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Jeffrey R. Holmstead
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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2022-0337

DIRECT TESTIMONY

OF

JEFFREY R. HOLMSTEAD

ON

BEHALF OF

UNION ELECTRIC COMPANY

d/b/a AMEREN MISSOURI

St. Louis, Missouri
August, 2022

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DIRECT TESTIMONY

OF

JEFFREY R. HOLMSTEAD

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jeffrey R. Holmstead. My business address is 201 M Street NW, Washington, D.C., 20036.

Q. What is your occupation?

A. I am an environmental lawyer and a partner at the law firm of Bracewell LLP, where I co-chair the firm's Environmental Strategies Group.

Q. Please describe your educational background and relevant work experience.

A. I received my B.A. in Economics, *summa cum laude*, from Brigham Young University in 1984, and my J.D. from Yale Law School in 1987. From 1987 to 1988, I served as a law clerk to Judge Douglas H. Ginsburg on the U.S. Court of Appeals for the District of Columbia Circuit.

I began working on federal Clean Air Act ("CAA") issues in 1989, when I joined the White House Staff of President George H.W. Bush. In the campaign leading up to the 1988 election, then Vice-President Bush had promised to push through new legislation to modernize the CAA, which had essentially remained unchanged since 1977. As a result of this campaign promise, the White House staff was very involved in the discussions that ultimately led to passage of the 1990 Amendments to the CAA, which created the current version of the CAA. Because of my role in the White House, I was deeply involved in efforts to implement the new 1990 CAA Amendments. From 1990 to early 1993, I was one of two White House staffers assigned to work with EPA on various CAA regulations.

I left the White House in early 1993 and shortly thereafter joined the law firm of Latham & Watkins, where I became a partner in the firm's environmental group. I was in this position until 2001, when I was appointed as the Assistant Administrator for Air and Radiation at the U.S. Environmental Protection Agency ("EPA"). I served in this position until August of 2005. In this capacity, I was the senior official in charge of implementing all the regulatory and permitting programs of the CAA. During my tenure at EPA, I oversaw and was intimately involved in developing a number of CAA regulations, including some of the New Source Review ("NSR") regulations at issue in the Ameren Missouri litigation in the U.S. District Court for the Eastern District of Missouri.

Since 2006, I have been a partner at Bracewell LLP, where my practice is focused on issues arising under the CAA, including the NSR program. A copy of my CV is attached as Schedule JRH-D1.

Q. How long have you been working on issues related to the federal Clean Air Act?

A. Since 1989, I have spent most of my professional career working on CAA issues.

II. <u>PURPOSE OF TESTIMONY</u>

Q. Why have you been asked to testify in this proceeding?

A. I have been asked to testify regarding Ameren Missouri's decisions not to seek NSR permits when it undertook the projects at the Rush Island Plant that gave rise to the District Court's decision – namely, (1) the projects performed during the Unit 1 outage in early 2007 ("Unit 1 Projects"); and (2) the projects performed during the Unit 2 outage in early 2010 ("Unit 2 Projects"). I will refer to the Unit 1 Projects and the Unit 2 Projects collectively as "the Rush Island Projects."

Q. Please provide a summary of your testimony and opinions.

A. I can summarize my testimony and opinions as follows:

- I have reviewed a number of documents related to Ameren Missouri's determinations that it did not need to obtain NSR permits for the Rush Island Projects. As reflected in these materials, the Company had three independent reasons for these determinations:
    1. Under the applicable Missouri regulations as they had been interpreted by the Missouri Department of Natural Resources ("DNR"), an NSR permit was not required unless a project would cause an increase in "potential emissions" at a facility, and none of the Rush Island Projects would increase potential emissions.
    2. None of the Rush Island Projects would be expected to cause an increase in actual annual emissions and thus would not trigger NSR.
    3. These same types of projects were done routinely throughout the industry. The Rush Island Projects were therefore considered "routine maintenance, repair and replacement" ("RMRR"), which is explicitly exempt from NSR.
- When Ameren Missouri determined that it did not need NSR permits for any of the Rush Island Projects, each of these conclusions was reasonable, given what

Ameren Missouri knew or should have known at the time. Ameren Missouri was not alone in determining that it did not need NSR permits for the types of projects the Company undertook at Rush Island between 2005 and 2010. Many other companies that owned or operated coal-fired power plants had done the same types of projects at their plants, and none of them had ever applied for or obtained an NSR permit for any of these projects. Based on the materials I have reviewed and my knowledge of EPA's regulations, if I had been advising Ameren Missouri at the time, I would have agreed that the Company did not need an NSR permit for any of the Rush Island Projects.

III. THE CLEAN AIR ACT AND ITS NEW SOURCE REVIEW PROGRAM

Q. What is the federal Clean Air Act?

A. The Clean Air Act (CAA for short) was originally enacted in 1970, expanded in 1977, and substantially expanded in 1990. Under the CAA, EPA and states regulate virtually every imaginable source of air pollution, including both "stationary sources" (such as power plants, industrial facilities and dry-cleaning operations) and "mobile sources" (such as cars, trucks, buses, and construction equipment). There are also CAA regulations that cover things such as leaf blowers, lawn mowers, paints and coatings, and consumer products such as hair spray and deodorant.

Q. Who is charged with implementing the Clean Air Act's requirements?

A. EPA implements some programs directly, but a number of CAA programs are based on the principle of "cooperative federalism," under which EPA provides broad standards and individual states have considerable discretion in choosing how to meet these standards. States develop their own versions of the basic federal programs and submit them to EPA for approval. Once EPA reviews and approves these programs, they become part of the "state implementation plans" (known as SIPs) that are a key feature of the CAA. Once these state programs are approved by EPA, the requirements of these programs displace the federal regulations that would otherwise apply in the individual states, and industrial facilities within each state are governed by the EPA-approved state programs. This was the case for Missouri, which administered the CAA under an EPA's approved SIP.

Q. What is the CAA's New Source Review program?

A. As its name implies, the New Source Review program is focused primarily on new sources of emission and ensures that new power plants and other new industrial sources are designed and built with modern pollution controls. It does so by requiring a permit for construction of new major sources of emissions. In issuing that permit for construction, the permitting authority (usually a state environmental agency) will identify the "best available control technology" ("BACT") that can be used to control emissions and then determine the emission limit that the source can meet by using that technology. This emission limit is incorporated as a legal requirement in the source's NSR permit.

The NSR program also applies to existing power plants, but only if they undergo a major modification that will cause a significant increase in emissions. There are many other CAA programs that are specifically designed to reduce emissions from existing power plants.

There are actually two different parts of the NSR program: (1) the Nonattainment New Source Review ("NNSR") program, which applies to plants located in nonattainment areas (i.e., areas with air quality that does not meet the EPA national ambient air quality standards); and (2) the Prevention of Significant Deterioration ("PSD") program, which applies to plants located in attainment areas (i.e., areas that meet the EPA's air quality standards). During the relevant time period, the area around the Rush Island Plant met the EPA's air quality standards for all pollutants, so it was subject only to the PSD program. The main purpose of the PSD program is to ensure that new plants or major modifications at existing plants will not cause a "significant deterioration" of air quality in areas that meet EPA's air quality standards.

Regulators and others who work on CAA issues often refer to both the PSD and the NNSR programs together as "the NSR program." I will adopt this custom and refer generally to the "NSR program" and the "NSR requirements," even though the Rush Island Plant was subject only to the PSD requirements of the NSR program during the relevant time period (because the air quality in the area around the plant met all EPA air quality standards).

Q. At an existing source like the Rush Island Plant, when would the NSR program apply?

A. The NSR program is referred to as a "construction" or "pre-construction" permitting program. If a company wants to build a facility that will be a "major source" of emissions as defined under the Clean Air Act, then that company must obtain an NSR permit before it can begin construction on the facility. The same requirement applies to any company that wants to make a modification to an existing plant that will cause a significant increase in emissions – known as a "major modification" under EPA's NSR regulations. The company must go through the NSR permitting process and obtain a permit before it can begin construction on the major modification. In either case—construction of a new source of emissions or a "major modification" of an existing source of emissions—the NSR program requires the permit to incorporate emissions limits based on up-to-date pollution control technology.

Q. What does the Clean Air Act say about when an existing source, like Rush Island, must get an NSR permit?

A. The statutory language of the CAA simply says that an NSR permit is needed for any "modification" of an existing source, and modification is defined as "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." 42 U.S.C. § 7411(a)(4). As EPA has noted, this definition essentially creates a two-part test that a plant operator must use in order to determine the applicability of NSR requirements to any particular project at an existing stationary source: (1) is there a physical or operational change? and (2) would that change cause the specified emission increase? 67 Fed. Reg. 80186, 80187 (Dec. 31, 2002) (preamble to proposed rule). Although there are a few regulatory complexities that sometimes come into play, if the answers to both questions are "yes," then that project is said to "trigger" NSR and permitting is required.

Q. What steps has EPA taken to explain and implement that NSR trigger?

A. Over the last 30 years, EPA has issued a number of rules regarding the types of projects at existing sources that "trigger" the need for an NSR permit. These rules all deal with the question of "applicability" – how to determine if an NSR permit is needed for a particular project or activity at an existing plant. EPA's NSR rules implement the basic two-part definition of "modification" in the CAA that I mentioned above. As EPA has explained:

> The reference to ''any physical change * * * or change in the method of operation'' in section 111(a)(4) of the Act [42 U.S.C. § 7411(a)(4)] could—read literally—encompass the most mundane activities at an industrial facility (even the repair or replacement of a single leaky pipe, or an insignificant change in the way that pipe is utilized). However, the EPA has recognized that Congress did not intend to make every activity at a source subject to major new source requirements . . . . As a result, the EPA has adopted several exclusions from the ''physical or operational change'' component of the definition. For instance, the EPA has specifically recognized that routine maintenance, repair and replacement, and changes in hours of operation or in the production rate are not by themselves considered a physical change or change in the method of operation within the definition of major modification. The EPA has likewise limited the reach of the second step of the statutory definition of modification by excluding all changes that do not result in an emissions increase above ''significance'' levels for the pollutant in question. Taken together, these regulatory limitations restrict the application of the NSR program . . . to only ''**major modifications**'' at existing major stationary sources.

61 Fed. Reg. at 38,250 (July 23, 1996) (preamble to proposed rule) (internal citations omitted, emphasis added).

Q. How has EPA applied the regulatory definition of "major modification" to activities at existing power plants?

A. Prior to 1988, EPA and the power industry generally viewed all replacement of existing plant components with functionally equivalent components as "routine maintenance, repair and replacement" (RMRR) and thus excluded from NSR. Before that time, there had never been an instance in which EPA, a state agency, or any court had found that an NSR permit was required for the replacement of functionally equivalent components at an operating power plant, even though such replacements were common in the industry.

In September of that year, however, EPA staff evaluated the applicability of the NSR program to a project to be undertaken at a Wisconsin Electric Power Company ("WEPCO") power plant and determined that it would be a major modification. This is known as the WEPCO decision and was the first time that an existing power plant was required to get an NSR permit.

Q. What was the WEPCO decision?

A. WEPCO had proposed to undertake a large project that involved replacing a number of components at a power plant that consisted of five coal-fired boilers, and EPA was asked to determine whether the proposed project would trigger NSR. The EPA staff determined that the project was not RMRR and that it would cause an increase in emissions that would exceed EPA's "significance" levels and would thus be a "major modification". The Company appealed this "applicability determination" to the EPA Administrator (the head of EPA), arguing that it was simply replacing old components with functionally equivalent components, but in October 1988 he reaffirmed the EPA staff determination, noting that the project was very extensive and could not be viewed as routine. As described by EPA, the project that WEPCO had proposed for five different generating units at the plant consisted of the following:

> Each unit was rated at 80 megawatts of electrical output capacity. The activity involved the replacement of numerous major components. The information submitted by WEPCO showed that the company intended to replace several components that are essential to the operation of the Port Washington plant. In particular, WEPCO sought to replace the rear steam drums on the boilers at units 2, 3, 4, and 5. According to WEPCO, these steam drums were a type of ''header'' for the collection and distribution of steam and/or water within the boilers. WEPCO viewed their replacement as necessary to continue operation of the units in safe condition. In addition, at each of the emissions units, WEPCO planned to repair or replace several other integral components, including replacement

> of the air heaters at units 1, 2, 3, and 4. WEPCO also planned to renovate major mechanical and electrical auxiliary systems and common plant support facilities. WEPCO intended to perform the work over a 4-year period, utilizing successive 9-month outages at each unit. The cost of the activity was estimated in 1988 to be $87.5 million. . . . EPA concluded at the time this activity was unprecedented in that EPA did not find a single instance of renovation work at any electric utility generating station that approached this activity in nature, scope and extent.

68 Fed. Reg. at 61,256–61,257. In reaching the decision that the WEPCO project was unprecedented in the electric utility industry, and therefore not RMRR, EPA "weigh[ed] the nature, extent, purpose, frequency, and cost of the work, as well as other relevant factors, to arrive at a common-sense finding" that the proposed project was not routine in the industry. The Administrator also agreed that the proposed project would result in a significant emission increase, thus making it a "major modification" that would require an NSR permit.

Q. What happened next?

A. The company appealed the Administrator's decision to the U.S. Court of Appeals for the Seventh Circuit. The court upheld EPA's determination that the project proposed by WEPCO was not routine replacement (i.e., not RMRR). On the other hand, the Court disagreed with the method EPA had used to determine whether the project would cause an increase in emissions and remanded this issue back to the Agency.

The utility industry expressed concern that the WEPCO decision on RMRR might result in many component-replacement projects, which they viewed as routine, being regulated by the NSR program. The WEPCO decision came out during the congressional deliberations over the 1990 CAA Amendments, and a number of members of Congress raised these concerns as part of this process. In response, the Government Accountability Office ("GAO") did a study which found that the WEPCO project was highly unusual and that most power plant replacement and repair projects would be less extensive. The Chairman of the House Energy and Commerce Committee (which was responsible for overseeing EPA) also sent a letter to EPA asking EPA to explain the scope of the WEPCO applicability determination and its implications for other power plants.

In his response to this letter, the then-EPA Assistant Administrator for Air and Radiation, the senior EPA official in charge of implementing the CAA (and one of my predecessors at EPA), reassured the Chairman and other member of Congress that the WEPCO decision would not have a significant impact on other power plants. His letter stated:

> As indicated in the GAO report, it is expected that most utility projects will not be similar to the WEPCO situation. That is, EPA believes that most utilities conduct an ongoing maintenance program at existing plants which prevents deterioration of production capacity and utilization levels.

He went on to state that "the ruling is not expected to significantly affect power plant life extension projects" and that "EPA's WEPCO decision only applies to utilities proposing 'WEPCO type' changes." Letter dated June 19, 1991, from EPA Assistant Administrator William Rosenberg to Chairman John Dingell.

Q. How did EPA respond to the WEPCO decision?

A. EPA issued a new rule in response to the decision known as the "WEPCO Rule." Although the Seventh Circuit had upheld EPA's determination that the project proposed by WEPCO was not RMRR, it disagreed with EPA's approach for determining whether the project would result in a significant emission increase (and thus be a "major modification" that required an NSR permit). As noted above, the utility industry also had concerns that the approach EPA used for WEPCO might cause many equipment-replacement projects, which they viewed as routine, to be regulated by the NSR program.

To address both these issues (as well as to adjust the NSR program to reflect the recently enacted 1990 CAA Amendments), EPA went through notice-and-comment rulemaking to clarify the way the federal NSR program would apply to existing power plants, including its approach to RMRR. The final WEPCO Rule was issued in 1992.

On the issue of RMRR, EPA deferred promulgating a formal regulatory definition of RMRR under the WEPCO Rule. Instead, EPA noted that:

> the issue has an important bearing on today's rule because a project that is determined to be routine is excluded by EPA regulations from the definition of major modification. For this reason, EPA plans to issue guidance on this subject as part of a NSR regulatory update package which EPA presently intends to propose by early summer. In the meantime, EPA is today clarifying that the determination of whether the repair or replacement of a particular item of equipment is "routine" under the NSR regulations, while made on a case-by-case basis, must be based on the evaluation of whether that type of equipment has been repaired or replaced by sources within the relevant industrial category.

57 Fed. Reg. 32,314, 32,326 (July 21, 1992) (preamble to final rule).

Q. What did the WEPCO Rule say about how to determine whether a project would result in a significant increase in emissions?

A. The WEPCO Rule clarified the way in which companies and regulators should determine whether projects at existing power plants (referred to as “electric utility steam generating units”) would result in an emission increase. For one thing, the Rule explicitly reaffirmed EPA’s view that a project would trigger NSR only if it “caused” an increase in emissions. Here is the way EPA discussed this issue in the Rule:

> The NSR regulatory provisions require that the physical or operational change "result in" an increase in actual emissions in order to consider that change to be a modification [see e.g., 40 CFR 52.21(2)(i)]. In other words, NSR will not apply unless EPA finds that there is a causal link between the proposed change and any post-change increase in emissions.

> *   *   *   *   *
>
> Consequently, where projected increased operations are in response to an independent factor, such as demand growth, which could have occurred and affected the unit's operations during the representative baseline period even in the absence of the physical or operational change, the increased operations cannot be said to result from the change and therefore may be excluded from the projection of the unit's future actual emissions.

57 Fed. Reg. at 32,326, 32,327.

The WEPCO Rule also clarified the way in which post-project emissions should be calculated at existing power plants. See 67 Fed. Reg. at 80,188. In the WEPCO case, EPA had argued that a plant owner had to assume that, after any type of change, the plant would operate at full capacity, 24-hours-a-day, 365-days-a-year. Thus, post-project emissions at existing power plants were based on the unit's maximum "potential-to-emit" after the change. To determine whether a project would cause a significant increase in emissions, the annual emissions that would occur if the plant operated at full capacity for 365-days-a-year were compared to the plant's actual annual emissions prior to the change. This is referred as the "actual-to-potential test." Under this test, any project is predicted to result in an emission increase because no unit actually operates round the clock for 365-days-a-year, meaning that future emissions are always predicted to be higher than past emissions.

The WEPCO court found that this test was unreasonable and that past actual emissions had to be compared with projected actual emissions in the future. The WEPCO Rule provided that pre-project actual emissions (often referred to as "baseline emissions" or the "baseline") should be compared to the emissions that were actually expected to occur in the future, referred to under the rule as "representative actual annual emissions." 57 Fed. Reg. at 32,337.

Q. Did EPA issue any subsequent NSR regulations that are relevant here?

A. Yes. In the 2002 NSR Reform Rule, EPA clarified how to compare past emissions with future emissions for purposes of determining whether a project (*i.e.*, a physical change at a facility) would cause an emission increase and thus potentially trigger NSR. When it comes to past annual emissions, power plants can select the highest total emissions during any consecutive 24-month period in the five years leading up to the change, and then divide that number by two to calculate "baseline emissions." This number represents past annual emissions.

When estimating future annual emissions (*i.e.*, what the annual emissions will be after the change), the rules are less prescriptive. They say that the plant must project what annual emissions will be for every 12-month period, on a rolling basis, for at least five years after the change. If a change will increase the capacity of the unit, then the plant must estimate future emissions on a 12-month rolling basis for 10 years after the change. If the projected future annual emissions in all the 12-month periods are always lower than the baseline emissions, then that's the end of the analysis. If estimated future emissions in any 12-month period are higher than the baseline emissions, you then move on to the next step in the applicability analysis, which is designed to determine whether this increase is caused by the project.

When EPA proposed these rules, it got public comments asking the agency to specify particular methods that should be used to estimate future emissions. EPA decided that doing so would not be feasible. As EPA explained when responding to these comments, environmental regulators could never understand all the factors that might affect future emissions because this would depend in large part on business issues. EPA did, however, require companies to take a number of specific factors into account when projecting future emissions. The regulations provide that:

> In determining the projected actual emissions . . . (before beginning actual construction), 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.

67 Fed. Reg. at 80,277 (preamble to final rule).

While the rules require consideration of these factors, it is important to note that EPA did not prescribe a particular methodology or formula that must be used in projecting future emissions. In fact, EPA specifically declined to do so. The understanding was that, if companies made such projections after considering all the relevant factors, regulators would not second guess them as long as these projections were reasonable. Technical Support Document (Response to Comments) for the Prevention of Significant Deterioration and Nonattainment Area New Source Review Regulations (Nov. 2002), at I-5-27, *available at* https://www.epa.gov/sites/default/files/2015-12/documents/nsr-tsd_11-22-02.pdf.

Q. Is this the end of the applicability analysis?

A. As I said, if the projected future annual emissions in all future 12-month periods are always lower than the baseline emissions, then that’s the end of the analysis. Otherwise, the next step is to consider whether the projected increase in emissions is actually caused by the project.

Annual emissions at an industrial facility change from year to year for reasons that have nothing to do with any changes at the facility itself. Emissions might increase substantially from one year to the next even though the facility remains entirely unchanged. At a power plant, annual emissions depend primarily on how often and how hard it is called upon to operate, which depends on a number of things, including weather, the number and operating status of other power plants in the area, the transmission infrastructure, and overall economic activity. The Clean Air Act is clear that a project will trigger NSR only if it will "cause" an emission increase. So, if an emission increase is not caused by the project, it does not trigger NSR.

The 2002 NSR Reform Rule addresses this causation requirement with an additional step. If your projections show an increase above baseline emissions after a proposed project, you must subtract the emissions that (1) "could have been accommodated during the baseline period" and (2) "that are also unrelated to the particular project, including any increased utilization due to product demand growth." *Id.* at 80,277.

IV. NSR APPLICABILITY AND APPROVED STATE PROGRAMS

Q. Do all state programs have identical NSR applicability provisions?

A. No. As noted above, individual states are given the opportunity to develop their own unique NSR programs. If EPA approves these programs as part of the State's SIP, then the State's regulations displace EPA's NSR regulations and apply to all facilities located within that state, which, as noted earlier, was the case in Missouri when Ameren Missouri was undertaking the Rush Island Projects. Over the years, individual states have developed their own NSR applicability provisions that in some cases are different from those in EPA's regulations, and these provisions have been incorporated into SIP-approved NSR programs.

Q. Can you provide some examples of the variability in NSR applicability provisions in different state programs?

A. One example is the Clark County, Nevada SIP. From 1981 to 2004, the approved Clark County SIP included a "potential-to-potential" test for determining whether a project would be a modification for purposes of NSR. It defined a "modification" as "any physical change in or change in the method of operation of an existing stationary source which increases or may increase *the potential to emit* for any air contaminant by any emission unit in the stationary source . . . ." District Board of Health Clark County Air Pollution Control Regulations Section 1.58 (emphasis added) (Revised 9/3/81). "Potential to emit" was defined as "the maximum capacity of a stationary source to emit a pollutant under its physical and operational design . . . ." Id. at Section 1.80 (Revised 9/3/81).

In my experience, some regulators prefer this "potential-to-potential" approach because it is an objective test that is easy to apply. If a project changes the physical characteristics of an emission unit in a manner that would increase its size or capacity to emit, it is reasonable to assume that it would likely cause an emission increase and should go through further regulatory analysis. If a project does not increase the size or capacity of an existing unit, it is "screened out" and there is no need to do a projection of future emissions.

By the mid-1990s, EPA began to urge Clark County to eliminate the potential-to-potential test. In the meantime, EPA developed the NSR Reform Rule and promulgated changes to the emissions applicability test at the end of 2002. In 2004, Clark County submitted a new SIP that EPA found would "establish the more inclusive test ('actual to potential') for evaluating source modifications and thereby replace the existing SIP NSR program's 'potential-to-potential' test, with the result that a greater number of source modifications would be subject to new source review." 69 Fed. Reg. at 31,064. However, the existing "potential-to-potential" applicability provision remained part of the SIP-approved program until September 2004, when the revised regulations were approved by EPA and incorporated into the Clark County SIP. 69 Fed. Reg. at 54,006.

The State of Connecticut also had a similar (but more complicated) set of applicability provisions in its SIP-approved NSR program. Under the 1989 Connecticut regulations, "modify" or "modification" means "any physical change in, change in the method of operation of, or addition to a stationary source which: (i) increases the potential emissions of any individual air pollutant from a stationary source by five (5) tons per year or more; or (ii) increases the maximum rated capacity of the stationary source unless the owner or operator of the stationary source demonstrates to the commissioner's satisfaction that such increase is less than fifteen percent (15%) and the change or addition does not cause an increase in the actual emissions or the potential emissions; or (iii) increases the potential emissions above [certain levels]." EPA approved these definitions into the state's SIP-approved NSR program in 1993. 58 Fed. Reg. 10,957, 10,963 (Feb. 23, 1993). As was the case in Nevada, EPA later urged the state to change its applicability provisions, and

EPA ultimately approved a SIP that changed the State's definition of modification. As EPA explained in proposing to approve the new definition,

> [Connecticut's] existing SIP-approved rules use a different approach for calculating the emission increase from a modification. Instead of the actual-to-potential test, the DEP uses the potential-to-potential test. This method compares the emission unit's potential before the modification with its potential after the modification. The DEP also does not allow sources the option to take credit for emission changes occurring source-wide. Adopting provisions that reflect the EPA rules that are currently in effect significantly improves Connecticut's program.

68 Fed. Reg. 2722, 2724 (Jan. 21, 2003). EPA approved the revised SIP shortly after its proposal. 68 Fed. Reg. 9009 (Feb. 27, 2003).

Q. And Missouri also has a SIP-approved NSR program?

A. Yes. The Missouri Department of Natural Resources, usually referred to as the Missouri DNR, is responsible for implementing Missouri's SIP-approved NSR program

Q. Please describe the NSR applicability provisions in Missouri's SIP-approved program.

A. Missouri's SIP-approved NSR program, 10 CSR 10-6.060 and 10-6.061, contains the permitting regulations that applied to Rush Island during the relevant time period. Not all projects undertaken at a source like Rush Island are subject to permitting requirements. Missouri's construction permit rules serve to identify "sources which are required to obtain permits to construct" and "establish[] requirements to be met prior to construction or modification of any of these sources." 10 CSR 10-6.060 (Purpose) (Nov. 30, 2006). The construction permit rules include applicability provisions to establish when sources are required to obtain permits to construct, including minor (referred to as "de minimis") permits, nonattainment NSR permits, PSD permits, and hazardous air pollutant permits.

The threshold applicability provisions for Missouri's permitting program are set forth under the heading, "Construction Permits Required – Applicability." Section (1)(C) of these regulations state that "[n]o owner or operator shall commence <u>construction or modification</u> of any installation subject to this rule . . . without first obtaining a permit from the permitting authority under this rule." 10 CSR 10-6.060(1)(C) (emphasis added) (Nov. 30, 2006). This tells us that construction permits (whether de minimis, nonattainment, PSD or hazardous) are required only when there will be "construction" or "modification" of a facility covered by the rule. Conversely, if the project or activity in question does not constitute "construction" or "modification," then the rules do not apply and the activity does not require any form of construction permit.

Under the Missouri SIP, a "modification" occurs only when the project will cause an increase in potential emissions. Similar to the Nevada program, the Missouri SIP defines "modification" as a physical or operational change of "a source operation" that causes an "increase <u>in potential emissions</u> of any air pollutant emitted by the source operation." 10 CSR 10-6.020(2) (M)(10)(emphasis added) (Nov. 30, 2006). "Source operation" is defined as "[a]ny part or activity of an installation that emits or has the potential to emit any regulated air pollutant or any pollutant listed under section 112(b) of the Act." 10-6.020(2)(E)(4), (2)(S)(16) (Nov. 30, 2006). The Missouri SIP defines potential emissions as "[t]he emission rates of any pollutant at maximum design capacity." 10 CSR 10-6.020(2)(P)(19) (Nov. 30, 2006). Thus, a project is a modification only if it will cause an increase in the emission rate when the source is operating at its maximum design capacity. If not, then the regulations tell us that the project is not subject to Missouri's construction permitting regulations, meaning that the source is not required to obtain a construction permit for the project before beginning construction or modification. Thus, the project is "screened out" at this point.

After this step, the Missouri NSR program is essentially the same as the EPA NSR program because the State, in 2006, incorporated the regulatory language from EPA's 2002 NSR Reform Rules into its SIP-approved program. Thus, if a project will cause an increase in potential emissions (and will therefore be a "modification"), the source must then determine whether it will cause a significant increase in actual emissions and therefore be a "major modification" that requires an NSR permit under 10 CSR 10-6.060(8). As discussed below, when Ameren Missouri determined that it did not need NSR permits for the Rush Island Projects, this is how the Missouri DNR applied the EPA-approved SIP permitting rules, as Ameren Missouri was well aware.

In the NSR enforcement case against Ameren Missouri, however, the EPA enforcement office argued, and the District Court found, that a project could be a "major modification" even if it was not a "modification." But just because a court adopted this interpretation of the SIP years after Ameren Missouri completed the Rush Island Projects does not mean that the reading of the SIP that I have outlined above was unreasonable before that time. To the contrary, the Missouri DNR, which is responsible for implementing the State's NSR program, read them the same way at that time, as discussed below, and it was the Missouri DNR that had responsibility for administering the CAA under the

Missouri SIP that EPA had approved. Those were the facts in front of Ameren Missouri and upon which it made its decision that NSR permits were not required.

Based on my experience as the head of EPA's Air Office and someone who has worked on Clean Air Act regulations for more than 30 years, the reading I have outlined above is how I would have read and understood the regulations before the District Court's decision in the enforcement case. And as I mentioned, this reading was also supported by MDNR. I believe that, before the District Court's later decision, this was clearly the most reasonable way to interpret the NSR permitting regulations in the Missouri SIP.

Q. How would you apply this reading of the Missouri SIP to make an NSR applicability determination concerning a project at an existing power plant?

A. In any NSR applicability determination, there are basically two questions: (1) Will a proposed project be a "physical change or change in the method of operation"? and (2) will the project cause an increase in emissions? You don't trigger NSR unless the answer to both questions is "yes." Although you can conclude that an NSR permit is not required if the answer to either question is "no," sources generally examine both questions out of an abundance of caution.

Q. How does an owner or operator determine if there will be a physical change at a facility?

A. As I testified earlier, EPA has repeatedly said that "physical change or change in the method of operation" is a broad concept that could conceivably cover almost anything done at a facility, like changing out a filter. So the analysis of whether a particular project or activity is a physical or operational change is primarily an analysis of whether the project falls within one of the exclusions found in the SIP-approved NSR rules. Under the SIP-approved Missouri NSR rules, the excluded project categories include an increase in hours of operation or production rates (if not explicitly prohibited by permit) and, most importantly, RMRR. When evaluating the type of maintenance and repair work typically performed during an outage, the question of whether such work constitutes a "physical change" turns on whether it qualifies as RMRR.

Q. If a proposed project is not RMRR (and thus is a physical change), how does the owner or operator determine whether the project will cause the necessary increase in emissions?

A. As discussed above, before the District Court's ruling in the Ameren Missouri case, the Missouri rules were read to establish a two-step process. Under Step One, the owner or operator must determine whether the project constitutes a "modification of any installation subject to this rule" in accordance with 10 CFR 10-6.060(1)(C). The SIP defines "modification" as a physical or operational change of a source operation that causes an increase in potential emissions from the source. *See* 10 CFR 10-6.020(2) (emphasis added). Potential emissions are defined as the emission rate of a pollutant "at maximum design capacity." 10 CFR 10-6.020(2)(P)(19). If a project doesn't increase the emissions at maximum design capacity, then the regulations tell us that it is screened out at this step. Again, I recognize that the District Court later determined that this step does not apply to NSR permitting, and the U.S. Court of Appeals for the Eighth Circuit affirmed that result on appeal. But that does not change my opinion that this was the most reasonable reading of the Missouri SIP at the time Ameren Missouri made its preconstruction decisions. This is how MDNR had interpreted and applied the SIP prior to the time Ameren Missouri made its decisions. As someone who has been involved in drafting and interpreting environmental regulations for more than 30 years, I would have agreed with the state's and Ameren Missouri's readings at that time.

Step Two under the Missouri SIP mirrors EPA's 2002 NSR Reform Rule. The regulations tell us that if a project is deemed a "modification" in Step One (because it will increase potential emissions), then the project must be evaluated to determine if it is a "major modification" under the Missouri SIP.

As I testified earlier, EPA's 2002 NSR Reform Rule codified a framework for evaluating whether a physical or operational change will cause a significant emission increase. That framework compares the baseline actual emissions prior to the change to the projected actual emissions after the change. The actual-to-projected-actual methodology from the NSR Reform Rule was adopted into the Missouri SIP in 2006 and was available for use by Ameren Missouri in evaluating the Rush Island Projects.

As noted, the 2002 NSR Reform Rule does not prescribe a particular calculation or formula that must be used for these analyses. EPA explicitly declined to do so and recognized that owners and operators will have discretion in making these calculations, provided that they satisfy the objective requirements of the rule.

While EPA did not specify a calculation method that must be used with the actual-to-projected-actual emissions test, EPA did attempt to ensure that the calculated increase between the baseline emissions (pre-change) and projected actual emissions (post-change) focuses on the increase *caused by* the change. For example, if a source experiences an increase in emissions after a project, but that increase is unrelated to the change – for example, if the source experiences increased utilization due to demand growth, and the source was capable of operating at that increased utilization level prior to the change – that unrelated emission increase must be excluded when comparing the project emission increase to the applicable significance threshold.

If a project is a physical or operational change that causes an increase in emissions, and the difference between the source's baseline actual emissions and projected actual emissions exceeds the applicable significance threshold, that change is a "major modification" that triggers NSR.

Q. Will an owner or operator be required to exercise engineering judgment or discretion in making this determination?

A. Yes. In comments on the proposed 2002 NSR reforms, some parties argued that EPA should include a specific methodology for projecting future emissions. EPA explained, however, that this was not appropriate or even feasible and instead recognized that companies would be in the best position to make such projections.

V. <u>AMEREN MISSOURI'S APPLICABILITY DETERMINATIONS</u>

Q. Have you been asked to evaluate some of Ameren Missouri's past NSR applicability determinations for this proceeding?

A. Yes.

Q. What information have you relied upon in evaluating these determinations?

A. I have relied on:

- the text of the Missouri SIP-approved NSR regulations;
- the history of the NSR program, including the WEPCO decision, the WEPCO rule, and the 2002 NSR Reform Rule;

- the implementation of the NSR program by Missouri and other states through SIPs;
- the interpretations and actions by Missouri DNR concerning its SIP and NSR requirements under that SIP;
- the state of the law at the time the decisions were made;
- the testimony and declarations of Ameren Missouri employees and MDNR representatives in the underlying District Court litigation; and
- my more than 30 years of experience dealing with NSR issues as a government official and a lawyer in private practice.

I am not relying upon any privileged or confidential information as support for my opinions.

Q. Who are the key Ameren employees whose testimony and declarations you reference?

A. Steven Whitworth and David Boll. Mr. Whitworth leads Ameren Missouri's Environmental Services Department and has done so since 2007. Schedule JRH-D2 (Whitworth Declaration) ¶ 2. The Environmental Services Department had responsibility for determining whether permits were required for the Rush Island Projects. Whitworth Declaration ¶ 3. The Environmental Services Department did so through collaborative discussion involving engineers in other departments who had knowledge about and responsibility for the projects. Whitworth Declaration ¶¶ 3-6. David Boll, a licensed professional engineer in Ameren Missouri's Environmental Project Engineering Department, was one such individual. Mr. Boll's responsibilities included supervising the work for the component replacement projects at issue at Rush Island and assessing the impact component replacements were expected to have on unit operations. Schedule JRH-D3 (Boll Declaration) ¶¶ 2-3. As their declarations describe, Messrs. Whitworth and Boll have personal knowledge of the permitting decisions Ameren Missouri made concerning the Rush Island Projects.

Q. Can you identify the projects and applicability determinations that you have been asked to evaluate?

A. I have been asked to evaluate Ameren Missouri's NSR applicability determinations for the Rush Island Projects.

Q. What permitting determinations did Ameren Missouri make for those projects?

A. Ameren Missouri determined that it did not need to obtain NSR permits for any of the Rush Island Projects.

Q. Do you know the basis for those determinations?

A. As I mentioned, I have reviewed a number of documents related to Ameren Missouri's determinations, all of which I understand were produced in the Ameren Missouri litigation in the U.S. District Court for the Eastern District of Missouri. As reflected in these documents, the Company had three basic reasons for these determinations:

- Under the applicable regulations in the Missouri SIP, as I read them and as they had been interpreted by the Missouri Department of Natural Resources, an NSR permit was not required unless a project would cause an increase in "potential emissions" at a facility, and none of the Rush Island Projects would increase potential emissions.

- Under the 2002 NSR rules incorporated into the Missouri SIP, none of the Rush Island Projects would be expected to cause an increase in actual emissions and thus would not trigger NSR.
- Because these same types of projects were done routinely throughout the industry, they were considered "routine maintenance, repair and replacement", which is explicitly exempt from NSR.

Whitworth Declaration ¶¶ 7-15.

Q. Can you summarize your opinion regarding the reasonableness of the permitting determinations made by Ameren Missouri for those projects?

A. At the times when Ameren Missouri determined that it did not need NSR permits for the Rush Island Projects, each of these was a valid reason for making this determination. Based on the regulations, regulatory interpretations, and guidance documents available at the time, and the state of the law as it existed then, if I had been advising Ameren Missouri at the time, I would have advised the Company that it did not need NSR permits for any of the projects.

Before the Rush Island Projects, many other companies that owned or operated coal-fired power plants had done the same types of projects at their plants, and none of them had ever applied for or been required to obtain an NSR permit for any of these projects. Ameren Missouri was certainly not alone in believing that it did not need NSR permits for the types of projects the Company undertook at Rush Island in 2007 and 2010, and its belief was reasonable given what it knew or should have known.

Q. Why do you say, if you had been advising Ameren Missouri "at the time"?

A. I understand that the question in this proceeding is whether Ameren Missouri acted reasonably when it decided that it didn't need NSR permits for projects performed during the Unit 1 or and Unit 2 outages. In retrospect, it's easy to criticize those decisions in light of the protracted litigation that ultimately found that the Company should have obtained NSR permits. But if you look at the regulatory and legal landscape at the time that Ameren Missouri made its compliance decisions, those decisions were entirely reasonable.

I've been dealing with NSR issues and power companies for more than 30 years as either a government official or an attorney in private practice. Based on this experience, I don't think any other company in Ameren Missouri's position would have made a different decision based on the regulatory landscape and the state of the law that existed in 2005 – 2010.

Q. You mention three reasons why Ameren Missouri decided that it didn't need NSR permits. Let us take them one at a time. The first reason was that none of the projects would increase "potential emissions" at either of the Units. Can you explain why this was reasonable?

A. Earlier in this testimony, I explained in detail the Missouri NSR regulations (which had been approved by EPA) and how the different provisions regarding "modification" and "major modification" could be read to work together. This is certainly how I would have interpreted these regulations before the court's ruling in the Ameren Missouri enforcement case. More importantly, this is also how the Missouri DNR understood and interpreted these regulations (its own regulations) at the time when Ameren Missouri did the Rush Island Projects.

In summary, under the Missouri SIP rules, the understanding was that an owner/operator didn't need to get any kind of construction permit, including an NSR permit, for a project at an existing emission unit unless it would be a "modification" of the unit; a project is a modification only if it will cause "an increase in potential emissions" from the unit; and potential emissions are defined as "[t]he emission rate of any pollutant at maximum design capacity." 10 CSR 10-6.020(2) (Nov. 30, 2006). Thus, the understanding was that a project is a modification only if it will cause an increase in the emission rate when the source is operating at its maximum design capacity. None of the projects at issue in this case increased the emission rate of either Unit 1 or Unit 2 when it was operating at its maximum design capacity. Boll Declaration ¶¶ 7-8. Because none of the projects was a "modification," Ameren Missouri's understanding was that none of the projects would trigger NSR for that reason alone. Whitworth Declaration ¶¶ 9, 13. This was a reasonable understanding at the time.

In fact, MDNR shared this understanding. Testifying on behalf of the Department in the Ameren Missouri litigation in the U.S. District Court for the Eastern District of Missouri, a senior MDNR official explained how all the permitting programs in the approved Missouri SIP were read together. These explanations are a bit dense for anyone not steeped in the permitting world, but she explained what I have summarized above. She mentioned a number of different types of "construction permits," which include NSR permits, but she said that you don't need to worry about any of the these permits unless you trigger the applicability provisions of Section 10 CSR 10-6.020(2), which I have quoted above. This provision says that a project at an existing unit is not a modification unless it will increase the "potential emissions" of that unit. According to MDNR, if it's not a modification, you don't need to get any of the state's construction permits, including an NSR permit.

To understand this testimony, you need to know that the requirements for different types of construction permits are covered in sections 5–8 of the regulations, and NSR permits are covered in sections 7 and 8. The Company's attorney asked MDNR's designated witness:

> So am I correct that the process that MDNR has employed for applicability assessments and then related permitting is, step one, you look at the definition of modification and determine if there's a physical or operation change that would cause an increase in potential emissions . . . and then, step two, if the answer is yes, you look to section 5, 6, 7, and 8 of the construction permitting rules to determine what the permitting requirements would be for the required permit, is that correct?

Moore Dep. at 87. She confirmed that yes, this is correct. In another part of her testimony, when the attorney was asking a complicated question about a step in the NSR applicability test, she answered:

> Well, the simplest matter is to look at the potential emissions of the project, and if that by itself does not trigger any permitting action, you don't need to [go to that step].

Moore Dep. at 82-83. The attorney then said: "So just to clarify, that if you have no potential project emission increases, you never need to get to the step two . . . ." Moore Dep. at 83. Again, she confirmed that this is correct.

This same MDNR official later discussed a formal applicability determination that the Department made in 2006 when asked about the replacement of some large components at another coal-fired power plant in Missouri, the Thomas Hill Plant. Moore Dep. at 100 –

102. The company had asked whether a proposed project to replace two cyclone burners at the plant at a cost of approximately $25 million would trigger permitting requirements. After the company responded to several information requests from MDNR officials, MDNR sent a formal applicability determination letter to the company stating:

> Since there will be no increase in the potential to emit, according to the applicant, the change can not be considered a modification, per Missouri State Rule. Therefore, since replacement of the cyclone burners does not meet the definition of . . . modification, the replacement is exempt from permitting requirements.

Letter dated July 21, 2006 from Kyra Moore, Missouri DNR Permits Section Chief, to Todd A. Tolbert, Associated Electric Cooperative, Inc., attached as Schedule JRH-D4.

Further supporting the reasonableness of this understanding of the Missouri SIP is the fact that other states had followed this same basic approach. As I mentioned above, both Nevada and Connecticut had similar applicability provisions in their SIP-approved NSR programs. In both cases, before the states considered whether there was a "major modification" that would trigger NSR, they first determined whether there would be a "modification," which was only the case if a physical change to a unit would increase its potential emissions. If not, an NSR permit was not required.

In 2015, Steven Whitworth, the Senior Director for Environmental Policy and Analysis at Ameren Missouri, signed a sworn declaration on behalf of the Company regarding the Company's pre-construction evaluations of the Unit 1 and Unit 2 Projects. After noting that he had worked in the Company's Environmental Services Department for over 16 years, he stated:

> Based on our considerable experience with NSR permitting under the Missouri SIP, and the language of the SIP, we understand that such projects would not increase the unit's annual rate of potential emissions, and therefore did not constitute "modifications" under the Missouri SIP. Accordingly, we determined that such Projects

> would not trigger the application of the Missouri Construction Permit Rule, meaning no construction permit was required.

Whitworth Decl. ¶¶ 9, 13. Ameren Missouri's approach to the Missouri SIP was entirely reasonable at the time. In fact, given that the state permitting agency had the same understanding of these regulations, I do not believe that any environmental specialist or lawyer at a power company would have reached a different conclusion.

Q. You mentioned a second reason why Ameren Missouri determined that it did not need NSR permits for the Unit 1 or Unit 2 Projects—that none of them would be expected to cause an increase in actual annual emissions from Rush Island. How does a company determine whether a particular project at a power plant will cause an annual emission increase for purposes of NSR?

A. As I explained in detail earlier, you have to start by determining your baseline emissions. Under the 2002 NSR Reform Rule incorporated into the Missouri SIP, power plants can select the highest total emissions during any consecutive 24-month period in the five years leading up to the project and then divide that number by two to calculate their annual "baseline" emissions.

When it comes to projecting future annual emissions (*i.e.*, what the annual emissions will be after the project), the NSR rules are necessarily less prescriptive. They simply say that the company, after taking a number of factors into account, must project annual emissions for the plant for every 12-month period, on a rolling basis, for at least 5 years after the change. If a change will increase the capacity of the unit, then the company must project future emissions for the plant on a 12-month rolling basis for 10 years after the change. If the projected future annual emissions in any of the 12-month periods are higher than the baseline emissions (*i.e.*, there is a projected increase in emissions over the baseline), then the next step is to subtract the amount of the increase that (1) "could have been accommodated during the baseline period" and (2) is also "unrelated to the particular project, including any increased utilization due to product demand growth." 40 CFR 52.21(b)(41)(ii)(c).

These regulations were understood as simply a more structured way of considering whether a particular project could actually cause an emission increase. This approach recognizes that emissions may go up after a project for reasons that have nothing to do with the project itself, often because of "demand growth." If there is more demand for electricity in the future compared to the baseline period, the plant may be called upon to operate more in the future to meet this demand (depending on the availability of other power plants in the area that can also meet this demand). If the plant had enough excess capacity during the baseline period to meet the increased demand, this was understood to mean that a projected increase in emissions "could have been accommodated during the baseline period" because the plant could have operated more to satisfy this demand even if the project hadn't happened. If, after subtracting the emissions that "could have been accommodated" and are unrelated to the project, there is still a projected increase, then that remaining projected increase may be understood to result from the project.

Q. Do the rules require a company to do numerical calculations to show that a project will not cause an emission increase?

A. The 2002 version of the NSR rules incorporated into the Missouri SIP did not require numerical calculations. Companies often relied on their knowledge of their operations and market to make these assessments. In many cases, making these assessments could be very easy. As long as the particular project will not increase the capacity of a plant or result in a material change in its efficiency, a company can usually determine that the expected increase in emissions is "unrelated to the particular project" as long as the plant "could have accommodated" those emissions before the project.

Q. Have you evaluated Ameren Missouri's determinations that none of the Rush Island Projects would cause an increase in actual annual emissions?

A. Yes.

Q. Were those determinations reasonable?

A. Yes, they were. I have reviewed the transcripts of depositions and testimony regarding this evaluation, and the best summary of Ameren Missouri's approach comes from Mr. Whitworth's 2015 declaration, where he says the following:

> In addition to assessing the applicability of the Missouri SIP and whether the 2007 Projects constituted routine maintenance repair and replacement, Ameren also assessed any impact of the Projects on projected actual future emissions. We had experience with and knowledge of the similar projects described above, and were familiar with the Rush Island units' operational characteristics. This included our knowledge that Ameren's coal-fired generating units operate below their available capacity and thus have a large amount of unused capacity to generate. Based on these and other considerations derived from our experience, knowledge and judgment, and based on the judgment of Ameren's engineering personnel, we in Environmental Services concluded that the 2007 Projects would not cause actual emissions to increase.

Whitworth Decl. ¶ 11. Ameren Missouri reached the same conclusion concerning the 2010 Projects. Whitworth Decl. ¶ 15. Ameren Missouri's approach was consistent with what I have seen from other companies, including companies in the power sector. If a particular project or set of projects will not increase the capacity of a unit or result in a material change in its efficiency, and the unit had plenty of excess capacity before the project, it is easy to conclude that the project will not cause an emission increase. Boll Decl. ¶ 15.

No matter how sophisticated the analysis, projections of future emissions at a power plant are always uncertain because they depend on many factors that are outside the company's control, including the weather, actions of other companies, and overall economic activity in the area served by the plant. Emissions of SO_2 from Rush Island varied considerably from year to year both before and after the Rush Island Projects occurred. Whitworth Declaration ¶¶ 30-33. If company experts know that, for technical reasons, a particular project or set of projects will not have any impact on how often a unit will operate or how much it will be able to produce (and therefore emit) in future years, they can reasonably conclude that the project or set of projects will not cause any increase in emissions without any calculations. That is the case here. Boll Declaration ¶¶ 7-19; Whitworth Declaration ¶¶ 11, 15. In my opinion, the Company's determination that the Rush Island Projects would not cause an increase in actual annual emissions was reasonable.

Based on my experience with the power sector, I think any other power company would have made the same determination.[1]

Q. Finally, you mentioned that Ameren Missouri also relied on the RMRR exclusion when it determined that it didn't need NSR permits. Can you explain why this was also reasonable?

A. As I mentioned earlier, both the federal NSR regulations and the State's SIP-approved NSR regulations have an explicit NSR exemption for projects that qualify as RMRR. NSR applies to an existing unit only if there is "a physical or operational change"

[1] I am also aware that Ameren Missouri performed some emissions calculations for the Unit 2 Projects after that work commenced. Whitworth Declaration ¶¶ 16-26. Although I am not relying on those calculations for my opinion that Ameren Missouri's pre-project applicability determinations were reasonable, I conclude that Ameren Missouri's post-project calculations for Unit 2 were reasonable as well.

at the unit that results in a significant emission increase. Any type of maintenance, repair or replacement project that qualifies as RMRR is explicitly excluded from the definition of a physical or operational change.

All federal and state NSR programs have an exception or an exclusion from NSR for routine maintenance, repair and replacement on existing units, and other permitting and regulatory programs do as well. In my experience, whenever an industrial facility is doing significant maintenance work during an outage, it will consider whether the work should be considered RMRR. In the vast majority of cases, operators simply rely on their experience with the ongoing maintenance of their facilities and their knowledge of maintenance practices within the industry to determine whether particular projects should be viewed as RMRR.

It is clear from the documents I have reviewed that, before undertaking the Rush Island Projects, Ameren Missouri considered whether they qualified as RMRR. They were aware of the maintenance, repair and replacement practices at the many different power plants they operate, and of those across the industry as well. Again, I will quote from Mr. Whitworth's declaration, where he made the following statement regarding both sets of projects:

> As explained in Mr. Boll's declaration, Ameren engineering personnel had also determined that the [Unit 1 and 2] Projects were routine in nature because, among other reasons, they were like-kind replacements of existing components with new components that were functionally equivalent. Ameren was aware that such replacements were commonly performed throughout the industry. I and my colleagues in Environmental Services knew that Ameren had conducted dozens of similar component replacements at its other generating units in prior years. Accordingly, I and my colleagues in Environmental Services determined, prior to the [Unit 1 and 2] Projects, that Ameren's routine boiler component replacements such as the [Unit 1 and 2] Projects constituted routine

> maintenance repair and replacement activities that are excluded from NSR permitting under the Missouri SIP.

Whitworth Decl. ¶¶10, 14. See also Boll Decl. ¶ 14. Ameren Missouri's determinations that the Rush Island Projects were RMRR were certainly reasonable at the time they were made.

By that time, many such projects (the replacement of boiler components such as reheaters, economizers, air preheaters, and boiler tubes) had been made throughout the industry. This is clear from a 2000 report titled *Routine Maintenance of Electric Generating* Stations that was issued by the Tennessee Valley Authority ("TVA"). The TVA report was based on an industry-wide survey and was explicitly noticed in the *Federal Register*. 65 Fed. Reg. 35154 (June 1, 2000). It reviews TVA and general industry experience with regard to a number of component replacement projects that were the same or similar to the Rush Island Projects and found that several hundred of them had been done on coal-fired power plants prior to 1999. TVA itself had done a number of them, but neither TVA (the federal government's public utility) nor anyone else had ever applied for an NSR permit for any such project or group of projects. Even considering all the Rush Island Projects together, they were much less extensive than the "WEPCO type" changes that EPA had said were unprecedented and the only type of component replacement project that would trigger NSR.

Thus, it was reasonable for Ameren Missouri to rely on the RMRR exclusion, and EPA's statements concerning its scope, in determining that the company was not required to seek NSR permits for any of the Rush Island Projects. At the time Ameren Missouri made these determinations, I don't believe that any power company in the country would have taken a different position. Even today, I believe that many power companies would make the same determination for such projects.

Q. Does this conclude your direct testimony?

A. Yes, it does.

DIRECT TESTIMONY OF JEFFREY R. HOLMSTEAD
CASE NO. ER-2022-0337
SCHEDULES

Index

Schedule	Description
JRH-D1	Curriculum Vitae of Jeffrey R. Holmstead
JRH-D2	U.S. v. Ameren Missouri, ECF 568-1, Declaration of Steven Whitworth (without exhibits)*
JRH-D3	U.S. v. Ameren Missouri, ECF 568-4, Declaration David Boll (without exhibits)*
JRD-D4	EXCERPTED Exhibit 7 (Applicability Determination Request) to Videotaped 30(b)(6) Deposition of Kyra Moore, United States v. Ameren Missouri, (Sept. 18, 2013)

*As noted on the face of Schedule JRH-D2 and Schedule JRH-D3, these declarations were redacted pursuant to the protective order, governing the use of confidential business information, entered by the U.S. District Court for the Eastern District of Missouri. The versions of these declarations provided here are the redacted versions, without exhibits, filed in the District Court.

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Professional Experience

Bracewell LLP, Washington, D.C. Office *2006-Present*
Partner and Head of the Environmental Strategies Group
The Environmental Strategies Group (ESG) is a multi-disciplinary group that includes environmental and energy attorneys, public policy advocates, and strategic communications experts – many of whom have had high-level government experience. As head of the ESG, Mr. Holmstead represents companies, business groups, and not-for-profit organizations on a wide range of environmental and energy-related issues related to the Clean Air Act.

United States Environmental Protection Agency *2001-2005*
Assistant Administrator for Air and Radiation
Appointed by President George W. Bush and confirmed by the U.S. Senate to oversee all regulatory and permitting programs created under the Clean Air Act. During his tenure at EPA, Mr. Holmstead was the architect of several of the Agency's most important initiatives, including the Clean Air Interstate Rule, the Clean Air Diesel Rule, the Mercury Rule for power plants, and the reform of the New Source Review program. He also oversaw the development of the Bush Administration's Clear Skies Legislation and key parts of its Global Climate Change Initiative.

Latham & Watkins, Washington, D.C. Office *1993-2001*
Associate and then Partner
As a member of the firm's Environmental Group, Mr. Holmstead represented a wide variety of companies and trade associations dealing with issues arising under several environmental statutes. Much of his work involved the Clean Air Act and, in particular, regulatory issues arising from the 1990 Amendments to the Clean Air Act.

The White House *1989-1993*
Associate Counsel to President George H.W. Bush
Served on the White House Staff as a member of the White House Counsel's Office. In this capacity, Mr. Holmstead was involved in discussions that led to passage of the Clean Air Act Amendments of 1990. After the Amendments were adopted, he was involved in the interagency review process for all major EPA rules arising under the Clean Air Act.

Davis, Polk, and Wardwell LLP, Washington, D.C. Office *1988-1989*
Associate
Worked on securities offerings and advised companies on a range of regulatory issues.

U.S. Court of Appeals for the District of Columbia Circuit *1987-1988*
Law Clerk to Judge Douglas H. Ginsburg

JRH-D1

Education

J.D., Yale Law School, 1987
B.A., *summa cum laude*, Brigham Young University, 1984

Noteworthy

- Chambers & Partners, *Chambers USA*, Climate Change, 2010-present; Environment, 2008-present
- Woodward/White, Inc., *Best Lawyers*, Environmental Law, 2008-present
- *US Legal 500*, Environment: Litigation, 2012

Congressional Testimony by Jeffrey R. Holmstead

U.S. House Committee on Energy and Commerce — May 16, 2018
Subcommittee on Environment
Hearing entitled "Legislation Addressing New Source Review Permitting Reform"

U.S. House Committee on Energy and Commerce — February 14, 2018
Subcommittee on Environment
Hearing entitled "New Source Review Permitting Challenges for Manufacturing and Infrastructure"

U.S. House Committee on Science, Space and Technology — February 7, 2017
Hearing entitled "Making EPA Great Again"

U.S. House Committee on Science, Space and Technology — October 22, 2015
Hearing entitled "EPA's 2015 Ozone Standard: Concerns Over Science and Implementation"

U.S. Senate Committee on Environment and Public Works — July 8, 2015
Hearing entitled "Road to Paris: Examining the President's International Climate Agenda and Implications for Domestic Environmental Policy"

U.S. House Committee on Science, Space and Technology — July 30, 2014
Hearing entitled "EPA's Carbon Plan: Failure by Design"

U.S. House Committee on Science, Space, and Technology — June 12, 2013
Subcommittee on Environment
Hearing entitled "Background Check: Achievability of New Ozone Standards"

U.S. House Energy and Commerce Committee — June 28, 2012
Subcommittee on Energy and Power
Hearing entitled "Implications of EPA's Proposed National Ambient Air Quality Standards (NAAQS) for Fine Particles (PM2.5)"

U.S. Senate Committee on Environment & Public Works — April 17, 2012
Subcommittee on Clean Air and Nuclear Safety
Hearing entitled "Review of Mercury Pollution's Impacts to Public Health and the Environment"

U.S. House Judiciary Committee — May 4, 2011
Subcommittee on Courts, Commercial and Administrative Law
Hearing entitled "Cost-Justifying Regulations: Protecting Jobs and the Economy by Presidential and Judicial Review of Costs and Benefits"

U.S. House Select Committee on Energy Independence & Global Warming — Dec. 11, 2008

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Hearing regarding the Administrative Procedure Act and "midnight" regulations

U.S. House Committee on Energy Independence and Global Warming — June 26, 2008
Hearing entitled "$4 Gasoline and Fuel Economy: Auto Industry at a Crossroads"

U.S. Senate Committee on Environment and Public Works — Jan. 24, 2008
Hearing entitled "Oversight of EPA's Decision to Deny California Waiver Request"

U.S. House Committee on Energy and Commerce — May 26, 2005
Subcommittee on Energy and Air Quality
Hearing on the President's Clear Skies Act, and the reduction of emissions of sulfur dioxide (SO2), nitrogen oxides (NOx) and mercury from power plants

U.S. Senate Committee on Environment and Public Works — March 20, 2003
Subcommittee on Clean Air, Climate Change, and Nuclear Safety
Hearing on alternative fuels and fuel additives

U.S. House Committee on Energy and Commerce — March 2, 2005
Subcommittee on Energy and Air Quality
Hearing entitled "Clean Air Act Transportation Conformity Provisions Contained in H.R.3, Transportation Equity Act: A Legacy for Users"

U.S. House Committee on Health, Education, Labor, and Pensions — Sept. 3, 2002
Subcommittee on Public Health
Hearings concerning proposed improvements to the New Source Review (NSR) program under the Clean Air Act

U.S. Senate Committee on Environment and Public Works — July 30, 2002
Hearing on the Congestion Mitigation and Air Quality Improvement program (CMAQ)

U.S. Senate Committee on Environment and Public Works — July 16, 2002
U.S. Senate Committee on the Judiciary
Joint hearing on New Source Review policy, regulations, and enforcement activities

Senate Committee on Energy and Natural Resources — May 23, 2002
Hearing concerning EPA's role in setting public health and environmental radiation protection standards for the proposed spent nuclear fuel and high-level radioactive waste repository at Yucca Mountain, Nevada

U.S. House Committee on Energy and Commerce — May 1, 2002
Subcommittee on Energy and Air Quality
Hearing entitled "Accomplishments of the Clean Air Act, as amended by the Clean Air Act Amendments of 1990"

U.S. House Committee on Energy and Commerce — April 18, 2002
Subcommittee on Energy and Air Quality

Hearing entitled "A Review of the President's Recommendation to Develop a Nuclear Waste Repository at Yucca Mountain, Nevada"

U.S. Senate Committee on Environment and Public Works Nov. 1, 2001

Hearing on S. 556 on its impact on the environment and the economy and any improvements or amendments that should be made to the legislation

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

UNITED STATES OF AMERICA,	)	
	)	
Plaintiff,	)	
	)	**Case No. 4:11-CV-00077-RWS**
v.	)	**Judge Rodney W. Sippel**
	)	
AMEREN MISSOURI,	)	
	)	
Defendant.	)	
	)	

AMEREN MISSOURI'S SUMMARY JUDGMENT MOTIONS

EXHIBIT A1

PORTIONS REDACTED PURSUANT TO ECF # 90

PART 1 OF 3

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UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

UNITED STATES OF AMERICA,	)	
	)	
Plaintiff,	)	
	)	**Case No. 4:11-CV-00077-RWS**
v.	)	
	)	**Judge Rodney W. Sippel**
AMEREN MISSOURI,	)	
	)	
Defendant.	)	
	)	

DECLARATION OF STEVEN WHITWORTH

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

1. I make this declaration on behalf of Ameren Missouri ("Ameren") based on my personal knowledge, and the records of Ameren or information available through employees of Ameren. I am prepared to testify to the following facts if called as a witness.

2. I am employed by Ameren Services Company, which provides services to Ameren Corporation's operating companies, including Ameren Missouri (which I will generally refer to below as "Ameren"). I have worked in Ameren's Environmental Services Department for over 16 years, and since 2007 I have managed and directed that Department. My title is Senior Director, Environmental Policy and Analysis. I am familiar with Ameren's emissions assessments for the 2007 and 2010 Projects at issue in this case.

Assessment of Projects for Construction Permitting Applicability

3. Ameren's Environmental Services Department ("Environmental Services") plays a lead role in evaluating whether environmental permits are required for activities Ameren

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undertakes, including whether major New Source Review ("NSR") or other construction permits are required under the Missouri State Implementation Plan ("SIP") Construction Permitting Rule, 10 C.S.R. 10-6.060. Typically, we reach a consensus decision within Environmental Services on permit applicability through collaborative discussion.

4. To assess the nature of a project and to determine whether it should be considered for air construction permitting, Environmental Services typically works in conjunction with Ameren engineering personnel in the Project Engineering and Performance Engineering departments. We will also consult other Ameren departments (for example, Corporate Planning) as needed.

5. Environmental Services staff have considerable knowledge and experience with assessing permit applicability regarding all manner of projects at Ameren, including component replacements at Ameren's power plants, like Rush Island. We used that prior experience with similar activities in assessing any emission impact of the 2007 and 2010 Projects.

6. Environmental Services also relies on the subject matter expertise of our engineering colleagues to identify projects that have the potential, from an engineering point of view, to result in emissions increases, due to their nature and scope. Ameren had conducted dozens of similar boiler component replacement projects at its other plants prior to performing the 2007 and 2010 Projects. Our experience with and knowledge gained from those similar projects informed our decision-making and analysis with respect to the 2007 and 2010 Projects.

7. Ameren assesses the impact that a project is expected to have on unit operations well before beginning construction, as part of its project planning and justification processes. Consistent with normal practice, Ameren assessed the expected impact of the 2007 and 2010 Projects before beginning construction of those projects.

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<u>Ameren's Emissions Assessment for the 2007 Projects at Rush Island Unit 1</u>

8. Ameren conducted a planned unit outage at Rush Island Unit 1 from approximately February to May 2007. During this outage, I understand that Ameren performed nearly 100 discrete projects. I understand that just four of those projects are at issue in this case: the replacements of the reheater, economizer, lower slope and air preheater components (the "2007 Projects"). While Ameren made emissions assessments with respect to all of the activities taking place during the 2007 Outage as a whole, to simplify the following discussion, I will refer to the 2007 Projects.

9. I understand from David Boll, currently Ameren's Consulting Engineer in Ameren's Environmental Project Engineering Department, that before the 2007 Outage, Ameren engineering personnel assessed the nature and scope of the 2007 Projects and the other projects planned to be undertaken during the 2007 Outage, and concluded that none of those projects would increase the unit's maximum annual rated design capacity given continuous year-round operations. Based on our considerable experience with NSR permitting under the Missouri SIP, and the language of the SIP, we understand that such projects would not increase the unit's annual rate of potential emissions, and therefore did not constitute "modifications" under the Missouri SIP. Accordingly, we determined that such Projects would not trigger the application of the Missouri Construction Permit Rule, meaning no construction permit was required.

10. As explained in Mr. Boll's declaration, Ameren engineering personnel had also determined that the 2007 Projects were routine in nature because, among other reasons, they were like-kind replacements of existing components with new components that were functionally equivalent. Ameren was aware that such replacements were commonly performed throughout the industry. I and my colleagues in Environmental Services knew that Ameren had conducted

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dozens of similar component replacements at its other generating units in prior years. Accordingly, I and my colleagues in Environmental Services determined, prior to the 2007 Projects, that Ameren's routine boiler component replacements such as the 2007 Projects constituted routine maintenance repair and replacement activities that are excluded from NSR permitting under the Missouri SIP.

11. In addition to assessing the applicability of the Missouri SIP and whether the 2007 Projects constituted routine maintenance repair and replacement, Ameren also assessed any impact of the Projects on projected actual future emissions. We had experience with and knowledge of the similar projects described above, and were familiar with the Rush Island units' operational characteristics. This included our knowledge that Ameren's coal-fired generating units operate below their available capacity and thus have a large amount of unused capacity to generate. Based on these and other considerations derived from our experience, knowledge and judgment, and based on the judgment of Ameren's engineering personnel, we in Environmental Services concluded that the 2007 Projects would not cause actual emissions to increase.

Ameren's Emissions Assessment for the 2010 Projects at Rush Island Unit 2

12. Ameren conducted a planned unit outage at Rush Island Unit 2 from approximately January to April 2010. During this outage, I understand that Ameren performed over 100 discrete projects. I understand that only 3 of these projects are at issue: the replacements of the reheater, economizer, and air preheater components of Rush Island Unit 2 (the "2010 Projects"). While Ameren made emissions assessments with respect to all of the activities taking place during the 2010 Outage as a whole, to simplify the following discussion, I will refer only to the 2010 Projects.

13. I understand from Mr. Boll that before the 2010 Outage, Ameren engineering personnel assessed the nature and scope of the 2010 Projects and the other projects planned to be

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undertaken during the 2010 Outage, and concluded that none of those projects would increase the unit's maximum annual rated design capacity given continuous year-round operations. Based on our considerable experience with NSR permitting under the Missouri SIP, and the language of the SIP, we in Environmental Services understand that such projects would not increase the unit's annual rate of potential emissions, and therefore did not constitute "modifications" under the Missouri SIP. Accordingly, we determined that such Projects would not trigger the application of the Missouri Construction Permit Rule, meaning no construction permit was required.

14. As explained in Mr. Boll's declaration, Ameren engineering personnel had also determined that the 2010 Projects were routine in nature because, among other reasons, they were like-kind replacements of existing components with new components that were functionally equivalent. Ameren was aware that such replacements were commonly performed throughout the industry. I and my colleagues in Environmental Services knew that Ameren had conducted dozens of similar component replacements at its other generating units in prior years. Accordingly, I and my colleagues in Environmental Services determined, prior to the 2010 Projects, that Ameren's routine boiler component replacements such as the 2010 Projects constituted routine maintenance repair and replacement activities that are excluded from NSR permitting under the Missouri SIP.

15. In addition to assessing the applicability of the Missouri SIP and whether the 2010 Projects constituted routine maintenance repair and replacement, Ameren also assessed any impact of the Projects on projected actual future emissions. We had experience with and knowledge of the similar projects described above, and were familiar with the Rush Island units' operational characteristics. This included our knowledge that Ameren's coal-fired generating

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units operate below their available capacity and thus have a large amount of unused capacity to generate. Based on these and other considerations derived from our experience, knowledge and judgment, and based on the judgment of Ameren's engineering personnel, we in Environmental Services concluded that the 2010 Projects would not cause actual emissions to increase.

16. In addition to the foregoing assessment of actual emissions, Ameren also documented an assessment of whether there was a reasonable possibility, within the meaning of the relevant rules, that the 2010 Projects would increase emissions from the unit. The Missouri state permitting rules had changed in late 2009, requiring Missouri operators to perform in certain instances a numerical calculation of emissions, a requirement that had not applied under either the applicable state or federal regulations prior to that. While we believed (see above) that no construction permit of any kind was required under the Missouri Construction Permitting Rule, and that the 2010 Projects were excluded from New Source Review permitting because they constituted routine maintenance repair and replacement, we nonetheless prepared a numerical calculation out of an abundance of caution.

17. To determine whether there was a reasonable possibility of an emissions increase from the 2010 Outage, Environmental Services prepared a numerical emissions projection. A true and correct copy of the results of that projection, titled "Rush Island Unit 2 – Spring 2010 Outage – Reasonable Possibility Analysis Summary" is attached hereto as Attachment 1. (The document attached as Attachment 1 is the summary or conclusion page of a much larger document containing all the details of Ameren's analysis. Ameren produced the entire analysis during discovery in this case, but given its volume has not attached it here. Ameren stands ready to provide it to the Court upon request.)

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18. Pursuant to 40 C.F.R. 52.21(b)(48) (as incorporated by reference in the Missouri SIP at 10 C.S.R. 10-6.060(8)), Ameren first calculated Unit 2's "baseline actual emissions" rate by taking the average annual rate from the 24-month period of April 2005 through March 2007. That rate was 14,288 tons per year.

19. Pursuant to 40 C.F.R. 52.21(b)(41)(i) (incorporated by reference in the Missouri SIP at 10 C.S.R. 10-6.060(8)), Ameren then determined Unit 2's "maximum annual rate" of future actual emissions in the five years following the date Unit 2 would resume regular operation after the 2010 Outage. That maximum annual rate was 16,818.88 tons per year. In Attachment 1, this is shown under the column labeled "Projected Actual Emissions (tons/year)." This calculation of emissions following the Projects did not yet account for causation, which the NSR regulations require be accounted for through application of the "capable of accommodating" provision.

20. We did not believe that any relevant fugitive emissions were quantifiable, and so did not project them according to 40 C.F.R. 52.21(b)(41)(ii)(b) (incorporated by reference in the Missouri SIP at 10 C.S.R. 10-6.060(8)). Emissions associated with startups, shutdowns and malfunctions were included in the projection of the maximum annual rate of projected future emissions following the 2010 Outage.

21. Finally, as required pursuant to the "capable of accommodating" provision (sometimes called the demand growth provision), 40 C.F.R. 52.21(b)(41)(ii)(c) (as incorporated by reference in the Missouri SIP at 10 C.S.R. 10-6.060(8)), Ameren determined the amount of emissions following the 2010 Projects that was unrelated to the 2010 Projects. We initially determined the amount of emissions that Unit 2 could have accommodated during the baseline period above and beyond those it actually emitted during the baseline period. That amount was

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3,275.11 tons per year. In Attachment 1, this is shown under the column labeled "Capable of Accommodating Emissions (tons/year)."

22. Ameren determined that additional amount of SO_2 emissions (3,275 tons per year) was unrelated to the Projects because it could have been emitted during the baseline period and was related to: (a) increased utilization due to increased market demand, up to a level not exceeding the unused capacity that actually was available during the baseline period; and/or (b) normal variations in hourly emissions rates due to a combination of factors unrelated to the 2010 Projects, none of which were expected to affect hourly emissions rates.

23. To determine the amount of emissions (if any) following the Projects that were related to the Projects, Ameren then excluded (*i.e.*, subtracted) a portion (2,531.15 tons per year, "Excluded Emissions" on Attachment 1) of the unrelated SO_2 emissions from the difference between baseline emissions (14,287.73 tons per year) and the emissions following the Projects (16.818.88 tons per year).

24. The result of this calculation was zero, and is shown as the "Net Change" on Attachment 1. Stated mathematically: 16,818.88 *minus* 14,287.73 *minus* 2,531.15 *equals* 0.00, the emissions related to the Project. (We did not subtract all 3,275.11 tons per year of unrelated emissions because that would have resulted in a negative number.)

25. Because, after following the requirements of the regulation, any amount of projected SO_2 emission increase related to the 2010 Projects was less than the 40-ton significance threshold for SO_2, Ameren determined that the 2010 Projects (and the 2010 Outage as a whole) would not cause a significant increase in emissions of SO_2.

26. Pursuant to 40 C.F.R. 52.21(b)(41)(ii)(a) (incorporated by reference in the Missouri SIP at 10 C.S.R. 10-6.060(8)), when determining the annual rate of "projected actual

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emissions," (as defined under 40 C.F.R. 52.21(b)(41)(i), Ameren considered all relevant information. In addition to the considered judgment and expertise of Environmental Services, we relied (as described above) on the judgment and expertise of Ameren's engineering personnel, performance engineering personnel, and Corporate Planning department, among others. Ameren considered all relevant information regarding Unit 2's historical operational data, Unit 2's expected business activity and Ameren's highest projections of business activity. Ameren also considered the amount of unused, but available generating capacity that was available to it during the baseline period, and which Unit 2 could have utilized had the market called upon it to do so. Ameren also considered the normal variations in hourly emission rates that occur during the normal operations of Unit 2.

27. Ameren retained records of this calculation. Since well before the Projects took place, Ameren reports the SO_2 emissions from both Rush Island units to EPA as part of its submission of CEMS data (see below).

Rush Island Emissions and Generation Over Time

28. Ameren's Environmental Services Department plays a role in monitoring the emissions of each of Ameren's plants, including Rush Island.

29. Rush Island's Continuous Emissions Monitor Systems (CEMS) measure and record emissions data on a continuous basis during Rush Island's operations. Ameren gathers that data and reports it to EPA. EPA keeps this data in databases and publishes it on the internet, where it can be accessed by the general public. The CEMS data contains multiple data points in addition to emissions, including gross generation. I am familiar with CEMS Data and use it routinely in carrying out my job responsibilities.

30. I reviewed the CEMS data for SO_2 emissions, NOx emissions, and gross generation over time. As the below table demonstrates, compared to 1990 levels, Rush Island's

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annual emissions of SO_2 in 2014 were just 39% of their 1990 levels, a decrease of over 27,500 tons per year. That decrease came about even though Rush Island's annual generation of electricity has increased and is now 152% of their 1990 levels, an increase of over 3 gigawatt-hours per year. Likewise, Rush Island's emissions of NOx are at just 28% of their 1995 levels, a decrease of nearly 9,000 tons per year.

Rush Island Generation and Emissions 1990-2014

Year	Unit 1 Generation	Unit 1 SO_2	Unit 1 NOx	Unit 2 Generation	Unit 2 SO_2	Unit 2 NOx
	(MWH)	(TPY)	(TPY)	(MWH)	(TPY)	(TPY)
1990	2,786	21,343	-	3,101	23,609	-
1995	3,614	21,412	4,593	2,821	22,209	7,734
1996	3,401	13,225	4,077	3,917	14,044	3,922
1997	3,735	13,484	3,826	3,222	11,659	3,032
1998	3,936	13,485	3,396	4,281	13,924	3,710
1999	3,721	12,653	2,711	4,276	14,543	2,981
2000	4,228	13,643	2,801	4,107	13,257	2,589
2001	3,169	8,963	1,824	3,794	10,912	2,295
2002	4,426	12,744	2,092	3,506	10,511	1,900
2003	4,565	13,127	1,928	3,797	11,866	1,856
2004	3,916	11,725	1,602	3,995	11,193	1,665
2005	4,467	14,070	1,971	4,952	14,315	2,098
2006	4,613	14,584	1,991	4,638	14,090	1,976
2007	2,936	9,126	1,268	4,484	13,336	2,019
2008	4,794	15,492	2,086	4,456	14,102	2,106
2009	4,484	14,754	1,927	4,000	13,573	1,934
2010	4,506	14,964	1,935	3,360	11,103	1,449
2011	3,802	12,272	1,587	4,853	15,764	1,853
2012	4,455	10,642	1,549	4,097	9,780	1,405
2013	4,359	9,595	1,525	4,581	9,992	1,542
2014	4,161	8,846	1,456	4,171	8,598	1,394

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Rush Island Emissions Variations Over Time

31. The amount of SO_2 emitted at Rush Island varies significantly from year to year. In my experience, such fluctuations are normal at coal-fired power plants and are caused by a variety of factors including variations in market demand. I have reviewed the emissions data for Rush Island for the decade from 1996 to 2006. I then determined the changes in emissions from year-to-year. Below is an accurate summary of the amount of SO_2 emitted at Rush Island from 1996 to 2006.

Rush Island SO_2 Emissions Variations Over Time

	Unit 1		Unit 2	
Year	SO_2 Emissions	Change from previous year	SO_2 Emissions	Change from previous year
1996	13,225	--	14,044	--
1997	13,484	259	11,659	-2,385
1998	13,485	1	13,924	2,265
1999	12,653	-832	14,543	619
2000	13,643	990	13,257	-1,286
2001	8,963	-4,680	10,912	-2,345
2002	12,744	3,781	10,511	-401
2003	13,127	383	11,866	1,355
2004	11,725	-1,402	11,193	-673
2005	14,070	2,345	14,315	3,122
2006	14,584	514	14,090	-225

32. I reviewed the SO_2 emissions data for Rush Island Unit 1 for 2007 to 2014. I have provided a chart of the SO_2 emissions by year for the unit, below. The data for 2007 only includes a partial year of service because the plant was not operating during the Spring 2007 outage. Annual emissions are now about 5,000 tons per year below their averages before the 2007 Projects.

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Unit 1 SO_2 Emissions After the 2007 Projects

Year	SO_2 (TPY)
2007	9,126
2008	15,492
2009	14,754
2010	14,964
2011	12,272
2012	10,642
2013	9,595
2014	8,846

33. I reviewed the SO_2 emissions data for Rush Island Unit 2 for 2010 to 2014. I have provided a chart of the SO_2 emissions by year for the unit, below. The data for 2010 only includes a partial year of service because the plant was not operating during the Spring 2010 outage. As with Unit 1, annual emissions are now about 5,000 tons per year below their averages before the 2010 Projects.

Unit 2 SO_2 Emissions After the 2010 Projects

Year	SO_2 (TPY)
2010	11,103
2011	15,764
2012	9,780
2013	9,992
2014	8,598

Title V

34. Environmental Services is responsible for obtaining and securing the renewal of Title V Permits for the Rush Island plant. The applicable permit for the Rush Island units at the

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time of the 2007 and 2010 outages, Operating Permit No. OP2000061, was issued on May 18, 2000. A true and correct copy of the Title V permit is attached hereto as Attachment 2 (AM-02511339).

35. It is my understanding that before issuing a Title V Permit, the Missouri Department of Natural Resources provides the draft permit to EPA for comment or objection. EPA did not make any objection to Ameren's Title V operating permit before it was issued on May 18, 2000.

36. Generally, Title V permits have a 5-year term length. Although Title V permits must be renewed before they expire, because of permitting delays, permit renewals often take years to complete.

37. On or about November 18, 2004, Ameren filed an application to renew the May 18, 2000 Title V permit (Permit No. OP2000061).

38. On or about May 29, 2010, the Missouri Department of Natural Resources provided EPA a copy of the draft Rush Island Title V Permit. EPA did not object to the permit renewal.

39. On August 30, 2010, MDNR renewed Ameren's Title V Permit for the Rush Island Units, Operating Permit No. OP2010-047. A true and correct copy of the Title V permit is attached hereto as Attachment 3 (AM-00424093).

I declare under penalty of perjury that the foregoing is true and correct.

Executed on April 23, 2015

Steven Whitworth

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UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

UNITED STATES OF AMERICA,	)	
	)	
Plaintiff,	)	
	)	**Case No. 4:11-CV-00077-RWS**
v.	)	**Judge Rodney W. Sippel**
	)	
AMEREN MISSOURI,	)	
	)	
Defendant.	)	
	)	

AMEREN MISSOURI'S SUMMARY JUDGMENT MOTIONS

EXHIBIT A2

PORTIONS REDACTED PURSUANT TO ECF # 90

JRH-D3

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

UNITED STATES OF AMERICA,	)	
	)	
Plaintiff,	)	
	)	**Case No. 4:11-CV-00077-RWS**
v.	)	
	)	**Judge Rodney W. Sippel**
AMEREN MISSOURI,	)	
	)	
Defendant.	)	
	)	

DECLARATION OF DAVID BOLL

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

1. I make this declaration on behalf of Ameren Missouri ("Ameren") based on my personal knowledge, and the records of Ameren or information available through employees of Ameren. I am prepared to testify to the following facts if called as a witness.

2. I have been employed by Ameren since 1981 and I currently hold the position of Consulting Engineer in Ameren's Environmental Project Engineering Department. I received a B.S. in Mechanical Engineering from Washington University in St. Louis in 1981. I am a licensed Professional Engineer in the States of Missouri and Illinois.

3. My responsibilities during the time relevant to this case included justifying capital projects; preparing documents associated with such justifications such as project justification and work order documents; assessing the impact of component replacements on the performance and operations of the unit; preparing requests for proposal to be let out for bids; and supervising the construction of capital projects, including the component replacements at issue in this case.

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The Projects

4. Ameren replaced portions of the reheater, economizer, lower slope and air preheater components of Rush Island Unit 1 (the "2007 Projects") during the outage that took place from approximately February to May, 2007.

5. Ameren replaced portions of the reheater, economizer, and air preheater components of Rush Island Unit 2 (the "2010 Projects") during the outage that took place from approximately January to April, 2010.

The Effect of the Projects on the Units' Maximum Design Capacity

6. I am familiar with the projects to replace the reheater, economizer, lower slope and air heater components that occurred during Ameren's planned unit outage at Rush Island Unit 1 from approximately February to May 2007 (the "2007 Projects"). I am also familiar with the projects to replace the reheater, economizer and air heater components that occurred during Ameren's planned unit outage at Rush Island Unit 2 from approximately January to April 2010 (the "2010 Projects").

7. The nature of these component replacement projects is such that they would not reasonably be expected to, and Ameren did not expect them to, increase the Unit's maximum design capacity or maximum annual-rated capacity assuming continuous year-round operation (or, as the concept is expressed in the electric power industry, the Unit's "maximum continuous rating.") Nor would they be expected to increase the Unit's designed steam flow rating or designed heat input capacity.

8. I have reviewed the actual effects of the Projects, and they did not actually increase the Units' maximum design capacity, maximum annual-rated capacity assuming

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continuous year-round operation, or maximum continuous rating. They did not increase the Unit's designed steam flow rating or designed heat input capacity.

<u>The Scope of the 2007 and 2010 Outages</u>

9. Ameren conducted a planned unit outage at Rush Island Unit 1 from approximately February to May 2007 (the "2007 Outage"). During such outages, Ameren attempts to schedule as many activities as possible to be completed, in order to minimize overall unit downtime, and because such outages are generally planned to occur only once every six years. During the 2007 Outage, Ameren conducted 93 discrete maintenance, repair and replacement projects at Unit 1. Some of these other projects are of the same size and scope as the Projects at issue. Ameren generally prepares a Post Outage Report detailing the work that is performed during an outage. A true and correct copy of the 2007 Unit 1 Post Outage Report is attached hereto as Attachment 1.

10. Of the 93 projects conducted during the 2007 Outage, I understand that only 4 are at issue in this case: the replacement of the reheater, economizer, lower slope and air heater components. Moreover, in addition to these 93 projects, during the same 2007 Outage, Ameren performed innumerable tasks as part of the boiler overhaul, all designed to improve the long-term reliability, availability, and efficiency of the boiler. These tasks are not captured in detail in the Post Outage Report.

11. Ameren conducted a planned unit outage at Rush Island Unit 2 from approximately January to April 2010 (the "2010 Outage"). During such outages, Ameren attempts to schedule as many activities as possible to be completed, in order to minimize overall unit downtime, and because such outages are generally planned to occur only once every six years. During the 2010 Outage, Ameren conducted 108 discrete maintenance, repair and

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replacement projects at Unit 2. Some of these other projects are of the same size and scope as the Projects at issue. Ameren generally prepares a Post Outage Report detailing the work that is performed during an outage. A true and correct copy of the 2010 Unit 1 Post Outage Report is attached hereto as Attachment 2.

12. Of the 108 projects conducted during the 2010 Outage, I understand that only 3 are at issue in this case: the replacement of the reheater, economizer, and air heater components. Moreover, in addition to these 108 projects, during the same 2010 Outage, Ameren performed innumerable tasks as part of the boiler overhaul, all designed to improve the long-term reliability, availability, and efficiency of the boiler. These tasks are not captured in detail in the Post Outage Report.

The Expected Effect of the Projects on the Units' Actual Post-Project Generation of Electricity

13. In my experience, Ameren assesses the impact that a project is expected to have on unit operations well before beginning construction, as part of its project planning and justification processes. Consistent with its normal practice, Ameren assessed the impact of the 2007 and 2010 Projects before beginning construction of those projects. As one of the engineers who had responsibility for preparing the project justification documents for these Projects, I was one of several Ameren personnel who assessed these issues. Typically, we assessed such issues together as a group, and reached a group consensus.

14. Prior to the Projects, I had been involved with dozens of projects at Ameren's other plants that were similar in nature and scope to the Projects. In particular, I had experience with reheater replacements at Labadie; economizer replacements at Labadie, Sioux and

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Meramec; lower slope replacements at Labadie and air preheater replacements at Labadie and Meramec.

15. In my experience, replacement activities such as the Projects do not cause the unit's generation to increase. These are all like-kind replacements, substituting one component for another, sometimes with minor changes in design that made the units more efficient. I understood that my colleagues at Ameren shared the same views.

16. I expected that these replacement projects would improve the efficiency of the units. The economizer replacements were specified to be more efficient than the designs they replaced. Moreover, by replacing the economizer and air preheater with new components with slightly changed designs that could better handle the low-sulfur coal that Rush Island was burning, the auxiliary power demands on the units would be reduced, making the units more efficient overall.

17. I did not expect the Projects to increase the equivalent availability of the unit as compared to the pre-project periods. (Equivalent availability is a measure of the unit's availability to operate and produce electricity. It is a common metric for availability that is used throughout Ameren, and to my knowledge the electric utility industry.) I understood that my colleagues at Ameren shared the same views.

18. This is true for at least two reasons. First, the equivalent availability of the Rush Island units before these Projects was already exceptional – above 90% and at times reaching annual rates of 95% to 96%. In my experience, it is unlikely for any coal-fired unit to achieve sustained equivalent availability above those levels. Second, generating units are complex machines that consist of thousands of components, most of which can and do fail at some point. It is the combined operation of all of these component parts that determines the level of unit

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availability. Based on decades of experience, I knew that these other components would continue to fail, limiting the overall availability of the unit. I understood that my colleagues at Ameren shared the same views.

19. I did not expect the Projects to increase the stated generating capability of the unit as compared to the pre-project periods, other than by increasing the units' efficiency. When ordering the components (reheater, lower slope, economizer, and air preheater) Ameren specified that the new components have the same thermal performance as the old components, meaning that the new components would not increase capability.

20. I am informed and believe that the documents set forth on Attachment 3 hereto, and attached as exhibits to Ameren's various motions being filed contemporaneously, are copies of Ameren's business records, made at or near the time of the occurrence of the matters set forth by, or from information transmitted by, a person with knowledge of those matters, kept in the course of regularly conducted activity, and made by the regularly conducted activity as a regular practice.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on April 23, 2015

David E Boll

David Boll

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ATTACHMENT 1

ATTACHMENT REDACTED

ATTACHMENT 2

ATTACHMENT REDACTED

ATTACHMENT 3

Attachment 3 to the Declaration of David Boll

Exhibits	
C1	Unit 1 RELS Project Justification Package, AM-00072570
C2	Unit 1 Air Preheater Project Justification Package, AM-00072850
C3	Unit 2 RELS Project Justification Package, AM-00072829
C4	Unit 2 Air Preheater Project Justification Package, AM-00072906
C5	Ameren 2005 Unit Capabilities Tables, AM-00943285
C6	Ameren 2006 Unit Capabilities Tables, AM-00175922
C7	Ameren 2009 Unit Capabilities Tables, AM-00067238

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EXHIBIT
Moore/MDNR
7
9-18-13 JL
PENGAD 800-631-6989

State of Missouri
Department of Natural Resources

Permit Action Management System (PAMS)

Permit
Review #: AP200605022 Record ID: 3310911
Permit Type: AP: Applicability Determination Request
DateReceived: 5/9/2006
Description: Replace Burners
Program: APCP
DNR's Staff: Klein, Lina

Facility
Facility ID: AP0001750001
Facility Name: Associated Electric (Thomas Hill Plant)
Location: 5693 Hwy F,
City: Clifton Hill ST: MO
County: Randolph Zip: 65244
Address Two:

Status
Start Date: 5/9/2006 Permit No:
Compl. Date: Exp. Date:
Status: On Schedule
Current Phase: Executive Review
Current Step: AP: No Permit Required

Applicant
Name: Associated Electric Cooperative
Address One: 2814 S. Golden
Address Two: PO Box 754
City: Springfield ST: MO
Zip: 65801 Phone: (417) 881-1204
Cnsltng. Firm: Todd Tolbert

Permit Timeline

Phase	Step	Name	Start Date	End Date	Agency Days Planned	Agency Days Used	Applicant Days Planned	Applicant Days Used
Check Application								
	10	AP: Receive, Log, Assign	5/9/2006	5/19/2006	3	10	0	0
Check Application								
	20	AP: Awaiting Completeness Check	5/19/2006	5/19/2006	27	1	0	0
		Assigned to Lina on 5/19/06 KH						
Technical Review								
	30	AP: Technical Review	5/19/2006	6/29/2006	106	41	0	0
Executive Review								
	40	AP: Unit Chief Review	6/29/2006	7/18/2006	14	19	0	0
		turned in to kendall 6/29. Ljk						
Executive Review								
	41	AP: Final Clerical Prep	7/18/2006	7/19/2006		0	0	1
		Prepping no construction permit required ltr for KLM signature. 7/19/06 kdm. Prep complete to KLM to sign.						
Executive Review								
	42	AP: Executive Review	7/19/2006	7/21/2006		0	0	2
		To KLM to sign. 7/19/06 kdm. Recd signed ltr from KLM. 7/21/06 kdm.						
Executive Review								
	50	AP: No Permit Required	7/21/2006	7/21/2006	0	0	0	1
		No construction permit required ltr mailed. File ready to prep for file room. 7/21/06 kdm. File prepped and sent ot file room. 7/21/06 kdm.						
				Totals:	150	71	0	4

Days Since Last Action: 0

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AM-00025867-MDNR

STATE OF MISSOURI

Matt Blunt, Governor • Doyle Childers, Director

DEPARTMENT OF NATURAL RESOURCES

www.dnr.mo.gov

JUL 2 1 2006

Mr. Todd A. Tolbert
Environmental Specialist II
Associated Electric Cooperative, Inc. - Thomas Hill Plant
P.O. Box 754
Springfield, MO 65801

RE: New Source Review Applicability Determination Request - Project: 2006-05-022
Installation ID Number: 175-0001

Dear Mr. Tolbert:

Your request for a determination of permit need for the replacement of cyclone burners for units 1 and 2 was reviewed by my staff. According to Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required*, **no construction permit is required** from the Missouri Air Pollution Control Program.

The cyclones in the two Thomas Hill units have been in service for over 37 years. Over the years coal ash and slag have accumulated within the metal casing that surrounds the inlet header and the barrel tubes. The ash and slag have combined with water from tube leaks to form a corrosive environment that has reduced the wall thickness of the cyclone barrel tubes. Ultrasonic readings have found areas where the wall thickness is only 0.1000-inch thick, compared to the original 0.250-inch thickness. In addition to the new cyclone barrel tubes, re-entry throat tubes, inlet/outlet/intermediate headers, upper and lower neck headers, and shut-off and control dampers will also be replaced.

The replacement parts for this project are expected to be $10 million for Unit 1 and $15 million for Unit 2. Those values represent approximately 2.8 percent of the replacement costs for each unit. Reconstruction is defined in 10 CSR 10-6.020 (2)(R)2 as:

> *"Where the fixed capital cost of the new components exceeds fifty percent (50%) of the fixed capital cost of a comparable entirely new source of operation or installation."*

The replacement does not constitute a reconstruction. Since there will be no increase in the potential to emit, according to the applicant, the change can not be considered a modification, per Missouri State Rule. Therefore, since replacement of the cyclone burners does not meet the definition of construction, reconstruction or modification, the replacement is exempt from permitting requirements.

You are still obligated to meet all applicable air pollution control rules, Department of Natural Resources' rules, or any other applicable federal, state, or local agency regulations. Specifically, you should avoid violating 10 CSR 10-3.030, *Open Burning Restrictions*, 10 CSR 10-6.170, *Restriction of Particulate Matter to the Ambient Air Beyond the Premises of Origin*, and 10 CSR 10-3.090, *Restriction of Emission of Odors*.

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AM-00025868-MDNR

A copy of this letter should be kept with the unit and be made available to Department of Natural Resources' personnel upon verbal request.

If you have any questions regarding this determination, please contact Lina Klein at the Air Pollution Control Program, P.O. Box 176, Jefferson City, MO 65102 or you may phone (573) 751-4817. Thank you for your time and cooperation.

Sincerely,

AIR POLLUTION CONTROL PROGRAM

Kyra L Moore

Kyra L. Moore
Permits Section Chief

KLM: lkk

c: Northeast Regional Office
PAMS File 2006-05-022

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust Its Revenues for Electric Service.	)))	Case No. ER-2022-0337

AFFIDAVIT OF JEFFREY R. HOLMSTEAD

WASHINGTON, D.C.) ss

Jeffrey R. Holmstead, being first duly sworn states:

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

Jeff Holmstead
Jeffrey R. Holmstead

Sworn to me this 27th day of July, 2022.

KAREN MARIE BISHOP
NOTARY PUBLIC
DISTRICT OF COLUMBIA
EXP. 4-30-27