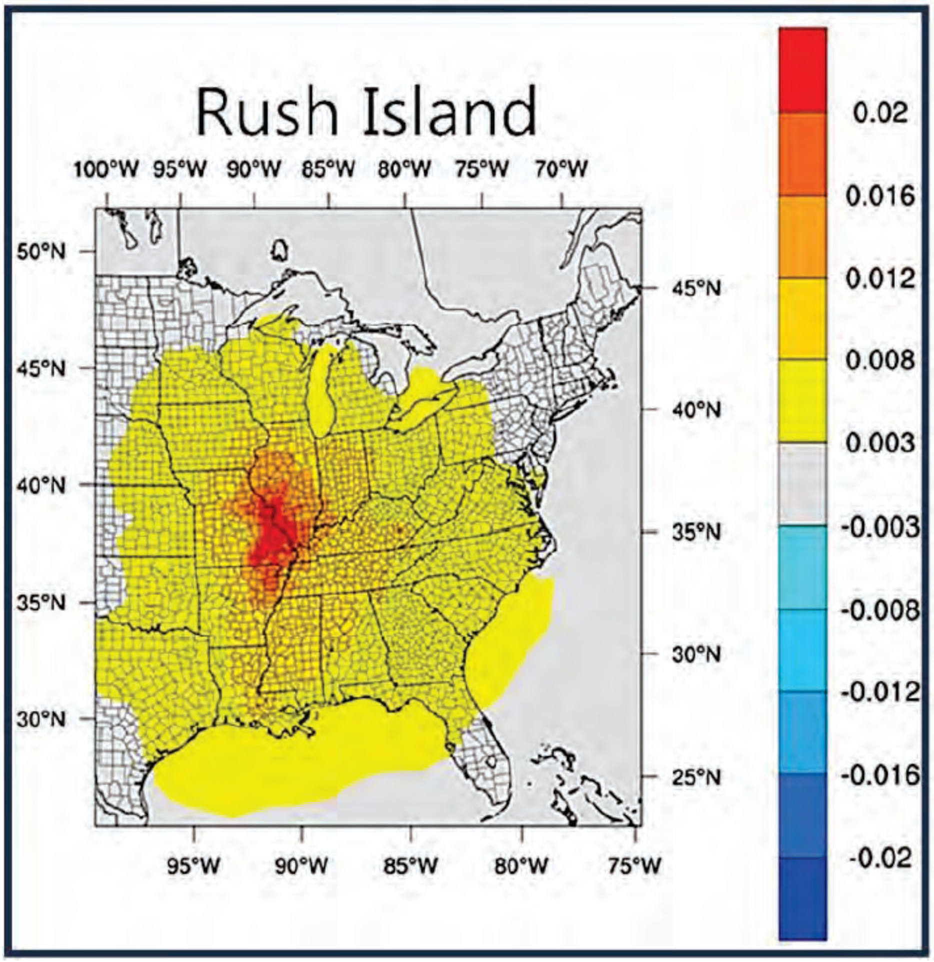


Pl. Ex. 1372 (described at Chinkin Test., Tr. Vol. 2-B, 22:2-19).

323. Compiling daily impact results into a single map and averaging the results provides a view of the annual average impact from Rush Island's excess SO_2 pollution on $PM_{2.5}$ concentrations. As seen in Figure 6, the area affected by Rush Island's excess SO_2 pollution

extends from the Gulf of Mexico to the Great Lakes, and from the middle of Kansas to the Atlantic coast.

Figure 6



Pl. Ex. 1364 (described at Chinkin Test., Tr. Vol. 2-B, 27:15-29:8).

324. The model predicted that at least one grid cell would have $PM_{2.5}$ concentrations 0.057 µg/ m^3 greater when averaged throughout the entirety of 2011. Chinkin Test., Tr. Vol. 2-B, 27:15-29:8.

d. Results of Two Different Models Show Rush Island's Excess Emissions Increased the Risk of Hundreds to Thousands of Premature Deaths

325. Plaintiffs presented two independent quantification methods to measure the harm from Rush Island's excess pollution. The first method relies on the results of a peer-reviewed risk assessment of 407 power plants, including Rush Island, published by Dr. Schwartz in 2009. Schwartz Test., Tr. Vol. 3-A, 88:11-89:18. The second method relies on the CAMx air quality modeling performed specifically for this case by the EPA's expert Chinkin.

326. Both risk assessments modeled $PM_{2.5}$ transport and concentration in ambient air. Using those concentrations, they estimated premature deaths in the exposed population. In doing so, both assessments applied the same approach used by public health agencies to quantify the risk of premature mortalities from exposure to $PM_{2.5}$, including the U.S. Centers for Disease Control, the World Health Organization, the National Academy of Sciences, and the EPA. Schwartz Test., Tr. Vol. 3-A, 83:6-87:9.

327. As described below, the models differ based on how they calculate concentrations and exposure. Despite these differences, the models showed consistent, comparable results among each other.

i. Dr. Schwartz Published a Peer-Reviewed Quantitative Risk Assessment for Rush Island's SO_2 Emissions in 2009

328. Unrelated to any litigation, the EPA's expert Dr. Schwartz previously co-authored a peer-reviewed, quantitative risk assessment of emissions from coal-burning power plants, including Rush Island. That assessment, "Uncertainty and Variability in Health-Related Damages from Coal-Fired Power Plants in the United States," was published in 2009 in the scientific journal "Risk Analysis." Schwartz Test., Tr. Vol. 3-A, 87:17-91:5.

329. Dr. Schwartz's 2009 risk assessment modeled SO_2 and resulting $PM_{2.5}$ pollution

using a pollution transport model known as a reduced-form model. The reduced-form model was calibrated to ensure consistency with actual monitoring data. Schwartz Test., Tr. Vol. 3-A, 89:19-90:10.

330. Reduced form models are commonly used in the scientific community to perform quantitative risk assessments. For instance, the National Academy of Sciences has used the reduced form model in performing similar risk assessments, and cited Dr. Schwartz's 2009 study in doing so. Schwartz Test., Tr. Vol. 3-A, 90:11-19.

331. Dr. Schwartz's 2009 risk assessment calculated 95% confidence intervals and incorporated uncertainties both for the modeled $PM_{2.5}$ exposure estimates as well as the concentration-response relationship. Schwartz Test., Tr. Vol. 3-A, 91:11-94:21. A 95% confidence interval means there is a 95% chance that the number of premature deaths that occurred as a result of excess pollution falls in the range identified in a given study. There is a remaining 5% probability (2.5% above the interval and 2.5% below the interval) that the number falls outside the identified range. Id.

ii. Dr. Schwartz Also Quantified Risk Based on Chinkin's CAMx Modeling

332. Dr. Schwartz also performed a second quantitative risk assessment based on the results of Chinkin's air quality modeling in this case using the CAMx model. Schwartz Test., Tr. Vol. 3-A, 95:5-95:14.

333. To evaluate impacts on premature mortality from the CAMx air quality concentrations, Dr. Schwartz relied on the most up-to-date concentration-response function for $PM_{2.5}$ available in the literature. Dr. Schwartz paired that concentration-response function with a reliable and peer-reviewed EPA risk assessment tool known as "BenMAP." BenMAP includes population and baseline mortality data for the entire country, including the areas impacted by

Rush Island's pollution. Schwartz Test., Tr. Vol. 3-A, 95:15-96:17.

334. Dr. Schwartz derived the specific concentration-response from a published, peer-reviewed meta-analysis he co-authored. The meta-analysis included all data points published by over 50 long-term epidemiological studies, with the goal of creating the best current function. Meta-analysis is "the standard approach for trying to integrate multiple studies . . . and come up with . . . the best estimate." Schwartz Test., Tr. Vol. 3-A, 96:2-11, 97:3-100:17.

335. Dr. Schwartz's meta-analysis included 95% confidence intervals reflecting uncertainty in the calculated $PM_{2.5}$ concentration-response relationship. These confidence intervals are narrower than those derived in Dr. Schwartz's 2009 risk assessment, because the meta-analysis incorporated results from millions of study participants. Schwartz Test., Tr. Vol. 3-A, 99:6-25, 101:21-102:7.

336. The confidence intervals for Dr. Schwartz's CAMx-based risk assessment do not include any uncertainty related to the accuracy of the modeled $PM_{2.5}$ exposure estimates; CAMx is a deterministic model that produces a precise number based on the laws of physics and chemistry and specific inputs. Public health professionals routinely use deterministic models to estimate health effects from incremental changes in air pollution. Chinkin Test., Tr. Vol. 2-B, 8:12-9:1; Schwartz Test., Tr. Vol. 3-A, 93:10-15, 102:8-104:6.

iii. Rush Island's Excess Emissions Caused Hundreds to Thousands of Premature Deaths

337. Public health risk assessments demonstrate the overall effect of exposing a population to an increased risk of harm. They do not identify a specific individual who was, or will be, harmed by an exposure. Schwartz Test., Tr. Vol. 3-A, 82:14-87:2, 104:19-107:2.

338. Based on the two risk assessments described above, Dr. Schwartz calculated premature deaths *expected* to result from Rush Island's excess emissions. This metric represents

an increased risk of harm, not any specific person's death. Table 1 shows Dr. Schwartz's calculated expected premature mortality, based on Rush Island's excess emissions. For 2007 to 2016, Dr. Schwartz calculated 637 and 879 expected premature mortality events based on the reduced form model and CAMx model, respectively. Dr. Schwartz calculated that after 2016, an average of 62 or 86 premature mortality events per year are expected, based on the reduced form and CAMx models, respectively. Schwartz Test., Tr. Vol. 3-A, 91:11-24, 95:25-96:4, 101:15-20, 104:15-18.

Table 1

Premature Mortality	Reduced Form Model (95% confidence interval)	CAMx Model (95% confidence interval)
Per Thousand Tons	3.9	5.4
2007-2016	637 (172 - 1,436)	879 (738 - 1,215)
2017 and beyond	62/ year	86/ year

339. Dr. Schwartz's risk assessments demonstrate that Rush Island's excess emissions pose substantial risk of harm to the exposed populations. They also show that the harm will continue until Rush Island's excess emissions stop. Schwartz Test., Tr. Vol. 3-A, 82:14-83:4, 107:3-16, 109:1-13.

340. The similarity of results, 95% confidence intervals, and peer-reviewed nature of these models provide me with a high degree of confidence in my conclusion that Rush Island's excess emissions have harmed public health and welfare. Schwartz Test., Tr. Vol. 3-A, 87:17-88:8, 89:19-90:10, 91:11-24, 94:13-21, 101:1-102:25, 109:1-13.

e. Ameren's Criticisms of the EPA's Model Are Not Persuasive

341. Ameren makes two main criticisms of the EPA's modeling methods and results: (1) that incremental changes smaller than the EPA's Significant Impact Levels (SILs) are meaningless, and (2) that modeling performed on behalf of the EPA in this litigation is

"[u]ncertain, [o]verstated, and [u]nreliable."

342. The SILs are "screening tools the EPA uses to determine whether a new source may be exempted from certain requirements under § 165 of the Act, 42 U.S.C. § 7475." Sierra Club v. E.P.A., 705 F.3d 458, 459 (D.C. Cir. 2013). "[Section] 165(a)(3) requires that an owner or operator . . . demonstrate that emissions from construction or operation of the facility will not cause or contribute to any violations of the increment more than once per year, or to any violation of the NAAQS ever." Id. at 460.

343. The EPA has not alleged, and its case does not depend on, any NAAQS or PSD increments violations in this case.

344. As a result, Ameren's SILs argument does not make the EPA's modeling methods or results less credible or convincing.

345. With respect to SILs, Ameren asserts that changes in concentrations below the EPA's established SILs do not represent a meaningful or significant threat to human health.

346. The SILs were designed for use in the PSD permitting process, to determine if, despite the installation of BACT, the creation or modification of a source would lead to NAAQS violations. Knodel Test., Tr. Vol. 1-A, 64:25-66:25, 92:23-93:25; NSR Manual (Pl. Ex. 1190), at AM-REM-00544163; MDNR Rule 30(b)(6) Dep., Aug. 10, 2018, Tr. 135:9-20, 135:25-136:4.

347. The SILs were derived from a statistical analysis of the limits of monitoring data, based on a finite network of variably-placed monitors. Morris., Tr. Vol. 5-A, 6:20-25. Recognizing that "there is an inherent variability in the air quality" "due to fluctuating meteorological conditions and changes in day-to-day operations of all air pollution sources in an area," the EPA developed the SILs using "a statistical analysis of the variability of air quality, using data from the U.S. ambient monitoring network for ozone and $PM_{2.5}$." (Ex. HB at HB_12.).

348. The EPA has relied on modeled concentration changes below the SILs in calculating human health benefits—including changes even below 0.01 μg/ m^3, orders of magnitude less than the 0.2 μg/ m^3 SIL value Ameren's expert Ralph E. Morris used as a comparator. Morris Test., Tr. Vol. 5-A, 14:10-16:20; Schwartz Test., Tr. Vol. 3-A, 108:3-25.

349. Independently, Ameren argues that the EPA's modeling results are "[u]ncertain, [o]verstated, and [u]nreliable." Ameren makes this argument based on (1) model noise, (2) the EPA's use of 2011 meteorology data as representative of other years, (3) the EPA's use of a baseline for its Labadie model that included FGD controls on Rush Island, and (4) the difference between 12-kilometer grid cell estimates and monitors point estimates.

350. I find that Ameren's arguments about these features do not render the EPA's modeling methods or results less credible or convincing.

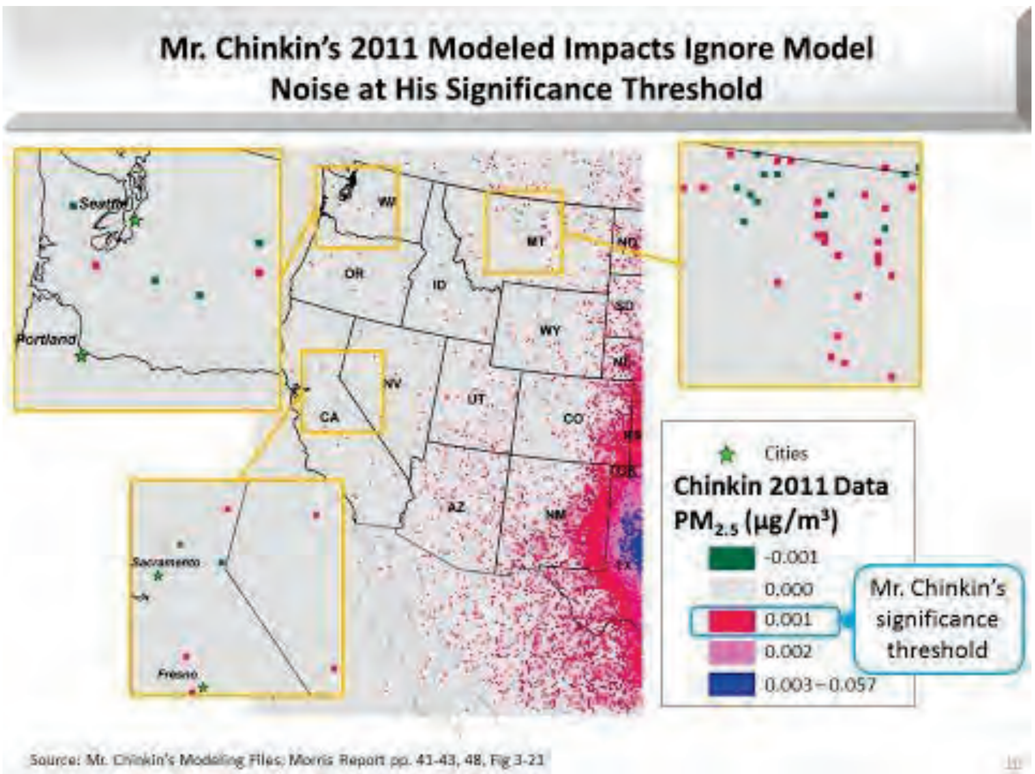
351. First, large-scale models—including the one from the EPA's expert Chinkin—include some noise. This is because algorithms conducting millions of calculations can produce data (the noise) that are not a direct result of the variables that are the focus of the model. In this case, for example, some of the data in Chinkin's model were not tied to a hypothetical reduction in SO_2 pollution. Ameren's expert Morris correctly notes that when relying on "this kind of approach using one simulation subtracting from another," the modeler "need[s] to be very careful" that "[he is] looking at concentrations above model noise." Morris Test. Tr. Vol. 4-B, 79:22-89:12.

352. Ameren argues that the presence of model noise near the EPA's 0.001 μg/m^3 modeling threshold makes the EPA's CAMx results unreliable. Ameren specifically points to model noise found in Montana, Washington, and California as shown in Def. Figure A.

353. Model noise is both positive and negative in these areas. Ameren does not present

any evidence demonstrating that the model noise has led to any bias or that the model noise played any significant role in the final results of the CAMx modeling. Therefore, Ameren's model noise argument does not make the EPA's modeling methods or results unreliable or unconvincing.

Def. Figure A



354. Second, Ameren argues that the EPA should have used year-specific meteorology data for every year since the Rush Island major modifications in 2007. I agree with Ameren that the EPA's model results would have been even more precise if they had run the voluminous and expensive CAMx model twelve or more times, for every year from 2007 through 2018. However, the EPA made a reasonable choice to run the data-, time-, and resource-intensive CAMx model four times using 2011 as a representative year (with a base and emissions-

controlled case for both Rush Island and Labadie). Ameren did not present sufficient evidence to demonstrate that this approach was unreliable or unconvincing.[10]

355. Third, Ameren argues that the EPA should have used the same baseline emissions scenario for its Rush Island and Labadie modeling. When the EPA modeled the impact of installing pollution equipment on Labadie, its base case assumed that pollution controls would also be installed on Rush Island, due to the outcome of this litigation. The point of the modeling was to determine whether emissions reductions from Labadie would affect the same population impacted by Rush Island's excess emissions. The EPA reasonably assumed that I would not order emissions reductions at Labadie if I did not also order emissions reductions at Rush Island. Under that condition, it would be inappropriate to use the same base case for Rush Island and Labadie CAMx modeling. Ameren's argument regarding baseline emissions does not make the EPA's modeling methods or results unreliable or unconvincing. Chinkin Test., Tr. Vol. 2-B, 31:21-33:22.

356. Fourth, Ameren argues that differences between 12-kilometer grid-cell model results and point-measurements of the $PM_{2.5}$ concentration near St. Louis make the EPA's CAMx modeling unreliable and unconvincing. As I explained above, modeling outputs will not perfectly match monitoring data. Any given monitor provides a point measurement of air quality at its location. In contrast, a photochemical grid model returns average air quality concentration values for a 12-square-kilometer area. FOF ¶ 312; Chinkin Test., Tr. Vol. 2-B, 15:3-17:7.

357. Ameren's argument about differences between monitoring data and modeled results does not make the EPA's modeling methods or results unreliable or unconvincing. The

[10] For example, Ameren did not provide a copy of the 2017 guidance document that Ameren's expert Morris says encourages modelers to use year-specific data. Morris Test., Tr. Vol. 4-B, 94:3-95:12. Without more information concerning that guidance, I cannot determine the weight to give this guidance.

EPA's expert Chinkin compared his model results to all the available monitoring data and found that his base case model performed "exceptionally" when compared with the actual data from national monitoring networks. FOF ¶ 316; Chinkin Test., Tr. Vol. 2-B, 17:8-18.

V. RUSH ISLAND'S EXCESS POLLUTION IS BEST REMEDIATED BY DECREASING EMISSIONS AT THE NEARBY LABADIE ENERGY CENTER

358. Ameren's violation of the Clean Air Act at Rush Island has resulted in more than 162,000 tons of excess SO_2 pollution through 2016. That amount is expected to grow to 275,000 tons by the time Rush Island finally complies with the PSD program. FOF ¶ 210-11.

359. Accordingly, Plaintiffs seek an injunction requiring Ameren, over time, to reduce pollution from its nearby Labadie plant in an amount equal to Rush Island's total excess emissions. By reducing future SO_2 emissions from the Labadie plant, Ameren can, ton for ton, remedy the harm it caused by failing to install pollution control technology that should have been installed in 2007 and 2010.

360. The Labadie plant is located near Labadie, Missouri, about 35 miles west of St. Louis. The plant consists of four units, each of which can generate about 600 megawatts of electricity, about as much as Rush Island's units can generate. Integrated Resource Plan (Pl. Ex. 1247), at USTREXR0006246 to 6247. Ameren plans to retire the four Labadie units in 2036 and 2042. Michels Test., Tr. Vol. 5-B, 18:20-23, Michels Dep., Aug. 14, 2018, Tr. 14:1-23, 109:21-110:13.

361. Dr. Staudt looked at multiple options for reducing future SO_2 emissions from the Labadie plant: natural gas conversion, wet FGD, dry FGD, DSI, and DSI with the addition of a fabric filter.

362. All these options are technically and practically achievable at Labadie. Staudt Test., Tr. Vol. 1-B, 102:11-103:6. The capital costs range from $55 million for DSI on all four

Labadie units to about $1 billion for wet FGD on all four units. Staudt Test., Tr. Vol. 1-B, 102:15-103:11. The operating costs range from $31 million/year for DSI with a fabric filter to a high but variable operating cost for a natural gas conversion. Id. at 103:12-20. The operating costs for DSI without a fabric filter would be about $53 million/year. Id. at 105:19-20. Natural gas conversion would have the highest emissions reductions, virtually eliminating SO_2 emissions. After that, wet FGD would achieve the greatest reductions, followed by dry FGD, DSI-FF, and DSI. The higher the reductions, the faster the remediation. Staudt Test., Tr. Vol. 1-B, 104:1-17.

363. The reduction capabilities of installing DSI without a fabric filter on all four units and wet FGD on two units are relatively close. It would take about the same amount of time to offset the excess pollution with these two technologies. Assuming, on the high side, annual uncontrolled emissions of about 38,000 tons per year, DSI on all four units would remove 19,000 tons per year and offset the excess within about 14 or 15 years, while wet FGD on two units would remove 17,000 tons per year and offset the excess in a little over 16 years. Staudt Test., Tr. Vol. 1-B, 106:23-107:11, 108:2-7.

364. The cost-effectiveness of the two options is also relatively similar: $4300/ton for wet FGD on two units compared to $3100/ton for DSI on four units. Id. at 107:12-15.

365. DSI could be installed in 18 months, more quickly than wet FGD. Staudt Test., Tr. Vol. 1-B, 106:8-20, Tr. Vol. 2-A, 16-17; Snell Test., Tr. Vol. 4-B, 30:17-31:6.

a. Reducing Future Pollution from Labadie Will Remediate the Harm from Rush Island for the Same Populations and to the Same Extent

366. The harm from Ameren's excess SO_2 emissions was imposed on tens of millions of people living in the communities impacted by Rush Island's pollution. As a result, these populations experienced increased risks of adverse health effects, including increased risk of

premature mortality. Schwartz Test., Tr. Vol. 3-A, 82:14-83:4, 110:10-22.

367. The linear concentration-response relationship for $PM_{2.5}$ exposure means that, in the range of concentrations studied, any incremental decrease in exposure produces a positive impact on public health. FOF ¶ 263; see also Schwartz Test., Tr. Vol. 3-A, 48:3-50:13.

368. Reducing pollution from Labadie by an amount equal to Rush Island's excess emissions will reduce the risk of adverse health effects and premature mortality in the exposed population by an amount equal to the increased risk from Rush Island's excess emissions. Schwartz Test., Tr. Vol. 3-A, 20:23-21:8, 110:10-22.

369. The populations that will benefit from these reductions are almost identical to those who were harmed by Rush Island's excess pollution. As a result, there is a particularly tight factual nexus between remedy and harm. This tight nexus is demonstrated by Dr. Schwartz's 2009 risk assessment. For most coal-fired power plants, the assessment showed significant variability in the health impacts of emissions depending on where each ton was emitted. Schwartz Test., Tr. Vol. 3-A, 88:9-89:12. However, Ameren's Rush Island and nearby Labadie plants had nearly identical health impacts per ton of SO_2, because they impact roughly the same populations. Schwartz Test., Tr. Vol. 3-A, 110:24-111:23, 116:23-118:4.

370. Chinkin's CAMx modeling confirms this close nexus. Chinkin modeled the benefits of installing pollution control options at Labadie in the same way he studied the impacts of Rush Island's excess pollution. This modeling shows that the two plants have similar pollution-impact profiles, affecting the same populations and to the same extent. Chinkin Test., Tr. Vol. 2-B, 31:21-33:5, 36:16-37:22.

371. Chinkin's CAMx modeling indicated that scrubber technology operated at two of Ameren's Labadie units would reduce SO_2 pollution by about the same amount in the same

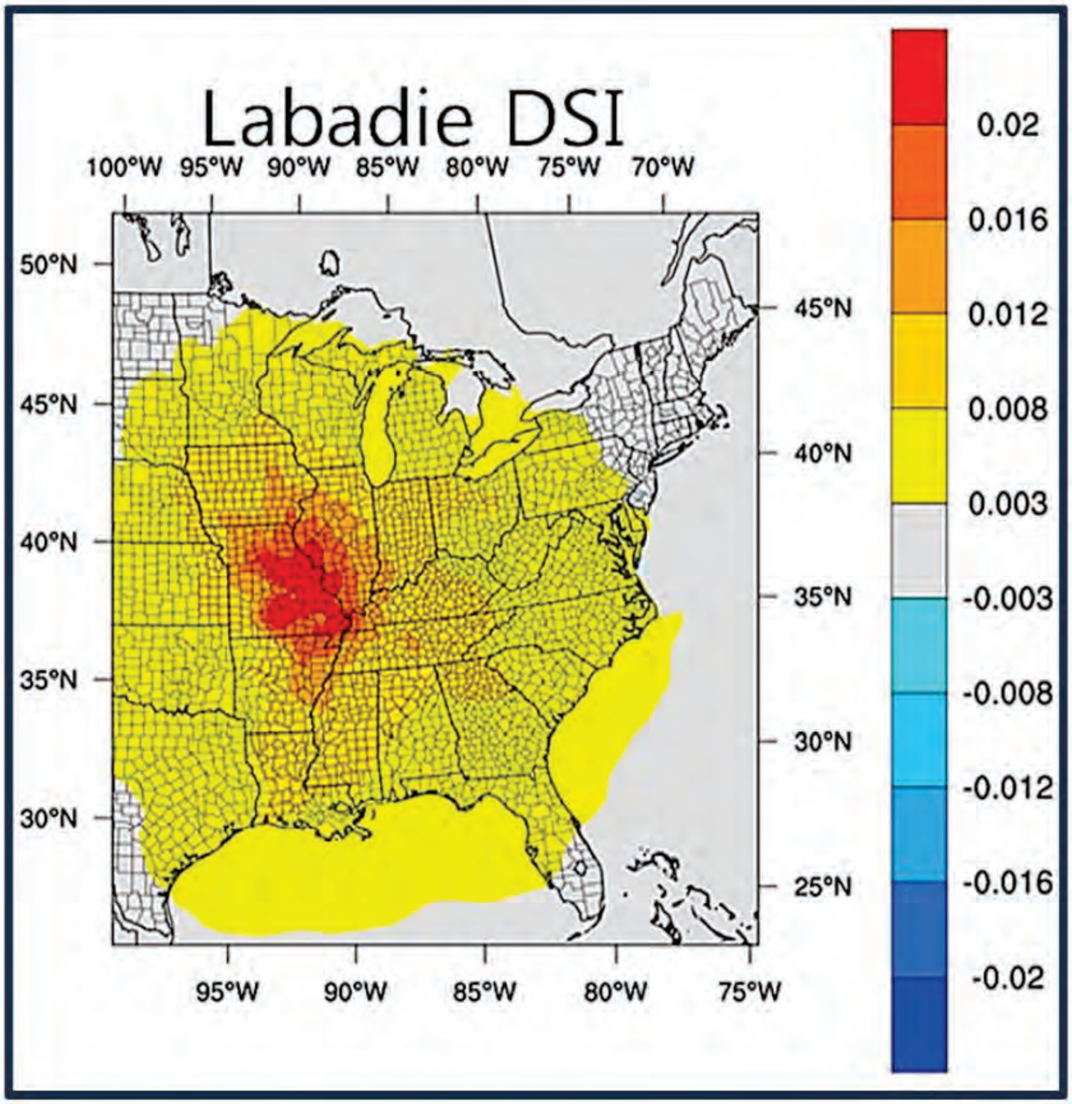
geographic region as Rush Island's excess pollution. Based on 2011 data, this control technology would have a maximum average annual impact of 0.054 µg/ m^3 (compared to 0.057 µg/ m^3 for Rush Island's excess pollution), and a maximum daily downwind impact on $PM_{2.5}$ concentrations of 2.44 µg/ m^3 (compared to 2.25 µg/m^3). Chinkin Test., Tr. Vol. 2-B 33:6-34:12; Model Results Map (Pl. Ex. 1362).

372. Similarly, the CAMx modeling shows that DSI technology operated at all four of Ameren's Labadie units would reduce SO_2 pollution by about the same amount in the same geographic region as Rush Island's excess pollution, as shown in Figure 7. Chinkin Test., Tr. Vol. 2-B, 34:20-36:5 Schwartz Test., Tr. Vol. 3-A, 111:24-112:8.

373. I find that reducing emissions SO_2 pollution from Ameren's Labadie plant will, on a ton-for-ton basis, benefit the same populations—and to the same extent—that suffered the harm from Rush Island's excess pollution. This finding is based on both the reduced form modeling prepared by Dr. Schwartz in his published 2009 risk assessment, as well as the CAMx modeling prepared by Chinkin for this case.

374. Ameren did not present evidence or testimony challenging Chinkin's conclusion that the SO_2 pollution from the Labadie Energy Center affects downwind $PM_{2.5}$ concentrations to the same scope and degree as the SO_2 pollution from the Rush Island facility.

Figure 7



Pl. Ex. 1362.

b. Society Will Benefit If Ameren Offsets Its Excess Emissions

375. The societal benefits associated with offsetting Ameren's excess pollution are substantial. Reducing the pollution from Labadie in an amount equal to Rush Island's excess emissions will result in an equal amount of avoided health effects, including premature mortality,

in the same population. Schwartz Test., Tr. Vol. 3-A, 20:23-21:8, 110:10-22.

376. These benefits have substantial economic value. In his 2009 risk assessment, Dr. Schwartz quantified the social cost Rush Island and Labadie's pollution, as well as the pollution of 405 other coal-fired power plants. In this study, Dr. Schwartz applied standard, peer-reviewed values used by public health professionals and the EPA to estimate economic benefits of pollution reduction. Schwartz Test., Tr. Vol. 3-A, 112:10-116:22. Based that study, Dr. Schwartz estimated the social benefits from remedying Rush Island's excess emissions would far surpass the costs of any control technology used. Compare Schwartz Test., Tr. Vol. 3-A, 116:23-118:4 with Def. Exs. IB & IC and FOF ¶ 362 (Labadie costs).

377. Chinkin's CAMx-derived benefits estimates are even higher than the results of the 2009 risk assessment, confirming that the benefits of remediating Rush Island's excess pollution exceed the costs. Compare Schwartz Test., Tr. Vol. 3-A, 118:16-24 with Def. Exs. IB & IC and FOF ¶ 362.

c. Ameren's Surrendering of Pollution Allowances Would Not Remedy Harms to the Populations Affected by Rush Island's Excess Emissions

378. Ameren offered to surrender SO_2 emission allowances under the Cross-State Air Pollution Rule (CSAPR) as mitigation for Rush Island's excess pollution. See Ameren Trial Brief, ECF Doc. 1071, at 13-15. CSAPR is a market-based program issued under the Good Neighbor Provision of the Clean Air Act and designed to reduce air pollution from upwind states to the benefit of downwind states. Knodel Test., Tr. Vol. 1-A, 100:10-16, 102:16-20; see 42 U.S.C. § 7410(a)(2)(D)(i).

379. Under CSAPR, which went into effect in 2015, the EPA establishes an SO_2 emission budget for each state. Knodel Test., Tr. Vol. 1-A, 100:10-101:17, 102:21-23. Each state then allocates allowances to individual units, with each allowance authorizing the source to

emit one ton of pollution. Knodel Test., Tr. Vol. 1-A, 101:22-102:8.

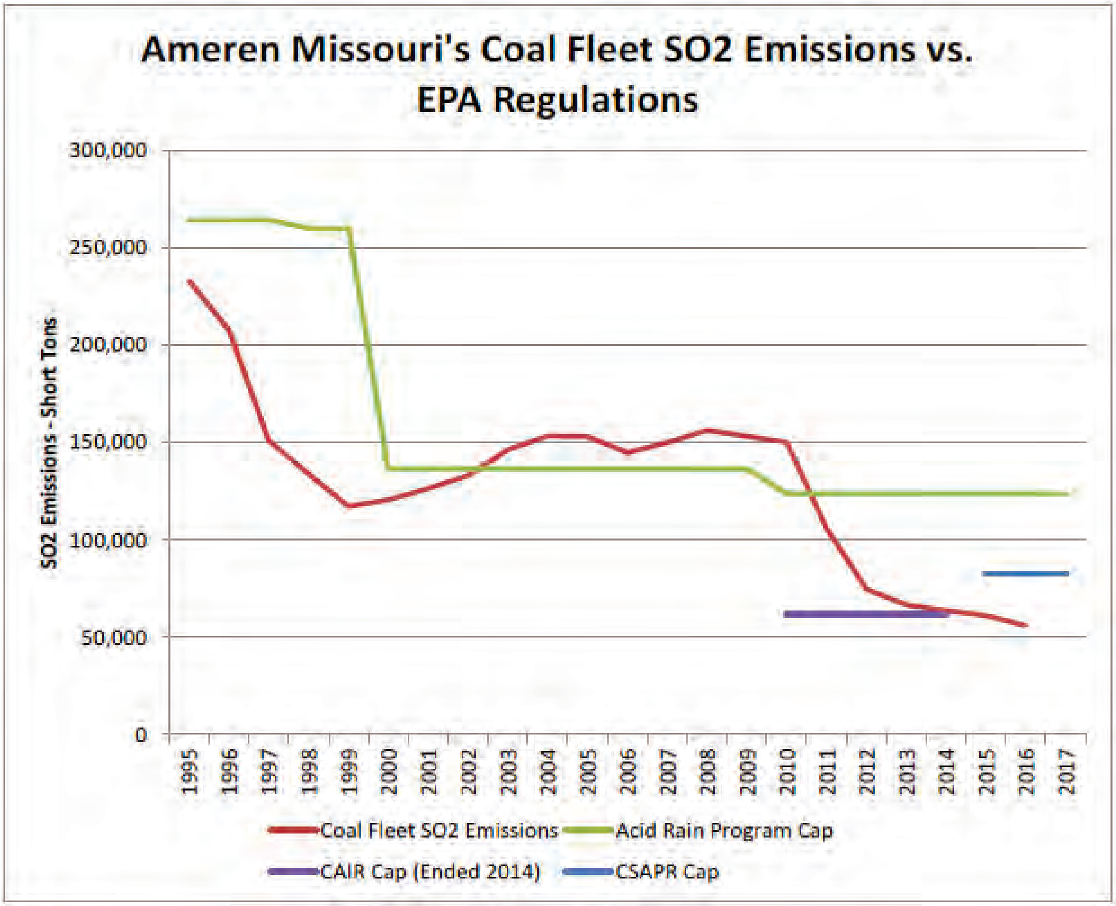
380. Allowances are freely tradable among regulated units, brokers, and other parties. (Harvey Decl. at 18.) During each year of the CSAPR programs, each regulated unit must monitor and report its SO_2 emissions. Shortly after the end of the year, the unit must surrender one eligible "allowance" for each ton of its reported emissions for the year. Id. If a utility does not use its allowances in a given period, it can carry over the unused allowances. The utility may either sell the allowances to another source in the same trading region or use the carryover allowances itself. Knodel Test., Tr. Vol. 1-A, 102:4-15, 102:24-103:3.

381. Missouri is part of Group 1 of the CSAPR SO_2 allowance trading program. Group 1 consists of 16 states, including those as far away as Wisconsin, Michigan, New York, Virginia, and North Carolina. Michels Test., Tr. Vol. 5-B, 12:19-13:23.

382. The Parties stipulated that, as of the beginning of 2019, Ameren held 237,184 CSAPR SO_2 allowances. ECF No. 1077-1 at 3; Pre-Trial Hearing Tr. 31:18-32:3 (Ameren counsel agreeing to use the United States' number); Michels Test., Tr. Vol. 5-B, 14:2-5.

383. In its 2017 Integrated Resource Plan, Ameren presented a graph (reproduced here as Figure 8) showing that its fleetwide SO_2 emissions are below the cap established by CSAPR, and that the allowance surplus is increasing each year:

Figure 8



Def. Ex. PV, at PV_5; Michels Test., Tr. Vol. 5-B, 14:8-15:5.

In this graph, the blue line represents Ameren's emissions limit based on its annual allocation of CSPAR allowances. Id. The red line represents the tons of SO_2 emitted from the entirety of Ameren's coal fleet in Missouri. The green and purple lines represent Ameren's respective limits for the Acid Rain Program and the Clean Air Interstate Rule (CAIR), the predecessor to CSAPR. As shown in Figure 8, the CAIR program had lower emissions limits for Ameren's fleet of power plants than any other program shown. Ameren never met the more challenging emissions limitations of CAIR, although its fleetwide emissions decreased during the CAIR program. By the time the CAIR program ended in 2014, Ameren's fleetwide emissions were about equal to the CAIR limit and substantially lower than the new CSAPR emissions limit.

384. Generally, power plant owners and operators have met the CSAPR limit by large margins. As of the end of 2016, Group 1 sources had banked 2,924,713 SO_2 allowances. EPA Report, "2016 Program Progress: Cross-State Air Pollution Rule and Acid Rain Program," (Pl. Ex. 1442).

385. The price for Group 1 SO_2 allowances is currently "very low" according to Ameren's trial expert economist. Celebi Test., Tr. Vol. 5-B, 72:9-11. Each allowance is about $2.50 under current market prices. Knodel Test., Tr. Vol. 1-A, 107:18-21.

386. Ameren did not present evidence or an argument demonstrating that surrendering allowances would actually decrease emissions. In its proposed findings of fact, Ameren stated that:

> Ameren currently relies on the use of CSAPR allowances to comply at Rush Island. For the period when CSAPR began in 2015 through 2018, Ameren has been allocated an average of 21,477 allowances per year, and has exceeded those allowances in several years. (Michels, Tr. Vol. 5-B, 7:14-8:4.) Based on these trends, it is reasonable to assume that Rush [I]sland's emissions may exceed allowances in the future as well.

Ameren's Proposed Findings of Fact, ECF No. 1110 at ¶277.

387. The cited testimony does not support Ameren's assertions. Michels, Tr. Vol. 5-B, 7:14-8:4. Instead, the testimony demonstrates that Rush Island has exceeded its allowances in only one year (2017), and over the past four years, Rush Island has accumulated 9,625 net allowances. Over its entire fleet, Ameren has accumulated 237,184 net allowances during the same period. ECF No. 1077-1at 3; Pre-Trial Hearing Tr. 31:18-32:3 (Ameren counsel agreeing to use the United States' number); Michels Test., Tr. Vol. 5-B, 14:2-5.

388. From CSAPR's effective date in 2015 through 2018, Rush Island has had the following allowances and actual emissions:

a. 2015: 24,310 allowances and 18,253 tons of emissions,

b. 2016: 24,237 allowances and 17,379 tons of emissions,

c. 2017: 18,686 allowances and 22,167 tons of emissions,

d. 2018: 18,675 allowances and 18,484 tons of emissions.

389. Ameren did not present evidence to demonstrate that CSAPR emissions limitations would become more difficult to meet. Instead, Ameren presented evidence that it would gain surplus credits for six years after the retirement of its Meramec Energy Center. Michels, Tr. Vol. 5-B, 8:16-20. These surplus credits would make CSAPR easier to meet.

390. Nor did Ameren present any evidence that, by trading allowances, it would actually decrease emissions in the same geographic area impacted by Rush Island and Labadie.

391. Ameren could trade its surplus allowances to power plants in Wisconsin, Michigan, New York, Virginia, or North Carolina. Michels Test., Tr. Vol. 5-B, 12:19-13:23.

392. The evidence does not support Ameren's assertion that surrendering its CSAPR emissions allowances would lead to actual emissions reductions remedying the harm to the populations impacted by Rush Island's excess emissions.

VI. ADDITIONAL EQUITABLE FACTORS SUPPORT THE REQUESTED REMEDIES

a. Liability Standards Were Well Understood in the Industry

393. I have already concluded that a reasonable power plant operator would have known that the modifications undertaken at Rush Island Units 1 and 2 would trigger PSD requirements. I have also concluded that Ameren's failure to obtain PSD permits was not reasonable. Ameren Missouri, 229 F.Supp.3d at 915-916, 1010-14.

394. After the liability trial in this case, I found that at the time of the Rush Island modifications, "the standard for assessing PSD applicability was well-established." It was also

"well-known" that the types of unpermitted projects Ameren undertook risked triggering PSD requirements. Id. at 915.

395. Despite these findings, Ameren now seeks to avoid PSD permitting by arguing that, if it knew about the consequence of its actions, it would have never triggered PSD in the first place. At trial, Ameren expert Campbell testified that Ameren could have used several options to avoid New Source Review (NSR) requirements. According to Campbell, Ameren would have used one of those "avoidance" options, if only it had known that the Rush Island modifications might be found to trigger PSD. Campbell Test., Tr. Vol. 4-A, 135:2-5. Campbell's avoidance options included canceling the projects, reducing the projects emissions without a permit, or reducing the projects emissions with a "minor permit." Campbell Test., Tr. Vol. 4-A, 49:7-19. The parties have referred to Campbell's opinions on this subject as his "PSD avoidance" theory.

396. Assuming they were viable, Ameren did not take any of the options identified by Campbell. Instead, Ameren proceeded with the projects without obtaining the required permits.

397. Campbell admitted that his PSD avoidance theory relies on an assumption that Ameren did not appreciate the risks of violating NSR when it undertook the largest modification in plant history. Campbell Test., Tr. Vol. 4-A., 136:5-9. Campbell did not talk to any Ameren employees about whether they ascertained the risks of violating NSR. Nor did Campbell talk to any Ameren employees about whether they would have taken or been able to take any of the avoidance options that he presented during his testimony. Id. 136:19-137:15.

398. Ameren's documents indicate that Ameren was aware of the possibility that NSR would be triggered at Rush Island. For example, on May 1, 2009, Ameren met with engineering firm Black & Veatch to review contracting strategies and to allow Black & Veatch to

"understand internal AmerenUE drivers." May 13, 2009 Conference Memorandum (Pl. Ex. 1111), at AM-REM-00319195. Included among the "Questions for thought" discussed at that meeting was "What is the tolerance for risk?" Id. at AM-REM-00319198, 319222. The Conference Memorandum summarizing the discussion of that question identified that "NSR is likely the biggest potential issue." Id. at 319199. Addressing a question about cash flow for any FGDs at Rush Island, the May 2009 Conference Memo identified that "NSR or EPA will likely be the driver to shift the schedule early." Id.

399. A June 2010 presentation to Ameren's Corporate Project Oversight Committee (CPOC) similarly identified "New Source Review" as one of several Clean Air Act "driving forces for additional control equipment" that Ameren was monitoring. See June 1, 2010 CPOC Presentation, Scrubber Technology Assessment, Rush Island Plant (Pl. Ex. 1099), at AM-REM-00288980; see also Ameren Rule 30(b)(6) Dep., Nov. 7, 2017, Tr. 59:25-60:10.

400. A February 2010 CPOC presentation identified NSR as among the relevant environmental concerns facing Rush Island. Specifically, the presentation identified NSR's "permitting and control requirements for new sources and existing sources that undergo 'major modifications.'" See February 5, 2010 Project Review Board Presentation—Rush Island FGD (Pl. Ex. 1100), at AM-REM-00289009, 011.

401. Campbell also testified that Ameren could avoid PSD by restricting operations. This opinion is similarly unsupported. To avoid PSD by restricting operations, a source can obtain a permit known as a synthetic minor permit. A synthetic minor permit limits a source to operate below significance thresholds under the PSD program. Knodel Test., Tr. Vol. 1-A, 67:5-14, 97:25-98:7.

402. Ameren did not apply for a synthetic minor permit prior to undertaking the

modification of Unit 1 in 2007 nor the modification of Unit 2 in 2010. Knodel Test., Tr. Vol. 1-A, 67:15-20; MDNR Rule 30(b)(6) Dep., Aug. 10, 2018, Tr. 137:5-9.

403. Ameren's director of corporate analysis, the official in charge of resource planning, testified that he was not aware of any instance where Ameren voluntarily restricted the operations of Rush Island. Michels Test., Tr. Vol. 5-B, 4:19-20, 5:1-9; Michels Dep., Aug. 14, 2018, Tr. 156:13-17.

404. Owners of baseload plants such as Rush Island generally avoid limiting plant operations, which are designed to run as much as possible. Staudt Test., Tr. Vol. 1-B, 20:16-24, 97:13-23; see also Ameren Missouri, 229 F. Supp.3d at 917 (Liability Findings ¶ 6 (Rush Island units are "baseload units" that "generally operate every hour they are available to run"), ¶ 7 ("The Rush Island units are among Ameren's most cost-effective units and carry much of the system load."), ¶ 59 (Rush Island units gain "economic advantage … by burning cheaper coal then their competitors")).

405. Dr. Staudt testified that he was not aware of any instance in which the owner of a baseload power plant like Rush Island accepted a limitation on operations in the way that Campbell suggests. Staudt Test., Tr. Vol. 2-A, 13:23-14:12. ("[T]hat doesn't happen very often, or I'm not sure if it's ever happened on a electric-generating unit.").

406. Despite its expert testimony, Ameren did not present any company witness or documents suggesting the pursuit of a synthetic minor permit was a realistic possibility, or ever considered for Rush Island.

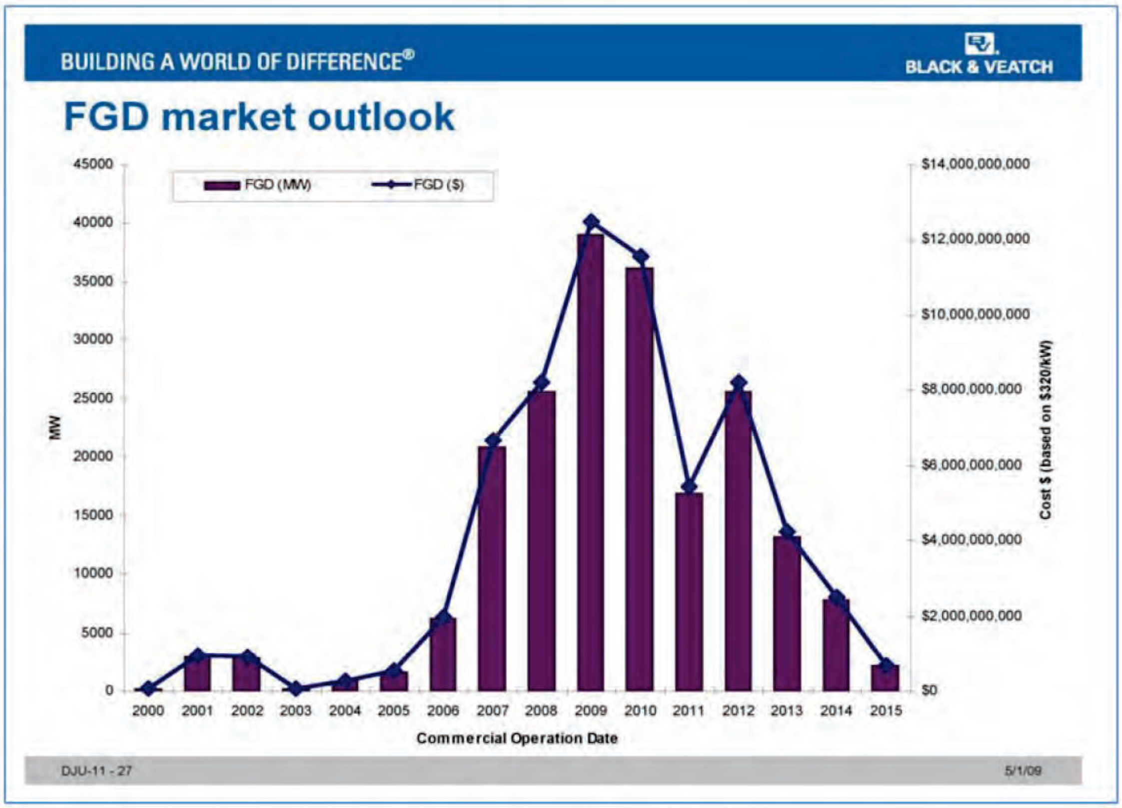
407. While Rush Island began burning lower sulfur coal after its modifications, Ameren has not accepted a permit limit at that level. Nothing currently requires Rush Island to burn lower sulfur coal. Staudt Test., Tr. Vol. 2-A, 17:5-16; Knodel Test., Tr. Vol. 1-A, 67:25-

68:19, 69:18-20.

b. Ameren Has Benefitted from Delaying Compliance at Rush Island

408. Between 2007 and 2010 was a period of peak market demand for the installation of scrubbers in the electric utility industry, as illustrated by Figure 9.

Figure 9



Pl. Ex. 1111, at AM-REM-00319231.

409. Ameren avoided this period of peak market demand to its benefit, as discussed in internal company documents. Staudt Test., Tr. Vol. 1-B, 28:3-31:1; Ex. 1111, at AM-REM-00319199, 231; Ameren's April 2011 Presentation for MPSC, Ex. 1009, at AM-02225216 (Ameren's business strategy "[a]llows Ameren Missouri to defer capital investments on environmental retrofits" and "delay its construction needs to avoid the likely timeframe of

greatest environmental retrofit construction.")

410. Ameren's internal documents also make clear that Ameren has understood for many years the possibility that scrubbers would be required as a result of NSR violations at Rush Island. Ex. 1009, at AM-02225205 ("New Source Review lawsuit by EPA may require flue gas desulfurization (FGD) systems or scrubbers at Rush Island."), and AM-02225216 (2011 fuel switch strategy "[a]llows Ameren Missouri additional time to complete its detailed engineering design should scrubbers ultimately be required.");

411. Today, the scrubber market is "slow" and there would be lots of "very eager suppliers" to get Ameren's business. That means not only that Ameren benefitted from the delay, but also that an FGD could be installed much more quickly today because the resources are more available. Staudt Test., Tr. Vol. 1-B, 32:2-33:3.

412. By delaying wet FGD scrubbers for more than ten years, Ameren also sold more power from Rush Island than it would have had it complied with the law. Operating a scrubber changes the dispatch cost of a unit (the cost that unit needs to break even in the market). Celebi Test., Tr. Vol. 5-B, 68:18-69:18. Because the unit's dispatch cost will increase, it may run less. The unit will also sell less energy to the grid because some of its energy is needed to power the scrubber itself. Celebi Test., Tr. Vol. 5-B, 68:18-70:15.

413. The sources that installed scrubbers when required have been at a competitive disadvantage to Rush Island. In contrast, by not installing scrubbers in 2007 and 2010, Ameren benefited from the ability to spend capital on other items or issue dividends.

c. Ameren Admits It Can Afford to Comply With the Requested Remedies

i. Ameren Has Abundant Financial Resources

414. Ameren Missouri and Ameren Corporation are "financially strong." Kahal Test.,

Tr. Vol. 2-A, 53:11-19, 59:23-60:5 (discussing the strength of Ameren's financial reports). Ameren Corporation is the sole owner of Ameren Missouri. Kahal Test., Tr. Vol. 2-A, 55:3-25. Ameren has strong credit ratings, access to capital on favorable terms, and can access far more capital than it needs for its current capital spending plans. Kahal Test., Tr. Vol. 2-A, 69:25-70:5.

415. Each year, Ameren reports financial information for Ameren Corporation and Ameren Missouri to the Securities and Exchange Commission (SEC). Kahal Test., Tr. Vol. 2-A, 56:9-16. In its latest Form 10-K, Ameren submitted the financial information contained in Table 2 for the calendar year 2018.

Table 2. Ameren Corporation and Ameren Missouri 2018 Financial Information

	Ameren Corporation	Ameren Missouri
Assets	$27,215,000,000	$14,291,000,000
Operating Revenue	$6,291,000,000	$3,589,000,000
Net Income	$815,000,000	$478,000,000
Shareholder Dividends	$451,000,000	$375,000,000
Capital Spend	$2,336,000,000	$914,000,000
Operating Cash Flow	$2,170,000,000	$1,260,000,000

Ameren 2019 10-K (Pl. Ex. 1340), at USTREXR0003003, 3055, and 3057.

416. Ameren also reports financial information to the Federal Energy Regulatory Commission (FERC) in a document called the FERC Form 1. Ameren reported the following financial data in its FERC Form 1s for the years 2012 through 2017.

Table 3: Ameren Corporation 2012-2017 Financial Information (dollars)

	Net Income	**Capital Spending**	**Dividends**	**Cash Flow**
2012	420,000,000	611,000,000	400,000,000	995,000,000
2013	399,000,000	668,000,000	460,000,000	1,135,000,000
2014	394,000,000	770,000,000	340,000,000	943,000,000
2015	356,000,000	631,000,000	575,000,000	1,239,000,000
2016	360,000,000	751,000,000	355,000,000	1,161,000,000
2017	326,000,000	786,000,000	362,000,000	1,018,000,000
Average	376,000,000	703,000,000	415,000,000	1,082,000,000

Pl. Exs. 1331-36; see Rule 1006 Summary of FERC Form 1s (Pl. Ex. 1388).

417. In the SEC Form 10-K and FERC Form 1s:

a. ***Assets*** refers to total property owned by the company and provides a sense of the company's size.

b. ***Operating revenue*** is the total amount the company receives from its services.

c. ***Net income*** means the after-tax profits of the business.

d. ***Shareholder dividends*** refers to the money paid to the owners of the company. Ameren Corporation has individual public shareholders, while Ameren Missouri is wholly owned by Ameren Corporation. Therefore, all Ameren Missouri's dividends go to Ameren Corporation.

e. ***Capital spend*** means the total capital spending.

f. ***Operating cash flow*** refers to the net funds that the company earns after expenses such as operating and maintenance spending, taxes, interest, and other costs. Throughout the period, the cash flow roughly equals the total of capital spending and dividends, indicating that the company is using its cash to fund capital projects with internally generated revenue and paying the rest in dividends.

Kahal Test., Tr. Vol. 2-A, 57:16-59:22, 63:10-64:12.

418. Ameren has three main options for financing capital projects. It can use revenues from its operations, obtain funds from debt markets, or issue new common stock (through the parent company). Kahal Test., Tr. Vol. 2-A, 66:21-67:24.

419. Ameren's stock has performed "extremely well" over the past five years. Kahal Test., Tr. Vol. 2-A, 60:8-17. Ameren's Form 10-K indicates that the parent company's stock price grew by more than 16% per year from 2013 to 2018. Ameren 2019 10-K (Pl. Ex. 1340), at USTREXR0003002; Kahal Test., Tr. Vol. 2-A, 60:8-61:6. This growth was considerably larger

than indexes reflecting the electric utility industry or the broader stock market. Id. Ameren's stock performance means that the company would have access to equity markets, if needed, to finance capital projects. Kahal Test., Tr. Vol. 2-A, 60:8-61:6.

420. In February 2019, Ameren announced a $6.3 billion capital spending program for the next five years. Ameren Feb. 15, 2019 Press Release (Pl. Ex. 1341). This program represents an increase in spending from the recent past, when capital spending averaged about $700 million per year. Kahal Test., Tr. Vol. 2-A, 64:13-65:21; Ameren Feb. 15, 2019 Press Release (Pl. Ex. 1341).

421. Ameren's strong credit ratings allow it to access debt markets on very favorable terms. Kahal Test., Tr. Vol. 2-A, 65:22-66:20. The corporate credit ratings for both Ameren Corporation and Ameren Missouri are at the top end of the triple B range, while the secured debt for Ameren Missouri is rated medium single A. Kahal Test., Tr. Vol. 2-A, 65:22-66:20.

ii. Ameren Agrees It Can Finance the Requested Relief

422. Ameren can afford to finance the pollution controls at issue in this case. Kahal Test., Tr. Vol. 2-A, 53:11-54:12. Ameren presented no evidence to the contrary. Instead, Ameren's lead counsel stated at trial that Ameren "can afford anything this Court orders." Ameren Closing Argument, Tr. Vol. 6, 34:12-13.

423. The annual capital cost of installing FGD at Rush Island is only about half as large as Ameren's average annual dividend in recent years. Installing FGD at both Rush Island units would result in about $200 million per year in capital costs over the four-year construction period plus an estimated $27 to $38 million in operating and maintenance costs once the FGD systems begin operating. Kahal Test., Tr. Vol. 2-A, 71:5-12; Callahan Dep., Nov. 8, 2017, Tr. 195:5-12. Ameren's average dividend payment to its parent company is about $415 million per

year and its operating cash flow is more than $1 billion. See Rule 1006 Summary of FERC Form 1s (Pl. Ex. 1388, summarizing Pl. Ex. 1331 through 1336). Compared to these metrics, the wet FGD operating costs "are a very small number." Kahal Test., Tr. Vol. 2-A, 71:5-22.

424. Plaintiffs also presented evidence of several pollution control options at Labadie, including FGD and DSI to offset the excess emissions from Rush Island. Dr. Staudt estimated that the capital cost of FGD at two Labadie units would be $465 million with $29 million in annual operating costs. Staudt Test., Tr. Vol. 1-B, 105:12-106:24; see also Kahal Test., Tr. Vol. 2-A, 71:5-22. Dr. Staudt also estimated that installing DSI at all four Labadie units would mean a capital cost of $55 million and annual operating costs of $53 million. Staudt Test., Tr. Vol. 1-B, 104:21-105:11.

425. These costs are a small fraction of Ameren's $6.3 billion capital plan for the next five years and its $1.1 billion annual operating cash flow. Kahal Test., Tr. Vol. 2-A, 64:13-65:21; Rule 1006 Summary of FERC Form 1s (Pl. Ex. 1388, summarizing Pl. Ex. 1331-1336).

426. The EPA's expert Matthew Kahal testified that Ameren could afford to implement any of the mitigation options identified by Dr. Staudt for Labadie or Rush Island. Kahal Test., Tr. Vol. 2-A, 71:23-72:1, 78:10-17. This testimony was not challenged on cross or by any Ameren witnesses.

iii. The Projected Ratepayer Impact of the Requested Relief Is Less Than Ameren's Yearly Rate Increases

427. As of 2016, Ameren Missouri had 1.2 million customers. Celebi Test., Tr. Vol. 5-B, 26:16-20.

428. Ameren is a regulated monopoly. Kahal Test., Tr. Vol. 2-A, 51:12-19. When Ameren incurs costs that are not being recovered by its rates, it can seek a rate increase from the Missouri Public Service Commission. Kahal Test., Tr. Vol. 2-A, 51:12-52:4. The Public Service

Commission reviews the request and determines whether any rate increase is appropriate to allow Ameren to recover its costs. Kahal Test., Tr. Vol. 2-A, 51:12-52:4.

429. In the ratemaking process, Ameren receives a profit (known as the rate of return) on capital spending. Kahal Test., Tr. Vol. 2-A, 68:24-69:19; Celebi Test., Tr. Vol. 5-B, 42:24-43:8 (noting inclusion of rate of return). The rate of return is set by the Missouri Public Service Commission. Kahal Test., Tr. Vol. 2-A, 68:24-69:24. In recent years, the rate of return for Missouri utilities has been about 9.5%. Kahal Test., Tr. Vol. 2-A, 68:24-69:24.

430. Expert witnesses for both parties calculated how much installing pollution controls could affect the rates paid by Ameren customers if Ameren seeks to recover those costs from ratepayers. See Kahal Test., Tr. Vol. 2-A, 72:21-25; Celebi Test., Tr. Vol. 5-B, 66:11-19.

431. Ameren could choose not to recover those costs from its ratepayers. The Public Service Commission could also elect not to allow full cost recovery, especially if it determines the costs are the result of Ameren's decision not to comply with the Clean Air Act. Kahal Test., Tr. Vol. 2-A, 77:7-78:6; Celebi Test., Tr. Vol. 5-B, 66:11-67:19.

432. The EPA's expert Matthew Kahal testified that wet FGD at Rush Island would result in an increase in customer rates of about 2.8% over 20 years (assuming the Missouri Public Service Commission allows full rate recovery). Kahal Test., Tr. Vol. 2-A, 74:22-75:1. Ameren's expert Dr. Metin Celebi found that FGD at Rush Island would increase customer rates by 2.4%.[11] Kahal Test., Tr. Vol. 2-A, 80:23-82:4.

433. For DSI at the Labadie station, Kahal testified that the controls could result in an increase to customer rates of between 0% and 2% over 14 years. Kahal Test., Tr. Vol. 2-A, 77:7-

[11] Despite his expert opinions, Dr. Celebi did not testify about the individual percentage increases due to the scrubbers at Rush Island and DSI at Labadie. Kahal read his expert disclosure report and testified about the contents of that report. Celebi Test., Tr. Vol. 5-B, 64:21-65:9.

79:12. Dr. Celebi calculated a 1.4% rate increase if Ameren sought to recover the costs of implementing DSI from consumers. Kahal Test., Tr. Vol. 2-A, 81:25-82:1.

434. Overall, Kahal estimated that installing FGD at both Rush Island units and DSI at all four Labadie units would increase customer rates from 2.8 to 4.8%, while Dr. Celebi estimated that those controls would increase rates by 3.8%. Kahal Test., Tr. Vol. 2-A, 80:23-82:4; Celebi Test., Tr. Vol. 5-B, 64:21-65:9.

435. Rate increases in that range are in keeping with Ameren's typical rate changes from year to year. Dr. Celebi testified that Ameren's rates increased 5.4% from 2016 to 2017, and that Ameren's 2017 Integrated Resource Plan predicted that rates would increase 2.9% per year over the period from 2018 to 2037. Celebi Test., Tr. Vol. 5-B, 65:15-66:10.

436. The rates Ameren charges its customers are well below the national average. In 2016, Ameren's rates were 14% lower than the national average. Kahal Test., Tr. Vol. 2-A, 72:4-20; Celebi Test., Tr. Vol. 5-B, 57:15-24. Even with the rate increases estimated by Kahal or Dr. Celebi, Ameren customers' rates would still be around 10% lower than the national average. Kahal Test., Tr. Vol. 2-A, 82:6-15. Ameren's rates are also at or below the median rates for utilities in both Missouri and in surrounding states. Celebi Test., Tr. Vol. 5-B, 82:2-83:14.

437. In December 2017, a change in the tax laws reduced Ameren's income tax rate, resulting in a 6.1% decrease in customer rates. Kahal Test., Tr. Vol. 2-A, 82:16-83:2, 83:15-23; Ameren Presentation, "Building a Brighter Energy Future," Feb. 14, 2019 (Pl. Ex. 1337) at USTREXR0002371; Celebi Test., Tr. Vol. 5-B, 84:2-8. The potential rate increases predicted by Dr. Celebi and Kahal are smaller than the rate decrease resulting from the tax law changes. Celebi Test., Tr. Vol. 5-B, 84:2-16.

iv. Ameren's Average Estimates of Rate Increase Are Misleading

438. At trial, and in its proposed findings of fact, Ameren asserted that the costs of installing FGD at Rush Island and DSI at Labadie would be disproportionate to the harm of its excess emissions.

439. Ameren's expert, Dr. Celebi, conducted rate impact analyses for controls that might be installed on Rush Island and Labadie. Celebi Test., Tr. 5-B 62:3-63:10. He analyzed that the annual average total cost for wet FGD at Rush Island and DSI at Labadie would be $196 million per year, for a total of $4.1 billion over the entire period. He then estimated a per customer cost of $3,422.

440. Dr. Celebi's per customer estimates are unrepresentative of the typical customer's experience, because he does not differentiate based on residential, commercial, or industrial users. A three-bedroom home does not use the same amount of electricity, nor pay the same electricity bill, as a department store or an aluminum smelter. When residential, commercial, and industrial ratepayers are lumped together, the larger sources have a disproportionate influence on the total electricity use and the average cost of electricity, per customer. Ameren could have accommodated these differences by differentiating residential, commercial, and industrial ratepayers or, at the very least, calculating a median value, but it did not.

441. Additionally, in part, Dr. Celebi presented his results as an average per-customer cost over twenty years of operation. When presenting these results, Dr. Celebi often failed to indicate whether his estimates were in 2016 dollars, 2025 dollars, or some other years' dollars. See, e.g., id. at 62:19-23, 63:8-10. Because the value of money changes over time due to, for example, inflation, Dr. Celebi's failure to provide the reference year makes his testimony more ambiguous.

442. I find that Ameren's average per customer rate increase estimates in dollars do not reflect the typical customer's experience.

CONCLUSIONS OF LAW

As I noted in the introduction to this opinion, my conclusions of law from the liability phase significantly influence my findings of fact and conclusions of law in the remedies phase. In the liability phase, I found that Ameren violated the Clean Air Act by making major modifications that increased SO_2 emissions at Rush Island without obtaining the proper Prevention of Significant Deterioration (PSD) program permit and installing the Best Available Control Technology (BACT). Sulfur dioxide (SO_2) has been regulated under the Clean Air Act for 50 years. Once emitted, most SO_2 converts into fine particulate matter ($PM_{2.5}$), a pollutant known to cause increased risks of premature mortality, heart and lung disease, and other adverse health effects. Modern pollution controls can dramatically reduce SO_2 emissions, saving lives in the process.

While the rest of the electric industry made great strides in reducing SO_2 pollution, Rush Island lagged behind, rising steadily in the ranks to become one of the country's largest sources of SO_2. That pollution contributed to $PM_{2.5}$ levels across much of the Eastern United States, a range extending from Texas and Minnesota to the Atlantic Ocean. The emissions were allowed because Rush Island was grandfathered into the Clean Air Act Amendments of 1977. Rush Island lost its grandfathered status when Ameren conducted major modifications of the plant, redesigning and rebuilding essential parts of its two boilers. These major modifications increased Rush Island's emissions, based on Ameren's own operating data, and Ameren should have expected the increase.

Now, in the remedies phase, the EPA seeks to bring Ameren's Rush Island facility into compliance with the law and to remediate the harm from the more than 162,000 tons—and counting—in excess SO_2 that Rush Island emitted after Ameren failed to obtain a PSD permit there. Specifically, the EPA seeks an order requiring Ameren to (1) apply for a PSD permit at Rush Island, (2) propose wet FGD as the BACT in its Rush Island permit application, (3) meet an emissions limitation of 0.05 lb SO_2/mmBTU, and (4) reduce emissions at Labadie on a ton-per-ton basis to remedy the more than 162,000 excess SO_2 emissions released by Rush Island.

Once Ameren installs BACT at Rush Island, it should capture nearly 99% of SO_2 emissions there. By that time, Rush Island will have emitted nearly 275,000 tons of excess pollution, impacting $PM_{2.5}$ concentrations across the Eastern United States. Ameren must reduce pollution released into those areas. Accordingly, the EPA presented evidence on control measures that Ameren could implement at its nearby Labadie Energy Center in order to remediate the excess emissions. The pollution from that facility affects the same communities—and to the same degree—as Rush Island's pollution on a ton-per-ton basis. Therefore, efforts to reduce Labadie's pollution would be closely tailored to remedy the harm created by Rush Island's excess emissions.

Ameren presents seven arguments against the relief the EPA requests at Rush Island and Labadie. First, Ameren argues that it should be allowed to obtain a minor permit, instead of the statutorily-required PSD permit. According to Ameren, if it had known better, it would have pursued other, less expensive compliance options than PSD permitting. I need not entertain this hypothetical or speculate what might have been. Ameren made a major modification that lengthened the life of, and increased emissions at Rush Island. It cannot now undue these modifications or regain its grandfathered status. Ameren must obtain a PSD permit.

Second, Ameren argues that the Missouri Department of Natural Resources (MDNR) should determine the Best Available Control Technology for Rush Island. I have already discussed this argument in my order denying Ameren's motion for summary judgment. United States v. Ameren Missouri, 372 F. Supp. 3d 868, 873 (E.D. Mo. 2019). At summary judgment, Ameren did not demonstrate, as a matter of law, that I do not have authority to determine what Ameren must propose as BACT. Id. In this case, I am not issuing a permit, replacing the notice and comment process, or otherwise altering the nature of the PSD permitting process. Consistent with my authority to restrain violations and "require compliance" with the Clean Air Act, the relief in this case merely orders Ameren to submit an application that proposes wet FGD as BACT. 42 U.S.C. § 7413(b)(3).

Third, Ameren argues that, if I do determine BACT, I should order the installation of the least effective control technology, DSI without a fabric filter. DSI is about half as effective as scrubber technology, and it has never been accepted as BACT for a coal-fired electric generating unit. Ameren would like the BACT analysis to settle on the "least expensive option" capable only of "moderate" emissions reductions. Deciding BACT based primarily on a cost-benefit analysis would itself be in conflict with the Clean Air Act, which requires emissions limits "based on the maximum degree of reduction" available. 42 U.S.C. § 7479(3).

Fourth, Ameren argues that the eBay factors do not support the EPA's requested relief. Based on my analysis of the eBay factors, I conclude that the EPA's requested remedy is narrowly tailored to the harm suffered, addresses irreparable injury that could not be compensated through legal remedies, serves the public interest, and is warranted when considering the balance of hardships in this case.

Fifth, Ameren argues that any relief ordered at Labadie would constitute a penalty waived by the EPA before the liability trial. The installation of DSI at Labadie is an equitable remedy that is narrowly tailored and does not penalize Ameren. DSI's capital costs are minimal, and when Ameren has fully accounted for Rush Island's excess emissions, it may choose to discontinue use of its DSI system. Ameren may also choose to install a more capital-intensive technology if it decides to do so, but I will not require that Ameren does so.

Sixth, Ameren argues that Sierra Club v. Otter Tail Power Co., an Eighth Circuit case concerning the statute of limitations for suing to remedy a PSD violation, essentially gives Ameren immunity for all the excess pollution it released after failing to obtain a PSD permit for Rush Island. See 615 F.3d 1008, 1011 (8th Cir. 2010). Ameren's reliance on Otter Tail is misplaced. The statute of limitations did not expire before the United States commenced this case against Ameren, and I do not find in this case that Ameren's operation without a permit is an ongoing violation. The "excess emissions" or "excess pollution" references throughout this opinion describe the pollution that Rush Island has emitted in excess of what it would have released had Ameren installed BACT as required by the PSD program.

Finally, Ameren argues that it should be able to surrender allowances from a distinct regulatory program that could otherwise be traded to plants in Wisconsin, Michigan, New York, Virginia, or North Carolina. Ameren presented no evidence at trial to demonstrate that surrendering allowances would actually decrease emissions and $PM_{2.5}$ concentrations in the communities affected by Rush Island. Therefore, this proposal is not narrowly tailored to remedy the harm suffered.

Pollution from Rush Island is regulated for a reason, and Rush Island remains one of the largest sources of SO_2 in the country. Applied to the record evidence, the broad scientific consensus dictates the conclusion that the $PM_{2.5}$ that resulted from the excess SO_2 pollution at Rush Island has harmed—and continues to inflict harm on—the public in the form of premature mortality and myriad other adverse health effects.

To remedy its violations, Ameren must obtain the necessary PSD permit for the facility, implement the best available control technology, and undertake emissions reductions at its Labadie plant commensurate with Rush Island's volume of excess pollution.

I. THE CLEAN AIR ACT REQUIRES THE BEST AVAILABLE CONTROL TECHNOLOGY FOR MODIFIED POWER PLANTS IN PSD AREAS

The 1970 Clean Air Act (CAA) was designed in part to "speed up, expand, and intensify the war against air pollution in the United States with a view to assuring that the air we breathe throughout the Nation is wholesome once again." H.R. Rep. No. 91-1146, at 1 (1970), reprinted in 1970 U.S.C.C.A.N. 5356, 5356; Wis. Elec. Power Co. v. Reilly, 893 F.2d 901, 909 (7th Cir. 1990) (quoting legislative history). One primary purpose of the statute is "to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population." 42 U.S.C. § 7401(b)(1).

Not satisfied with the results achieved under the 1970 statute, Congress added the New Source Review program to the Act in 1977 to ensure that additional requirements were imposed on new and modified sources of air pollution. New York v. EPA, 413 F.3d 3, 10 (D.C. Cir. 2005). The PSD component of NSR was "aimed at giving added protection to air quality" while fostering economic growth in a manner consistent with preservation of existing clean air resources. Envtl. Def. v. Duke Energy Corp., 549 U.S. 561, 567 (2007) (noting that "NSPS . . . did too little to "achiev[e] the ambitious goals of the 1970 Amendments"); 42 U.S.C. § 7470. In areas that already meet the NAAQS, the 1977 amendments required BACT on new and modified sources that would otherwise increase pollution. Hawaiian Elec. Co. v. EPA, 723 F.2d 1440, 1447 (9th Cir. 1984) ("Congress found that it was important to reduce pollution levels below those mandated by the standards and that the best means of doing so was to require the installation of BACT on all sources which would otherwise increase pollution."). Pursuant to the PSD program, modification of a major source is prohibited unless, among other requirements:

> (1) a permit has been issued for such proposed facility in accordance with this part setting forth emission limitations for such facility . . .
>
> (3) the owner or operator of such facility demonstrates . . . that emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of [among other things] any . . . national ambient air quality standard [NAAQS] in any air quality control region . . . [AND]
>
> (4) the proposed facility is subject to the best available control technology for each pollutant subject to regulation . . . .

42 U.S.C. § 7475(a); see also id. §7479(2)(C) (explaining that modification of a source constitutes "construction" with respect to the requirement to obtain a permit). Among the other five requirements listed in this section, modification of a source is prohibited unless the owner (1) obtains a PSD permit, (2) installs BACT at the facility, and (3) demonstrates that, even when BACT is installed, permitted emissions from that facility will not violate the NAAQS.

II. THE EBAY STANDARD GOVERNS INJUNCTIVE RELIEF

The liability phase of this case established that Ameren violated the Clean Air Act when it modified Rush Island "without obtaining the required permits [and] installing best-available pollution control technology." United States v. Ameren Missouri, 229 F. Supp. 3d 906, 914 (E.D. Mo. 2017). The question presented now is what to do about Ameren's violations.

Section 113(b) of the Clean Air Act authorizes district courts to "restrain such violation[s], to require compliance, . . . and to award any other appropriate relief" where a source owner or operator "has violated or is in violation of" statutory or regulatory prohibitions. 42 U.S.C. § 7413(b). Courts have jurisdiction to craft "complete relief in light of the statutory purposes;" that jurisdiction is "not to be denied or limited in the absence of a clear and valid legislative command." Mitchell v. Robert De Mario Jewelry, 361 U.S. 288, 291-92 (1960); see also Weinberger v. Romero-Barcelo, 456 U.S. 305, 313 (1982) (courts enjoy the entire range of their historic equitable powers to craft relief unless Congress placed limitations on those powers "in so many words or by necessary and inescapable inference").

When considering injunctive relief, a court evaluates whether

> (1) [the plaintiff] has suffered irreparable injury; (2) . . . remedies available at law, such as monetary damages, are inadequate to compensate for the injury; (3) . . . considering the balance of hardships between the plaintiff and defendant, a remedy in equity is warranted; and (4) . . . the public interest would not be disserved by a permanent injunction.

eBay Inc. v. MercExchange, L.L.C.: 547 U.S. 388, 391 (2006).

In addition to the eBay factors, several principles guide the crafting of remedies in a case like this. First, the ordered relief must enforce the statutes created by Congress:

> If Congress has prohibited certain behavior, I do not have discretion to determine "whether enforcement is preferable to no enforcement at all." United States v. Oakland Cannabis Buyers' Coop., 532 U.S. 483, 497 (2001). In these circumstances, my discretion is limited to evaluating how equitable considerations "are affected by the selection of an injunction over other enforcement mechanisms." Id.

Ameren Missouri, 372 F. Supp. 3d 868, 877.

Courts cannot "override Congress' policy choice, articulated in a statute, as to what behavior should be prohibited." Oakland Cannabis Buyers' Coop., 532 U.S. 483, 497 (2001). A remedy should grant "complete" relief to fulfill the statute's purposes. C.f. Mitchell, 361 U.S. at 296 (noting "little room for . . . discretion not to order" equitable reimbursement and that a court either proceeding under general equity powers or the Fair Labor Standards Act has authority to order "legal relief[] necessary to do complete justice between the parties.").

Next, "[a]n injunction must be tailored to remedy specific harm shown." Rogers v. Scurr, 676 F.2d 1211, 1214 (8th Cir. 1982). The injunction should be "no more burdensome to the defendant than necessary to provide complete relief to the plaintiffs." Califano v. Yamasaki, 442 U.S. 682, 702 (1979). Where, as here, the United States seeks to enforce a public interest statute, a court places "extraordinary weight . . . upon the public interests" because the "suit involve[es] more than a mere private dispute." United States v. Marine Shale Processors, 81 F.3d 1329, 1359 (5th Cir. 1996) (citing Virginian Ry. v. Sys. Fed'n No. 40, AFL, 300 U.S. 515, 552 (1937)).

Additionally, where an injunction will remediate environmental harm, courts have considered "(1) whether the proposal 'would confer maximum environmental benefit,' (2) whether it is 'achievable as a practical matter,' and (3) whether it bears 'an equitable relationship to the degree and kind of wrong it is intended to remedy.'" United States v. Deaton, 332 F.3d 698, 714 (4th Cir. 2003) (quoting a standard articulated in United States v. Cumberland Farms of Conn., Inc., 826 F.2d 1151, 1164 (1st Cir.1987) and echoed in United States v. Sexton Cove Estates, Inc., 526 F.2d 1293, 1301 (5th Cir. 1976)).

III. AMEREN MUST MAKE RUSH ISLAND COMPLIANT BY OBTAINING A PSD PERMIT WITH EMISSIONS LIMITATIONS BASED ON WET FGD

The PSD program's BACT requirement is a "technology-forcing" standard that is meant to "stimulate the advancement of pollution control technology," a central goal of the 1977 Amendments. Wis. Elec. Power Co. v. Reilly, 893 F.2d 901, 909 (7th Cir. 1990) ("The legislative history suggests and courts have recognized that in passing the Clean Air Act Amendments, Congress intended to stimulate the advancement of pollution control technology."). The BACT requirement codified at 42 U.S.C § 7475(a)(4) is the cornerstone of the PSD program. It advances both Congress's public protection and technology-driving aims. Accordingly, my remedies determination is based on a careful examination of what constitutes BACT for Rush Island.

a. BACT Sets Emissions Limitations Based on the Maximum Degree of Pollution Reduction Achievable

As defined by Congress in the Clean Air Act, BACT is an "emissions limitation based on the maximum degree of reduction of each pollutant subject to regulation." 42 U.S.C. § 7479(3); see also Sierra Club v. Otter Tail Power Co., 615 F.3d 1008, 1011 (8th Cir. 2010). Determining BACT is a case-by-case endeavor that incorporates consideration of "energy, environmental, and economic impacts and other costs." 42 U.S.C. § 7479(3); 40 C.F.R. § 52.21(b)(12) (further defining BACT). While BACT is determined on a case-by-case basis, "the permitting authority's analysis must in all circumstances give effect to the purpose of BACT, which is to promote the use of the best technologies as widely as possible." In re Gen. Motors, Inc., 10 E.A.D. 360, 364 (E.A.B. 2002).[12] As noted by the Ninth Circuit, BACT requires use of "the most current, state-of-the-art pollution controls" available. Grand Canyon Trust v. Tucson Elec. Power Co., 391 F.3d 979, 983 (9th Cir. 2004). "[F]ailure to consider all available control alternatives in a BACT analysis constitutes clear error," unless the control alternative would require the evaluator to "redefine the source." Helping Hand Tools v. U.S. Envtl. Prot. Agency, 848 F.3d 1185, 1194 (9th Cir. 2016).

In practice, BACT follows a "top-down" approach used by the EPA and MDNR to ensure that the most effective technology is actually selected. FOF ¶ 77. The Supreme Court has explained the top-down process as providing:

> that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent—or "top"—alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgement agrees, that technical considerations, or energy, environmental, or economic impacts justify a

[12]The Environmental Appeals Board (EAB) is the final decision-maker on administrative appeals arising under environmental statutes administered by EPA, including the Clean Air Act. See Sierra Club v. Wisconsin DNR, 787 N.W.2d 855, 867 n.6 (Wis. App. 2010).

conclusion that the most stringent technology is not "achievable" in that case.

Alaska, Dep't of Envtl. Conservation v. EPA, 540 U.S. 461, 475-76 (2004) (quoting EPA's Draft New Source Review Workshop Manual, Oct. 1990 [Pl. Ex. 1190] ("NSR Manual") at B2); see also Chipperfield v. Mo. Air Conserv. Comm'n, 229 S.W.3d 226, 239-40 (Mo. Ct. App. 2007). "So fixed is the focus on identifying the 'top', or most stringent alternative, that the analysis presumptively ends there. . . ." In re Northern Mich. Univ. Ripley Heating Plant, 14 E.A.D. 283, 294 (E.A.B. 2009). The top option constitutes BACT unless something unique about the plant prevents it from using the same "top" controls.[13] Id.

The top-down method consists of five steps: (1) identify all applicable control technologies; (2) remove any technically infeasible controls; (3) rank feasible controls by effectiveness; (4) determine if the most effective option is achievable considering the energy, environmental and economic impacts; and (5) select a BACT emissions limitation. Pl. Ex. 1190 [NSR Manual] at AM-REM-00544123-MDNR; see also FOF ¶ 74.

b. Industry Experience and Ameren's Own Analyses Show FGD Technology Is Economically and Technically Feasible at Rush Island

The parties do not dispute the outcome of the first three steps in the BACT analysis.[14] As the parties agree, there are four available control technologies, all of which are technically feasible for Rush Island. FOF ¶¶ 180-81. As ranked in descending order of effectiveness, these

[13] The Ninth Circuit has stated that "the burden of proof [is] on the 'applicant to justify why the proposed source is unable to apply the best technology available.'" Citizens for Clean Air v. U.S. EPA, 959 F.2d 839, 845 (9th Cir. 1992) (quoting NSR Manual). To meet that burden, the source must "demonstrate that the technology is technically or economically infeasible." Id.; see also FOF ¶ 76. If the "top" control is eliminated in Step 4, the next most effective technology is considered, and so on, until the most effective remaining option is selected as BACT. Alaska, Dep't of Envtl. Conservation v. U.S. E.P.A., 298 F.3d 814, 822 (9th Cir. 2002), aff'd sub nom. Alaska Dep't of Envtl. Conservation v. E.P.A., 540 U.S. 461 (2004).

[14] While Dr. Staudt included natural gas conversion in his BACT analysis, Dr. Staudt and the EPA agree with Ameren that natural gas conversion is not an appropriate technology for consideration. Tr. Vol. 2-A, 21:6-17, 22:23-23:18.

are:

(1) Wet FGD technology (sometimes called a "wet scrubber")
(2) Dry FGD technology (sometimes called a "dry scrubber")
(3) DSI implemented in parallel with a fabric filter
(4) DSI implemented as a stand-alone control

FOF ¶ 113. Based on these options, the next question is whether the "top" control—wet FGD technology—should be eliminated as not "achievable" after an evaluation of its energy, environmental, or economic impacts. The great weight of evidence presented at trial shows wet FGD is achievable.

Over the last forty years, about 200,000 megawatts of coal-fired electric generating capacity have been fitted with FGD technology. See Figure 1; FOF ¶ 14. FGD scrubbers are currently installed on hundreds of coal-fired electric generating units, including about 84% of the coal-fired electric generating capacity in the United States. See FOF ¶ 16. While other plants adopted FGD technology en masse, Rush Island has lagged behind. In 2007, the Rush Island plant ranked 154th in the nation in SO_2 emissions. Ten years later, it was the tenth-most SO_2 polluting plant in the nation. FOF ¶ 18.

Ameren suggested at trial that FGD technology is more appropriate for new plants as opposed to existing plants. Ameren's suggestion is contradicted by the evidence. Of the more than 170,000 MW of coal-fired electric generating capacity now controlled with wet FGD, about 120,000 MW are retrofitted units. See Figure 2; FOF ¶ 17. About three quarters (90,000 MW) of that retrofitted generating capacity has been installed between 2005 and 2015. Figure 2, FOF ¶ 17.

The emissions reductions achievable by FGD do not depend on whether the technology is built with new plant or retrofitted on an existing one. FOF ¶ 162. The prevalence of FGD at both new and existing units indicates that FGD is achievable at Rush Island. As the EPA noted in the NSR Manual: "In the absence of unusual circumstance, the presumption is that sources within the same source category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category." Pl. Ex. 1190 [NSR Manual] at AM-REM-00544146-MDNR; FOF ¶ 79.

Ameren has provided no evidence of an unusual circumstance at Rush Island that is relevant to the BACT determination. FOF ¶ 219. Ameren's BACT expert Colin Campbell testified that Rush Island's status as an existing plant not otherwise required to install BACT constitutes an unusual circumstance. Id. However, as shown in Figure 2, more FGD-controlled generating capacity exists at retrofitted, existing plants than at new plants. See also FOF ¶ 17.

Based on its own studies, Ameren has no evidentiary basis to rule out FGD in Step 4. At trial, Ameren only briefly mentioned energy or environmental impacts of wet FGD. Specifically, Ameren's expert Snell discussed the auxiliary power consumed by FGD systems, which reduced power output to the grid. FOF ¶ 190. Snell also mentioned wastewater costs and mercury controls. FOF ¶ 192. However, Ameren did not explain how these energy and environmental impacts made wet FGD unachievable. Nor did Ameren suggest that these environmental impacts are different from the kinds of impacts experienced at other pulverized coal-fired power plants. See NSR Manual (Pl. Ex. 1190), at AM-REM-00544146-MDNR; Staudt Test. Vol. 1-B, at 63:14-64:6.

Around the time Ameren was rebuilding Rush Island Unit 2, Ameren was also studying how and whether FGD might be installed at Rush Island. Ameren's engineering studies, undertaken over a period of years at a cost of about $8 million, concluded that wet FGD was both economically and technically feasible at Rush Island. The engineering studies determined that wet FGD was the best option for the plant to control SO_2. FOF ¶ 29-31.

The economic impacts of implementing wet FGD do not render the technology unachievable. The EPA's expert Dr. James Staudt estimated, based on Ameren's engineering studies, that the direct capital costs of implementing wet FGD technology at Rush Island would be $582 million in 2016 dollars. FOF ¶ 124. That total translates to an "average" cost-effectiveness of $3,854 per ton of SO_2 removed. FOF ¶ 225. Even according to Campbell's testimony, this value is well below MDNR's threshold for acceptable average cost effectiveness. Id., n.7. Ameren did not present any evidence or testimony demonstrating that $3,854 per ton was too high or out-of-line with the average cost effectiveness incurred by other electric utilities with FGD.[15] Id. In fact, Ameren's own engineering study concluded that the cost of wet FGD at Rush Island would be consistent with industry benchmarks. FOF ¶ 226. MDNR and other agencies have concluded that both wet and dry FGD are economically acceptable for pulverized coal-fired power plants. For all these reasons, there is no basis for excluding FGD technology from the BACT assessment at Step 4, whether based on energy, environmental, economic impacts or other costs.

The last step of the BACT analysis (Step 5) involves determining an achievable emission rate based on the chosen wet FGD technology. As with Steps 1 through 3, there is no material dispute about what the achievable emission rates would be for wet FGD at Rush Island. FOF ¶¶ 229-31. Wet FGD has been widely adopted over the years, and its performance continues to improve. Wet FGD's emissions rates have steadily fallen. See Figure 3; FOF ¶ 221. By 2016, the top 50% of FGD-equipped plants averaged a 12-month emission rate of 0.058 lb/mmBTU, and the top 20% of FGD-equipped plants averaged a 12-month emission rate

[15] Ameren's BACT expert Campbell testified that he reached no conclusions on whether the average cost-effectiveness of wet FGD would be considered unacceptable in this case. FOF ¶ 225.

of 0.024 lb/mmBTU. See Id. These numbers have fallen by more than 20% between 2008 and 2011 and by another 20% or more between 2011 and 2016. See Figure 3. Ameren's engineering studies echo the broader trend of increasing effectiveness. In the first two phases of its study, Ameren identified its Rush Island FGD design-rate as 0.06 lb/mmBTU. FOF ¶ 33. In late 2010, Ameren lowered the target design-rate of its planned scrubbers to 0.04 lb/mmBTU. FOF ¶ 52.

Based on a reasonable compliance margin, Dr. Staudt testified that BACT for the Rush Island units at the time of the illegal modification would have been 0.08 lb/mmBTU for Unit 1 and 0.06 lb/mmBTU for Unit 2, both on a 30-day rolling average. FOF ¶ 202-03. The record showed these rates were reasonable given the technological capabilities at those times and consistent with the nearly two-dozen contemporaneous BACT determinations at similar facilities. FOF ¶ 100-105. Ameren presented no evidence at trial to dispute that these emissions rates were achievable. Ameren's expert Campbell even testified that 0.05 lb/mmBTU was achievable. FOF ¶ 231. If applied today, the evidence shows that wet FGD could meet a 30-day rolling-average emissions limitation no less stringent than 0.05 lb/mmBTU. FOF ¶ 233.

c. Ameren's Arguments Against PSD Permitting Mischaracterize Case Law, Ameren's Permitting Options, and the Nature of BACT

Ameren presents three arguments to avoid permitting under the PSD program. First, Ameren argues it need not install BACT because it would have sought less costly ways avoid PSD permitting had it known its major modifications would trigger PSD obligations. Second, Ameren argues that I should not make any BACT determination as part of my ruling, because that decision is appropriately left to the permitting authority MDNR. Third, Ameren argues that DSI—a far less-effective (and less costly) control technology than wet FGD—should be considered BACT at Rush Island. None of these three arguments is persuasive.

i. As a Major Stationary Source That Performed Major Modifications, Ameren Must Obtain a PSD Permit, Not a "Minor Permit"

Ameren argues that had it known its modifications would trigger PSD obligations, it might have sought a synthetic minor permit. With a minor permit, a source can limit its emissions below a threshold that would trigger PSD requirements. FOF ¶ 401. At trial, Ameren's expert Campbell testified in support of this theory. See Campbell Test., Tr. Vol. 4-A, 49:9-24, 80:20-83:7.

This argument is not supported by law. First, it requires speculation about what actions Ameren might have taken, rather than an examination of what actions Ameren actually took. By statute and regulation, once Ameren undertook major modifications, Ameren was required to comply with BACT. Rush Island Units 1 and 2 are modified facilities; they cannot obtain "minor" permits for their "major modifications." To find otherwise would require me to ignore the statue and regulations. See 42 U.S.C. § 7475(a)(1), (4); 40 C.F.R. § 52.21(j)(3) (any "major modification shall apply best available control technology"); 40 C.F.R. § 52.21(r)(1) (any source that modifies without permit approval is subject to enforcement); United States v. Ohio Edison Co., 276 F. Supp.2d 829, 850 (S.D. Ohio 2003) (a "modification triggers permitting requirements under the CAA as well as the duty to install pollution controls."). The statute and the regulations set forth "without exception" that all major modifications are subject to CAA requirements. Oregon Envtl. Council v. Oregon Dep't of Envtl. Quality, No. 91-13-FR, 1992 WL 252123, *22-23 (D. Or. Sept. 24, 1992).

NSR requirements apply to all major modifications, including those illegally constructed. The United States District Court for the District of Oregon explained:

> The [State Implementation Plan] does not exempt a source of pollutants from the new source review requirements simply because the 'major modification' was constructed prior to the issuance of a requisite permit. Moreover, if such an

exemption were allowed, a windfall would be created for those major new or modified sources that disregarded the SIP-mandated requirements.

Oregon Envtl. Council v. Oregon Dep't of Envtl. Quality, 1992 WL 252123, at *23. Other district and appellate courts have made similar rulings. See, e.g., United States v. Midwest Generation, 720 F.3d 644, 646 (7th Cir. 2013) (modifying plant without a permit is a "risky strategy" because, if challenged, the plant may need "to undertake a further round of modifications to get the permit"); United States v Cinergy Corp., 618 F.Supp.2d 942, 961-62, 965 (S.D. Ind. 2009) (holding that the only compliance alternative "was to apply for the necessary permits or shut down the units"); United States v. Louisiana-Pacific Corp., 682 F. Supp. 1141, 1166 (D. Colo. 1988) ("requirements of the [PSD] program have been met only upon receipt of PSD permits").

Ameren "must suffer the consequences of the action it chose to take—even if these, or some of these, might have been avoided had it taken a different course of action." United States v. Westvaco Corp., 2015 WL 10323214, at *8 (Md. Feb. 26, 2015). Ameren's "initial failure to comply with the requirements of the Clean Air Act" should not "now inure to its benefit." New York v. Niagara Mohawk Power Corp., 263 F. Supp. 2d 650, 663 (W.D.N.Y. 2003). It cannot now obtain a minor permit as a means of avoiding PSD permitting. Ameren must come into compliance with the law by obtaining a PSD permit and meeting BACT emissions limitations.

Even if Ameren's argument that it should be allowed to apply for a minor permit had merit, it is unsupported by the evidence. The facts that run contrary to Ameren's assertion that it would have applied for a minor permit include:

- The PSD standards were clear long before Ameren undertook the Rush Island modifications. FOF ¶¶ 393-394.
- Ameren did not present any company witness or document suggesting the pursuit of

a synthetic minor permit was a realistic possibility. FOF ¶ 406.

- Ameren's director of corporate analysis testified that he was not aware of any instance where Ameren voluntarily restricted the operations of Rush Island. FOF ¶ 403, and
- Restricting Rush Island's operations would have been inconsistent with the purposes of the modifications. FOF ¶ 404.

Ameren did not present evidence of any baseload power plant operator restricting a facility's operations in the manner Ameren now claims in hindsight it would have. Because they are the cheapest generating sources and so reliably dispatched, utilities like Ameren hesitate to put operating or fuel limitations on their baseload plants. Cinergy, 618 F. Supp. 2d 942, 947 (S.D. Ind. 2009) (quoting testimony of Cinergy witness). Ameren's post hoc PSD-avoidance argument runs contrary to the facts in this case and is not supported by the law.

ii. None of Ameren's Arguments or Evidence Prevent Me From Ordering Ameren to Propose Wet FGD as BACT

In its proposed conclusions of law, Ameren renews its argument from summary judgment that I cannot and should not make a BACT determination. According to Ameren, I should leave any BACT determination to the permitting authority MDNR, respecting its notice and comment process. As I noted in my order denying summary judgment, Plaintiffs have not asked me to write and issue a permit. Ameren Missouri, 372 F. Supp. 3d 868, 873, Instead, Plaintiffs request that I order Ameren to propose wet FGD as BACT in the permit application Ameren submits to MDNR. This requested relief does not violate any of the principles raised by Ameren in its motion for summary judgment. Id. Additionally, the cases Ameren previously cited in its motion for summary judgment do not support its argument that I cannot order Ameren to propose wet FGD as BACT. Id. (citing Westvaco, 2015 WL 10323214, at *11 (D. Md. Feb. 26, 2015) ;

Cinergy, 618 F. Supp. 2d 942, 955 (S.D. Ind. 2009). Ameren does not present any other citations or evidence to support this argument.

I conclude that I am able to order Ameren to propose wet FGD as BACT.

iii. Ameren's Arguments for the Least Effective Control Technology, DSI, Contradict the Nature and Definition of BACT

Ameren argues that DSI, a technology that removes about 50% of SO_2 emissions, constitutes BACT for Rush Island. DSI is about half as effective as FGD and has never been accepted as BACT for coal-fired electric generating units. FOF ¶ 167. Ameren prefers DSI because it is less costly overall and per-ton than other control technologies. However, BACT does not permit a source to install the most cost-effective technology. The plain language of the statute requires emissions limits "based on the maximum degree of reduction" available. 42 U.S.C. § 7479(3).

To support its position, Ameren argues that FGD technology should have been excluded at Step 4 of the BACT analysis because of its "economic impacts." The costs Ameren cites are not based on any unique physical or operational characteristics of Rush Island. Ameren was unable to identify any material feature that distinguishes Rush Island from the rest of the industry or electric market. Ameren's argument is premised entirely on its expert Campbell's economic analysis. That analysis was inconsistent with BACT permitting practices and Campbell's own past guidance, and I give Campbell's testimony little weight. FOF ¶¶ 134-40.

In BACT permitting, two cost metrics are often consulted, (1) average cost-effectiveness, and (2) incremental cost-effectiveness. FOF ¶¶ 82-83. The EPA's expert Dr. Staudt calculated average cost-effectiveness for wet FGD at Rush Island and determined the costs were achievable. FOF ¶ 199. Dr. Staudt made his calculations according to the standard overnight cost methodology. FOF ¶ 124.

In their calculations, Ameren's experts included costs that are traditionally excluded from BACT analyses for consistency and comparison's sake. Ameren's expert Snell admitted that his cost estimates were not developed for the purpose of a BACT analysis. FOF ¶ 128. Ameren's expert Campbell still included Snell's cost estimates in his incremental cost-effectiveness comparison. Incremental cost-effectiveness considers the per-ton change in cost of reducing SO_2 pollution using two compared technologies. Based on that comparison, Campbell eliminated wet FGD from his BACT analysis. Ameren's experts offered no opinions on the average cost-effectiveness of wet FGD.[16]

According to Campbell, the incremental cost-effectiveness of wet FGD compared to DSI exceeds a threshold used by MDNR in BACT determinations. FOF ¶ 141. This explanation misstates how incremental cost-effectiveness analysis usually operates in reality. Measuring incremental cost may be useful when evaluating control options ranked next to each other with similar control efficiencies. FOF ¶ 83. Campbell did not compare incremental technologies, he compared one of the most effective control technologies with one of the least. FGD technology can remove 95% or more of SO_2 emissions, while DSI can remove only 50%. These differences in effectiveness are not incremental.

"[W]here a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if any, between the application of the control technology on those other sources and the particular source under review." Pl. Ex. 1190 [NSR Manual] at AM-REM-00544148-MDNR. Ameren's analyses do not provide any distinguishing characteristic of wet FGD implementation at Rush Island that makes the technology unachievable or significantly more costly than other similar

[16] Ameren's sole reliance on incremental cost-effectiveness to eliminate wet FGD while ignoring average cost-effectiveness is inconsistent with a proper top-down analysis. FOF ¶ 84.

sources.

Ameren's main attempt to differentiate Rush Island from other plants depends on a false distinction between new plants and existing, retrofitted plants. Specifically, Ameren points out that the New Source Performance Standards (NSPS) do not apply to existing plants such as Rush Island. However, the NSPS emission rate does not fundamentally change the BACT methods or results. FOF ¶¶ 87-89; Ameren Missouri, 2019 WL 1384631, at *3 (citing Columbia Gulf at *4). Instead, the NSPS emission rate serves as a "floor" for any BACT determination; BACT at any facility cannot be less stringent that the NSPS for that source category. 42 U.S.C. § 7479(3). Ameren's new-versus-existing plant distinction does not demonstrate that Rush Island is so unusual as to make wet FGD unachievable.

d. SO_2 BACT For Rush Island Was Wet FGD Technology at the Time of the Modifications and Remains So Today

The parties do not dispute what control technologies are available to reduce SO_2 emissions, whether those technologies could be implemented at Rush Island, or their relative effectiveness: wet FGD is the most effective control technology, and it is technically and economically feasible at Rush Island. The parties disagree, however, about whether wet FGD is achievable "taking into account energy, environmental, and economic impacts and other costs." 42 U.S.C. § 7479(3). Based on the evidence presented at trial, wet FGD is achievable when taking into account these factors. FOF ¶¶ 184-88, 200.

Although the specific emission rate may vary somewhat, FGDs are the best available SO_2 controls at coal-fired power plants. Chipperfield v. Mo. Air Conserv. Comm'n, 229 S.W.3d 226, 240 (Mo. Ct. App. 2007) ("In general, pulverized coal-fired boilers burning low-sulfur coal, such as Powder River Basin ("PRB") coal, may use dry FGD, while boilers burning high-sulfur coals, such as eastern bituminous coal, must use wet FGD."); Cinergy, 618 F.Supp.2d 942, 955

("BACT would require a scrubber that removed 99% of the SO_2"). The evidence presented at trial does not provide any support for the proposition that FGD technology, the "top control" for SO_2 removal, should be ruled-out based on "energy, environmental, and economic impacts" associated with its application. As a result, I conclude the following:

(1) At all times pertinent to this case, BACT for SO_2 pollution at Rush Island would have been determined based on the application of wet FGD technology.

(2) At the time of the Unit 1 major modification in 2007, BACT for SO_2 pollution would have required a 30-day rolling-average emissions rate of no more than 0.08 lb/mmBTU. FOF ¶ 208.

(3) At the time of the Unit 2 major modification in 2010, BACT for SO_2 pollution would have required a 30-day rolling-average emissions rate of no more than 0.06 lb/mmBTU. Id.

(4) At present, BACT for SO_2 pollution at Rush Island requires a 30-day rolling-average emissions rate of no more than 0.05 lb/mmBTU. FOF ¶ 213.

e. The eBay Factors Require Rush Island to Comply with PSD Permitting and BACT Emissions Limitations

The United States asks this Court to order Ameren to apply for a PSD permit within 90 days from the issuance of a final order, and to implement BACT no later than four and one-half years from this Court's order. A balancing of the eBay factors confirms that an injunction directing Ameren to propose wet FGD as BACT at Rush Island is an appropriate method to end Ameren's violation of the PSD program at Rush Island.

When considering injunctive relief, I evaluate whether:

> (1) [the plaintiff] has suffered irreparable injury; (2) . . . remedies available at law, such as monetary damages, are inadequate to compensate for the injury; (3) . . . considering the balance of hardships between the plaintiff and defendant, a remedy in equity is

> warranted; and (4) . . . the public interest would not be disserved by a permanent injunction.

eBay Inc. v. MercExchange, L.L.C.: 547 U.S. 388, 391 (2006).

Ameren concedes the first two factors of the eBay standard are "in essence satisfied" in this case. (Def. Closing Arg., Tr. Vol. 6, 33:23-25 ("And I agree with the Government that the first two factors are - the eBay factors are in essence satisfied.")). Ameren argues, however, that the costs of pollution controls, borne by Ameren and passed onto ratepayers, weight the balance of hardships and public interest prongs in Ameren's favor.

i. The Communities Downwind of Rush Island Have Been Irreparably Injured

Environmental harm, "by its nature . . . is often permanent or at least of long duration, i.e., irreparable." Amoco Prod. Co. v. Gambell, 480 U.S. 531, 545 (1987); see also, United States v. Production Plated Plastics, Inc., 762 F. Supp. 722, 729 (W.D. Mich. 1991) (violations of an environmental statute usually result in irreparable injury); Ohio Valley Envt'l Coalition v. U.S. Army Corps of Engineers, 528 F. Supp.2d 625, 630 (S.D. W.Va 2007) ("because to damage the environment is often irreversible, this harm is frequently justification for a restraining order or an injunction"). I have closely reviewed the evidence presented at trial concerning harms the public has suffered because of the excess SO_2 emissions resulting from Ameren's failure to obtain a permit. Based on that evidence, I conclude that Ameren's failure to obtain a permit caused irreparable damage.

At trial, the EPA presented voluminous data demonstrating that Rush Island's excess emissions have increased the risk of heart attack, asthma attack, stroke, and premature death in downwind communities. FOF ¶¶ 251-53. Dr. Schwartz testified at length about the concentration-response relationship between $PM_{2.5}$ concentrations and premature mortality. Dr.

Schwartz and Lyle Chinkin also explained how SO_2 converts to $PM_{2.5}$, and the mechanisms by which $PM_{2.5}$ can cause harm. Id.; ¶¶ 240, 305-07.

In contrast, Ameren's experts Dr. Valberg and Dr. Fraiser testified contrary to the scientific consensus on $PM_{2.5}$'s human health impacts. Dr. Fraiser contradicted the scientific consensus that that $PM_{2.5}$ is a no-threshold pollutant that causes increased mortality on a linear basis.[17] Dr. Fraiser also offered opinions that were outside her area of expertise. FOF ¶¶ 274-75. Dr. Valberg's testimony in other cases and regulatory matters, on the same topics as were before me, has frequently been rejected by the EPA and courts. FOF ¶¶ 281-84.

Rush Island's excess emissions have created harmful $PM_{2.5}$ that has increased the risk of human health impacts in downwind communities. FOF ¶ 265. The EPA's independent modeling efforts estimated that the excess emissions have contributed to hundreds of premature deaths. FOF ¶ 338, Table 1. These environmental and human health impacts demonstrate irreparable injury from Rush Island's PSD violation. Cinergy, 618 F. Supp. 2d at 964 (finding irreparable harm from "significant health and environmental effects in the form of $PM_{2.5}$" resulting from excess SO_2). The first eBay factor is satisfied.

ii. Legal Remedies Are Inadequate to Remedy the Harm

Damages are inadequate to address the harm from excess emissions at Rush Island. See Def. Closing., Tr. Vol. 6, at 33:23-25; Gambell, 480 U.S. at 545 (explaining that environmental harm "can seldom be adequately remedied by money damages"). The facts of the case demonstrate that money damages would be inadequate here. Because of Rush Island's excess emissions, an increased risk of disease and premature mortality extends across thousands of miles of the Eastern United States. The public and environmental nature of the harm render

[17] Dr. Fraiser admitted, however, that the NAAQS do not guarantee zero risk. FOF ¶ 273.

monetary awards ineffectual: There is no individual to compensate. The additional risks of disease and premature mortality are spread across the population of the Eastern United States. Legal remedies alone cannot address the harm.

iii. The Balance of Hardships Weighs in Favor of an Injunction Ordering Ameren to Install Wet FGD at Rush Island

This opinion contains extensive discussion of the harm the downwind communities are suffering due to Ameren's decision to ignore the statutory requirement that it install pollution controls at the modified Rush Island. The Plaintiffs are suing to enforce a statute enacted to reduce the kind of harm Ameren's excess pollution has created, and they would suffer great hardship if I allow Ameren to continue to operate Rush Island without BACT. Meanwhile, an injunction ordering Ameren to comply with the Clean Air Act and install BACT imposes a relatively minor hardship on Ameren. Ameren will have to install at Rush Island the same pollution controls that power utility companies—including Ameren—must install at facilities across the country.

Ameren admits that it can "afford anything this Court orders." Def. Closing Arg., Tr. Vol. 6, 34:13. At the same time, Ameren expresses concern that its customers will bear the costs of compliance in the form of rate increases. Ameren asserts that the average customer will have to pay thousands more dollars over 20 years to reimburse Ameren for its capital expenditures.

This alleged hardship does not tip the balance in Ameren's favor. The costs of pollution controls are a cost of doing business; the Clean Air Act struck that balance when it mandated BACT measures for new and modified sources. See Introduction supra. Moreover, nothing in this order requires Ameren to recover the costs of compliance and remediation from its ratepayers. Ameren does not need to submit the costs as reimbursable, and the Missouri Public Service Commission has the discretion to allow only partial cost-recovery or to bar recovery because the costs result from Ameren's Clean Air Act violations. FOF ¶ 431.

Even if the control costs are passed onto ratepayers in their entirety, the resulting rate increase would be within the range of recent rate increases. FOF ¶¶ 435. On this point, Ameren presented conflicting, unrepresentative, and mischaracterized cost estimates. FOF ¶¶ 439-442. For example, one of Ameren's methods calculated average cost increase estimates and assumed that the cost of installing pollution controls will apply equally to all customers, regardless of whether they are residential, commercial, or industrial. FOF ¶ 440. This method over-estimates the costs that most of its customers, especially residential customers, will bear. Id.

In contrast, the EPA presented cost estimates on a percentage basis, and compared them with Ameren's recent cost increases. According to the EPA, the total cost of installing FGD at Rush Island and DSI at Labadie would lead to rate increases between 2.8 and 4.8%. FOF ¶ 434. Ameren also presented evidence using this methodology and calculated a similar percentage increase of 3.8%. Id. Of course, the Rush Island portion of these rate increases would have been borne by the ratepayers ten years ago had Ameren complied with the law.

For context, these projected increases are less than the most recent annual increase levied by Ameren (5.4%), as well as the rate decrease that was triggered by the 2017 federal tax law (6.1%). FOF ¶¶ 435, 437. Regardless of whether Ameren is allowed by the PSC and ultimately passes on the costs of compliance to customers, Ameren can readily finance and install wet FGD at Rush Island while staying profitable.

iv. Compliance at Rush Island Serves the Public Interest

The United States brought this civil action to enforce a public interest statute. The United States has clearly established that it is in the public interest for Ameren to comply with the Clean Air Act.

Ameren's argument to the contrary depends entirely on the costs it asserts this injunction will impose on rate-payers. As I discuss above in Section VI.c.iii, the estimated cost increases are modest. The estimated value of the benefit to the public is much larger than estimated costs to Ameren. FOF ¶¶ 375-77.

f. Ameren's Arguments That Rush Island's Excess Pollution Was Not Harmful Are Not Convincing

To influence the eBay analysis, Ameren argues that Rush Island's excess SO_2 pollution was either harmless as a matter of law (because of certain regulatory thresholds), or harmless as a matter of fact (based on the testimony of Ameren's toxicology experts). These arguments do not withstand scrutiny.

i. The National Ambient Air Quality Standards (NAAQS) Do Not Establish a Safe Threshold For SO_2 Pollution

Ameren's claim that the NAAQS render PSD requirements unnecessary is contradicted by the plain language and history of the PSD program and the NAAQS. Congress enacted the PSD program to address pollution occurring in areas already meeting the public health protections set forth in the NAAQS. C.f. TVA v. Hill, 437 U.S. 153, 194 (1978) ("[I]t is … the exclusive province of the Congress not only to formulate legislative policies and mandate programs and projects, but also to establish their relative priority for the Nation.").

The NAAQS predate the PSD program and exist to protect public health and welfare. 42 U.S.C. § 7409(b). The process of setting the NAAQS does not require the EPA to "definitively identify pollutant levels below which risks to public health are negligible." American Trucking Ass'n v. EPA, 283 F.3d 355, 369-70 (D.C. Cir. 2002). When it makes NAAQS determinations, "EPA does not purport to set the NAAQS at a level which would entirely preclude negative health outcomes." North Carolina v. TVA, 593 F. Supp. 2d 812, 822 n.6 (W.D.N.C. 2009), rev'd on other grounds 615 F.3d 291 (4th Cir. 2010). As even Ameren's expert Dr. Fraiser agrees, the NAAQS do not set a black-and-white threshold below which $PM_{2.5}$ poses no risk to human health. FOF ¶ 273.

The EPA's years of implementing the Clean Air Act and the PSD program also contradict Ameren's argument. The EPA has emphasized *ad nauseum* that there is no known safe threshold below which incremental increases in $PM_{2.5}$ exposure do not create incremental increases in risk to human health and welfare. 78 Fed. Reg. 3086, 3098, 3118-19, 3148 (Jan. 15, 2013); Final Integrated Science Assessment (Dec. 2009) at 2-12, 2-25 & 6-75 [Pl. Ex. 1209]; 71 Fed. Reg. 61144, 61158 (Oct. 17, 2006); 62 Fed. Reg. 38652, 38670 (July 18, 1997).

The EPA's scientific determinations mirror the broad consensus of the world's public health authorities. The great weight of the evidence demonstrates that $PM_{2.5}$ has a linear concentration-response function down to concentrations well below the NAAQS. See FOF ¶¶ 266-272. The overwhelming weight of evidence supports that $PM_{2.5}$ is a no-threshold pollutant, meaning it can pose risks to human life and health at any concentration level. See, e.g., 78 Fed. Reg. 3086, 3092, 3119 (Jan. 15, 2013) (citing Lead Industries v. EPA, 647 F.2d at 1156 n.51); FOF ¶¶ 256-62.

Ameren is not the first company to argue that the NAAQS set thresholds that shield against or limit PSD obligations. Hawaiian Electric (HECO) maintained before the Ninth Circuit that the EPA could not "impose emission restrictions that are more stringent than necessary to protect NAAQS" in a PSD permit. Hawaiian Electric v. EPA, 723 F.2d 1440, 1446-47 (9th Cir. 1984). The Ninth Circuit rejected the argument. After recounting the legislative history and examining the statute's text, the court concluded, "it is absurd for HECO to maintain that EPA may not, through a PSD permit, require pollution controls which yield air quality better than

NAAQS." Id. Similarly, I will not ignore the harm from Rush Island's excess emissions merely because these excess emissions were released in an attainment area with $PM_{2.5}$ levels below the NAAQS.

ii. The "Significant Impact Levels" Do Not Determine the Meaningfulness of Human Health Impacts

Similar to its NAAQS assertions, Ameren argues that pollution impacts below the EPA's "significant impact levels" (or SILs) are harmless. Ameren points out that the EPA has established a SIL of annual $PM_{2.5}$ impacts of 0.2 $\mu g/m^3$ for some areas. This value is almost four times higher than the highest impact of Rush Island's excess emissions when averaged over an entire year. SILs are not a valid means of determining the significance of downwind health effects. Instead, SILs are a regulatory tool for assessing whether a source's emissions might exceed NAAQS despite the installation of BACT. See FOF ¶¶ 342-48. Ameren's use of the SILs as a benchmark for its excess pollution is not supported by pertinent law or relevant fact.

Clean Air Act Section 165(a)(3) requires operators looking to implement a major modification to demonstrate that the pollution from the modified facility will not cause or contribute to a downwind NAAQS exceedance. 42 U.S.C. § 7475(a)(3). The EPA established the SILs to be screening tools aimed at identifying which facilities might lead to NAAQS exceedances. Pl. Ex. 1205 [Guidance on Significant Impact Levels] at USTREXR0003853-3855. But "[t]he SIL values identified by the EPA have no practical effect unless and until permitting authorities decide to use those values in particular permitting actions." Id. at 3-4.

Just as the NAAQS do not establish a "zero-risk" threshold under which pollution is safe, the SILs do not establish a level below which there is no risk of harm from a facility's pollution. The SILs are, at bottom, a compliance demonstration tool, helping permit applicants and permitting authorities determine whether additional air quality modeling of a proposed source is needed. They provide NAAQS modeling guidance for the PSD permitting process.

The EPA's practice of assessing the benefits of Clean Air Act regulations further supports this legal analysis. The EPA models the effects of pollution concentration reduction by amounts well below the SILs, including the effects of changes less than 0.01 $\mu g/m^3$. FOF ¶ 348. Ameren's SILs argument does not overcome the wealth of evidence demonstrating that Rush Island's emissions led to irreparable harm that should be remedied.

iii. Ameren's Reliance on Scientific Uncertainty Is Misguided and Its Reliance on Fringe Toxicological Evidence Is Unpersuasive

Finally, Ameren asserts there is too much uncertainty about any harm from its excess emissions to justify the expense associated with installing scrubbers. Ameren's counsel argued in closing that "[t]here are uncertainties at every stage of the causal relationship that plaintiffs must prove." Def. Closing., Tr. Vol. 6, at 34:19-21. Ameren complains that Plaintiffs do "not identify[] or even predict[] any person's real-world death." ECF No. 1068 at 4. This argument mischaracterizes the level of scientific certainty needed and displayed in this case. There is widespread consensus among public health agencies and scientists that $PM_{2.5}$ causes adverse health effects, including cardiovascular effects such as heart attacks and strokes, respiratory effects such as asthma attacks, and premature mortality. FOF ¶¶ 251-54.

Ameren's reliance on individualized uncertainty misconceives the case. This is not a toxic tort case. The Clean Air Act curbs harm borne by a population, not a single person. By enacting the Clean Air Act, Congress sought "to protect public health and welfare from any actual or potential adverse effects" from air pollution. 42 U.S.C. § 7470(1) (emphasis added). Public health regulation evaluates and communicates risk, not diagnoses or proximate causes of any one individual's health problems or death. Numerous epidemiological studies reviewed by the experts in this case have shown that increases to SO_2 and $PM_{2.5}$ concentrations increase the risk to the public of lung disease, heart disease and premature mortality. FOF ¶¶ 260-62.

Further, Ameren overstates and misconstrues the nature of uncertainties presented in the EPA's modeling. There is no question that $PM_{2.5}$ increases the risk of premature mortality. Instead, the primary uncertainties in the EPA's case relate to specific quantifications of that risk. In his analyses, Dr. Schwartz laid no claim to absolute precision. On the contrary, Dr. Schwartz carefully documented the uncertainty in his risk assessments by providing peer-reviewed, 95% confidence intervals that bounded the certainty of his estimates. FOF ¶¶ 331, 335. Taken together, Dr. Schwartz's two assessments show that Rush Island's excess pollution has substantially harmed public health and welfare.

Next, Ameren insists that, though epidemiology can show correlation, it can never establish causation. Sulfate $PM_{2.5}$ is only one component of a mixture that Ameren believes should be isolated for rigorous epidemiological or toxicological analysis. Ameren's toxicologists argue that there is no toxicological literature that establishes the poisonous dosage of $PM_{2.5}$ or sulfate. This argument incorrectly interprets the relevant scientific literature. The scientific consensus is that $PM_{2.5}$ exposure is harmful at all relevant exposure levels. This consensus is not based exclusively on epidemiological research. <u>See, e.g.</u>, FOF ¶ 259; <u>see also generally</u> Pl. Ex. 1209 [NAAQS ISA] (considering, among other things, "controlled human exposure studies" and "toxicological studies"). It also derives from the findings of toxicologists and medical practitioners endeavoring to settle on a coherent, cross-discipline understanding of the relationship between health effects and changes in ambient $PM_{2.5}$ concentrations. FOF ¶ 259. Ameren's attempts to inject uncertainty into the broad scientific consensus do not undermine the wealth of evidence demonstrating human health impacts due to sulfate-created $PM_{2.5}$ particles.

Finally, the structure of the Clean Air Act itself disposes of Ameren's argument.

Congress made clear in passing the Clean Air Act that when a source "increases the amount of any air pollutant," it must be subject to NSR (among other requirements). See, e.g., 42 U.S.C. § 7411(a)(4). Even in attainment areas with low $PM_{2.5}$ concentrations, the Clean Air Act requires facilities like Rush Island that undergo major modifications to install BACT. See 42 U.S.C. § 7475(a)(3). Regardless of whether Ameren is correct about the harm $PM_{2.5}$ causes at low concentrations, the Clean Air Act grants courts jurisdiction to provide "appropriate relief" to remedy Ameren's violation. See 42 U.S.C. § 7413(b)(3).

IV. LABADIE MUST REDUCE EMISSIONS COMMENSURATE WITH THE EXCESS EMISSIONS RELEASED BY RUSH ISLAND

a. The eBay Factors Support the EPA's Requested Injunctive Relief at Labadie

Injunctive relief at Rush Island will bring the plant into compliance with the PSD program, ending the release of excess SO_2 emissions and $PM_{2.5}$ there. However, BACT measures at Rush Island will not redress the harm from the last ten years. A balancing of the eBay factors leads me to conclude that injunctive relief is necessary at Labadie in order to remediate Rush Island's excess emissions.

i. The Same Irreparable Injury Analysis of Rush Island's Excess Emissions Applies to Labadie

The record establishes that in the last ten years, Rush Island's release of more than 162,000 tons of excess SO_2 pollution has increased the risk of adverse health effects, including premature mortality. The EPA's experts quantified these effects at trial. FOF ¶ 376-77. Dr. Schwartz testified at length about the concentration-response relationship between $PM_{2.5}$ concentrations and premature mortality. Dr. Schwartz and Lyle Chinkin also explained how SO_2 is transported from Rush Island across the country, its conversion to $PM_{2.5}$, and the mechanisms by which $PM_{2.5}$ can cause harm. These environmental and human health impacts demonstrate irreparable injury from Rush Island. Cinergy, 618 F. Supp. 2d at 964.

ii. Legal Remedies Are Inadequate to Remedy the Harm

Ameren admits there is no adequate remedy at law to address the environmental harm documented in this case. Def. Closing., Tr. Vol. 6, at 33:23-25. Because the environmental harm and health risks are spread across the population of the Eastern United States, there is no one person or discrete group of people to compensate. I find that an "economic award would not sufficiently compensate" for injuries and the increased risk of harm resulting from Ameren's failure to obtain a PSD permit at Rush Island. Franklin County Power, 546 F.3d at 936; see also Westvaco, 2015 WL 10323214, at *9 (D. Md. Feb. 26, 2015); Cinergy, 618 F. Supp. 2d at 961.

iii. Plaintiffs Suffer the Balance of the Hardships

The balance of hardships for equitable relief at Labadie compares well with the balance of hardships at Rush Island. On one hand, Rush Island's excess emissions have created a widespread risk of harm to public health. On the other hand, accounting for those excess emissions requires some cost on Ameren's part. The costs of pollution reductions at Labadie are well within Ameren's financial capabilities. FOF ¶¶ 440-444. Implementing DSI on the four Labadie units would cost $55 million dollars in capital investment and then $53 million a year in operating costs. FOF ¶ 362. Ameren did not present any evidence that paying these costs would cause it any hardship. On the contrary, Ameren Missouri's FERC Form 1 filings reveal it has an exceptionally strong and profitable financial standing. FOF ¶¶ 415-16. If the Missouri Public Service Commission does not allow Ameren to seek reimbursement for the cost of implementing DSI, Ameren can readily finance it with a fraction of the annual dividends it has issued in recent years. See FOF ¶¶ 415 Table 2, 416 Table 3.

iv. Pollution Reductions at Labadie Serve the Public Interest

An award of injunctive relief at Labadie to account for Ameren's excess emissions serves the public interest. This remedy protects life and health through full enforcement of the protections Congress set forth in the permitting scheme of the Clean Air Act. The cost of remediating the harm from Rush Island's excess emissions pales in comparison to the public health benefit. Using standard, peer-reviewed estimates, Dr. Schwartz estimated the monetary value of social benefits that would accrue from offsetting Rush Island's excess emissions. The benefits of emissions reductions would far surpass any financial costs Ameren will face. FOF ¶¶ 375-76. Remediating the harm from non-compliance also reduces any economic advantage Ameren gained by violating the law, placing it on more equal footing with companies that have complied with the Clean Air Act.

b. Reducing Pollution from Nearby Labadie Is Relief Narrowly Tailored to Remedy the Harm from Ameren's Violations.

To remediate the harm from Rush Island's excess pollution, the EPA requests that Ameren reduce SO_2 emissions from its Labadie plant in an amount equal to Rush Island's excess emissions. The goal of this requested relief is to reduce $PM_{2.5}$ concentrations for the same population that experienced increased $PM_{2.5}$ concentrations and increased risk of adverse health effects due to Rush Island's failure to obtain a PSD permit.

Ameren argues that because Labadie is "totally innocent," and Ameren has not violated the Clean Air Act there, my order that Ameren install pollution controls at Labadie is an "extreme remedy" that constitutes a penalty. On the contrary, the remedy is based on straightforward equitable principles and the authority I have under the Clean Air Act "to restrain" violations, "to require compliance," and "to award any other appropriate relief." 42 U.S.C. § 7413(b). I have 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. United States v. Cinergy, 582 F. Supp. 2d 1055, 1060-61 (S.D. Ind. 2008).

This relief is narrowly tailored "to remedy specific harm shown." Rogers v. Scurr, 676 F.2d 1211, 1214 (8th Cir. 1982). There is a tight geographic nexus between the harms Rush Island caused and the benefits gained through reducing Labadie's emissions. Pollution from Labadie affects the same communities as those affected by Rush Island, and to the same degree. FOF ¶ 369. Accordingly, any efforts undertaken to reduce at Labadie pollution would correspond ton-for-ton with the harm caused by Rush Island's excess emissions. Pl. Exs. 1362 & 1364; FOF ¶¶ 368, 373. Controlling Labadie's emissions offers a rare opportunity to right Ameren's wrong on the same terms.

This relief also respects the persuasive factors considered by other courts evaluating environmental remedies. Specifically, reducing emissions at Labadie (1) "would confer [the] maximum environmental benefit," allowed, (2) is "achievable as a practical matter," and (3) bears "an equitable relationship to the degree and kind of wrong it is intended to remedy." United States v. Deaton, 332 F.3d 698, 714 (4th Cir. 2003).

First, this order achieves the maximum possible environmental benefit in this case. When Ameren reduces emissions at Labadie commensurate with the excess emissions from Rush Island, Ameren will have put the public in the place it would have been absent Ameren's Clean Air Act violation. Second, there is no dispute that commonly available pollution controls (DSI, FGD) are achievable as a practical matter. No obstacle stands in the way of DSI or FGD being installed on Labadie. FOF ¶ 362. Finally, the remedy bears an equitable relationship to Rush Island's excess emissions because of the tight geographical link between Rush Island's emissions and Labadie's emission. Ameren's ton-for-ton reductions at Labadie will lower the risks of premature mortality and disease in the same communities impacted by Ameren's Rush Island violations.

c. DSI Installation at Labadie Is Not a Penalty

At trial, Ameren argued that any injunction against its Labadie plant would constitute a penalty, which the EPA waived when it moved to strike its jury demand. As I ruled at the time, "[w]hen relief 'goes beyond remedying the damage caused to the harmed parties by the defendant's action,' [ ] it is properly viewed as punitive and therefore legal in nature." U.S. v. Ameren Missouri, No. 4:11 CV 77 RWS, 2016 WL 468557, at *1 (E.D. Mo. Feb. 8, 2016) (quoting Johnson v. S.E.C., 87 F.3d 484, 488 (D.C. Cir. 1996)). Ameren correctly notes that I cannot issue injunctive relief that would constitute a penalty. However, Ameren's application of that legal principle to the facts of this case is incorrect. By ordering emissions reductions up to, but not surpassing, the excess emissions from Rush Island, I am ordering relief that goes exactly to "remedying the damage caused to the harmed parties by the defendant's action." Id.

To further ensure that any relief at Labadie does not surpass the damage caused by Rush Island, I will order Ameren to base its relief at Labadie on DSI control technology. The capital costs of DSI without a fabric filter are a small fraction of the capital costs of any other control technology. While FGD installation at two units may cost more than $500 million, DSI installation on Labadie's four units would cost only $55 million. FOF ¶ 424. Operating DSI without a fabric filter on all four Labadie units would cost about $53 million per year. Id. As a result, the overall expense of DSI comes predominantly from operating expenses. Ameren can therefore install DSI on Labadie's four units, operate DSI for as many years as necessary to remediate Rush Island's excess emissions, and terminate its use of DSI without suffering significant lost capital assets. Installing DSI—or some more effective pollution control technology—at Labadie provides the relief necessary to remedy the harm from Rush Island without penalizing Ameren.

By the time Rush Island implements BACT measures and comes into compliance with PSD, the facility will have emitted nearly 275,000 excess tons of SO_2. FOF ¶ 211. The record shows Ameren has multiple options to reduce Labadie's emissions by the same amount. If they are implemented soon, these measures will reduce SO_2 pollution by as much as 250,000 tons before 2036, the year two of the four Labadie units are slated for retirement. Installing DSI at Labadie will reduce SO_2 pollution in the area commensurate with the volume of Rush Island's excess emissions, and will benefit the same communities burdened by the harm caused by the violations. I will order Ameren to begin operating Labadie with DSI, or a more effective pollution control, beginning no later than three years after this order.

V. AMEREN'S FAIR NOTICE ARGUMENT FAILS

Ameren argues that I should not order injunctive relief at either Rush Island or Labadie because the EPA did not provide fair notice of its regulatory interpretations of the Clean Air Act. Fair notice is an administrative law concept that "preclude[s] an agency from penalizing a private party for violating a rule without first providing adequate notice of the substance of the rule." Howmet Corp. v. E.P.A., 614 F.3d 544, 553 (D.C. Cir. 2010) (quoting Satellite Broad. Co., Inc. v. FCC, 824 F.2d 1, 3 (D.C.Cir.1987). When evaluating whether this constitutional requirement has been met, courts determine whether a regulated party "would be able to identify, with 'ascertainable certainty,' the standards with which the agency expects parties to conform." Id. at 5353-54 (quoting Gen. Elec. Co. v. U.S. E.P.A., 53 F.3d 1324, 1329 (D.C. Cir. 1995), as corrected (June 19, 1995)). The "ascertainable certainty" standard does not require an agency to define how a given regulation applies to every set of facts. That function is served by adjudication. See United States v. Cinemark USA, Inc., 348 F.3d 569, 580 (6th Cir. 2003) ("An agency's enforcement of a general statutory or regulatory term against a regulated party cannot be defeated on the ground that the agency has failed to promulgate a more specific regulation.") (citing SEC v. Chenery Corp., 332 U.S. 194, 201 (1947)).

Courts also consider "whether the regulated party received, or should have received, notice of the agency's interpretation in the most obvious way of all: by reading the regulations." Howmet Corp. v. E.P.A., 614 F.3d at 553 (quoting Gen. Elec., 53 F.3d 1324, 1329). The regulations at issue concern the EPA's definition of "projected actual emissions." The regulations provide instructions in how regulated entities should determine projected actual emissions. Specifically,

> the owner or operator of the major stationary source:
> (a) Shall consider all relevant information, including but not limited to, historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans under the approved State Implementation Plan; and
> (b) Shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions

40 C.F.R. § 52.21(b)(41)(ii). The regulations also allow a "demand growth exclusion" where owners and operators

> Shall exclude . . . that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (b)(48) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth

Id. § 52.21(b)(41)(ii)(c).

Ameren argues that the EPA failed to give notice of how it applies these two subparagraphs to the facts of any given case. Ameren also argues that "on its face" the "all relevant information" standard in 40 C.F.R. § 52.21(b)(41)(ii)(a) fails to provide "ascertainable certainty."

These arguments are unconvincing. The regulation in question is not "baffling and inconsistent" or "unclear" in the way that courts have found other regulations subjected to fair notice challenges. E.g. Gen. Elec., 53 F.3d at 1330. Instead, the regulation provides a clear, if flexible standard: owners and operators of major stationary sources "[s]hall consider all relevant information . . . ." 40 C.F.R. § 52.21(b)(41)(ii). Immediately after this standard, the regulation provides examples of specific factors that should be considered, including "historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the state or federal regulatory authorities, and compliance plans under the approved State Implementation Plan." Id. The EPA evaluated these same factors when presenting evidence before me that Ameren's projected emissions had increased. Ameren Missouri, 229 F. Supp. 3d at 946-71. Ameren had fair notice of how "projected annual emissions" should be determined under § 52.21(b)(41)(ii).

Ameren also objects to the EPA's application of the demand growth exclusion. The demand growth exclusion applies when a power plant's projected emissions increases are caused by an increase in system-wide demand growth. Ameren argues that the EPA only considered plant-specific, rather than system-wide, demand growth. Ameren also objects to a "restaurant" metaphor that the EPA used to explain temporal demand for electricity generation.[18]

[18] At the liability phase of the trial, the EPA used a restaurant metaphor to explain the relationship between a baseload power plant and system-wide electricity demand. Specifically, the EPA suggested that a baseload power plant is analogous to a high-demand restaurant that has no available seating during the lunch and dinner rushes. Increased demand for meals during these times does not increase the number of meals served at the restaurant. The EPA presented this metaphor for argumentative purposes only. This metaphor does not reveal any new aspect of the regulations at hand. As a result, there is no "fair notice" issue at stake.

In making these arguments, Ameren mischaracterizes how the EPA applied the demand growth exclusion. The EPA did not evaluate market demand at Rush Island. Instead, the EPA evaluated Rush Island's relationship to system-wide demand. Specifically, the EPA presented evidence that Rush Island is a baseload power plant that runs as frequently as possible. Ameren Missouri, 229 F. Supp. 3d at 972-73. This means that Rush Island's own generating capacity and maintenance needs, rather than demand, determine when it is operated. Id. at 975. Because Ameren mischaracterizes the EPA's approach to the demand-growth exclusion, its fair-notice argument fails.

Finally, Ameren argues that the EPA failed to give fair notice that it would use an actual emissions standard—as opposed to a projected emissions standard—when determining whether Ameren made a major modification at Rush Island. According to Ameren, Missouri's 2007 State Implementation Plan only referred to a pollution source's "potential to emit." After the liability phase trial, I found that both Rush Island's projected and actual emissions increased due to its major modifications. Id. at 952-54, 956-58. Ameren does not argue any fair notice issue concerning the "projected emissions" aspect of the regulation. If projected emissions were the only criteria to determine major modifications, then Ameren would still be liable for major modifications at Rush Island. Consequently, there is no fair notice issue at stake. Ameren's fair notice arguments fail and do not provide a reason to deny the EPA's requested injunctive relief.

CONCLUSION

In the 1977 Clean Air Act Amendments, Congress struck a balance. The Act allowed then-existing power plants to continue emitting high levels of pollution until their owners made major modifications at those plants. At that point, they would have to apply for a PSD permit and meet reduced emissions requirements. For thirty years, Ameren benefitted from this policy, operating Rush Island without the need to apply for a PSD permit. When Ameren decided to make major modifications to expand Rush Island's capacity, Ameren refused to play by the rules Congress set. It did not apply for the required PSD permit, and in so doing skirted PSD's requirement to install the best available technology to control the pollution Rush Island emits.

To remedy its violation of the Clean Air Act, Ameren must now apply for a PSD permit for Rush Island within ninety days, propose wet FGD as BACT in its permit application, and implement BACT no later than four and one-half years from this order. However, to stop there would be to abet Ameren's Clean Air Act violation and to ignore the public harm that violation has caused. Mindful of my authority to grant other appropriate injunctive relief under the Clean Air Act, I cannot ignore that harm.

In addition to the relief I order at Rush Island, I will also order Ameren to reduce its pollution at Labadie in an amount equal to Ameren's excess emissions at Rush Island. Ameren may choose whether it will achieve the reductions by installing DSI or some other more effective pollution control at Labadie. This is not a penalty for Ameren's violation of the Clean Air Act; it is an attempt to put the Plaintiffs in the place they would have been had Ameren complied with PSD program requirements from the start. The ton-for-ton reduction at Labadie directly remediates the public harm Ameren has caused and reverses the unjust gain Ameren has enjoyed from its violation of the Clean Air Act at Rush Island.

Accordingly,

IT IS HEREBY ORDERED THAT Defendant Ameren shall apply for a Prevention of Significant Deterioration permit for the Rush Island Energy Center within ninety days of the date of this Order. Ameren must propose wet flue-gas desulfurization as the technology-basis for its Best Available Control Technology proposal.

IT IS FURTHER ORDERED THAT Defendant Ameren shall operate Rush Island Units 1 and 2 in compliance with an emissions limit that is no less stringent than 0.05 lb SO_2/mmBTU on a thirty-day rolling average within four and one half years of the date of this Order.

IT IS FURTHER ORDERED THAT Defendant Ameren shall install a pollution control technology at least as effective as dry sorbent injection at the Labadie Energy Center within three years from the date of this Order. That technology shall remain in use at Labadie until Ameren has achieved emissions reductions totaling the same amount as the excess emissions from Rush Island, as defined in this Order, through the time Ameren installs BACT at Rush Island.

IT IS FURTHER ORDERED THAT I will retain jurisdiction over this case until Ameren has fully implemented the remedies set forth in this Order.

RODNEY W. SIPPEL
UNITED STATES DISTRICT JUDGE

Dated this 30th day of September, 2019.