FILED
April 30, 2024
Data Center
Missouri Public
Service Commission

Exhibit No. 10

Ameren – Exhibit 10
Holmstead
Direct
File No. EF-2024-0021

Exhibit No.:	
Issue(s):	Prudence and Reasonableness of Ameren Missouri's NSR Permitting Decisions
Witness:	Jeffrey R. Holmstead
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Union Electric Co.
File No.:	EF-2024-0021
Date Testimony Prepared:	Nov.21, 2023

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. EF-2024-0021

DIRECT TESTIMONY

OF

JEFFREY R. HOLMSTEAD

ON

BEHALF OF

UNION ELECTRIC COMPANY

d/b/a AMEREN MISSOURI

St. Louis,Missouri
November 21, 2023

TABLE OF CONTENTS

DIRECT TESTIMONY

OF

JEFFREY R. HOLMSTEAD

FILE NO. EF-2024-0021

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jeffrey R. Holmstead. My business address is 2001 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 federal New Source Review ("NSR") regulations at issue in the Ameren Missouri litigation in the U.S. District Court for the Eastern District of Missouri (the "District Court").

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.

Q. To what extent have you worked with electric utilities on CAA compliance issues?

A. Since I joined Bracewell in 2006, much of my practice has involved working with electric utilities on CAA compliance issues, including NSR compliance. I have advised a number of individual electric utility companies on whether they would need to obtain NSR permits for specific projects at existing facilities.

II. PURPOSE OF TESTIMONY

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 Energy Center ("Rush Island") that gave rise to the District Court's decisions – 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 ("MDNR"), 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—regardless of any emissions impact.

- 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's understanding of the law and its conclusions concerning NSR applicability were in line with the views of state regulators and the public statements from EPA's program office at the time.
- Ameren Missouri's understanding of the law and its conclusions concerning NSR applicability were also in line with the views of most other electric utilities at the time. 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. Indeed, there is evidence that hundreds of such projects had been undertaken at coal-fired units throughout the country prior to the Rush Island Projects, and not one had ever sought or obtained an NSR permit for any of them.
- 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. <u>THE CLEAN AIR ACT AND ITS NEW SOURCE REVIEW PROGRAM</u>

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 in Missouri for most CAA programs, which have been approved by EPA and are administered by MDNR.

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

A. Congress added the New Source Review (NSR) program to the CAA as part of the 1977 amendments to the Act. In 1978 and again in 1980, EPA issued regulations to implement the NSR program. EPA updated those federal regulations in 1992 and again in 2002, as I will discuss below. States could either adopt the federal regulations in their SIPs or develop their own version of the NSR program and, with EPA approval, implement the state version of NSR though the SIP.

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 such permits 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 federal NSR program also applies to existing power plants, but only if they undergo a "major modification." Under the federal NSR regulations, a "major modification" is defined as a physical or operational change that causes a significant net increase in annual emissions. The NSR program is not the primary regulatory program for controlling emissions from existing power plants. In fact, there are many other CAA programs that are specifically designed to reduce emissions from such plants.

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 actual annual 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.

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. As the name implies, 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 convention and refer generally to the “NSR program” and “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).

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. 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 approved by EPA and incorporated into SIP-approved NSR programs. As noted earlier, Missouri has its own EPA-approved NSR program, which was in place when Ameren Missouri was undertaking the Rush Island Projects.

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

A. Yes. Some SIPs employed a "potential-to-potential" approach for measuring increases in emissions in determining NSR applicability.

A. The Potential-to-Potential Test for Determining NSR Applicability

Q. What is the "potential-to-potential" test for determining whether a project would cause an emissions increase?

A. As the name suggests, the "potential-to-potential" test is based on a facility's potential emissions when operating at its maximum capacity. It compares potential emissions before a proposed change to potential emissions after that change. The potential-to-potential test is often based on a facility's maximum potential hourly emissions rate, but it can also be based on annual emissions. When annual emissions are used, the "potential" emissions are the maximum emissions that the unit could potentially emit, assuming that the unit operates at its highest achievable rate for every hour in the year. Because the assumed hours of operation are the same in both the "before" and "after" calculation (8,760 hours, the number of hours in a standard, non-leap year), the potential-to-potential test boils down to asking whether the change would increase the maximum achievable hourly rate of emissions. If it won't, the NSR permitting inquiry is at an end; an NSR permit is not required.

Q. Did SIPs use this "potential-to-potential" test to evaluate emissions increases for NSR applicability?

A. Yes. 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 and does not require a company to estimate how much the subject source (e.g., a power plant) will operate in the future. If a project changes the physical characteristics of an emission unit in a manner that would increase its size or operational capacity, 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.

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]." Conn. Agencies Regs. § 22a-174-1 (1990). 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 encouraged the state to change its applicability provisions. Connecticut eventually did so, with EPA approving the change in 2003. 68 Fed. Reg. 9009 (Feb. 27, 2003).

Like the SIPs in Nevada and Connecticut, the SIP approved by EPA for Missouri also had a potential-to-potential emissions test for determining applicable permitting requirements. As discussed below, MDNR and Ameren Missouri believed that the potential-to-potential emissions test remained applicable leading up to and when all of the Rush Island Projects were constructed.

Q. Was that Missouri SIP approved by EPA?

A. Yes. Missouri has had a SIP-approved NSR program dating back to 1980. 45 Fed. Reg. 30626 (May 9, 1980). A revised version of the State's NSR program, which included the applicability provisions discussed below, was approved by EPA in 1996. 61 Fed. Reg. 7714 (Feb. 29, 1996). This means that ever since 1980, the NSR program applicable to facilities in Missouri would be found in Missouri's EPA-approved regulations, and MDNR has had primary responsibility for implementing Missouri's SIP-approved NSR program.

B. <u>Missouri's Two-Step Approach to NSR Applicability</u>

Q. Please describe the NSR applicability provisions in Missouri's SIP-approved program that were in effect when the Rush Island Projects were undertaken.

A. Missouri's SIP-approved NSR program, 10 CSR 10-6.060 and 10-6.061 (Nov. 30, 2006), 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 served 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). These permitting 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 were set forth under the heading, "Construction Permits Required – Applicability." Section (1)(C) of these regulations stated that "[n]o owner or operator shall commence construction or modification 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) (Nov. 30, 2006) (emphasis added). 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.

"Construction" under the Missouri SIP was the creation of a new source of emissions (i.e., a new facility). Thus, the "construction" part of the rule did not apply to the Rush Island Projects because it was not a new facility. Under the Missouri SIP, a "modification" occurs only when a project at an existing facility will cause an increase in potential emissions from that facility. Similar to the Nevada and Connecticut programs described above, the Missouri SIP defines "modification" as a physical or operational change of "a source operation" that causes an "increase in potential emissions of any air pollutant emitted by the source operation." 10 CSR 10-6.020(2)(M)(10) (Nov. 30, 2006) (emphasis added). "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 defined 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 under the SIP 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. Regulators would say that the project is "screened out" at this point.

If a project is a modification under this "potential-to-potential" emissions test, then the Missouri regulations proceed to a second step, in which MDNR must determine whether the "modification" is also a "major modification." For that second step (determining whether the project is also a "major modification"), the Missouri SIP directed MDNR to apply the federal NSR rules by incorporating them by reference. 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). If the proposed project would not first increase potential emissions, the Missouri SIP, as it was understood at the time of the Rush Island Projects, said that no permit was required.

Q. Was this how MDNR applied the SIP?

A. Yes. 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 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, attached as Schedule JRH-D2. 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 . . . ."[1] Moore Dep. at 83. Again, she confirmed that this is correct. *Id.*

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 cannot 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-D3.

In short, both the text of the Missouri SIP as it existed when Ameren Missouri performed the Rush Island Projects, and the settled application of that text by MDNR at the time, first asked whether a project would increase potential emissions. If it would not, then the project was not a "modification" and thus there was no need to apply step two (the federal PSD regulations incorporated into the SIP) to determine whether the project was also a "major modification" requiring an NSR permit.

[1] Step two being further evaluation of what the actual annual emissions would be after the project's completion.

Q. If there was a need to proceed to step two under the Missouri SIP, what would come next?

A. As I mentioned, step two under the Missouri SIP incorporated the federal NSR regulations directly. 10 CSR 10-6.060(8). The SIP approved by EPA at the time of the Rush Island Projects incorporated many (but not all) of the federal PSD rules found at 40 C.F.R. Part 52 (2002). 10 CSR 10-6.060(8) (Nov. 30, 2006). Thus, application of step two (considering whether the "modification" was also a "major modification") required reference to the federal PSD regulations as well as how those regulations had been interpreted and applied by EPA.

C. <u>EPA's NSR Regulations Incorporated into the Missouri SIP</u>

Q. How did the 2002 federal NSR regulations, incorporated into the Missouri SIP, define "major modification"?

A. A "major modification" is a "physical change or change in the method of operation" of a major stationary source that "would result" in a "significant net emissions increase." As EPA has noted, this definition essentially creates a two-part test for a "major modification" 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 final NSR rule). If the answers to both questions are "yes," then that project is said to "trigger" NSR and permitting is required prior to commencing construction. The regulations exclude from the definition of "physical change" any "routine maintenance, repair or replacement" ("RMRR" for short). The regulations do not specify, however, how a major stationary source should calculate projected future emissions and thereafter determine whether the project causes any such projected increase.

Q. What steps has EPA taken to explain and implement the "major modification" trigger in the federal NSR rules?

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. 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 utility industry generally viewed all replacement of existing power plant components with functionally equivalent components as 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 (also known as "generating units"), 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. Having decided that the work did not fall under the RMRR exclusion, and that the work would cause emissions increases that would exceed EPA's "significance levels," the EPA decided that the project would constitute 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, the Administrator 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 require power plants to obtain NSR permits for many component-replacement projects that they viewed as routine. 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 General Accounting Office ("GAO"), now called the Government Accountability Office, 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. Among other things, GAO interviewed EPA staffers involved in NSR issues. The Chairman of the House Energy and Commerce Committee (which was responsible for overseeing EPA) also sent a letter to EPA asking the agency 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 members of Congress that the WEPCO decision would not have a significant impact on other power plants. His letter affirmed the views of EPA staff reported in the GAO Report:

> 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, attached as Schedule JRH-D4.

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 57 Fed. Reg. at 32,323-26. 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 change at a power plant would result in an emission increase because no plant actually operates round the clock for 365-days-a-year, meaning that future emissions would always be 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 on the definition of "major modification"?

A. Yes. In the 2002 NSR Reform Rule, EPA clarified how to compare past actual emissions with projected future actual 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 as a "major modification." When it comes to past actual 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" in tons per year. This number represents past actual annual emissions.

When estimating future actual annual emissions (*i.e.*, what the annual emissions will be after the change), the rules 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. But the rules do not prescribe any particular method for estimating or projecting future actual annual emissions.

When EPA proposed these rules, it got public comments asking the agency to specify particular methods that should be used to estimate future actual annual emissions, but EPA decided that doing so would not be feasible. As EPA explained when responding to these comments, environmental regulators could not enumerate all the factors that might affect future emissions because this would depend in large part on business and economic 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-5-25 to I-5-28, *available at* https://www.epa.gov/sites/default/files/2015-12/documents/nsr-tsd_11-22-02.pdf (attached as Schedule JRH-D5)

If the projected future actual annual emissions in all the 12-month periods are always lower than the baseline emissions, then that's the end of the analysis, and an NSR permit is not required. 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 actually caused by the project.

Q. How do you determine whether a projected increase in future emissions would be caused by a particular project?

A. Actual 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 within the area served by the utility system. 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.

Q. In your experience, in the period from 2000 – 2010, how would a reasonable power plant operator in Missouri have determined whether it needed an NSR permit for a particular project?

A. As I mentioned earlier, a reasonable power plant operator would have applied the approved SIP (here, the Missouri SIP), because that is the law that actually applies. During the time period when Ameren was planning and undertaking the Rush Island Projects, it was reasonable to read the Missouri SIP as requiring NSR permits only for something that would be <u>both</u> a "modification" (*i.e.*, it would cause an increase in potential emissions) and a "major modification" (*i.e.*, it would cause an increase actual annual emissions above the applicable significance levels). If a project would not be a modification (because it would not cause an increase in potential emissions), there would have been no need to determine whether it would also be a major modification. On the other hand, if a project will cause an increase in potential emissions (and thus be a modification), the operator would need to determine whether it would also be a major modification for which an NSR permit is required.

Q. How would a reasonable power plant operator determine whether a project would be a "major modification"?

A. In assessing whether something is a "major modification" under the NSR rules, 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 a significant increase in actual annual 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. A key exclusion under both the federal rules and the SIP-approved Missouri NSR rules is for projects that are considered to be RMRR. When evaluating the type of maintenance and repair work typically performed during an outage at a power plant, the question of whether such work constitutes a "physical change" normally depends on whether it qualifies as RMRR.

Q. And what would a reasonable power plant operator consider in applying the RMRR exclusion?

A. A reasonable power plant operator would consider the plain text of the RMRR exclusion, which covers "repair" and "replacement" of components in addition to "maintenance." The reasonable power plant operator would also consider the available statements by the regulators concerning the scope of the RMRR exclusion, including those statements by EPA I have summarized above. The operator would also consider the extent to which similar projects have been done at other plants and whether other operators have obtained NSR permits for such projects.

Q. If a proposed project is not RMRR (and thus is a physical change), how would a reasonable power plant operator determine whether the project will cause an increase in emissions that would trigger NSR?

A. 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 annual emissions prior to the change to the projected actual annual emissions after the change. The actual-to-projected-actual methodology from the NSR Reform Rule was adopted into the Missouri SIP in 2006. But to reiterate the point I made earlier, it is clear that, at the time of the Rush Island Projects, both MDNR and Ameren Missouri believed that it was not necessary to apply this actual-to-projected-actual rule to projects (like the Rush Island Projects) that would not increase potential emissions and would thus be "screened out" of permitting requirements.

If you assume that the actual-to-projected-actual rule had been triggered, the 2002 NSR Reform Rule does not prescribe a particular method for making projections about future actual emissions after a physical change is made to a plant. In fact, 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 projected 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. To project future emissions and to determine whether any projected increase would be caused by a particular project, the plant operator always needs to exercise engineering judgement.

Q. This seems very complicated. If there is any question as to whether a project might be viewed as a "major modification," why wouldn't a plant owner simply get an NSR permit for it?

A. First of all, one thing that was not complicated was the threshold determination that needed to be made under the Missouri SIP: would the change increase potential emissions at maximum design capacity? There is no dispute that for the Rush Island Projects, potential emissions would not increase when the plant is operating at its maximum design capacity Ameren Missouri's engineers made this very clear (see Boll Declaration, attached as Schedule JRH-D6), and no one has ever disputed this fact. Knowing that to be the case, and understanding that under the Missouri SIP the Rush Island Projects were screened out, there was no reason to get a permit.

Moreover, the process for getting an NSR permit is long and costly, especially for a coal-fired power plant, in large part because of opposition from environmental groups that oppose all such plants. By the late 1990s, it could easily take several years to obtain an NSR permit for a coal fired power plant, followed by one to two years of litigation to defend the permit in court.

V. ROLE OF ENVIRONMENTAL SERVICES DEPARTMENT

Q. Ameren Missouri was supported on all environmental matters by the Environmental Services Department within Ameren Services Company. Did this department undertake reasonable efforts to understand New Source Review requirements before the Company began planning the Rush Island Project?

A. It is clear that the Environmental Services Department was very well aware of the NSR program and NSR requirements. Among other things, Ameren Missouri was a member of the Utility Air Regulatory Group ("UARG"), a large coalition of power companies and national trade associations that kept its members well informed about NSR regulatory and litigation developments. The record shows that Ameren Missouri participated actively in UARG meetings about NSR and other regulatory issues. Even though UARG was represented by a law firm that competes with my own, I can say that at the time, UARG was the best source in the country for information and analysis of regulatory and permitting requirements for coal-fired power plants. The record shows that UARG provided Ameren Missouri with detailed information about NSR developments on a regular basis in the years leading up to the Rush Island Projects. It is clear that Ameren paid close attention to NSR requirements – the specific requirements in the Missouri NSR regulations and EPA's efforts to implement NSR on a national basis. From its participation in UARG, Ameren Missouri was aware that many other companies had done the same types of projects at coal-fired power plants that it was planning to undertake at Rush Island, and that no other company had sought NSR permits for such projects.

Q. What type of information did the Environmental Services Department receive from UARG regarding NSR requirements and the type of projects that required NSR permits?

A. I have had the chance to review numerous documents that UARG provided to Ameren's Environmental Services Department, and they are remarkably comprehensive. It is clear that UARG was paying close attention to regulatory actions involving the NSR program and also to the NSR enforcement actions that EPA had brought against electric utilities. UARG was also providing its member companies (including Ameren) with detailed information and analysis about these matters. On at least one occasion, a key official from EPA's NSR Group (Lynn Hutchinson) attended an in-person meeting with UARG members (including Steven Whitworth from Ameren's Environmental Services Department) to discuss the 2002 NSR Reform Rule I mentioned earlier.

Mr. Whitworth was very involved in UARG, as his testimony filed in this docket demonstrates. He was Ameren's official representative on the UARG Policy Committee (which directed all UARG activities) and on the "Planning, Repair, Enforcement, and Permitting" ("PREP") Committee, which was focused on NSR. Through UARG (and especially the PREP Committee), Ameren's Environmental Services Department was well informed about:

- The numerous regulatory actions that EPA had taken over the years to establish and then revise the NSR program, including all the actions I discussed earlier. See Schedule SCW-D9, Schedule SCW-D13, Schedule SCW-D14.
- How the NSR regulations had been interpreted and applied by regulators over the years, including the WEPCO decision and the letter I discussed earlier from the head of the EPA Air Office—the letter stating that only "WEPCO type changes" would trigger NSR and that the WEPCO decision "is not expected to significantly affect power plant life extension projects." See Schedule SCW-D4.
- How other utilities were interpreting the NSR regulations. In fact, Ameren received a detailed memorandum from UARG showing that other power companies had collectively made more than a hundred component replacements that were the same as or similar to the component

replacements in the Rush Island Projects—and that no one had sought an NSR permit for any of these projects. See Schedule SCW-D6.

- The positions taken by EPA's Office of Enforcement and Compliance Assurance ("OECA") in the utility NSR enforcement initiative. See Schedule SCW-D4, Schedule SCW-D11, Schedule SCW-D12
- The conflict between the ways in which NSR was being interpreted by EPA's program office (the Office of Air and Radiation) and the interpretations that OECA was advancing in the NSR enforcement cases. See Schedule SCW-D3, Schedule SCW-D5.
- The arguments that utilities were making in response to OECA's enforcement interpretations. See Schedule SCW-D4, Schedule SCW-D11, Schedule SCW-D12.[2]
- The fact that EPA lost more often than not in the litigated cases. I was aware of this fact, but it is interesting to see the updates that UARG regularly provided its members to show the decisions made in enforcement cases, along with slides showing that more courts were agreeing with utilities than with EPA. See Schedules SCW-D10 to SCW-D18.

Q. What does the record show regarding the role of the Environmental Services Department in reviewing the Rush Island Projects for New Source Review requirements?

[2] The utility industry was certainly not the only industry sector that strongly disagreed with regulatory interpretations that EPA took in NSR enforcement actions. EPA has pursued NSR enforcement initiatives against refineries, wood products plants, cement plants, and glass manufacturing plants. And companies targeted by those enforcement initiatives strongly objected to positions taken by the EPA enforcement office.

A. It is clear that the Environmental Services Department made the decision that no NSR permits were required for either of the Rush Island Projects. This was made clear in the declaration and testimony submitted by Steven Whitworth in the District Court case. On December 4, 2013, and September 5, 2014, Steven Whitworth gave depositions in the District Court enforcement case. In 2015, Mr. Whitworth provided a sworn declaration, attached hereto as Schedule JRH-D7. That prior testimony by Mr. Whitworth explained in some detail the role that he and the Environmental Services Department played in reviewing the Rush Island Projects and how they determined that that the Company did not need NSR permits for them. Mr. Whitworth has confirmed that prior testimony and expounded upon it in his direct testimony filed contemporaneously in this docket.

VI. AMEREN MISSOURI'S APPLICABILITY DETERMINATIONS

Q. Have you been asked to evaluate Ameren Missouri's NSR applicability determinations on the Rush Island Projects?

A. Yes, I have been specifically asked to provide my opinion on whether Ameren Missouri's pre-project applicability determinations were reasonable.

Q. How do you go about determining whether Ameren Missouri made a reasonable determination that the Rush Island Projects would not trigger NSR?

A. This can be done only by looking at the regulatory and legal landscape that existed at the time—what Ameren Missouri knew or should have known when it had to make these determinations. That's why I have talked about the applicable regulations, the things that MDNR and EPA were saying about those regulations, the views and actions taken by other companies dealing with the same issues, the positions EPA was taking in

NSR enforcement cases, and the court decisions in those cases. In hindsight, it's tempting to look at the results of the enforcement action against Ameren Missouri, but the Company could not reasonably have anticipated these results (e.g., that the District Court would interpret the Missouri SIP in a completely different manner than MDNR itself had interpreted and applied it) when it was planning the Rush Island Projects and deciding whether it needed NSR permits for them.

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 MDNR 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; 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 led Ameren Services Company's Environmental Services Department from 2007 until 2018, when a corporate reorganization occurred. From 2018 until his recent retirement, Mr. Whitworth led the environmental services department dedicated exclusively to Ameren Missouri. 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-D6 (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.[3]

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 pre-project NSR applicability determinations for the Rush Island Projects.

[3] As noted above, Mr. Whitworth confirmed this prior testimony in his direct testimony filed contemporaneously in this docket.

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. In addition, I have reviewed Mr. Whitworth's testimony in the District Court and in this docket. As reflected in these documents, the Company had three basic reasons for these determinations, any one of which by itself was sufficient to justify not obtaining an NSR permit:

- Under the applicable regulations in the Missouri SIP, as they had been interpreted by MDNR, 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 (i.e., the Rush Island Projects were screened out of permitting requirements).
- 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—regardless of any emissions impact.

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. 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 <u>then</u>, 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 were undertaken, 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 at the time.

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 based on the District Court's later interpretation of the requirements in a manner different than they were understood and applied a decade earlier. But if you look at the regulatory and legal landscape at the time that Ameren Missouri made its compliance decisions—as one must do in order to evaluate the prudence of those 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.

A. <u>Potential Emissions</u>

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 MDNR 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.

In 2015, Steven Whitworth, the Senior Director for Environmental Policy and Analysis at Ameren Services Company, signed a sworn declaration on behalf of Ameren Missouri 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 an environmental specialist or lawyer at any power company would have reached a different conclusion.

It's also important to note that Missouri was not alone in having SIP-approved regulations that "screened out" projects that would not increase potential emissions. 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.

It is undisputed that none of the Rush Island Projects 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 be a "major modification" that would trigger NSR. Whitworth Declaration ¶¶ 9, 13. This was a reasonable understanding at the time.

B. <u>Actual Emissions</u>

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. Is this correct?

A. Ameren Missouri clearly believed that such a determination was not required because none of the Rush Island Projects would be a modification under the Missouri NSR Program, but Ameren Missouri did consider the question of whether the Projects would cause an increase in actual emissions, albeit in a qualitative manner rather than by doing calculations.

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 rely on their knowledge of their operations and the markets they serve to make these assessments. In many cases, making these assessments can be relatively straightforward. As long as the particular project will not increase the capacity of a plant or result in a material change in its efficiency sufficient to change its dispatch order on the system (and there is no evidence that the Rush Island Projects did either of these things), an electric utility 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. EPA acknowledged as much in 2005, when it stated that the existing 2002 NSR rules would generally produce the same result as would a rule that would be triggered only by an increase in maximum achievable hourly rate (i.e., an increase in potential emissions). See Schedule SCW-D13.

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. Based on my experience with the power sector, I think that other power companies would have made the same determination.[4]

Again, I am aware that that the District Court found that Ameren Missouri's consideration of future actual emissions was not consistent with the Court's interpretation

[4] I am 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 given what Ameren Missouri knew or should have known at the time about the actual-to-projected-actual test.

of EPA's NSR requirements, but this decision came almost a decade after Ameren had made its determinations. In my opinion, based on what the Company knew or should have known at the time, Ameren Missouri's determination that the Rush Island Projects would not cause an increase in actual annual emissions was reasonable.

C. RMRR

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 you think that this was 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" 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.

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, at those operated by their Illinois affiliate, 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.

D. Applicability Determinations

Q. Could Ameren Missouri have consulted with the permitting agency to confirm its conclusions that no permit was required for the Rush Island Projects?

A. This is possible but rarely done—and never (as far as I know) in a case such as this one, where company officials were familiar with the applicable NSR regulations and, based on their understanding of these regulations, reasonably believed it was clear that they didn't need permits for the Rush Island Projects.

To get this kind of assurance, the plant owner must seek a formal "applicability determination" from the permitting agency, and this process often takes many months and, in some cases, it can take more than a year. When maintenance or replacement projects are needed at a plant and can only be done during a planned outage, companies do not want to take the time to get an applicability decision unless it involves a novel issue of first impression. This wasn't the case here.

I should also point out that this kind of pre-approval or consultation is not required under any federal or state rules, and EPA has acknowledged that it is normally not practical for companies to do so.

Q. Was it reasonable for Ameren Missouri to proceed with the Rush Island Projects without asking MDNR if the Company needed to obtain NSR permits for them?

A. Yes. As I mentioned earlier, this kind of pre-approval or consultation is not required under any federal or state rules, and regulatory agencies have acknowledged that it is normally not practical for companies to do so. When a company believes that it understands the relevant regulations (as Ameren Missouri did here), there is no need to consult with the permitting agency about specific situations. Regulated parties may also reasonably rely on prior applicability determinations issued by the regulators. It would certainly have been reasonable for Ameren Missouri to rely upon the "no permit required" letters issued by MDNR for similar projects at other electric utilities in Missouri.

It also appears that, if Ameren Missouri had consulted with MDNR ahead of time about the Rush Island Projects, MDNR would have said that neither of them required an NSR permit. This is clear from the testimony offered by Kyra Moore, the Director of MDNR's Division of Environmental Quality and from prior "no permit determinations" referenced in her testimony. She testified that, as MDNR understood its own rules at the time, a project at an existing power plant would not need an NSR permit unless it was a "modification," and a project is not a modification unless it would increase potential emissions at a plant when operating at its maximum design capacity. Ameren Missouri was aware of the plain text of the Missouri SIP and how it had been applied by MDNR to exclude boiler component replacement projects from NSR requirements, where such projects would not increase potential emissions. The declaration and testimony of Mr. Whitworth make this abundantly clear.

It is undisputed that none of the Rush Island Projects increased potential emissions at Rush Island. Thus, under the Missouri SIP as MDNR understood and applied it, if the Company had sought a formal "no permit needed" letter for the Rush Island Projects, it appears that it would have received one.

Q. Should Ameren Missouri have sought the concurrence of EPA before proceeding with the projects?

A. No. Again, there is no requirement in federal or state regulations for a company to consult with any regulatory agency regarding permitting decisions in a case such as this one. Even if a company wanted to seek concurrence of a determination that no permit is required in a state with a SIP-approved NSR programs (like Missouri), the company would normally go to the state permitting authority (in this case MDNR)—not to EPA. And as I just noted, if Ameren Missouri had gone to MDNR, MDNR almost certainly would have said that the Company did not need NSR permits for the Rush Island Projects.

When companies decide whether a permit is needed for a particular project, they almost always do what Ameren Missouri did in this case: they rely on what the regulations say, what regulators have said about permitting requirements, what they know based on their experience, and what they know from industry groups such as UARG.

The information that UARG provided to Ameren Missouri includes a body of EPA guidance and interpretations that support Ameren Missouri's applicability determinations, as I have summarized above. Moreover, I again note that a key official from EPA's NSR

Office actually gave a briefing to UARG members on the applicability provisions of the 2002 NSR rule, which was in place when Ameren Missouri planned and undertook the Rush Island Projects.

For all these reasons, it would have been surprising if the Company had consulted with either MDNR or EPA regarding the question of whether permits were required.

Q. If EPA and MDNR interpret MDNR's regulations in a different way, which interpretation is considered to be correct?

A. When a state has a SIP-approved NSR program (as Missouri does), the state has primary responsibility for implementing it. If EPA disagrees with a state's interpretation of the SIP, EPA's interpretation does not automatically control. In enforcement cases, the court will decide which interpretation is correct, which is what happened here. The District Court found that EPA's interpretation of the MDNR rules was the correct one—not that EPA's interpretation of a SIP-approved program always controls. As I noted earlier, the District Court found that the definition of "modification" in the Missouri SIP did not apply to NSR, but the Court did not find that MDNR's and Ameren Missouri's understanding of the SIP-approved NSR program unreasonable. I understand that the latter is the question in this case: was it reasonable for Ameren Missouri to have interpreted the Missouri SIP as it did, based on what it knew or should have known at the time?

VII. THE DISTRICT COURT DECISIONS

Q. In the NSR enforcement case against Rush Island, did the District Court apply the interpretation of the Missouri SIP held by MDNR and Ameren Missouri?

A. No. In the NSR enforcement case, EPA's enforcement office argued, and the District Court found, that, when the 2002 NSR Reform Rules were incorporated into the Missouri SIP, this effectively eliminated the first step in the Missouri applicability regulations, which provided that a repair or replacement project at an existing plant would not be a major modification unless it was a "modification," as defined above. This was not done explicitly, but the Court believed that this is what EPA intended when it approved a SIP-revision to incorporate the 2002 Rules. Thus, under the Court's reading, a project could be a "major modification" even if it was not a "modification." This was an issue of first impression that no court had previously decided.

Q. Does the fact that a court later ruled against Ameren Missouri mean that Ameren Missouri's understanding of the state's NSR regulations was unreasonable at the time?

A. No. It is important to remember that the court adopted this interpretation of the state's regulations years after Ameren Missouri had completed the Rush Island Projects. Until the court's decision, the Missouri DNR (the state agency in charge of implementing the SIP-approved NSR program) interpreted them differently and told companies that a project at an existing plant would not be a "major modification" that would trigger NSR unless it was a "modification" that would increase the plant's potential emission when operating at its maximum design capacity.

The record shows that, when Ameren Missouri was planning the Rush Island Projects and determining whether it needed NSR permits for them, this was its understanding of the regulations too. At that time, it was certainly reasonable to believe that you must first determine whether a project is a "modification" before you need to decide whether it is a "major modification." Given that this was the most straightforward interpretation of the regulations and was also Missouri DNR's interpretation of them, it was reasonable for Ameren Missouri to believe that the Rush Island Projects would not trigger NSR unless they would increase the plant's potential emissions. Nobody contended in the District Court litigation that the Rush Island Projects increased potential emissions.

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. I believe that, before the District Court's decision, this was the most reasonable way to interpret the NSR permitting regulations in the Missouri SIP.

Q. It seems like you're basically saying that the District Court and 8th Circuit got it wrong—that Ameren Missouri acted lawfully when it went ahead with the Rush Island Projects without getting NSR permit.

A. No, I am not taking issue with any of their decisions. As I noted earlier, their decisions are the law. But the question here is ***not*** whether Ameren Missouri violated the Clean Air Act. That issue was decided by the courts. As I understand it, the only question within the purview of the Commission is whether Ameren Missouri officials acted prudently in deciding that they did not need NSR permits for the Rush Island Projects, based on the facts and circumstances known to them in 2005-2010. I am simply pointing out that, based on what Ameren Missouri knew or could have known at the time, it was reasonable for Company officials to believe that they did not need NSR permits for the Rush Island Projects.

Q. Is there anything in the history of the District Court litigation that supports the conclusion that Ameren Missouri made reasonable decisions?

A. As I have said, the question of whether these decisions were reasonable or prudent was not before the court, and the District Court did not specifically address this question in any of its orders. However, when EPA filed a motion for partial summary judgement asking the court to rule that the Rush Island Projects did not qualify as RMRR, the judge denied it, holding "I cannot say that no reasonable factfinder could find for Ameren." *United States v. Ameren*, No. 4:11-cv-77, Mem. Order on Cross-Mot. Summ. J. at 16 (Feb. 24, 2016). The District Court also denied several other EPA motions for partial summary judgement on other issues, noting that there were material issues of fact that required hearing from witnesses on both sides. *See e.g. id.* at 25; *see also id.* at 46-48. Although the Court eventually ruled in favor of EPA on these issues, it never said that Ameren Missouri's positions on these issues were unreasonable.

It is also notable that, after ruling in favor of EPA, the District Court stayed its order granting injunctive relief pending a decision on appeal to the 8th Circuit. The Court agreed with Ameren "the legal questions were substantial and matters of first impression" and found that "Ameren's appeal may raise issues of first impression sufficient to satisfy" the requirements for obtaining a stay pending review. *United States v. Ameren*, No. 4:11-cv-77, Order Granting Motion to Stay (Oct. 22, 2019) at 2.

Q. How do you square your claim that Ameren Missouri acted reasonably with the District Court's statement in the 2019 remedy opinion "that Ameren's failure to obtain PSD permits was not reasonable"?

A. First, the issue of whether Ameren Missouri acted reasonably, based on what it knew or should have known at the time, was not before the District Court. That Court found that Ameren's interpretation of the MDNR regulations (which was the same as MDNR's interpretation of its regulations) was incorrect and that, based on a correct reading of the regulations, Ameren Missouri had acted unlawfully. This is not the same as saying that Ameren Missouri acted unreasonably based on what it knew or should have known at the time. In any case, the quote you mentioned is not even from the relevant District Court opinion—the 2017 liability opinion in which the court found that Ameren Missouri had violated the Clean Air Act by commencing construction without getting an NSR permit. Instead, the quote is from the 2019 remedy opinion, which dealt with a different issue: what injunctive relief should be imposed for the violation the District Court found in the 2017 liability opinion.

Q. Did the 2017 liability opinion establish that Ameren Missouri's failure to obtain PSD permits was "not reasonable"?

A. No. The Clean Air Act is a strict liability statute. A court does need to find that a Company acted unreasonably or imprudently in order to find it liable for violating the statute (or regulations issued under the statute.)

The District Court's liability opinion made no findings of fact concerning whether Ameren Missouri was reasonable or acted reasonably under the circumstances. The only time that the District Court characterized something as "not reasonable" in the liability opinion came in its conclusions of law. And there, each reference to "not reasonable" concerned only the actual annual emissions calculations offered by Ameren Missouri at trial. <u>See</u> 229 F. Supp. 3d at 1010 ("Ameren's emissions calculations are not reasonable analyses ***under the PSD rules*** and therefore do not show that Ameren should not have expected an emissions increase.") (emphasis added); id. at 1012 (emissions analyses did not comply with NSR requirements "***and therefore*** was not reasonable under the law") (emphasis added); id. at 1014 (post hoc calculation offered "does not serve as a reasonable emissions calculation"); id. ("Ameren failed to perform a reasonable analysis ***under the PSD rules***") (emphasis added). The District Court was commenting on the reasonableness of the actual annual emissions analyses based on the Court's reading of the PSD rules—nothing else. The District Court's characterization of those analyses as "not reasonable" meant only that the calculations did not conform to the requirements of the PSD rules as the court had declared them in its summary judgment order and in the liability opinion itself.

The District Court did not pass judgment on whether it was reasonable for Ameren Missouri to believe that its projects would not trigger PSD permitting under the Missouri SIP because they would not increase potential emissions. Nor did it pass judgment on whether it was reasonable for Ameren Missouri to believe that its projects would not cause annual emissions to increase, because the Rush Island units were capable of accommodating increased utilization and emissions. And nowhere did the District Court pass judgment on whether Ameren Missouri's interpretation and application of the "routine" exclusion for the Rush Island projects was reasonable or unreasonable.

Ameren Missouri's actions comported with the law as it was widely understood at the time and were consistent with the approaches taken by similarly situated electric utilities across the country. For these reasons, I believe that they were reasonable.

Q. Do other aspects of the District Court litigation support the conclusion that it was not about whether Ameren Missouri had acted unreasonably?

A. As I mentioned earlier, the question of whether Ameren Missouri acted reasonably or made prudent decisions when it decided not to seek NSR permits for the Rush Island Project was <u>not</u> before the District Court. The question for the court was whether, under the applicable regulations, Ameren Missouri was required to get such permits before undertaking the Projects. The court found that Ameren Missouri's interpretation of the relevant regulatory provisions was incorrect and that, under the correct interpretation, Ameren Missouri had violated the law by failing to obtain NSR permits. The court did not say that Ameren Missouri's interpretations were unreasonable – just that they were incorrect.

There is, however, one aspect of the District Court litigation that is relevant to the question of reasonableness. In a summary judgement motion, Ameren Missouri argued that EPA was required to show that a "reasonable power plant operator" would have made a different determination regarding the impact of the Rush Island Projects on future emissions. Put another way, Ameren Missouri argued that EPA, in order to prevail, had to show that Ameren Missouri had violated a "standard of care" when it determined that the Rush Island Projects would not cause an emissions increase. The Court rejected this argument, holding that "EPA is not required to present standard of care evidence on what a 'reasonable power plant operator or owner' would expect." Memorandum and Order (Feb. 24, 2016) at 39. This makes it clear that Ameren Missouri's prudence or the reasonableness of its decisions was not before the District Court.

Q. Did the District Court find that Ameren Missouri was wrong when it determined that neither of the Rush Island Projects would cause and increase in potential emissions (i.e., that the emissions rate from the units when operating at maximum design capacity would not change)?

A. No. It was undisputed that Ameren Missouri's determination about potential emissions was correct. All the District Court did was determine that the absence of an increase in potential emissions would not screen out a project from NSR review.

Q. Did the District Court find that that Ameren Missouri did not have a reasonable basis for believing that the Rush Island Projects were the type of projects routinely done in the industry?

A. No. In its liability decision, the District Court did point out that Ameren Missouri officials had acknowledged that the Rush Island Projects occurred during the most significant outages in the history of the plant. But there is nothing in the applicable rules saying that repair and replacement projects that are done during "significant outages" cannot be RMRR. The consensus industry view was that economizer, reheater, waterwall, and boiler equipment replacements were routine in the industry and not subject to NSR permitting. Ameren Missouri, its Illinois affiliates, and other companies had performed such work frequently—both as stand-alone projects and aggregated together in a single outage. But I am not aware of any company that sought an NSR permit for them. Nowhere does the District Court say that Ameren Missouri did not have a reasonable basis for believing that the Rush Island Projects were routine in the industry and thus excluded from NSR at the time those decisions were made.

Q. Did the District Court find that Ameren Missouri did not have a reasonable basis for believing that the Rush Island Projects would not increase annual emissions?

A. The District Court found that the approach Ameren Missouri used for evaluating whether the Projects would increase annual emissions was the wrong one, but it did not find that Ameren Missouri had no reasonable basis for the approach it took. As I noted earlier, this was the approach that other power companies were also using at the time.

Q. Didn't the District Court find that the approach EPA used to show that the Rush Island Projects were expected to increase emissions had been "well known" since 1999 and that, under this approach, Ameren Missouri should have expected an increase in annual emissions?

A. The District Court's liability decision notes that "Ameren's testifying expert conceded that the method used by the United States' experts . . . has been 'well-known in the industry' since 1999." 229 F. Supp. 3d at 915. This approach, known as "the Koppe-Sahu method" after the names of EPA's testifying experts, was used only in NSR enforcement cases. It was never established in any EPA regulations, and Ameren Missouri (and other power companies) have argued vigorously that it is not a valid method for determining whether repair and replacement projects would cause an increase in annual emissions. This is because if a company repairs or replaces a piece of equipment that has been responsible for *any* downtime at a power plant, the Koppe-Sahu "method" *always* predicts it will cause an increase in emissions. Also, even though some repair and replacement projects clearly reduce emissions, the method is not capable of predicting an emissions decrease. The District Court ultimately decided that the Koppe-Sahu method could be used in the enforcement case against Ameren Missouri, but the Court did not hold that it was the only acceptable method or that Ameren Missouri lacked a reasonable basis for rejecting it.

I have worked with many power companies on NSR issues over the last 17 years, and I can say that none of them, even today, use the Koppe-Sahu method to determine whether repair and replacement projects will cause an increase in annual emissions. I am not aware of any company in any industry that uses this method to determine whether repair or replacement projects will cause an increase in emissions.

Q. Didn't the District Court find that Ameren Missouri expected the Rush Island Projects to increase annual unit availability and therefore should have expected that the Projects would increase emissions as well?

A. That is what the District Court wrote, even though every Ameren Missouri witness testified that he would not have expected actual annual availability to increase over the relevant baseline. But putting that discrepancy aside, it is undisputed that Ameren Missouri officials knew, prior to the projects, that Rush Island had been operating below its available capacity. Based on their sworn testimony, they believed that, even if the projects would improve availability, this would not actually cause an increase in annual emissions because the plant could have accommodated a large increase in emissions even without the projects. This is the approach that other power companies often took in evaluating whether repair and replacement projects would cause an emissions increase, and it was certainly a reasonable approach at the time.

Q. Didn't the District Court find that actual annual emissions at Rush Island increased after Ameren Missouri completed the Projects?

A. As I mentioned earlier, annual emissions at a facility can change (sometimes substantially) from year to year for reasons that have nothing to do with any changes at the facility itself. At power plants, annual emissions depend on how often and how hard it is called upon to operate, which depends on a number of things, including overall economic activity, the number and operating status of other power plants in the area, and the transmission infrastructure, which often changes over time. In general, when an area is growing economically, power plant emissions in that area normally increase because of "demand growth."

Under the federal NSR rules incorporated into the Missouri SIP, the question is whether an increase in emissions is ***caused*** by the project in question. It is undisputed that, before the Rush Island Projects, the plant was "capable of accommodating" greater levels of utilization and annual emissions. As EPA and courts have repeatedly emphasized, the NSR program is a pre-construction permitting program, and the question is whether the company should have anticipated that a project or group of projects would in the future cause an emission increase. When a unit is capable of accommodating increased utilization and emissions, the fact that emissions increased after the fact does not shed any light on whether the company should have expected, before the outage, that component replacements would be the "predominant cause" of such an increase.

VIII. AMEREN MISSOURI'S ENVIRONMENTAL COMPLIANCE PLANNING

Q. Doesn't the record show that Ameren Missouri engaged outside experts to begin planning for the installation of scrubbers at Rush Island, in anticipation that they would be required under NSR?

A. No. This is not correct. The record shows that Ameren Missouri did have a very robust environmental compliance planning program, which involved regular updates based on anticipated regulatory requirements, but NSR was not viewed as a primary driver of pollution controls. In early 2002, the Bush Administration announced its proposed "Clear Skies" legislation, which would have required substantial reductions in SO2 emissions from coal-fired power plants throughout the country. Shortly thereafter, Ameren Missouri began to evaluate options for reducing SO2 emissions from all its coal-fired units, including those at Rush Island.

In early 2004, when it became clear that there were not enough votes in the Senate to pass Clear Skies, the Bush EPA announced plans for a regulatory approach that ultimately became the Clean Air Interstate Rule ("CAIR"), which was finalized in 2005 and imposed a stringent new cap on SO2 emissions from coal-fired units in the eastern half of the U.S. At the same time, EPA issued the Clean Air Mercury Rule ("CAMR"), which anticipated that that SO2 scrubbers would also be used as a way to reduce mercury emissions from coal-fired power plants. After CAIR and CAMR were struck down in court in 2008 as being insufficiently stringent, the Obama EPA announced that it would be imposing more stringent regulatory requirements to reduce SO2 and mercury emissions from coal-fired power plants. The record shows that Ameren Missouri's environmental compliance planning was focused on these regulatory initiatives. Some planning documents noted that NSR might also eventually require scrubbers, but it is clear from the record that NSR was not viewed as a significant regulatory risk or the primary driver of new pollution control requirements.

Q. Did Ameren consider NSR as part of its environmental compliance planning process?

A. I have had the chance to review numerous documents related to Ameren Missouri's environmental compliance planning process and found it to be very impressive. I have also had the chance to work with many other power companies since I left EPA in 2005. All of them, including Ameren Missouri, were well aware of upcoming regulatory requirements that would require substantial reductions in SO2 and mercury emissions from coal-fired power plants in the eastern half of the U.S—CAIR and CAMR beginning in 2005 and, after the Obama Administration took office in 2009, the Cross State Air Pollution Rule ("CSAPR") and the Mercury and Air Toxics Standards ("MATS"). At the time, these rules were by far the most costly environmental regulations that EPA had ever issued and would soon require utilities to make enormous investments in scrubbers and other pollution control technology. However, none of these rules mandated specific pollution control equipment, and CAIR, CAMR, and CSAPR involved "cap-and-trade" programs that gave the industry great flexibility in determining how to reduce their emissions. For this reason, companies had to consider a range of different compliance options, including the installation of scrubbers and operational changes involving switches to lower-sulfur coal.

Like all power companies, Ameren Missouri was primarily focused on these new regulatory requirements. The record shows, however, that the Company was also aware of NSR and that some companies had settled NSR enforcement cases by agreeing to install pollution controls that they were planning to install anyway to meet these new regulatory requirements. Thus, as part of its compliance planning, Ameren Missouri eventually did a "sensitivity" study to consider what might be required under NSR. See Schedule SCW-D22. It is clear, however, that the Company did not view NSR as a program that was likely to require the installation of new emission controls at Rush Island or any of its other coal-fired power plants.

Q. When Ameren Missouri was undertaking its environmental compliance planning process, was its consideration of New Source Review requirements reasonable?

A. Ameren Missouri's conclusion at the end of that process that its environmental compliance plan should be driven by the applicable regulations (CAIR/CSAPR and CAMR/MATS) and not by the threat of NSR litigation was a reasonable one. As I noted earlier, since leaving EPA in 2005, I have advised numerous utilities that owned and operated coal-fired power plants in the 2005-2010 time period when Ameren was planning and undertaking the Rush Island Projects. None of them viewed NSR as a program that was likely to require the installation of new pollution controls on existing coal-fired power plants. EPA targeted many of their plants in its NSR enforcement initiative, and some of them settled those cases with EPA by agreeing to install costly new pollution controls. But in almost all cases, they simply agreed to install pollution controls that they were already planning to install to meet the requirements of CAIR, CSAPR, or MATS. None of them viewed NSR as a driver of new pollution controls. It is clear from the documents I have reviewed that Ameren Missouri shared this view, and it was reasonable in light of what Ameren Missouri knew or could have known at the time.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Petition of Union Electric Company d/b/a Ameren Missouri for a Financing Order Authorizing the Issue of Securitized Utility Tariff Bonds for Energy Transition Costs related to Rush Island Energy Center.	))))))	Case No. EF-2024-0021

AFFIDAVIT OF JEFFREY R. HOLMSTEAD

WASHINGTON, D.C.

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.

J R Holmstead
Jeffrey R. Holmstead

Sworn to me this 15th day of November 2023.

JEFFREY R. HOLMSTEAD

2001 M Street, NW, Suite 500 | Washington, D.C. 20036 | 202.828.5852 |
jeff.holmstead@bracewelllaw.com

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

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

Jeff Holmstead Congressional Testimony

U.S. Senate Committee on Environment and Public Works *Hearing entitled "Hearing to Examine S. 2662, The Growing American Innovation Now (GAIN) Act"*	November 6, 2019
U.S. House Committee on Energy and Commerce Subcommittee on Environment *Hearing entitled "Legislation Addressing New Source Review Permitting Reform"*	May 16, 2018
U.S. House Committee on Energy and Commerce Subcommittee on Environment *Hearing entitled "New Source Review Permitting Challenges for Manufacturing and Infrastructure"*	February 14, 2018
U.S. House Committee on Science, Space and Technology *Hearing entitled "Making EPA Great Again"*	February 7, 2017
U.S. House Committee on Science, Space and Technology *Hearing entitled "EPA's 2015 Ozone Standard: Concerns Over Science and Implementation"*	October 22, 2015
U.S. Senate Committee on Environment and Public Works *Hearing entitled "Road to Paris: Examining the President's International Climate Agenda and Implications for Domestic Environmental Policy"*	July 8, 2015
U.S. House Committee on Science, Space and Technology *Hearing entitled "EPA's Carbon Plan: Failure by Design"*	July 30, 2014
U.S. House Committee on Science, Space and Technology Subcommittee on Environment *Hearing entitled "Background Check: Achievability of New Ozone Standards"*	June 12, 2013
U.S. House Committee on Energy and Commerce Subcommittee on Energy and Power *Hearing entitled "Implications of EPA's Proposed National Ambient Air Quality Standards (NAAQS) for Fine Particles (PM2.5)"*	June 28, 2012
U.S. Senate Committee on Environment and Public Works Subcommittee on Clean Air and Nuclear Safety *Hearing entitled "Review of Mercury Pollution's Impacts to Public Health and the Environment"*	April 17, 2012

U.S. House Committee on Judiciary — 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 Committee on Select Energy Independence and Global Warming — December 11, 2008
Hearing regarding the Administrative Procedure Act and "midnight" regulations

U.S. House Committee on Select 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 — January 24, 2008
Hearing entitled "Oversight of EPA's Decision to Deny the California Waiver"

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. 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, 'The Transportation Equity Act: A Legacy for Users'"

Committee on Environment and Public Works — February 9, 2005
Hearing entitled "Environmental Protection Agency's Fiscal Year 2006 Budget"

U.S. House Committee on Energy and Commerce — July 21, 2004
Subcommittee on Energy and Air Quality
Hearing entitled "Methyl Bromide: Update on Achieving the Requirements of the Clean Air Act and the Montreal Protocol"

U.S. House Committee on Energy and Commerce — July 15, 2004
Subcommittee on Energy and Air Quality
Hearing entitled "Status of U.S. Refining Industry"

U.S. House Committee on Government Reform — July 7, 2004
Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs
Hearing entitled "Driving Down the Cost of Filling Up"

House Committee on Energy and Commerce — April 21, 2004
Joint Hearing: Subcommittee on Commerce, Trade, and Consumer Protection and Subcommittee on Energy and Air Quality
Hearing entitled "Current Environmental Issues Affecting the Readiness of the Department of Defense"

U.S. House Committee on Energy and Commerce — July 22, 2003
Subcommittee on Energy and Air Quality
Hearing entitled "'Bump-Up' Policy under Title I of the Clean Air Act"

U.S. House Committee on Energy and Commerce — July 8, 2003
Subcommittee on Energy and Air Quality
Hearing entitled "'The Clear Skies Initiative: A Multipollutant Approach to the Clean Air Act"

U.S. House Committee on Energy and Commerce — June 3, 2003
Subcommittee on Energy and Commerce
Hearing entitled "The Status of Methyl Bromide Under the Clean Air Act and the Montreal Protocol"

U.S. Senate Committee on Environment and Public Works — April 8, 2003
Subcommittee on Clean Air, Climate Change, and Nuclear Safety
Hearing entitled "Clear Skies Act of 2003"

U.S. Senate Committee on Environment and Public Works — March 20, 2003
Subcommittee on Clean Air, Climate Change, and Nuclear Safety
Hearing entitled "Clean Air Act: Alternative Fuels and Fuel Additives"

U.S. Senate Committee on Environment and Public Works — March 13, 2003
Subcommittee on Clean Air, Climate Change, and Nuclear Safety
Hearing entitled "Transportation and Air Quality: CMAQ and Conformity Programs"

U.S. Senate Committee on Health, Education, Labor and Pensions — September 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 *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*	May 23, 2002
U.S. House Committee on Energy and Commerce Subcommittee on Energy and Air Quality *Hearing entitled "Accomplishments of the Clean Air Act, as amended by the Clean Air Act Amendments of 1990"*	May 1, 2002
U.S. House Committee on Energy and Commerce 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"*	April 18, 2002
U.S. House Committee on Appropriations Subcommittees on Veterans Affairs, Housing and Urban Development, and Independent Agencies *Hearing entitled "Departments of Veterans Affairs and Housing and Urban Development, and Independent Agencies Appropriations for 2003"*	March 12, 2002
U.S. Senate Committee on Governmental Affairs *Hearing entitled "Public Health and Natural Resources: A Review of the Implementation of our Environmental Laws—Parts I and II*	March 7, 2002
U.S. Senate Committee on Environment and Public Works *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*	November 1, 2001
U.S. House Committee on Energy and Commerce Subcommittee on Oversite and Investigations *Hearing on "Issues Concerning the Use of MTBE in Reformulated Gasoline: An Update"*	November 1, 2001
U.S. Senate Committee on Environment and Public Works *Hearing on EPA Nominations*	May 17, 2001

IN THE UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

UNITED STATES OF MISSOURI,)
Plaintiff,)
vs.) Civil Action No.
) 4:11-CV-00077-RWS
AMEREN MISSOURI,)
Defendant.)

VIDEOTAPED 30(b)(6) DEPOSITION OF KYRA MOORE
TAKEN ON BEHALF OF AMEREN MISSOURI
SEPTEMBER 18, 2013

VIDEOTAPED 30(b)(6) DEPOSITION OF KYRA MOORE, produced, sworn, and examined on September 18, 2013, between the hours of 8:30 a.m. and 7:10 p.m. of that day at the offices of Stinson Morrison Hecker, LLP, 230 W. McCarty Street, Jefferson City, Missouri,before Jennifer L. Leibach, CCR No. 1108, within the state of Missouri, in a certain cause now pending in the United States District Court, Eastern District of Missouri, Eastern Division, wherein United States of America is the plaintiff and Ameren Missouri is the defendant.

Schedule JRH-D2

Page 2

APPEARANCES

FOR THE PLAINTIFF:
Mr. Andrew C. Hanson
Mr. Bradford McLane
U.S. DEPARTMENT OF JUSTICE
601 D Street N.W.
Washington, DC 20004
(202) 514-9859
Andrew.hanson@usdoj.gov

FOR THE DEFENDANT:
Mr. Stephen J. Bonebrake
Mr. David M. Loring
SCHIFF HARDIN, LLP
6600 Sears Tower
Chicago, Illinois 60606
(312) 258-5646
Sbonebrake@schiffhardin.com

FOR THE WITNESS:
Mr. Timothy P. Duggan
OFFICE OF THE ATTORNEY GENERAL
PO Box 899
Jefferson City, Missouri 65102
(573) 751-3640
Tim.duggan@ago.mo.gov

Page 3

APPEARANCES

FOR THE US EPA/REGION 7:
Mr. Alex Chen
11201 Renner Boulevard
Lenexa, Kansas 66219
(913) 551-7962
Chen.alex@epa.gov

CERTIFIED COURT REPORTER:
Jennifer L. Leibach, CCR No. 1108
ALDERSON COURT REPORTING
1155 Connecticut Ave, NW
Suite 200
Washington, DC 20036
(800) 367-3376

ALSO PRESENT: Sam Schneiders, Videographer
Steven C. Whitworth

Page 4

INDEX

EXHIBIT INSTRUCTIONS
Original exhibits to be attached to the original transcript.

Page 5

Schedule JRH-D2

Page 6

EXHIBIT INDEX (continued):

Page 7

IT IS HEREBY STIPULATED AND AGREED by and between counsel for the plaintiff and counsel for the defendant that this deposition may be taken by Jennifer L. Leibach, a Certified Court Reporter, CCR No. 1108, thereafter transcribed into typewriting, with the signature of the witness being expressly reserved.

(Exhibit No. 1 was marked for identification.)

VIDEOGRAPHER: Okay. We are on the record. Today's date is September the 18th of 2013. The time is approximately 8:37 a.m. This is the video deposition of Kyra Moore. It's in the matter of United States of America versus Ameren Missouri, Civil Action No. is 4:11-CV-00077-RWS. And this is in the U.S. District Court, Eastern District of Missouri, Eastern Division. We're here today at the law offices of Stinson Morrison & Hecker at 230 West McCarty Street in Jeff City, Missouri. If the attorneys could please state their appearance.

MR. BONEBRAKE: My name is Steve Bonebrake and I'm with the law firm of Schiff Hardin and I am here today on behalf of Ameren Missouri, defendant in the lawsuit.

MR. LORING: David Loring, law firm of Schiff Hardin, here on behalf of the defendant, Ameren Missouri, as well.

MR. DUGGAN: Tim Duggan, I'm with the Missouri Attorney General's Office and I am here on behalf of the

Page 8

Department of Natural Resources.

MR. HANSON: Andrew Hanson with the U.S. Department of Justice and I'm here on behalf of plaintiff, United States.

MR. MCLANE: Brad McLane also on behalf of United States.

MR. CHEN: Alex Chen with the U.S. Environmental Protection Agency, Region 7.

MR. BONEBRAKE: And then I have just one clarification. This is a Rule 30(b)(6) deposition of the Missouri Department of Natural Resources. And as I understand it, Ms. Moore is -- has been designated by that agency to testify today on its behalf. So if we don't have any preliminaries, then we'll proceed to some questions.

VIDEOGRAPHER: And then the swearing in.

MR. BONEBRAKE: Okay.

VIDEOGRAPHER: And the court reporter will now swear in the witness.

KYRA MOORE,

of lawful age, having been produced, sworn, and examined on the part of the defendant, testified as follows:

DIRECT EXAMINATION

QUESTIONS BY MR. BONEBRAKE:

Q. Good morning.
A. Good morning.

Page 9

Q. As I just mentioned, my name is Steve Bonebrake and I'm with the law firm of Schiff Hardin. We represent Ameren Missouri in connection with the lawsuit that brings us here today, which includes Clean Air Act brought by the United States, including prevention of significant deterioration program claims.
Could you please state and spell your full name for the record?
A. My name is Kyra Moore, first name is K-y-r-a, last name is Moore, M-o-o-r-e.
Q. And do you have a middle initial?
A. L.
Q. Thank you. What is your current home address?
A. 810 Maupin, M-a-u-p-i-n, Road, Columbia, Missouri 65203.
Q. And what is your current business address?
A. 1659 East Elm Street, Jefferson City, Missouri 65101.
Q. And is that work address an office of the Missouri Department of Natural Resources?
A. Yes, it is.
Q. Is that the headquarters for that agency?
A. It is the office of the department's Air Pollution Control Program.
Q. And what is your birth date?

Page 10

A. March 5th, 1968.
Q. 1968? I would like to -- to show you a -- an exhibit that's been marked Moore/MDNR. It's been marked for identification as Exhibit No. 1.
MR. BONEBRAKE: Dave, if you could hand that out to the folks around the table.
THE WITNESS: Sorry. Yes.
BY MR. BONEBRAKE:
Q. And this is a copy of the subpoena with a writer for the 30(b)(6) deposition today and that writer contains a number of topics for you of the deposition of Missouri Department of Natural Resources.
And do you understand, Ms. Moore, that you are testifying today on behalf of the Missouri Department of Natural Resources with respect to the topics that are identified in the writer to the subpoena?
A. Yes, I do.
Q. I'd like to start with just a few general instructions for the deposition with the -- with the goal of trying to get as clean and understandable of a transcript as we can for our conversation today. We will -- we will proceed question-and-answer style, so I will ask questions and ask then for you to answer those questions. So if you could wait for me to complete my questions, I would appreciate it and I will try to wait for you to complete your

Page 11

answers before I ask you any further questions.
A. Okay.
Q. If there's something ambiguous in my questions, please let me know and I'll try to reframe it or rephrase it so that we have a common understanding of what I'm -- what I'm asking you. If you don't mention it and it's ambiguous, I'll assume that you understood what I was asking you. Okay?
A. All right.
Q. If you answer a question and then later think of something that would either change the answer or from your perspective make it more complete --
A. Uh-huh.
Q. -- please let me know. At any time, we can get that on the record for you.
A. Okay.
Q. And also I was going to mention we will probably be using a number of acronyms today. In fact, I know we will. So I thought I would put a few of them on the record up front to try to expedite the process so we have a common understanding of the terms. I will use the terms US EPA or EPA as short for the United States Environmental Protection Agency. Is that okay with you?
A. Yes.
Q. MDNR for the Missouri Department of Natural

Page 12

Resources?
A. Yes.
Q. I will use NSR as short for New Source Review, which is comprised of the prevention of significant deterioration and non-attainable NSR programs. Is that okay as well?
A. Yes.
Q. PSD, short for the prevention of short deterioration program.
A. Yes.
Q. And if I use any acronyms during the course of the deposition and you're not sure what I'm asking you, again let me know and I'll try to state it out so that --
A. Okay.
Q. -- we have a common understanding of what I ask. And if you use an acronym in the course of your answer, I may ask you to spell it out in the record as well.
A. Okay.
Q. And if you need a break during the course of the deposition, let us know and we'll take a break as soon as we can, consistent with the line of questioning that we're on.
And you understand that you are testifying today under oath?
A. Yes.

Page 13

Q. Are you represented by counsel today at the deposition?
A. Yes, I am.
Q. And who is your counsel today for the deposition?
A. Tim Duggan.
Q. Who is your current employer?
A. The Missouri Department of Natural Resources, specifically the air pollution control program.
Q. And what is your current position?
A. I am the director of the air program.
Q. And when you say air program, that's short for air pollution control program?
A. Air pollution control program, yes.
Q. And what are the responsibilities of the air program?
A. The air program within the Department of Natural Resources is the agency that -- is the designated authority to do the Clean Air Act in the state of Missouri, in addition to other regulations, but it is the Missouri program that does the Clean Air Act.
Q. Now when you say "does the Clean Air Act," do you mean implements for the state the federal Clean Air Act?
A. Right.
Q. And how does it implement for the state the

Alderson Reporting Company
1-800-FOR-DEPO

Schedule JRH-D2

Page 14

federal Clean Air Act?
A. Through several different sections in our program. We do permitting, we do compliance enforcement, we do planning which involves rulemaking and creation of our SIPS, our state implementation plan, with EPA. We do a variety of other projects as well --
Q. Okay.
A. -- within the program.
Q. So is -- is one of the duties of the air program to issue construction permits?
A. Yes, that's correct.
Q. And would that include PSD construction permits?
A. Yes.
Q. And is one of the duties of the air program also to make determinations regarding the applicability of construction permitting requirements?
A. Yes, that's correct.
Q. And would that include duties to make determinations regarding applicability of the PSD program for sources in Missouri?
A. Yes.
Q. That is correct?
A. Yes, that's correct.
Q. And what are your specific duties as director?

Page 15

A. I oversee the program so all the activities of the program fall under my purview. I have several different managers that assist me with that, but permitting is one of the main sections of the program in addition to enforcement planning that I mentioned earlier and a couple of other fiscal and budgets sections.
Q. So what -- what managers report to you?
A. I have six managers. Do you want their names or?
Q. No, might be easiest if you will give me positions.
A. Okay. The first we have an inspection maintenance section that's actually housed in our St. Louis regional office, but they report to me that manage our emission program in the St. Louis non-attainment area. And then the other five sections are housed in the same building with me. The permit section, that's self-explanatory. The planning section that handles the rules and the state implementation plans. The air quality analysis section which handles our emission inventory and our monitoring duties. The compliance enforcement section, again self-explanatory to some extent. And our fiscal and budget section, which handles our budget and our personnel issues within the program.
Q. Does the compliance and enforcement -- do you

Page 16

call that a section?
A. Yes, those are all sections.
Q. Does that section then have responsibilities for bringing enforcement actions against sources in Missouri that violate the state of Missouri's air regulations?
A. Yes, that is one of their duties.
Q. You mentioned there was a permitting section that reported to you as well?
A. Yes.
Q. And is a duty of the permitting section, then, the issuance of PSD permits and the determination of applicability of PSD requirements?
A. Yes, that is one of their tasks.
Q. And how long have you been director?
A. Two years.
Q. And when did you start with MDNR?
A. In March of 1999.
Q. And what was your initial position?
A. I was hired into the air program as a permit writer in the construction permit unit in 1999.
Q. And did you go by a different name, by chance, in 1999?
A. Yes, I was hired in my maiden name which is Hayes, H-a-y-e-s, for about six months.
Q. Okay. And how long were you permit engineer?

Page 17

A. I didn't bring that with me. For a couple years, I wrote permits in that unit and then in approximately March 2002, I became the supervisor of the construction permit unit. My official title was interim supervisor for a couple years and then I was the permit section chief after that.
Q. So from -- from 1999 to 2002 while you were a permit engineer, was your primary duty determining applicability of construction permit requirements and issuing construction permits?
A. Yes, issuing permits was the main duty. Applicability determinations is one part of that, so.
Q. And that would have included PSD permits?
A. Yes, I was involved in a couple PSD permits.
Q. Now you mentioned your position changed in 2002?
A. Yes.
Q. And did you say you became a supervisor at that time?
A. I was the unit chief which is the supervisor of that -- the construction permit unit, supervising approximately ten permit writers, I believe, for two years.
Q. So that brings us to 2004?
A. Yes.
Q. What happened at that point?

Schedule JRH-D2

Page 66

correct?
MR. HANSON: Objection, lack of foundation, document speaks for itself.
THE WITNESS: This -- this would be -- yes, the first place I would go if I was a source to look for applicability of permitting.
BY MR. BONEBRAKE:
Q. And when you were a permit engineer and then a manager in the construction permitting section, did you look to the applicability section of the construction permitting rules as a starting place to determine whether or not a construction permit would be required?
A. Yes.
Q. And if you could turn with me to the definition section, which is 6.020 and the definition of modifications, which is in section capital M, item number 9 on page 11. And is this the definition of a modification that would trigger a construction permitting requirement under the Missouri Construction Permitting Rules?
A. Yes, if that term modification is used in the 6.060, that's correct.
Q. And just to refresh your recollection, if we go back to page 21, section 1(C), I believe the first sentence in that section begins, no owner or operator shall commence construction or modification. Do you see that,

Page 67

ma'am?
A. Yes.
Q. So would it be correct, then, that for purposes of that -- defining that term modification in section 1(C), you would look to the definition on M9 on page 11?
MR. HANSON: Objection, the document speaks for itself.
THE WITNESS: Yes.
BY MR. BONEBRAKE:
Q. And a modification as defined by the rules provides as follows: Any physical change or change in method of operation of a source operation or tenant air pollution control equipment which would cause an increase in potential emissions of any air pollutant emitted by the source operation.
Now, are potential emissions also defined in the rule?
MR. HANSON: Objection, same objection.
BY MR. BONEBRAKE:
Q. And I can give you a shortcut to page 13.
A. I was going to say in 1996, it should.
Q. Section P, 18.
A. Yes.
Q. Is that the definition of potential emissions

Page 68

that's used for purposes of defining -- determining whether or not a modification would be expected to occur?
MR. HANSON: Same objection.
THE WITNESS: Eighteen is the definition of potential to emit, yes.
BY MR. BONEBRAKE:
Q. So would that be the definition that a permit engineer or permit manager at MDNR would use to determine whether a modification would be expected to occur that would trigger a construction permit requirement?
A. It would be the definition we would use to define what the potential emissions of the source are. And that is one piece of the modification, yes.
Q. And when you say "one piece of the modification," what do you mean?
A. Well, it says any physical change or change in method of operation, so you need to determine that first and then go to the potential emissions. It's all tied together.
Q. Okay. So MDNR first needs to determine whether or not there's a physical or operational change; is that correct?
A. Yes.
Q. And -- and assuming the answer is yes, it then would need to determine whether that physical or operational change would cause an increase in potential emissions; is

Page 69

that correct?
A. Yes.
Q. And those things must be true in order for there to be a modification of an existing source that requires a construction permit. Is that also true?
MR. HANSON: Objection, the document speaks for itself.
THE WITNESS: Let me read the definition of modification again. So yes.
BY MR. BONEBRAKE:
Q. And the term potential emit indicates that the potential emissions of the unit are the emissions operating at full capacity every hour of every day of year; is that correct?
MR. HANSON: Same objection.
THE WITNESS: Yes, the potential emissions is defined as continuous operation.
BY MR. BONEBRAKE:
Q. At maximum capacity?
A. Yes.
Q. And so the concept of changes in utilization are really irrelevant for that definition, right, because the definition assumes constant utilization at full capacity; is that right?
MR. HANSON: Objection, vague and ambiguous.

Schedule JRH-D2

Page 70

THE WITNESS: Yeah, I'm not understanding the question. The -- could you repeat that?
BY MR. BONEBRAKE:
Q. Sure. I think we talked about the fact that the concept of potential emissions assumes utilization at full capacity every day, every hour, in a year; right?
A. Yes.
Q. So if you're looking at changes in potential emissions, whether or not the facility would change its utilization, in fact, is irrelevant because the definition assumes you're running all out all the time?
MR. HANSON: Vague and ambiguous, lack of foundation, objection.
THE WITNESS: The -- when we calculate potential emissions, we need to calculate the potential based on the operation that's occurring.
BY MR. BONEBRAKE:
Q. Uh-huh.
A. So yes, the potential emissions of that particular project we will review. So if that project operated this certain way, that's the potential emission calculations that we would review. So I'm not understand -- understanding the semantics, I guess.
Q. Well, when MDNR makes a determination of -- of potential emissions, does it consider the source's actual

Page 71

anticipated utilization or does it simply assume maximum utilization?
A. We would calculate the maximum potential of -- of the operation that is presented to us. I'm not understanding.
Q. Okay. Well, if the source -- if the source wasn't willing to take a synthetic minor limitation --
A. Right.
Q. -- you, in making a potential to emit determination, you would not consider actual plant utilization, you would assume maximum utilization every day of the year; right?
A. Yeah.
MR. HANSON: Objection, lack of foundation, vague and ambiguous.
BY MR. BONEBRAKE:
Q. I'm sorry, what was your answer?
A. Yes, I mean, the potential emissions is just that. It's the potential -- the maximum amount possible that they could emit with that equipment without any conditions.
Q. And -- and when we go back to the definition of the term modification, it talks about any physical change or change in method of operation and it goes on to say which would cause an increase in potential emissions.
A. Uh-huh.

Page 72

Q. So under MDNR's construction permit rules to determine whether a modification would occur, was MDNR then looking to determine whether a proposed activity at an existing source would change the potential to emit of that source?
MR. HANSON: Objection, lack of foundation.
THE WITNESS: I'm not understanding the direction of the question, if you could rephrase.
BY MR. BONEBRAKE:
Q. Okay. We'll try again.
A. Okay.
Q. The definition of modification uses the words which would cause an increase in potential emissions.
A. Right.
Q. Right?
A. Yes.
Q. That suggests to me that when MDNR makes a determination of whether a modification would be expected to occur, it is looking at whether the physical or operational change causes the potential emissions of the emission unit at issue to change. Is that your understanding as well?
A. I would phrase it as we are looking at any modification that is going to increase emissions. And the source would be providing that information to us, that they are going to change this equipment, change this method of

Page 73

operation and in doing so, this is the change of emissions that we anticipate. That's how I would phrase that. I don't know if that answered your question or not.
Q. Well, the definition of modification refers specifically to potential emissions; correct?
A. Yes.
Q. So when we're looking at whether emissions are going to change, as you put it, isn't the rule directing MDNR and sources to look at whether there's going to be a change in potential emissions?
A. Yes, that's -- definition of modification does state potential emission.
Q. And so when MDNR made applicability determinations under this rule, was it looking at changes in potential emissions, if any, of an emission unit?
MR. HANSON: Objection, lack of foundation.
THE WITNESS: Based on the definition, we would look at the increase in potential emissions, yes.
BY MR. BONEBRAKE:
Q. And is that consistent with your understanding of MDNR's actual applicability determination practice from the mid-1990s up until the reform rule changes which you mentioned earlier were adopted?
A. Right.
MR. HANSON: Objection, vague and ambiguous.

Schedule JRH-D2

Page 74

THE WITNESS: That would fit my understanding of -- of what we did and that we would look at a project that was submitted to us as a modification and look at the increase in potential emissions, yes.
BY MR. BONEBRAKE:
Q. Okay. So if there were a physical or operational change, but that physical or operational change would not be expected to change the emission unit's potential to emit, there would be no modification --
MR. HANSON: Objection, lack of foundation.
BY MR. BONEBRAKE:
Q. -- correct?
A. I would -- it -- I would need to look at a specific case for that, but in general, that would fit the definition of modification, yes. But it's hard to say that that would apply in every case without looking at a case by case example.
Q. I'll have a few for you.
A. I'm sure you will.
Q. And absent a modification, there's no construction permit requirement, I think we talked about that before, but that's correct as well; is it not?
A. Yes.
Q. Is it -- is it true that the potential emissions of a unit can change in only one of two ways;

Page 75

either an increase in design production capacity or a change in the emission rate?
A. The potential emissions of the entire installation or just a --
Q. Of the emission unit is where I'm focused.
A. Of the emission unit? There is one other situation that would come to mind and we refer to that as a removal of a bottleneck. So if you have a piece of equipment that has a maximum amount of design rate but is limited lower than their maximum design rate by a previous piece of equipment and then you remove that piece of equipment and so the bottleneck is gone, that could also increase potential emissions.
Q. Okay. So those are the three scenarios in which the potential emissions of an emission unit could change?
A. Those are the most common.
Q. Okay. But otherwise, changes to an existing emission unit that do not eliminate a bottleneck, do not change emission rate and do not change production capacity, don't change the potential to emit of the emission unit; is that correct?
MR. HANSON: Objection, compound, lack of foundation.
THE WITNESS: I would say that covers most of

Page 76

the situations, but there are a lot of specifics that I may not be thinking of that -- that could. So it -- everything is case by case in our world.
BY MR. BONEBRAKE:
Q. Uh-huh. Well, can you think of any others than those three?
A. Well, what you state like I can think of if you change the type of fuel, and I don't know if that fits in one of your categories.
Q. Emission rates was one of my categories.
A. Yeah, so that would probably fall into that.
Q. Let me go back to the manual, which we had marked earlier as Exhibit No. 5. And if I could turn your attention to page 20 of that manual, it's internal 20 of 53 page marking.
A. Okay.
Q. And I think we determined earlier that this was the August 7, 2000 revised version of this -- of this manual; is that correct?
A. Yes. It appears to be the case.
Q. All right. And does figure 3, applicability flowchart, does that -- does that provide an indication of how construction permit applicability is to be determined?
A. This is one version of many flowcharts created to try and explain the applicability process in permitting,

Page 77

yes.
Q. Okay. The first -- is the first step to find the existing installation potential emissions?
A. That's correct.
Q. And the installation, is that MDNR's version of the -- the word "source?"
A. I don't know the definition of source, but the definition of installation for MDNR is the -- it encompasses the entire plant, if you will.
Q. So when we talked earlier about whether or not a facility was a major source, it would be -- at MDNR, the question would be whether the installation was major; is that correct?
A. Yes, our regs use the term installation.
Q. So installation would include all emission units at a given facility?
A. That's correct.
Q. And then the second step in the applicability determination flowchart is to calculate the potential emissions of the project; is that correct?
A. Yes.
Q. And as referred to I think in this document is capital P small c?
A. Uh-huh.
COURT REPORTER: Is that a yes?

Schedule JRH-D2

Page 82

MR. HANSON: Objection, vague and ambiguous, lack of foundation, calls for hypothetical.
THE WITNESS: The potential emissions of that unit appear to be zero and if that is the only change that's occurring, most likely the potential emissions at that project would be zero.
BY MR. BONEBRAKE:
Q. Okay. And was that the applicability process that MDNR was using for construction permitting applicability assessments for both major and minor sources, and again focused on the period from 1996 up until the time that any reform rule revisions were implemented in the state rules?
A. Yes.
Q. Question for you a little further down on page 15, it's the third full paragraph. It starts with, at this point.
A. Uh-huh.
Q. And the second sentence reads, potential of construction should only include new equipment or additional capacity. Do you see that?
A. Yes.
Q. And so the potential emissions of construction with respect to existing equipment would only change if there was an increase in capacity of that existing equipment; right?

Page 83

MR. HANSON: Objection, lack of foundation, document call – speaks for itself.
THE WITNESS: That is the definition of potential to construction in this document, yes.
BY MR. BONEBRAKE:
Q. Okay. If we go back to the flowchart on page 21 – excuse me, on page 20. We were just talking about the step involved in the applicability process of assessing the potential emissions of the project; right?
A. Yes.
Q. Now, if there is an expected increase in potential emissions of the project, then would the next step in the applicability process be to look at whether or not there would be a net emissions change as well related to that project?
MR. HANSON: Objection, document speaks for itself.
THE WITNESS: Yes. You would look at – if this is for an existing facility, yes, you would look at – you could choose to look at the net emissions change, yes.
BY MR. BONEBRAKE:
Q. When you say "could choose," what do you mean by that?
A. Well, the simplest matter is to look at the potential emissions of the project and if that by itself does

Page 84

not trigger any permitting action, then you don't need to do the net emissions change. It's a simplified –
Q. I see.
A. – calculation.
Q. So just to clarify, that if you have no potential project emission increase, you never need to get to the step two netting question; is that correct?
A. Or if the potential emissions of the project are below a threshold where it would not be beneficial to use a net emissions increase calculation, yes.
Q. Okay. And then under this 2000 manual, if you have an expected increase in potential emissions of the project and an expected net emission increase, then would you look to confirm that you have a physical or operational change that's not otherwise excluded? Would that be the next step in the process?
A. Could – could you restate? So you've calculated potential emissions and then what's your question, the next step?
Q. Yeah, let's assume – let's step back a second. In order for there to be a modification, we need to have a physical or operational change that causes an emission increase; correct?
A. Right.
Q. So if – if under this manual we have an

Page 85

emission increase of the project –
A. Yes.
Q. – and a net emission increase –
A. Yes.
Q. – then would you also need to look to see if you have a physical or operational change that's not otherwise excluded from permitting requirements under the rule?
MR. HANSON: Objection, lack of foundation, compound.
THE WITNESS: That would be part of the review. I don't know if the next step, sometimes that's done before you get to the potential emission calculation, so.
BY MR. BONEBRAKE:
Q. Fair enough.
A. Okay.
Q. But in any event, that's a step that needs to occur?
A. Yes, you can review that, yes.
Q. And by the way, while you were performing duties either as a permit engineer or a manager, do you recall ever relying upon the manual that is Exhibit 5 or any version thereof?
A. Not extensively. As I mentioned earlier, this was always considered a work in progress. I just noticed

Schedule JRH-D2

Page 86

it's dated 2000 and due to staffing workload, we didn't -- once this was drafted, we didn't have a lot of time and -- available time to update it and modify it. I would say I used the flowchart in its form multiple times in addition for drafting permits and reviewing permits, but also to explain our permitting process to outside entities. Other than that, the document was available for review and guidance but it was not heavily relied upon until its recent configuration, which is what is on our Web site to date.
Q. Now, when you say you used the flowchart to explain the process to outside entities, were any of those outside -- was US EPA among any of those outside entities?
A. I don't recall any specific -- I mean, this is explaining the Missouri minor source permitting more so than the PSD, but EPA would have been privy to this document, so conversations on it may have come up.
Q. Well, with respect to that -- that last answer, as we just were looking at the definition of modification as it's used in the applicability section --
A. Yes.
Q. -- and I think you've indicated before, did you not, that MDNR was using the concept of change in potential emissions to determine applicability of all construction permitting requirements, was that not correct?
MR. HANSON: Objection.

Page 87

THE WITNESS: Yes.
MR. HANSON: Vague and ambiguous.
BY MR. BONEBRAKE:
Q. Yes? On page 21 in section 4, that section provides in the first sentence, once the applicability has been determined, permit reviewers will refer to the individual sections of the rule to find -- rules to find out what is required. The main difference is in the sections 5, 6, 7, and 8 involve the extent of air quality impact analysis in the pipe, if any, of control evaluation. Do you see that?
A. Yes.
Q. 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 operational change that would cause an increase in potential emissions and net emissions, and then step two, if the answer is yes, you look to sections 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?
MR. HANSON: Objection, compound.
THE WITNESS: Yes. Once you have the potential emissions, you would review our rules to determine what type of permit to draft.

Page 88

BY MR. BONEBRAKE:
Q. And what type of permit is addressed in section 5?
A. Section 5 refers to section 5 of our construction permit rule 6.060, which is our De Minimus permit review.
Q. And section 6?
A. Section 6 refers to our minor permits.
Q. And sections 7 and 8?
A. Seven and 8 are both the major permits. Eight would be the PSD permit rules, seven would be the non-attainment NSR rules.
Q. And this document is directing us, then, to look at those sections to determine what should be in those respective types of permits; correct?
A. Yes.
(Exhibit No. 7 was marked for identification.)
BY MR. BONEBRAKE:
Q. Okay. We're showing to the witness has been marked as Deposition Exhibit No. 7 – 7 for identification.
A. Okay.
Q. Can you take a moment to take a look at that document, please?
MR. BONEBRAKE: And I'll note for the record that this is a multi-page exhibit bearing Bates-stamp

Page 89

Nos. AM-00025867-MDNR through AM-00025884-MDNR. Make that 885-MDNR.
BY MR. BONEBRAKE:
Q. Have you had a chance to take a look at the exhibit?
A. Yes, briefly.
Q. And is this exhibit comprised of a no permit required letter dated July 21, 2006 from MDNR to Associated Electric Cooperative, Inc. and related documents?
A. That's correct.
Q. And I wanted to use this exhibit to talk a little bit about your file system to make sure that we understand the documents that have been produced to us by MDNR.
A. Okay.
Q. So if you bear with me through some administrative questions here.
A. Yes.
Q. The first page of this exhibit is a document entitled permit action management system or parens PAMS, end parens. What is this document? What's its purpose?
A. We have had some type of permit action management system, the most current is PAMS. There's been different iterations of that database since the mid-'80s, I believe. It is a database that we track every project

Schedule JRH-D2

signed this letter, would that have been an inquiry you would have expected MDNR to make of a source proposing this kind of project?

A. Not necessarily. If the project engineer did not find that relevant to the determination, no, she would not have asked that.

Q. And there's nothing in the file, is there, that indicates that the project engineer thought that was relevant?

A. I'm not seeing that.

MR. HANSON: Objection, the document speaks for itself.

BY MR. BONEBRAKE:

Q. About halfway down the first page of your letter, there's a -- there's a letter to reconstruction. Do you see that?

A. Yes.

Q. Is that an NSPS concept?

A. Yes.

Q. That's capital N-S-P-S. Is the concept of reconstruction relevant for construction permitting applicability assessments?

MR. HANSON: Objection, vague and ambiguous. Also vague as to time.

THE WITNESS: Well, it was part of the

determination in this letter that it was not reconstruction and therefore no construction permit is required. So it is relevant in this situation.

BY MR. BONEBRAKE:

Q. Do you know if -- if the NSPS program has any permitting requirement?

A. The NSPS --

MR. HANSON: Objection, outside the scope.

THE WITNESS: The NSPS program, if you will, is just different sets of rules and standards that sources have to comply with. It has a role in permitting, but your question is does it require a permit?

BY MR. BONEBRAKE:

Q. Correct, when triggered.

MR. HANSON: Same objection.

THE WITNESS: Not necessarily. It would be case by case. The new source -- the new source performance standard is not going to trigger a permit by itself, so.

BY MR. BONEBRAKE:

Q. Okay. All right. And then the next paragraph after the quote of reconstruction, I'd like to talk about that paragraph --

A. Okay.

Q. -- a little bit. The second sentence in that paragraph reads, since there will be no increase in the

potential to emit, according to the applicant, the change cannot be considered a modification per Missouri state rule. Do you see that?

A. Yes.

Q. And the Missouri state rule that you are referencing in your letter here is 10 CSR 10-6.060; is that correct? And you can see --

A. The particular state rule --

Q. Just point you to the first paragraph as well, if that's helpful for you.

A. Right, the -- I mean, the answer's yes, but because the definition of modification is technically in 6.020, but yes, the 6.060 is the permit rule.

Q. So in your letter, then, you were -- you were finding, you were making a determination -- strike that.

In this MDNR letter signed by you, MDNR was making a determination that the replacement of cyclone burners would not be a modification under Missouri's construction permitting rules, correct?

A. That's correct.

Q. And that would mean there was no permit -- construction permit of any kind required for this project, including no PSD permit; is that correct?

A. That is the determination made at this time.

Q. Okay. And the sentence that I just read

refers to the fact that there will be no increase in the potential to emit. Do you see that?

A. Yes.

Q. And is it correct, then, that MDNR was looking for applicability review purposes at whether the proposed cyclone burner project would change the potential to emit of the emission units effected by the cyclone burner project?

A. Yes.

Q. And in this case, MDNR found that the proposed replacement of cyclone burners would not change the potential to emit of Units 1 and 2 at the Thompson -- at the Thomas Hill plant; is that correct?

A. There was no increase in the potential emissions, that is correct.

Q. And as we discussed earlier in connection with the -- the rule, when there is no increase in the potential to emit of the emission unit, there is no modification under Missouri's construction permitting rules; is that correct?

A. Yes.

Q. And do you know in reference to the -- the phrase "increase in the potential to emit," whether MDNR was looking at the annual potential to emit of Units 1 and 2 at the Thomas Hill plant?

MR. HANSON: Objection, vague and ambiguous.

THE WITNESS: It looks like it was the -- yes,

Schedule JRH-D2

Page 102

the potential emissions of the -- it would be annual, as you state.
BY MR. BONEBRAKE:
Q. And it would be annual for what reason?
A. Well, it's the potential emissions as defined as 8,760 hours, so it would be annual.
Q. So as of 2006, then, MDNR is determining that a change in an emission unit does not require a construction permit of any kind unless that change increases the potential to emit of the emission unit; is that correct?
MR. HANSON: Objection, lack of foundation, vague as to time.
THE WITNESS: The determination was made in this case that -- that no permit was required based on no increase in emissions, yes.
BY MR. BONEBRAKE:
Q. And the no increase in emissions was no increase in potential emissions of the emission units; right?
A. Yes.
Q. And do you know based upon your review how MDNR determined that there would be no increase in the potential emissions of the emission units?
A. Based on the data in this project file, the project reviewer, in this case Lina Kline, obtained that information through the letter and through subsequent e-mails

Page 103

with the facility.
Q. But would it be true based upon your experience that the replacement of tubes within a boiler would typically change the maximum emission capacity of a boiler?
MR. HANSON: Objection, calls for speculation, lack of foundation, also hypothetical.
THE WITNESS: In this case, that was the determination. As I mentioned earlier, everything we do is very case by case, so making that broad statement is not something I can do.
BY MR. BONEBRAKE:
Q. By the way, do you know if cyclones in boilers are comprised of tubes?
A. No, I do not.
Q. Okay.
(Exhibit No. 8 was marked for identification.)
BY MR. BONEBRAKE:
Q. Okay. We're going to present to you a document that's been marked as Deposition Exhibit No. 8. It's a three-page document bearing Bates-stamp Nos. AM-00631952-MDNR through 1954. And if you could take a look at that, please.
A. All right.
Q. Have you had a chance to take a look?

Page 104

A. Yes, I do.
Q. And what is this document?
A. This is a general overview of air permitting for the air pollution control program.
Q. And were you involved in the preparation of this document?
A. I was.
Q. And what was that involvement?
A. I believe my recollection is I put this together with the assistance of the other staff members listed on here, Kendall Hale and Mike Stansfield, to give a mile-high view of the air permitting in Missouri.
Q. And was this document intended to be provided to sources in Missouri to provide guidance regarding construction permitting?
A. It was one piece of guidance. I think the reason I put it together was for internal staff. My recollection is when we switched program directors, this was something I utilized to explain our permitting process to our new program director.
Q. Was this -- was this document posted on MDNR's Web site at any time?
A. No, I don't believe so. It may have been included in our air advisory form Web site, but I would have to check that history to know.

Page 105

Q. But it was provided to permit engineers as guidance to construction permitting requirements?
A. It was utilized more for management. It was available to permit staff because it was on our network, but it was more of a -- attempt to simplify our permit process for my upper management.
Q. Okay. At the top of the second page, it's the second bullet from the top. And the first sentence reads, potential emissions of proposed project determine type of construction permit needed. And the next sentence reads, potential emissions are calculated based on maximum design capacity of the installation assuming continuous year-round operation. Can you describe for us whether -- whether this is a description -- well, strike that.
Is this a -- a description of the way to determine whether or not a change at an existing source would be a modification?
A. Yes, this is -- again, this is a very simplified approach to construction permits and this is describing potential emissions and that they are calculated 8,760 hours per year maximum design capacity. That is what that bullet is for.
Q. Okay. So consistent with our -- with our earlier discussion when MDNR was assessing construction permit applicability and looking at the issue of change in

Schedule JRH-D2

Matt Blunt, Governor • Doyle Childers, Director

STATE OF MISSOURI
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.*

Recycled Paper

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

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

JUN 19 1991

OFFICE OF
AIR AND RADIATION

Honorable John D. Dingell
Chairman, Subcommittee on Oversight
and Investigations
Committee on Energy and Commerce
House of Representatives
Washington, D.C. 20515

Dear Mr. Chairman:

Thank you for enclosing a copy of the September 1990 GAO report entitled "Electricity Supply -- Older Plants' Impact on Reliability and Air Quality" with your October 9, 1990 letter. Your letter raises several questions concerning the impact of older power plants' "life extension" on the reliability of electricity supply. Enclosed are responses to your questions.

If you have any further questions, please do not hesitate to contact us.

Sincerely yours,

William G. Rosenberg
Assistant Administrator
for Air and Radiation

Enclosure

cc: Honorable Charles A. Bowsher
Comptroller General, GAO

Printed on Recycled Paper

Question 1.

Please explain what measures (other than life extensions) will be used to meet "future demand". What will be the role of conservation and new plants?

Response 1.

The role of renewable resources and especially conservation in meeting current demand is significantly higher than 10 years ago, despite regulatory obstacles, inequitable incentives and insufficient research and development support. In fact, few conventional electric generation options can today compete with energy efficiency investment to meet future demand. Recent estimates suggest that energy demand can be halved by 2010 with a savings of over 4300 billion to the U.S. economy.

The cost-competitiveness of conservation and renewable resources will be further increased by the Clean Air Act Amendments of 1990 and assessments of environmental externalities. Preventing significant increments of pollution through energy efficiency can be an important supplement to "end of smokestack/scrubber" technologies.

In addition to lower capital costs, lower financial risks, high reliability and pollution prevention benefits, energy efficiency is achieved by investing in the operation and maintenance of the various energy-consuming sectors of the economy. Any improvements in energy productivity (increasing economic output with stable or declining energy input) will simultaneously enhance national energy security and the international competitiveness of American business. Finally, the development of a competitive "efficiency and renewable resource industry" to compete with such German and Japanese initiatives will be another by-product of this quicker, cheaper, cleaner approach to future demand.

Question 2.

Are such (life) extensions going to be cheaper and less time consuming with the enactment of title I of the Clean Air Act bill, S. 1630? Please explain.

Response 2.

Title I does not have much direct bearing on life extension projects. New source review is only implicated by life extension projects to the extent that they increase emissions and are thus considered modifications under Part C or D. As discussed in the answer to question 5, companies have and use discretion in project design and permitting to avoid increasing emissions and triggering the modification provisions. However, even if they could not or did not "net out" of new source review, power plant modifications would not face any significantly different treatment under the amendments in SO_2 or PM-10 nonattainment areas. Of course, if, due to a SIP call in a nonattainment area the state required the power plants to reduce their emissions, presumably the state would apply such a requirement to existing sources without regard to whether they were undergoing modification. In that case the cost of pollution controls would be attributed to the nonattainment program rather than the new source review program.

In ozone nonattainment areas where major stationary sources of NOx would be required to meet the same requirements as major stationary sources of VOC, under Section 182(f) of the amendments, power plants would be subject to the RACT provisions. Power plants undergoing a covered modification (under the new source review program) would have to achieve LAER instead. Like all major stationary sources in these areas, they would also have to procure offsets at the ratios stipulated for the various nonattainment severity categories. The cost of NOx offsets (if they were required) would thus increase the cost of a modification.

Question 3.

Please discuss in greater detail the "reliability of the electricity supply" from life extensions, taking into account the "different approaches to life extensions" discussed in the GAO report. Is there reason to be concerned about the reliability of these plants in meeting demand? Please explain. If they are not reliable, what are the contingencies?

Response 3.

EPA has not looked into the issue of "reliability of electricity supply" from life extensions.

Question 4.

Do you agree with the demand figures? What are the real and timely alternatives to life extension to meet this anticipated demand?

Response 4.

The demand figures are included in a statement, quoted below, that appears on page 8 of the GAO report.

> The Department of Energy (DOE) and industry experts predict that demand for electricity will increase through the 1990s, outstripping planned additions to generating capacity. In 1989 the nation's total electric generating capacity was about 684,000 megawatts (MW). DOE projects a need for an additional 102,000 MW capacity by the year 2000, and utilities have made plans to construct plants that will produce only about one-third of this additional amount. Also, in 1989 the North American Electric Reliability Council (NERC) projected that utilities' planned additions would be insufficient by 1998. Moreover, according to NERC, some areas of the eastern United States will be at serious risk of supply disruptions in the early 1990s if the demand for electricity reaches the high end of the organization's forecast.

First of all, it is important to note the distinction between the capacity supply and capacity demand estimates. Increase in electric demand (in gigawatts) between 1989 and 2000 refers to the increase in annual peak demand by 2000. Increase in "capacity demand" is defined to include the change in peak demand plus a planning or required reserve margin. The increase in generating capacity needed (or "capacity supply") estimates reflect the difference between current (1989) electric generating capacity estimates (including cogeneration and imports) and future capacity needs (which are assumed to equal the "capacity demand" estimates). Because there is excess capacity in some areas of the country today, the required increase in supply will be less than the forecasted increase in demand. The DOE statement cited by GAO appears to refer to a required increase in capacity supply, and the NERC forecasts refer only to capacity demand (as well as planned capacity additions).

Growth in capacity demand (1989-2000) forecasted by NERC and adjusted for 2000 is about 207 gigawatts, and falls within the range forecasted in the EPA high and low base cases for the new acid rain provisions in the Clean Air Act (about 138-213 gigawatts). EPA agrees with the NERC demand capacity figure.

The increase in generating capacity supply needed (1989-2000) cited by GAO as DOE's forecast is 102 gigawatts. This is less than assumed in the EPA base cases. Note however, according to DOE/EIA "1990 Annual Energy Outlook", the increase in capacity supply needed was forecasted to be 186 gigawatts, which is in the upper end of the range assumed in the EPA base cases. So EPA is unsure of GAO's statement regarding DOE's forecast of 102 gigawatts.

Question 5.

I am uncertain about this EPA comment as reported by EPA. I can read it several ways, particularly with the word "significantly." What does EPA intend or mean? What is DOE's view? How will WEPCO affect acid rain legislation plants? Please explain. What is the Administration doing to clarify the matter? To what extent is the matter fully in EPA's control? What legal or other challenges are possible or likely? What relevant interpretative rulings has EPA issued or planned? What is their legal effect? How are they helpful? Please consider in your reply the enclosed letter from the National Independent Energy Producers.

Response 5.

Some background on the NSPS and PSD programs and the life extension project at WEPCO's Port Washington, Wisconsin facility, may be helpful to respond to these questions. As noted in the GAO report, Congress dictated that modifications at existing plants be treated as new sources for purposes of the NSPS and PSD (as well as nonattainment new source review) provisions of the Clean Air Act. The Act defines modification as: 1) a physical or operational change that 2) increases emissions. Under the NSPS program, emissions increases are measured in terms of hourly potential emissions, while PSD considers increases in annual actual emissions. EPA's regulations contain several limitations on the broad statutory language, including, for example, an exemption for routine changes.

In addition, EPA regulations contain broad "netting" provisions that enable source owners to offset emissions increases with equivalent reductions and thereby avoid the applicability of new source emissions standards or BACT limits. Under NSPS, netting may occur within the affected facility (e.g., an individual utility boiler) and involve physical restrictions on emissions capabilities (such as addition of pollution control equipment). Under PSD and nonattainment area new source review, netting may occur within the entire plant and may involve operational as well as physical restrictions on the plant's emissions.

Prior to the WEPCO court decision, EPA applied a "current actual" to "future potential" test to all nonroutine changes at existing plants in determining emissions increases under the PSD bubble rule. That is, EPA assumed initially that following the changes, the plant would operate at its full potential to emit. Source owners could -- and frequently did -- avoid PSD applicability, however, through legally binding physical or operational limitations restricting actual emissions to levels not significantly greater than levels prior to the change. The owner would estimate the source's actual emissions following the change. If the owner projected that the source likely would not increase its actual emissions following the change, it would accept an actual emissions "cap." However, if the projection later proved inaccurate, and the owner desired to increase the source's actual emissions, it would need to obtain a new source permit at that time. As a result of the WEPCO court decision, modifications involving "like-kind" replacements, such as the WEPCO life extension project itself, now will be able to use a "current actual" to "future actual" test for PSD applicability purposes. In essence, this means that EPA, rather than the source owner, is responsible for accurately projecting a plant's actual emissions following a modification to determine whether the plant's emissions are within the bubble. If EPA projects no actual emissions increase, the source's emissions would not be legally capped.

Regarding WEPCO's life extension project, due to age-related deterioration and loss of efficiency, both the physical capability and actual utilization of the WEPCO power plant had greatly declined over time. The project involved the replacement of major internal components at all five of WEPCO's existing coal-fired steam electric boilers at its Port Washington plant. This project would restore the physical and economic viability of the existing powerplant and extend its useful life for approximately 20 years. In its decision regarding WEPCO, EPA determined that the physical changes contemplated by the proposed project were nonroutine in nature and consequently were not categorically excluded from PSD or NSPS modification requirements. 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. To the extent that life extensions at such plants involve only an enhanced maintenance program, new source requirements may not apply for two reasons. First, the life extension may involve no nonroutine physical or operational change. If so, it would be excluded from new source provisions for that reason alone. Even if the life extension did involve nonroutine changes, it still would not trigger new source requirements if it did not increase pollution on an hourly basis (for NSPS purposes) or an annual basis (for PSD and nonattainment new source review purposes). It should also be noted that WEPCO is not a Clean Coal Technology or repowering project, nor is it (1) being implemented to comply with Title IV or any other Clean Air Act requirements, or (2) a basis (for PSD and nonattainment new source review purposes). It should also be noted that WEPCO is not a Clean Coal Technology or repowering project, nor is it (1) being implemented to comply with Title IV or any other Clean Air Act requirements, or (2) a voluntary pollution control project or research project of any kind. EPA's WEPCO decision only applies to utilities proposing "WEPCO type" changes, i.e., nonroutine replacement that would result in an actual emissions increase. This is the basis for the EPA statement that the ruling is not expected to significantly affect power plant life extension projects.

In addition, it is important to point out that GAO was incorrect in its formulation of the choice that utility companies actually face. GAO stated that the utility company judgment on whether to build a new plant or instead to extend the service life of an existing plant depends on the relative costs of "two sources emitting pollution at a low rate, and not on a comparison of the high cost of a new plant emitting pollution at a low rate and the lower cost of an older plant emitting pollution at a higher rate." In fact, as explained above, due to EPA's netting rules, the owner of an existing source almost always has the choice of merely avoiding increases in emissions at existing plants, and is not required to meet the stringent emissions limits that apply to wholly new sources. Thus, using the nomenclature of the GAO report, the utility's choice is indeed between a new, "lower" emitting plant and an older, "higher" emitting plant. The only condition EPA has ever placed on the latter option is to insist that the source owner prevent the older plant from emitting at even higher levels.

EPA recently proposed a rule (copy enclosed) that would revise the agency's Prevention of Signficant Deterioration (PSD) and nonattainment New Source Review regulations for the addition, replacement or use of pollution control projects (a project undertaken at a utility unit to reduce emission) at existing electric utility steam generating units. Changes that occur at a source that are intended to restore capacity or to improve the operational efficiency of the facility are not considered to be part of a pollution control project for purposes of this proposal. The proposal would not include pollution control projects as modifications, unless the reviewing authority determines that the project will render the unit less environmentally benefirical. Until the proposal is final, EPA will continue its current policy of determining of pollution control projects are excluded from NSR on a case-by-case basis. The implementation of the proposed rule should not cause any negatice environmental effects.

Schedule JRH-D4

United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park, NC 27711

November 2002
http://www.epa.gov/ttn/nsr/rule_dev.html

Technical Support Document for the Prevention of Significant Deterioration and Nonattainment Area New Source Review Regulations

Schedule JRH-D5

Technical Support Document for the Prevention of Significant Deterioration and Nonattainment Area New Source Review Regulations

Integrated Implementation Group
Information Transfer and Program Integration Division
Office of Air Quality Planning and Standards
U. S. Environmental Protection Agency
Research Triangle Park, NC 27711

November 2002

Schedule JRH-D5

This document has been reviewed by the Information Transfer and Program Integration Division of the Office of Air Quality Planning and Standards, EPA, and approved for publication. Mention of trade names or commercial products is not intended to constitute endorsement or recommendation for use. Copies of this report are available through the Library Services Office (MD-35), U.S. Environmental Protection Agency, Research Triangle Park NC 27711, (919) 541-2777, or from National Technical Information Service, 5285 Port Royal Road, Springfield VA 22161. You may also access this document on EPA's website at http://www.epa.gov/ttn/nsr/rule_dev.html.

Table of Contents

Volume I: Comments Received by the End of the Comment Period

Schedule JRH-D5

Table of Contents

Schedule JRH-D5

Table of Contents

Table of Contents

Schedule JRH-D5

Table of Contents

Table of Contents

Table of Contents

Schedule JRH-D5

Table of Contents

Table of Contents

Table of Contents

Table of Contents

Volume II: Comments Received After the End of the Comment Period

Table of Contents

Schedule JRH-D5

applicability test outweigh any residual burden placed on them to maintain the necessary post-change source records when they are required to do so. See also our response to comments on this issue following section 4.2 of this volume.

We believe that these added recordkeeping and reporting (of emissions exceedances) measures will improve the overall compliance rate and provide the information necessary for reviewing authorities to assure that such changes are made consistent with the CAA requirements. Altogether, we believe that the final rules focus on the types of changes occurring at existing emissions units that are more likely to result in significant contributions to air pollution. The final rules will also require greater accountability on a source's part to retain information from which the reviewing authority can determine the nature of any changes that are made at specific emissions units, as well as the actual emissions increases that are associated with those changes. We believe these added benefits far outweigh the additional burden of maintaining the records. Additionally, many existing SIP programs (such as minor NSR programs) already require such emissions tracking, so this requirement is generally not considered to be an inappropriate or unnecessary burden on industry.

We disagree with those commenters who believed the actual-to-projected-actual test was contrary to the CAA and WEPCO. Please see our responses in Sections 5.2.3 and 5.3.4 for further details.

For our response as to why we do not believe the actual-to-projected-actual test should include an enforceable emission cap , see Section 5.5.

Comment:

5.4.3 Adequacy of Existing Emission Projection and Tracking Abilities

5.4.3.1 Adequacy of existing emission projection and tracking abilities for utilities

Two industry commenters (IV-D-263, 308) believed that the utility industry emission projection and tracking abilities were adequate for purposes of applying the actual-to-enforceable-future-actual test. One utility industry commenter (IV-D-294) stated that power pools will continue to require utilities to accurately predict projected capacity utilization. Therefore, the commenter argued, emission projection and tracking abilities will continue to support the actual-to-future-actual test.

STAPPA/ALAPCO (IV-D-259) maintained that the deregulation of the utility industry would change its ability to provide accurate emission projections. Local public utility commissions had historically required utilities to make reliable estimates of future capacity utilization, but deregulation of electric utilities was quickly reducing the public utility commission's role. Therefore, according to STAPPA, utilities will no longer be able to accurately project emissions.

5.4.3.2 Adequacy of existing emission projection and tracking abilities for non-utilities

Fourteen industry commenters (IV-D-210, 221, 254, 260, 263, 264, 270, 273, 289, 299, 301, 308, 311, 313), two utility industry commenters (IV-D-252, 254), and one regulatory agency commenter (IV-D-253) maintained that non-utility industry facilities do have sufficient recordkeeping and reporting to track future emissions, with reliability comparable to that of the utility industry sector. These commenters believed that requirements under the title V operating permit program and other regulations adopted pursuant to the 1990 CAAA had improved the emission projection and tracking abilities of non-utility sources so that they would be able to comply with the actual-to-future-actual test. Furthermore, these commenters suggested that EPA now has broad experience with a number of industries other than utilities.

Six industry commenters (IV-D-210, 263, 264, 270, 308, 313) cited the CAM rule as providing substantially more information from the non-utility sector than was available when the WEPCO rule was promulgated. Two industry commenters (IV-D-260, 313) noted that requirements for yearly emission inventories would mean that adequate emissions tracking information was available. These commenters further indicated that annual emission statements of actual VOC and NO_x emissions were currently required in the Northeast Ozone Transport Region. Another industry commenter (IV-D-301) stated that they had completed an extensive and costly project to establish accurate emission factors for many rubber manufacturing processes, and that these factors could easily be used to quantify post-modification emissions. One industry commenter (IV-D-311) stated that the ability to track emissions was dependent upon assuming that demand for the company's product was within projections.

Two regulatory agencies (IV-D-246, 287) and STAPPA/ALAPCO (IV-D-259) maintained that non-utility industry facilities did not have adequate emission tracking and projection capabilities. STAPPA/ALAPCO (IV-D-259) stated that emission factors and other methods used by non-utility sources were not sufficiently accurate to quantify either past emissions or future actual emissions. Two of these commenters (IV-D-246, 259) further commented that most industries did not have ability to track NO_x emissions in particular. One commenter (IV-D-246) noted that emissions tracking might be adequate for some non-utility sources using continuous emissions monitors (CEMs), or that other stringent quality assurance/quality control measures might be acceptable on a case-by-case basis.

5.4.3.3 Adequacy of existing emission projection and tracking abilities should not be a consideration

Two industry representatives (IV-D-260, 313) commented that the adequacy of existing emission projection and tracking abilities should not be a consideration in determining whether to apply an actual-to-future-actual test. The commenters believed that the uncertainties associated with an actual-to-future-actual test were probably less than those for an actual-to-potential test because they were based on known factors and did not include safety factors.

Response:

We believe that the tracking requirements in the final rules alleviate many of the commenters' concerns about industry's alleged inability to predict their post-change actual emissions increases. Numerous industry commenters indicated that they believed adequate emissions predictions could be made. We agree that all sources are now in a better position to predict post-change emissions increases. Nevertheless, when, according to its best calculations, the physical or operational changes being planned for one or more existing emissions units at a major stationary source will not constitute a major modification, yet there is a reasonable possibility that the project may result in a significant emissions increase, the source must document its findings [including a description of the project, an identification of emissions units whose emissions could increase as a result of the project, the baseline actual emissions for each emissions unit, the projection of post-change actual emissions before adjustments, the adjusted post-change emissions (post-change actual emissions, or potential emissions) and the reason for the adjustment (for example, increase in product demand unrelated to the change)]. If the projection of post-change actual emissions shows a significant increase, the source must also document its compliance with applicable netting procedures if it uses offsetting emission reductions elsewhere at the major stationary source to avoid being a major modification. With the exception of EUSGUs, however, sources are not required to report their post-change annual emissions unless the recorded annual emissions rate in any given year exceeds the baseline actual emissions by a significant amount and is inconsistent with the original projections.

In addition, where there is a reasonable possibility that the project may result in a significant emissions increase (even though a source's projection of post-change emissions shows that it would not), the final rules require a source to maintain emissions data for all emissions units that are changed. The source must maintain this information and compare it to the calculated baseline actual emissions for at least 5 years. (We will presume that any emissions increases that occur after 5 years are not associated with the physical or operational changes.) If the project will increase the design capacity or potential to emit of any emissions unit, the source must maintain and compare this data for that emissions unit to its baseline actual emissions for 10 years. (This extended period allows for the possibility that the increased capacity that the source added via the physical or operational changes could be fully utilized during a normal business cycle.) The information that must be maintained may include *continuous emissions monitoring data, operational levels, fuel usage data, source test results, or any other readily available information of sufficient accuracy for the purpose of determining an emissions unit's post-change emissions. With the exception of EUSGUs, the source must report to the reviewing authority any post-change annual emissions rate only when that rate exceeds the baseline actual emissions rate by a significant amount and is inconsistent with the original projections. See, for example, new §52.21(r)(6)(iv). For EUSGUs, however, an annual report of post-change annual emissions is required even when the projected post-change emissions rate is not exceeded. See, for example, new §52.21(r)(6)(iii).*

As mentioned earlier, we believe that these added recordkeeping and reporting measures are justified and will improve the overall compliance rate and provide the information necessary for reviewing authorities to assure that such changes are made consistent with the CAA requirements. Altogether, we believe these regulatory amendments focus on the types of changes occurring at existing emissions units that are more likely to result in significant contributions to air pollution. The amendments will also require greater accountability on a source's part to retain information from which the reviewing authority can determine the nature of any changes made to emissions units, as well as the actual emissions increases that are associated with those changes.

Industry commenters generally indicated that they would be able to make a projection of a project's post-change emissions and track their actual emissions following the change as required by the new "actual-to-projected-actual" applicability test. We believe that most sources should be able to adequately project the emissions increases that will result from the physical and operational changes that they choose to make. If for some reason the projection is not accurate, the required tracking of emissions for 5 years following the changes will determine whether a significant emissions increase has actually occurred. Where the change is found to be a major modification, despite the projections made by the source, the reviewing authority will be expected to proceed with the process of subjecting the source to the major NSR requirements.

We disagree with the commenter who stated that increased competition and deregulation in the electric utility industry would lead to less accurate estimates of post-change utilization and demand growth. Nevertheless, the new rules require modified EUSGUs to submit a notice to the reviewing authority prior to beginning actual construction that is not considered a major modification. and must submit post-change annual emissions rate data, in tons per year, annually for 5 years after a change is made. Again, this requirement applies to EUSGUs when the new "actual-to-projected-actual" applicability test shows that the change will not result in a significant emissions increase at the unit (or significant net emissions increase at the source), even in cases when the post-change annual emissions during the 5-year period do not show a significant emissions increase. We believe these provisions will continue to provide accurate information on post-change emissions at EUSGUs. Moreover, we believe that EUSGUs will continue to have adequate emission projection and tracking capabilities, regardless of deregulation of some aspects of public utilities. Also, EUSGUs are still required to meet rigorous monitoring requirements under title IV.

5.5 Proposal to Create Enforceable 10-year Emissions Level

Comment:

5.5.1 Support Enforceable 10-year Emission Level

One industry commenter (IV-D-273) and one utility industry commenter (IV-D-252) supported the 10-year emission limit. Another industry commenter (IV-D-321) supported a 10-year tracking period, but did not specifically endorse the proposed enforceable 10-year emission level. One industry commenter (IV-D-250) stated that a 10-year limit would be acceptable if the applicant desires it.

One utility industry commenter (IV-D-252) believed the temporary emissions cap was necessary to ensure that a significant net emissions increase did not occur. The commenter stated that "Otherwise, as it stands now, if these estimates of future emissions prove to be low, it is possible that a source would have inappropriately avoided NSR review at the time of the modification of the unit and the only 'penalty' they would pay would be to install BACT or LAER emission controls years after they would otherwise have had to."

5.5.2 Oppose Enforceable 10-year Emission Level

Twenty-seven industry commenters (IV-D-219, 254, 260, 263, 264, 265, 266, 270, 279, 283, 289, 292, 293, 297, 298, 299, 301, 302, 304, 306, 307, 308, 310, 311, 313, 314, 315), eight utility industry commenters (IV-D-251, 261, 266, 278, 279, 294, 300, 318), eight regulatory agency commenters (IV-D-211, 216, 246, 255, 262, 287, 305, 317), STAPPA/ALAPCO (IV-D-259) and four environmental commenters (IV-D-291, 303, 325, 327) opposed the enforceable 10-year emission level for various reasons. One of the utility commenters (IV-D-251) requested that the EPA withdraw the proposal for the 10-year limit.

One utility industry commenter (IV-D-251) questioned EPA's statements regarding the necessity of the 10-year cap. The commenter reminded the EPA that utility sources were already required to submit 5 years of post-change emissions data to the reviewing authority. This requirement would provide adequate assurance that a source did not inappropriately avoid NSR review. The commenter also asserted that it was unlikely that a source would make a modification and then wait 5 years to use the modification in order to avoid major NSR permitting. The commenter also questioned how the current proposal alleviates EPA's concern that reviewing authorities can "only examine data submitted after-the-fact by the source." The commenter explained that once a source had committed to meeting a certain emissions level to qualify for minor rather than major NSR, the source had accepted responsibility for ensuring compliance with the emission limitations contained in the preconstruction permit. The commenter contended that the proposed temporary cap just served to extend the period of post-change data provision from 5 years to 10 years.

5.5.2.1 10 years is too long

Twelve industry commenters (IV-D-263, 264, 270, 293, 297, 298, 301, 302, 307, 308, 313, 314) and one utility industry commenter (IV-D-261) maintained that 10 years was too long a period for an enforceable emission level to be in place. These commenters believed that the emission limit period did not have to equate to the look back period for determining the emission baseline. Four industry commenters (IV-D-264, 270, 293, 313) explained that the purpose of the two different periods was different. The look back period defined the representative year to which future emissions could be compared. The future year determined whether a change caused an emissions increase.

Seven industry commenters (IV-D-264, 270, 297, 298, 307, 313, 314) felt emission increases would occur well before 10 years, and therefore believed the period for the limit was too long. One industry commenter (IV-D-298) believed that any emissions increase resulting from a change would occur in a short period of time, probably less than 2 years. The commenter (IV-D-298) and another industry commenter (IV-D-302) recommended a 2-year limit if the EPA were to adopt a limit.

Two industry commenters (IV-D-297, 314) indicated that 10 years could be several product cycles, and that a 10-year limit would require a business to accurately forecast the demand for products it was not yet making. One industry commenter (IV-D-307) agreed, stating that market returns were expected and weighed before a project was constructed. Three other industry commenters (IV-D-264, 270, 313) also indicated that changes were not generally made to achieve benefits years into the future.

5.5.2.2 10 years is not long enough

Two environmental commenters (IV-D-291, 303) maintained that the emission limit must be permanently enforceable by the EPA and by citizens, as provided in sections 113 and 304 of the CAA. Three regulatory agencies (IV-D-211, 246, 262) and STAPPA/ALAPCO (IV-D-259) also recommended a permanent limit. Another regulatory agency (IV-D-216) agreed that it was preferable to track emissions indefinitely. These commenters noted that a short-term limit could complicate future applicability determinations and compromise air quality.

STAPPA/ALAPCO (IV-D-259) also indicated that a temporary limit was inconsistent with current practice, in which the permanent enforceable limit on PTE was contained in the preconstruction permit and carried over into the title V permit.

5.5.2.3 Other reasons to oppose

Twelve industry commenters (IV-D-265, 266, 289, 293, 297, 301, 302, 304, 307, 313, 314, 315), five utility industry commenters (IV-D-271, 278, 294, 300, 318), and two environmental commenters (IV-D-291, 303) opposed the enforceable 10-year emission level for various reasons. One utility industry commenter (IV-D-278) held that the 10-year limit would not be a temporary limit, but would become a "*de facto* baseline" for any additional permitting at the facility and would discourage reviewing agencies from allowing increases in PTE at the facility. Two utility industry commenters (IV-D-278, 294) further explained that the 10-year limit would likely be used in SIP planning to meet air quality goals, which would make it unlikely that the reviewing agencies would allow an increase at the end of the 10-year period. One of the utility industry commenters (IV-D-294) stated that the problem would be even worse when the limits were met using pollution controls, as State law would force the source to continue to operate the controls.

One industry commenter (IV-D-307) maintained that the 10-year limit was not based on economic theory. The commenter had several questions about how the 10-year limit would work, including whether the source would have to reassess changes made during the 10-year period, how the baseline would be determined if changes were made during the 10-year period, and what would happen if the past actual emissions decreased.

One industry commenter (IV-D-265) and one utility industry commenter (IV-D-294) opposed the 10-year limit because the regulatory structure for designing and implementing such limits was in its infancy. Two utility industry commenters (IV-D-294, 318) stated that the EPA had not explained how the temporary limit would be terminated or relaxed at the end of the 10-year period.

Another industry commenter (IV-D-301) opposed the 10-year limit because of the additional enforcement liability it would impose. The commenter argued that it would be unfair to subject a facility to enforcement proceedings if it exceeded the limit, as predicting future emissions was difficult.

Two industry commenters (IV-D-289, 313) objected to the 10-year limit, claiming that it usurped State prerogatives. The commenter stated that "How tightly to weave the PSD/NSR applicability net is a decision for each State to make in the context of its SIP."

An industry commenter (IV-D-266) stated that the unit would constantly be subject to a "temporary" emissions limitation since the limit established for any given change would not expire before the next change was made.

Three utility industry commenters (IV-D-271, 294, 318) felt the 10-year limit would discourage sources from making efficiency improvements. Two of the commenters (IV-D-271, 294) stated that the efficiency improvements were required to reduce emissions, and the 10-year limit was thus counter to the EPA's greenhouse gas emission reduction program. One of the commenters (IV-D-318) further explained that the temporary limits would make many projects economically infeasible.

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

Schedule JRH-D6

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.

Schedule JRH-D6

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

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

The Scope of the 2007 and 2010 Outages

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

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.

<u>The Expected Effect of the Projects on the Units' Actual Post-Project Generation of Electricity</u>

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

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

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

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

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

Schedule JRH-D7

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

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.

<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

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

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

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.)

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

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

Schedule JRH-D7

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

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.

<u>Rush Island Generation and Emissions 1990-2014</u>

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

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.

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

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