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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. EF-2024-0021

SURREBUTTAL TESTIMONY

OF

STEVEN C. WHITWORTH

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
March 22, 2024

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SURREBUTTAL TESTIMONY

OF

STEVEN C. WHITWORTH

FILE NO. EF-2024-0021

I. INTRODUCTION

Q. Please state your name and business address.

A. Steven Whitworth, 20 Pine Valley Drive, Collinsville, Illinois

Q. Are you the same Steven C. Whitworth who previously filed direct testimony in this case?

A. I am.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond to the testimony of Staff witnesses Claire M. Eubanks and Keith Majors, and Office of Public Counsel ("OPC") witness Jordan Seaver on the topic of Ameren Missouri's permitting of the Rush Island Projects.[1]

II. ESD'S PERMITTING PROCESS

Q. In your direct testimony, you described how ESD reviewed the Rush Island Projects for the applicability of any permitting requirements prior to the relevant outages. You also testified in your Direct Testimony that those reviews by ESD of the Rush Island Projects followed the normal ESD process for ensuring the projects complied with any applicable permitting requirements. Did any of the

[1] Capitalized phrases or terms used in this testimony, if not specifically defined in it, have the meaning given such terms in my Direct Testimony.

rebuttal testimony offered in this matter contradict your Direct Testimony on these topics?

A. No. The pre-project ESD review of the Rush Island Projects followed the normal process for such reviews concerning activities in Missouri. ESD became aware of these projects after their initial budgeting and scoping, and the assessments ESD provided of the Rush Island Projects followed the typical process for projects in Missouri.

Q. Why do you qualify that answer by referring to the ESD process for the review of projects "in Missouri"?

A. Please recall, as I explained in detail in my Direct Testimony, that the law in Missouri differed from the law in Illinois, and ESD reviewed projects in both jurisdictions for permitting requirements under these separate sets of laws. In Missouri, the permitting requirements were set forth in the Construction Permits Required rule within the Missouri SIP. In Illinois, the federal PSD rules applied directly and did not get incorporated into an approved SIP. This meant that between 2005 and 2009, ESD was required to prepare emission calculations to determine PSD applicability in Illinois, but there was no need to perform such calculations in Missouri in any case where the post-project potential emissions would not increase, as was the case for the Rush Island Projects. Unless I specifically state otherwise, when I describe the process for ESD review of projects for the applicability of permitting requirements, I am referring to the process that ESD applied in the review of projects at Missouri plants.

Q. On pages 19-20 of her Rebuttal Testimony, Ms. Eubanks "suggests" that "Ameren Missouri did not assess legal and environmental risks during the work approval process" for the Rush Island Projects.[2] Is she right?

A. No. I described the pre-project review ESD performed of the Rush Island Projects in my Direct Testimony. In that pre-project review, ESD considered the nature and scope of the projects and their potential impact on emissions, and concluded that the Rush Island Projects did not trigger PSD permitting—or any permitting, for that matter—under the Missouri SIP. The only document that Ms. Eubanks cites that "suggests" to her that the ESD review may not have occurred is the Project Risk Management Plan documentation for the Rush Island Projects, which has a box titled "legal/environmental risks" that is not filled in or marked with an "X".

Q. Does that contradict your testimony in any way?

A. No. ESD did not use these Project Risk Management Plan documents in the course of its review of projects for permitting requirements. In fact, none of the Project Risk Management Plan provisions applied to ESD work at all. The Project Risk Management Plan and the documents used in it were part of the budgeting process that Power Operations (in this case) would go through, which would typically occur before ESD got involved to review a project for permitting requirements. The fact that this one box was not marked on the Project Risk Management Plan is not surprising, and has nothing to do with ESD's review for permitting requirements.

Q. Ms. Eubanks also notes your Direct Testimony, in which you say the ESD review of the Rush Island Unit 1 projects occurred in 2006 "approximately a

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[2] Eubanks Rebuttal, p. 19, l. 16 to p. 20, l. 18.

year after" the 2007 component replacements on Unit 1 were approved by Mr. Rainwater.[3] Was that unusual?

A. No. ESD would typically review projects for permitting requirements after the initial scoping and budgeting. Providing that level of review after a project received the initial approval to move forward was a way of efficiently focusing ESD's resources on the projects that "made the cut" rather than on hypothetical projects that may or may not take place.

Moreover, the fact that a project received sign-off from the CEO or other executives does not represent some sort of irrevocable commitment to undertake the project. Things can and do change, as the authorization documents cited by Ms. Eubanks makes clear. For example, the Unit 2 project as described by the budget authorization form signed by Mr. Rainwater noted that the lower slope panels would be replaced as part of the work on Rush Island Unit 2, and that this and the other relevant work on the unit would take place in 2009. But neither of those assumptions turned out to be true. The outage was moved from 2009 to 2010, and it did not include the lower slope replacement.

The bottom line is that the budgeting documents cited by Ms. Eubanks represent only one step in the process for budgeting projects, and were never intended for use by ESD nor used by ESD in documenting ESD permitting decisions. Nothing about these documents contradicts my testimony that ESD reviewed the Rush Island Projects prior to undertaking them, and concluded that no permitting was required based on our understanding of the law at the time.

[3] *Id.* at p. 20, l. 14.

Q. Can you summarize your understanding of the legal requirements that ESD applied to evaluate projects in Missouri between 2005 and 2010?

A. Yes. The "Construction Permits Required" rule in the Missouri SIP was what one would look at to determine whether a project required a PSD permit or any other sort of permit. That rule stated that permitting was required only for the "construction" of new sources or the "modification" of existing sources, and the Missouri SIP defined "modification" as increasing the potential emissions of an existing source. In other words, unless you are building a new source or modifying (increasing the potential emissions) of an existing source, no permitting is required. If a modification does occur (by increasing potential emissions), then one would look to the other parts of the "Construction Permits Required" rule to determine what sort of permit might be required.[4] If the increase in potential emissions was minor, a "de minimis" permit was required. If the increase in potential emissions was large enough (e.g., 40 tons per year for sulfur dioxide), then a PSD permit was required. But if there was no potential emissions increase expected, then the project needed no permitting at all. That was the case for the Rush Island Projects.

The reason that was the case for the Rush Island Projects was that the only thing that could increase potential emissions from a coal-fired unit like those at Rush Island would be something that increased the maximum designed hourly rate of heat input. These projects did not do that. Availability of a unit (pre- or post-project) has nothing to do with the maximum designed hourly rate of coal burn.

I should note that while not necessary, given the lack of an increase in potential emissions, we did also evaluate the nature of the work as well, because if the work was

[4] And no permit would be required regardless of whether the projects also constituted RMRR or did not increase actual emissions post-the projects.

"routine maintenance, repair or replacement" ("RMRR" for short) it would not trigger permitting even if there would have been a potential or actual emissions increase. We understood that RMRR excluded work that was routine for the utility industry, and that this specifically covered boiler tube replacement.

Finally, we understood that sources were expected to make these applicability determinations on their own, and there was no requirement to document these decisions or to seek confirmation of them from regulators. And given the fact that the project documents would always demonstrate that none of the work increased the maximum designed hourly rate of coal burn, there was nothing more to document.

Q. Can you summarize how ESD came to hold this understanding of the legal requirements?

A. Yes. We read the Missouri SIP. We read the PSD regulations. We saw how the Missouri SIP said PSD would not apply unless there was a modification (i.e., an increase in the potential emissions). We further read how Missouri excluded boiler tube replacements from permitting requirements because such replacements were considered routine by MDNR. We read the MDNR guidance on how the permitting requirements would apply. We read the letters in which MDNR actually applied the permitting requirements to projects, and concluded that they did not trigger permitting. We consulted with legal counsel, both in Ameren Services Company and with lawyers for the Utility Air Regulatory Group, recognized as experts in New Source Review and PSD permitting. We talked with other utilities in Missouri and across the nation about the applicable legal requirements. And we read the interpretations that EPA's program office (Office of Air and Radiation) put out regarding the application of the PSD rules.

All of these steps led me and my colleagues in ESD to believe that we were aligned with our Legal Department, with MDNR, with industry in Missouri, with other utilities across the country in UARG and its counsel, and with the EPA program office on the legal standards to use in determining whether the Rush Island Projects would trigger any permitting requirements. Did the District Court later rule that a modification under the Missouri SIP is not limited to increases in potential omissions? Yes, but none of the parties I just identified knew or had reason to know that at the time.

Q. Staff suggests that you should not have relied upon guidance from MDNR, and instead should have confirmed your understanding of the permitting requirements in Missouri by going to EPA and asking it for guidance. How do you respond?

A. The text of the Missouri SIP and its Construction Permits Required Rule appeared straightforward, requiring construction permits only for "construction" and "modification," which the regulations explained in plain terms as activity that increases the potential to emit. MDNR's guidance documents said the same thing, and that is how MDNR consistently applied the rule to specific projects. For all these reasons, we thought the law was clear, and there is no reason to ask anyone to confirm what we already know.

But even if there had been some confusion about the Missouri SIP, no one would go to EPA to clear that up. Permitting requirements in Missouri are a matter of state law, under the approved Missouri SIP. We would not go to EPA to ask EPA to interpret the state law. That is not what sources in Missouri did when they had questions about permitting requirements—they sent correspondence to MDNR asking for determinations, and MDNR responded with letters announcing its determinations. Some of these determinations from MDNR copied EPA, and to my knowledge EPA never objected to them or said MDNR had delivered an incorrect interpretation of the law. We didn't send any such correspondence to MDNR on the Rush Island Projects because given other MDNR letters about which we were fully aware at the time, we knew exactly how MDNR applied the Missouri SIP, which was exactly how we applied it.

I read in the Rebuttal Testimony of Ms. Eubanks her quote from the deposition of Kyra Moore in 2013 where she responded to a hypothetical question of whether MDNR would defer to EPA in case of a disagreement between the agencies on how to interpret the Missouri. Eubanks Rebuttal, p. 27, ll. 21-26. I am not aware of an instance in which that actually occurred, and it was not something we understood to be the case at the time ESD made the relevant permitting decisions here (i.e., between 2005 and 2010). In their surrebuttal, Company witnesses Holmstead and Moor explain why EPA cannot simply override a state's interpretation of the state SIP by issuing a contrary.

If the MDNR letters setting forth MDNR's interpretation that no permits were required for projects under the Missouri SIP could not be relied upon and were of no value—which seems to be the implication by Ms. Eubanks in her Rebuttal Testimony—then one wonders why either the source or MDNR would go through the time, the trouble and the expense involved in such correspondence.

The fact is that MDNR—not EPA—was the permitting authority under the Clean Air Act for sources in Missouri. Because MDNR's interpretation fit with our reading and understanding of the Missouri SIP, there was no reason to seek a second opinion from EPA, and that is not what other utilities did either.

Q. How did ESD apply its understanding of the law to its pre-project review of the Rush Island Projects for any permitting requirements?

A. We looked at the scope of the projects and the components at issue. We evaluated both the potential emissions impact and the applicability of the RMRR exclusion. On emissions, we concluded that the Rush Island Projects would not increase potential emissions because they would not increase the maximum design capacity of the boiler to burn coal, to produce steam, or to emit pollutants. Based upon EPA guidance concerning the PSD rules, we further understood that this meant there would be no significant net emissions increase caused by the projects. These evaluations were based on our engineering judgment and experience, and not memorialized in any calculation, because that conclusion was obvious to any engineer (and no one has ever suggested otherwise). Moreover, we understood that no such calculation or recordkeeping was required; the lack of a potential emissions increase was inherent in the scope of the projects themselves. On the RMRR exclusion, we understood that these component replacements were of the sort routinely performed throughout the utility industry and consistent with the EPA program office's definition of RMRR. Here again, ESD's conclusion on RMRR was a qualitative judgment and not written down because we had actual knowledge of dozens of projects like those to be done at Rush Island for which permits were never sought or required, and about which no EPA enforcement ever occurred.

Q. On page 28 of her rebuttal testimony, Ms. Eubanks says that Ameren Missouri did not look at both emissions and RMRR for the activities at Unit 1 in 2007. Is she right?

A. No, Ms. Eubanks is wrong. She bases that incorrect statement on a misreading of the District Court's liability decision. What that decision says is that we did not perform "emissions calculations" in our determination that the Rush Island Unit 1 replacements would not trigger permitting requirements. And that is what I have testified here – we did no calculations. But ESD did not need to do any calculations to evaluate whether potential emissions would increase. We considered the scope of the Rush Island Projects and determined that they would not increase the maximum achievable hourly rate of heat input, and thus would not increase the potential emissions. ESD's determinations were correct—none of the Rush Island Projects increased the potential emissions. In the absence of any increase in potential emissions, it was understood by Ameren Missouri and MDNR that PSD permitting would not apply under the Missouri SIP. And in the absence of any increase in potential emissions (i.e., an increase in the maximum hourly emissions rate) at units like Rush Island, which could accommodate increased annual generation and emissions even without the proposed work, EPA had stated that there would not likely be a significant net emissions increase under the PSD rules. We performed this qualitative evaluation of the potential for the Rush Island Projects to increase emissions before approving them.

There is a distinction between the qualitative evaluation of potential emissions that ESD performed prior to the Rush Island Projects, and the emission calculation for the Unit 2 replacements that were performed by Mr. Hutcheson after the Unit 2 outage began. As Staff acknowledges, these after-the-fact calculations were different from the Company's pre-project qualitative analyses described by Mr. Whitworth.

Q. Okay. But as you sit here today,
you're not going to dispute any testimony that Mr.

Whitworth has offered that there was a review prior
the 2010 outage of the projects?

A. So specifically a review and not a
quantitative kind of analysis that Mr. Hutcheson did
that did -- that my understanding at least is
after the project had commenced.

Q. Right.

A. So you're saying a qualitative
review?

Q. Correct.

A. I don't have any information to, you
know, state one way or the other.

Q. And you understand that there was a
difference between Mr. Hutcheson's
calculations that occurred after the project began on
Unit 2 and the pre-project review that occurred for
Unit's 2 scope through the Environmental Services
Department, that qualitative review?

A. I have not seen any documentation of
their qualitative review so I can't speak to whether
his quantitative analysis was different than the
qualitative analysis they may or may not have done.

Q. So we're really talking about two
different things, the qualitative analysis that you
say may or may not have been done and then the Mike
Hutcheson's calculations which came after the fact,
those are two different things you understand?

A. They are two different things, yes.[5]

The calculation that Mr. Hutcheson did in January 2010, shortly after the 2010 Project began was for the purpose of assessing EPA's Notice of Violation (also sent in January 2010) which alleged that over 40 different projects at all four coal-fired plants constituted "major modifications," which looks to actual (distinct from potential)

[5] Deposition of Claire M. Eubanks, File No. EF-2024-0021, p. 26, l. 19 to p. 27, l. 23 (Mar. 11, 2024).

emissions. It was separate and apart from the actual pre-project permitting decisions made by ESD and that I have testified about in my Direct Testimony and here in Surrebuttal. Those qualitative pre-project evaluations are the basis of the permitting decisions at issue, and therefore are what the Commission should consider for prudence.

Q. In discussing ESD's pre-project permitting decisions, Ms. Eubanks brings up the Taum Sauk impoundment failure, and suggests that the "system-wide issues" of "over-compartmentalization and financial pressure" documented in Staff's investigation of that failure may have played a role in ESD's permitting decisions.[6] How do you respond?

A. I worked in ESD at the time of the Taum Sauk impoundment failure and at the time of the subsequent investigations by Staff and FERC. ESD had no role in that failure or in any of the contributing causes of that failure. In the report issued by Staff, the discussion of "over-compartmentalization" concerned only the Power Operations Department, and was not referring to any failure of communication with ESD.[7] Any suggestion that ESD was "siloed off" from the operating companies, such as Ameren Missouri, would be inconsistent with my personal experience at the time. ESD, like the Legal Department, was housed within Ameren Services Company—a shared services company that worked with all the affiliates and had broad exposure to all the affiliates' operations.

Moreover, ESD's permitting decisions for the Rush Island Projects were driven by our understanding of the legal requirements under the Missouri SIP. We had all the

[6] Eubanks Rebuttal, p. 13, ll. 1-2.
[7] Staff's Initial Incident Report, File No. EF-2007-0474, pp. 79–80 (Oct. 24, 2017); Eubanks Deposition, supra, Ex 12.

information we needed to determine whether the projects would increase potential emissions. And we were correct about that—they did not – even the District Court agrees that it was undisputed that potential emissions would not increase.[8] We also had all the information necessary to determine that the component replacements at issue were routine for the utility industry. Although the District Court faulted Mr. Hutcheson for not considering whether the projects would change unit availability in his post-project calculations for Unit 2, the District Court also recognized that ESD did not consider such changes relevant under the legal standards as we understood them at the time. Any "over-compartmentalization" found by Staff in its Taum Sauk report did not apply to ESD and did not affect ESD's permitting decisions on the Rush Island Projects.

Neither did any "financial pressure" play a role in ESD's permitting decisions on the Rush Island Projects. We applied the law as we understood it to the facts of the projects, and drew a reasonable conclusion that no permitting was required. Nobody has ever said that ESD's permitting decisions concerning Rush Island were driven by money or the product of any sort of pressure—financial or otherwise. Ms. Eubanks apparently agrees, because she admitted in her deposition she could not connect ESD's permitting decisions to any Taum Sauk issue.[9]

Q. What about Ms. Eubanks' citation to the testimony of Mr. Boll and Mr. Meiners, who stated that neither spoke to anyone in ESD about whether the work on Rush Island Unit 1 would require permitting?

[8] United States v. Ameren Missouri, 4:11-cv-77-RWS, (E.D. Mo. Jan. 21, 2016), ECF No. 711 at 10 n.4 ("It is undisputed that the projects were not expected to and did not increase the units' potential emissions.").
[9] Eubanks Deposition, supra, p. 116, l. 23 to p. 117, l. 7.

A. I do not recall speaking to either Mr. Boll or Mr. Meiners about whether the projects on Rush Island Unit 1 in 2007 would require permitting. But that is not surprising, because it was the job of ESD to determine whether permits would be required, not the job of a project engineer such as Mr. Boll or a plant manager such as Mr. Meiners. And as I discussed in my Direct Testimony, there were many ways in which projects could be brought to the attention of ESD. Neither Mr. Boll nor Mr. Meiners was the only line of communication into ESD at the time. The upcoming outage schedule and the associated scopes of work were published within the Company and available to ESD, as I described in my Direct Testimony.[10] These items were discussed at higher levels of management by Mr. Boll's supervisors, Mr. Meiners' supervisors, and my supervisor Mike Menne, who coordinated the work of ESD. I did not depend upon getting a phone call from either Mr. Boll or Mr. Meiners in order to identify upcoming projects for review by ESD.

Following its normal procedures and applying its understanding of the applicable legal requirements, at the time of the projects, ESD conducted a pre-project review of the Rush Island Projects for applicable permitting requirements, and concluded that no permits were required. I have seen nothing in any testimony that seriously suggests otherwise.

Q. Ms. Eubanks notes that ESD did not ask the Legal Department to confirm its decisions concerning the Rush Island Projects. Was that unusual?

A. Not at all. We rely upon the Legal Department for legal interpretations, not engineering judgment. Throughout my tenure in ESD, I was in regular communication with the Legal Department about the proper interpretation of the Missouri SIP and the PSD regulations incorporated into the Missouri SIP. One such issue concerned whether there

[10] Whitworth Direct, p. 21, ll. 4-16.

was any requirement to perform written emissions calculations, or to document our permitting decisions in any way, for projects in Missouri during this time period (i.e., 2005-2010). Our use of the qualitative approach, rather than written emissions calculations or other documentation of our permitting decisions, was consistent with the interpretations we received from the Legal Department on the Missouri SIP at this time. I can state without reservation that ESD's understanding of the Missouri SIP was in complete alignment with that of Ameren's Legal Department. Having been given the views of the Legal Department on the applicable permitting requirements, it was the job of ESD to apply those requirements to the facts of any project, using our engineering knowledge and judgment. There was no reason to ask the Legal Department to confirm our analysis that the Rush Island Projects would not increase potential emissions, would not likely cause actual emissions to increase (because the units were capable of increased generation even absent the projects) and were routine within the industry.

Q. Ms. Eubanks goes on to note that the Company apparently did not "consult with" anyone outside the Company "when it made the decision not to seek a permit" for the 2007 work at Rush Island Unit 1.[11] How do you respond?

A. As I have explained, ESD applied the law as we understood it to the facts of the projects, and concluded that no permitting applied to the Rush Island Projects. I have also explained that we based our understanding of the legal requirements, as applied by ESD in that review, on the text of the regulations, on discussions about those regulations with the Ameren Legal Department, on the established interpretation of those regulations by MDNR, on the shared understanding we had with other regulated entities in Missouri,

[11] Eubanks Rebuttal, p. 28, ll. 21-24.

on the advice of lawyers for UARG concerning the federal PSD regulations, on the shared understanding about the federal PSD regulations with other utilities across the country, and on the public statements by EPA's program office concerning the scope and application of the federal PSD regulations. These public statements were summarized in my Direct Testimony from page 16, line 11 to page 17, line 18, and in the schedules to my direct testimony referenced therein.

After we considered these sources and applied them to the facts of the Rush Island Projects, we believed the answer was clear and required no further confirmation from the regulators or anyone else. It is true that we did not seek formal confirmation of ESD's permitting decisions. But that does not mean we acted independently of the guidance we received. ESD in fact relied upon that guidance in making the relevant permitting decisions, and I believe it was reasonable to have done so.

I also want to make clear that Ameren Missouri did not hide these projects from the regulators. Capital projects like the Rush Island Projects are reflected on Ameren Missouri's property records, and have been publicly discussed in prior proceedings before this Commission—some of which have been cited by Mr. Birk in his Direct Testimony, others of which Ms. Eubanks acknowledges in her Rebuttal Testimony. As I noted in my Direct Testimony, and which Staff does not dispute, MDNR employees inspected Rush Island during the projects and certified the plant as in compliance. EPA asked MDNR to join the litigation it subsequently filed, and MDNR refused. Such interactions confirmed our understanding that the Rush Island Projects did not trigger any permitting requirements under the Missouri SIP.

Ms. Eubanks notes that we did not get our own "no permit required" letter from MDNR.[12] But she does not claim that, had we done so, it would say anything differently than (1) the many letters in the record finding that no permit is needed in the absence of an increase in potential emissions, (2) the permitting manuals issued by MDNR identifying potential emissions as the trigger for PSD permitting, or (3) Ms. Moore's deposition testimony that MDNR did not require permits unless potential emissions increased. By analogy, Ameren Missouri does not correspond with the Commission or its Staff about every decision it makes with respect to whether that decision requires some kind of Commission permission – e.g., a certificate of convenience or necessity, or some kind of rule variance. Rather, Ameren Missouri understands the Commission's rules and its prior decisions interpreting them and regularly determines no action by the Commission is required. In those cases, there is no point in burdening the agency with questions to which we already know the answer.

Q. If ESD had asked EPA to confirm ESD's understanding of the legal requirements in connection with ESD's permitting decisions on the Rush Island Projects, would it have made any difference?

A. No. ESD's understanding of the federal PSD rules was consistent with the EPA's program office in charge of those rules, the Office of Air and Radiation, during the relevant time period. This was made plain to us through our work with the Utility Air Regulatory Group ("UARG"), as I discussed in my Direct Testimony. Attorneys for UARG read and summarized for us the statements coming out of the EPA's Office of Air and Radiation on the interpretation and application of the PSD rules. As I also described

[12] Eubanks Rebuttal, p. 29, ll. 3-6.

in my Direct Testimony, we also heard directly from EPA officials, such as Lynn Hutchinson, at UARG meetings that focused on the interpretation and application of the PSD rules. Those statements by EPA reinforced two key points that were consistent with our understanding of the legal requirements. First, projects that do not increase the maximum hourly rate of emissions (i.e., don't increase potential emissions) will not trigger PSD. Second, the RMRR provision, which excludes projects from permitting requirements, applies to projects that are routine for the *industry*[13] and is not limited to trivial or "de minimis" activities at a given unit.

Q. Does a regulated entity need to get an applicability determination in order to make a reasonable decision on whether permitting applies?

A. No. The expectation is that sources will make the applicability determinations all on their own, and do not have to get the regulators to bless a decision that permitting requirements do not apply. If this Commission adopts a contrary rule, and holds that prudence requires a utility to get regulatory approval of any applicability decision, then the Commission will have rewritten the federal PSD program in a way contrary to how the federal courts of appeals have said the program should work: the source makes its decision and may then proceed with the project on that basis alone. This was our understanding of how the PSD program was supposed to work when we made our permitting decisions on the Rush Island Projects. And Messrs. Holmstead and Moor confirm in their Surrebuttal Testimony that this understanding remains correct today.

Q. Mr. Whitworth, Staff reads your testimony here as disputing the court rulings that found Ameren Missouri liable for violating the Clean Air Act in

[13] The District Court, years later, said this was wrong and that one must focus on what is routine for the unit but that is not what EPA's program office was telling utilities at the time.

undertaking the projects without first obtaining PSD permits. Is that what you are doing?

A. Absolutely not. The courts found that we made the wrong decision, and that this decision was based on an incorrect understanding of the law. But no court has found that our understanding of the law was unreasonable. And neither does Staff contend that our understanding of the law was unreasonable.

Q. But doesn't Staff suggest that Ameren Missouri knew that undertaking these projects risked NSR violations?

A. Actually, no. Whatever confusion Staff's Rebuttal Testimony sowed on this subject was cleared up by their deposition testimony. Staff's position is that Ameren Missouri knew the risks of an NSR violation were expensive emission controls and potentially the loss of allowances.

Q. If you could turn to -- I think it's
on Page 17 of your rebuttal testimony.

A. Okay. I am there.

Q. I don't know if it's exactly Line 30
but there's a question that says are there other
contemporaneous documents suggesting that Ameren Missouri
understood the risk of violation before
approval of the 2010 project. Do you see that?

A. Yes. That begins on Page 18.

Q. Okay. Great.

A. On my version.

Q. All right. And then your answer is,
yes, correct?

A. Yes.

Q. Okay. Are you saying that Ameren
believed that these Rush Island projects risked

triggering New Source Review?

A. **No. I'm saying that there are documents from the time that suggest to Ameren Missouri that violating New Source Review has risks.**

Q. Okay. But you're not saying that Ameren employees understood that these specific Rush Island projects risked triggering New Source Review?

A. I think the only document -- **no**.

Q. No, you're not saying that Ameren employees thought that these specific Rush Island projects risked NSR triggering?

A. These documents talk about Ameren Missouri's understanding of New Source Review and the risks related to, you know, either a violation or triggering New Source Review not specifically the Rush Island 2007 and 2010 project.

Q. Was there any documentation that you saw that indicated to you that an Ameren employee thought that those specific Rush Island projects risked triggering New Source Review?

A. **No.**[14]

This is true—we were aware (from our participation in UARG, as well as other sources) that EPA sought such remedies in the cases they brought. But that does not mean we anticipated that the Rush Island Projects—or any projects, for that matter—triggered NSR. As I explained in my Direct Testimony, we were therefore surprised when the courts disagreed with us on the law and found us liable.[15]

Q. Ms. Eubanks quotes from the District Court's 2019 remedy opinion, stating that in the Court's 2017 liability opinion it had found that at the time of the Rush Island projects "the standard for assessing PSD applicability was well-

[14] Eubanks Deposition, supra, p. 140, l. 9 to p. 141, l. 20. (emphasis added).
[15] Whitworth Direct, p. 54, l. 5-15.

established" and that it was "well-known" that projects like those at Rush Island "risked triggering PSD requirements."[16] How do you respond?

A. I agree that is what the District Court wrote. But Ms. Eubanks ignores two fundamental facts, which put these quotes in context. First, the referenced language from the District Court talks about measuring emissions increases, not about RMRR. If a project is RMRR, one does not need to deal with any emissions analyses. Second, the District Court was applying a different legal standard for emissions analyses than we in ESD had applied in making the permitting decisions.

> Q. As you sit here today, is it your understanding that that approach that Ameren Missouri had was different from the determinations of law that Judge Sippel made for the legal standards applicable to permitting?
>
> A. The testimony Ameren Missouri has provided in this case as to what their understanding of the law was at the time of the projects is different that what the judge found, yes.[17]

Recall that we (and MDNR) interpreted the Missouri SIP to impose a two-step process for permitting. At step one, the question was whether potential emissions would increase. If so, then you would go to step two and apply the PSD regulations to see if that potential emissions increase amounted to a "significant net emissions increase" that triggered PSD permitting. But if at step one there was no potential emissions increase, then the inquiry ends and the conclusion is that no permitting (of any sort) is required. In 2016, the District Court issued a decision that held that both Ameren Missouri and MDNR were wrong in their interpretation of the Missouri SIP—that the PSD regulations incorporated into it apply independently, whether or not there is a potential emissions increase.

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[16] Eubanks Rebuttal, p. 11, ll. 28-31.
[17] Eubanks Dep., p. 21, ll. 10-18.

So, when the District Court writes in 2017 or 2019 that "the standard for PSD applicability was well established" at the time of the projects, we understand it to mean just that: the standard under the federal PSD rules found at 40 C.F.R. § 52.21. We do not believe the Court meant "the standard for permitting under the Missouri SIP" because there was no court that addressed that standard before the Court did in 2016 and—as remains undisputed—MDNR consistently interpreted the Missouri SIP's permitting requirements to turn on potential emissions, not availability improvement. None of the decisions that the District Court cited for "the standard for PSD applicability" involved the Missouri SIP, and at the time ESD performed its pre-project review of the Rush Island Projects we had no idea that a court would subsequently interpret the Missouri SIP differently than our interpretation, which was consistent with MDNR's established understanding. Ms. Eubanks discussion of what the courts said years later is nothing more than a hindsight review that is irrelevant to the question in this case.

Q. Ms. Eubanks cites two sentences from the Federal Register, where EPA approved the revision to the Missouri SIP in which Missouri incorporated the federal PSD rules, and suggests those two sentences means you should have known that potential emissions was no longer the trigger for application of the PSD rules. How do you respond?

A. The Federal Register entry cited by Ms. Eubanks stated that the provisions of the federal PSD rule found at 40 C.F.R. § 52.21 "supersede the state provisions for purposes of the PSD program" and "any conflicting provisions in the Missouri rule."[18] But Ms. Eubanks ignores statements in that same entry showing that EPA's approval was not

[18] 71 Fed. Reg. 36,486, 36,487, 36,489 (June 27, 2006).

intended to change any aspect of state law: "This final action merely approves state law as meeting Federal requirements and imposes no additional requirements beyond those imposed by state law."[19] And again: "[T]his rule approves pre-existing requirements under state law and does not impose any additional enforceable duty beyond that required by state law."[20] The incorporation of the federal PSD rules in 40 C.F.R. § 52.21 had been a part of state law since 2004.

> In the summer of 2004, Missouri revised Missouri rule 10 CSR 10-6.060, Construction Permits Required . . . to incorporate the changes to the Federal NSR program. These rule revisions were adopted by the Missouri Air Conservation Commission on August 26, 2004, and became effective under state law on December 30, 2004.[21]

When it incorporated the federal PSD rules into the Missouri Construction Permits Required rule in 2004, MDNR plainly did not think it was changing the way the law worked in Missouri. In fact, MDNR continued to exclude projects for permitting if they had no increase in potential emissions, even after it made the incorporation effective under state law, as Messrs. Holmstead and Moor explain in their Direct Testimonies.

Nothing in that 2006 Federal Register entry cited by Ms. Eubanks put us on notice that MDNR's incorporation of the 2002 PSD rules wiped away the rest of the construction permits required rule, which made potential emissions the trigger for permitting requirements to apply.

> Q. Is there any indication that was provided that in incorporating the 2002 rules into the SIP that the construction permit rules would no longer approach modification as the trigger for permitting, that is modification being increase in the potential to emit?

[19] *Id.* at 36,488.
[20] *Id.*
[21] *Id.* at 36,487.

A. This document specifically is what you're asking?

Q. Yes.

A. I don't think that this document uses the phrase modification.

Q. Was there any notice provided, that you're aware of, that the incorporation of the 2002 rules into the Missouri SIP would mean that the modification provisions of the Missouri SIP were no longer applicable?

A. Specific to EPA adopting the Missouri SIP, this document here or --

Q. EPA statement or MDNR statement. Did anybody provide any notice that by incorporating the 2002 rules into the PSD into the SIP that it meant that the pre-existing modification rules were no longer applicable?

A. So I do know that EPA commented on the proposed rule making that DNR submitted and I do know that there was also -- Ameren Missouri's permit referenced both modification and major modification. But other than that, I'm not aware of anything else.

Q. And did any of that provide notice that the modification provisions of the Missouri SIP would no longer be applicable once the PSD rules were incorporated into it?

A. I don't know.[22]

The two lines cited by Ms. Eubanks did not give notice to MDNR either, because MDNR continued with its existing approach of using potential emissions as the trigger for any permitting requirement to apply. Schedule SCW-D20, which Staff does not address, is from a 2011 version of MDNR's permitting manual, which obviously post-dates the

[22] Eubanks Dep., supra, p. 92, l. 22 to p. 94, l.4.

2006 approval of Missouri's incorporation of the federal PSD rules. Even then—five years later—MNDR still maintains potential emissions as the trigger.

Q. But do you dispute the District Court statement that, in cases outside of Missouri that did not involve the Missouri SIP, EPA had been known to use a formula, designed by its litigation experts Ranajit Sahu and Robert Koppe, to emissions increases on the basis of availability improvement alone?

A. Of course not. EPA's litigation position and its reliance on the Koppe-Sahu formula in those cases was known to industry. But the Koppe-Sahu formula had no relevance to demonstrating whether *potential* emissions would increase, which was the test as we understood it in Missouri.[23]

That formula was a post-project actual emissions test which was irrelevant given our understanding at the time of the projects that under the Missouri SIP, once it was determined that potential emissions would not increase, the permitting question was over.

Neither did we use the Koppe-Sahu method for our work in Illinois, where the federal PSD regulations were directly applicable. We discussed the Koppe-Sahu formula in UARG meetings, as the Schedules to my Direct Testimony show. What those Schedules also show is that we understood the Koppe-Sahu test to be outcome-determinative—always projecting an increase and never a decrease and was not set forth in any regulation or guidance document. We did not therefore believe the Koppe-Sahu test was reasonable to use even in Illinois. Staff would apparently agree that was a reasonable conclusion, as Ms. Eubanks' responses to questions about the Koppe-Sahu methodology shows.

> Q. Were you aware that that methodology always show[s] an increase in availability in

[23] Whitworth Direct, p. 13, ll. 7-10.

generation?

A. I can't agree to that or disagree with that. I've not heard that before that.

Q. You're not aware of that fact?

A. I don't know that it is a fact.

Q. Okay. So does that sound reasonable to you, a methodology that always shows an increase in the availability in generation?

A. I can't speak to that.

Q. Does it sound reasonable to you as a methodology as an engineer?

A. No.

Q. So you would agree it would be reasonable then for the utilities to contest that methodology?

A. Without knowing the fact that it always shows the availability increases, I can't – can't say for certain.

Q. If the utilities through testimony of Koppe and Sahu had developed the fact that it always shows an increase in availability, always shows an increase in generation, if you accept that as true, would it then be reasonable for the utilities to contest that methodology when it's being applied against them?

A. If that was established that it was always going to show the same result under a wide variety of cases, I think that's probably something that is reasonable to contest.

Q. Even if it's well-known?

A. Yes. Something can be well-known and not be reasonable.[24]

[24] Deposition of Claire Eubanks, File No. ER-2022-0337, p. 119, l. 8 to p. 120, l. 15 (Mar. 24. 2023).

Our rejection of the Koppe-Sahu methodology for use under the PSD rules was consistent with the majority of courts that had considered the issue at the time of the Rush Island Projects. See Schedule SCW-D13, Schedule SCW-D15, and Schedule SCW-D16.

Had we heard about the Koppe-Sahu formula? Yes. Did we have any reason to believe that it was applicable in Missouri? No, because it does not address potential emissions. Did we think it should be used elsewhere? No, because it is outcome-determinative and will only show increases. A litigation theory can be both "well-known" and wrong at the same time—as Staff concedes—and this is how we (and the majority of courts at the time) viewed EPA's Koppe-Sahu theory.

Q. But the District Court also found that it was "well-known" that projects like these "risked triggering PSD requirements," as Ms. Eubanks notes in her Rebuttal Testimony.[25] How do you respond to that?

A. Here again, the reference the Court makes is to "PSD requirements,"—not to "the requirements for PSD permitting under the Missouri SIP." MDNR had consistently determined that large projects on coal-fired units do not trigger the requirements for PSD permitting under the Missouri SIP unless they would increase the potential emissions. Not one of the cases cited by the District Court arose in Missouri and was governed by the Missouri SIP. Even Mr. Seaver concedes it was reasonable for Ameren Missouri to look to the Construction Permits Required rule in the Missouri SIP to determine what permitting applied.

Q. We looked earlier at Exhibit No. 2 from
the Eubanks deposition and the reference there to the
Construction Permits Required rule. Do you recall
that? Do you have a copy --

---

[25] Eubanks Rebuttal, p. 11, ll. 29-31.

A. Exhibit 10?

Q. -- there?

That might be easier to look at.

A. Exhibit 10? Is that -- oh, no, I see.

Q. Two from the Eubanks deposition.

A. Yes. Yes, I have it.

Q. You see that first page. 10 CSR 10.6-060, the Construction Permits Required?

A. Yes.

Q. Okay. Would it be reasonable for a source in Missouri to look at the Construction Permits Required section of the regulations to see whether a project required a construction permit?

A. Yes. I think that's a reasonable thing to consider.[26]

Nor does Mr. Seaver fault Ameren Missouri for using potential emissions as the trigger for any permitting requirements.

Q. Yeah. Are you offering any opinion in this matter that it was unreasonable for the Environmental Services Department to be making its permitting decision on the basis of whether the project would increase the potential emissions?

A. I do not believe that it was unreasonable for the Environmental Services Department to use that as a -- as a part of their decision.

Q. Are you -- do you believe it was reasonable for the Environmental Services Department to believe that only if the potential emissions increased, would permitting be required under the Construction Permits Required rule?

THE WITNESS: Could you read the question

[26] Deposition of Jordan Seaver, File No. EF-2024-0021, p. 110, ll. 1-19.

back.

COURT REPORTER: "Question: Do you believe it was reasonable for the Environmental Services Department to believe that only if the potential emissions increased, would permitting be required under the Construction Permits Required rule."

THE WITNESS: I don't know.[27]

Q. Was the emissions increase issue the only one where the District Court, in holding Ameren Missouri liable, applied a different legal standard than that ESD had used in its permitting decisions?

A. No. The District Court also applied a more narrow interpretation of RMRR than we had understood EPA had established. We believed that the standard for RMRR was what was routine in the industry, and we applied that inquiry on a component-by-component basis. We relied on the many statements by EPA's program office in the 1990s and in the 2000's that the RMRR exclusion would apply to project that are routine in the industry, including instances in which multiple components are replaced to the tune of several million dollars. In was on this basis that we concluded that the component replacements scheduled for the Rush Island Projects were excluded from permitting as RMRR.

The District Court, however, did two things differently on the RMRR issue. First, it decided to aggregate separate work orders together into one big "project" for each unit, and apply the RMRR exclusion to the combined "project" consisting of four components (at Rush Island Unit 1) or three components (at Rush Island Unit 2). We had no notice that the District Court would aggregate together separate work orders and analyze the

[27] Seaver Dep., supra, p. 109, ll. 3-24.

aggregated activities as one combined "project" for RMRR purposes. Second, the District Court construed RMRR to apply only to trivial, "de minimis" activities routine for the given unit. The District Court did so despite the fact EPA admitted that it had applied the RMRR exclusion to projects that were more than "de minimis" in size and that most courts had concluded that EPA's established interpretation of RMRR meant that it covered projects that were routine for the industry. We did not anticipate this legal ruling either.

Q. Mr. Seaver suggests that the Company should have expected all this as a result of EPA's 1988 decision concerning the Wisconsin Electric Port Washington Plant. Is he right?

A. Absolutely not. First, the WEPCo Port Washington Project was nothing like the Rush Island Projects, so the fact permits were required for Port Washington tells us nothing about whether they should have been expected for Rush Island. Second, EPA's public descriptions of its WEPCo decision make clear that it did not have broad application to the boiler component replacements like those at Rush Island. Mr. Seaver either ignored (or was ignorant of) these facts when he offered his opinion about WEPCo, and nothing about WEPCo suggests Ameren Missouri's permitting decisions were imprudent.

Q. Why do you say the WEPCo Port Washington Project was different from Rush Island?

A. The WEPCo Port Washington Project was not just different from Rush Island—it was different from any project before or since.

First, the Port Washington Project increased the hourly potential emissions, and on that basis was found to trigger both the New Source Performance Standards ("NSPS") and PSD permitting. As I have previously explained, the Rush Island Projects were not expected to (and did not) increase hourly potential emissions. EPA never claimed otherwise, and never claimed that the NSPS applied to the Rush Island Projects. The absence of any increase in potential emissions at Rush Island was a critical issue, and one of the main reasons why we concluded no permitting requirements would apply under the Missouri SIP.

Second, the EPA focused on the fact that the Port Washington Project involved steam drum replacements—something that EPA found was "unprecedented" in the utility industry. The Rush Island Projects did not involve any such rare or "unprecedented" component replacements.

Third, the purpose of the Port Washington Project was to recover capacity that the units had permanently lost due to age-related deterioration. Here, the Rush Island units were in excellent shape, and had high availability prior to the projects. Although some of the work in the Rush Island Projects was meant to address minor deratings that occurred from time to time as a result of pluggage, that was nothing like the permanently lost capacity that Port Washington could not otherwise regain unless it did the plant-wide project. As EPA noted, one Port Washington unit could not even be turned on for safety reasons.

Fourth, the Port Washington Project was determined to be necessary to keep the plant operating past its established retirement dates. The alternative to doing the work at Port Washington was retirement of the plant. Here, the Rush Island Projects were not slated for retirement and retirement was not on the table as an alternative to performing the work.

Fifth, the Port Washington Project was truly massive—it would cover all five units at the plant, last for at least four years, and involve successive outages at each unit lasting nine months. The projected expense was over $70 million in 1988 dollars. Here, the outages were on the order of three months each, which is not unusual for the industry, and cost substantially less.

We did not consider the Port Washington Project to be comparable in the Rush Island Projects in any way. When confronted with the facts of the Port Washington Project at his deposition, Mr. Seaver changed his testimony and admitted that the Port Washington Project was distinguishable from the Rush Island Projects.

> Q. We're talking about New Source Performance
> Standards, NSPS, triggering and it's based on the
> increase in hourly potential emissions. Right?
>
> A. Okay. So I, after reviewing part of the
> document, do see that in order to answer your
> question, it does appear that it says that the
> projects at WEPCO would trigger the NSPS.
>
> Q. And specifically because they would
> increase the hourly potential emissions. Correct?
>
> A. Increase the emissions rate which would
> probably be -- the rate would be over a period of
> time. So yes, hourly emissions.
>
> …
>
> Q. But we know that the work at Rush Island
> on these Rush Island projects did not increase the
> hourly potential emissions. You know that to be the
> case. Right?
>
> A. I don't know.
>
> Q. You don't dispute that that is correct, do
> you?
>
> A. I will not dispute that, no.

Q. Okay. So if it is correct that the work for the Rush Island projects did not increase the hourly potential emissions, then in that sense the Port Washington project and the Rush Island projects were different, were they not?

A. If that's the case, then they would be different in that respect, yes.

…

Q. And in relative terms the capacity degradation and loss at Port Washington was much greater than the 30 to 50 megawatt derate at Rush Island in your mind?

A. That is greater, yes.

Q. And the cause of the capacity loss at the Port Washington project was different from the cause of the derates at Rush Island. Correct?

A. I believe so, yes.

Q. Specifically we saw in Exhibits 3 and 4 the discussion about the age-related deterioration and cracking in the steam drums. Do you recall that?

A. I do.

Q. Okay. But here as we see in Exhibit 10 the issue with respect to the derates is pluggage. Do you see that?

A. Yes.

…

Q. Okay. So the cause of the lost capacity at Port Washington was age-related deterioration. The cause of the derates at Rush Island was pluggage. In that sense the cause of the capacity issues were different, were they not?

A. Those are different, yes.

Q. And you understand that at the Port Washington project, that capacity had been permanently lost. Right?

A. For at least one of the units I believe.

Q. Well, yes. Absolutely for one because they couldn't even turn it on. Right?

A. Correct.

Q. Right. But you also saw the references in the documents by Mr. Clay and others at EPA that in order to reach the original capability of the unit, the repair work had to be done on all of them. Do you recall that?

A. I don't recall that specifically, but I do recall that he said the work had to be done in order to return the plant to its operating capacity.

…

Q. Okay. And so we talked earlier about the fact that at Port Washington the only way to get to the original design capacity, the original 400 megawatt plant-wide capacity, was to do the Port Washington life extension project. Right?

A. That was what the documents said, yes. I'm not sure that that was the only route, but yes, that's what the documents state.

Q. That's a fair reading of the EPA documents, is it not?

A. Yes.

Q. Here at Rush Island before the work was done, the units could reach their maximum designed capacity, could they not?

A. Not -- at least at all -- at the very least, not at all times. I mean, it doesn't appear that way.

…

A. Before the projects were done what do I know about how it would reach its maximum capacity?

Q. Either unit one or unit two at Rush Island. Yes, that's what I'm asking.

A. I'm not sure.

Q. But we do know that at Port Washington you couldn't get to that maximum design capacity without doing a life extension project. Right?

A. That is what the documents state, yes.

Q. And in that sense the Port Washington project is different from the Rush Island project, is it not?

A. I don't know.

Q. You don't have any opinion on that?

A. If your question is are the projects' details different for the Port Washington case and the Rush Island case, then yes, I agree.

…

Q. We saw earlier today that the Port Washington project was intended to extend the life of those five units past their established retirement dates. Do you recall that discussion from earlier today?

A. Yes.

Q. All right. And that you recall EPA noted in its Exhibits 3 and 4 that the alternative to the work was to retire the Port Washington plant. Do you recall that?

A. I believe I recall reading that at one point, yes.

Q. With the Rush Island project, there was no talk about extension of operation past the retirement date, was there?

A. Which retirement date are we talking about?

Q. There was -- well, let me ask, are you aware of any retirement date that had been established for the Rush Island units?

A. Yes.

Q. Okay. What was that retirement date?

A. 2042.

Q. Okay. Was there any discussion in 2000 -- or around the 2007 and 2010 Rush Island projects about those projects being necessary to extend the operation of Rush Island past those retirement dates?

A. Not that I know of.

Q. Do you know of any discussion about the Rush Island projects that indicated that they were necessary in order to extend the operation of Rush Island past any established retirement date?

A. Not that I know of.

Q. And you're -- you understand that these Rush Island projects, when they were evaluated, were never compared against the alternative of retiring the plant. Correct?

A. Not that I know of. I don't know if that was considered or not though.

Q. Are you aware of any evidence to suggest that had these projects not been done, that is the Rush Island projects, the plant would have been retired?

A. Well, it would have been retired eventually.

Q. Was there any prospect of immediate retirement that was put off as a result of the Rush Island projects?

A. Not that I know of.

Q. And in that sense, the Rush Island projects were different from the WEPCO Port

Washington projects, were they not?

A. I would agree, yes.

…

Q. And we also saw earlier that the Port Washington project would involve for each unit a nine-month outage. Do you recall that?

A. At Port Washington?

Q. Yes.

A. That sounds familiar, yes.

Q. And were you aware that the outages at issue here for Rush Island were on the order of three months?

A. That sounds right. Offhand I don't know specifically, but that sounds right to me.

Q. So whether we're talking about the number of components or the length of the outage, the Port Washington project is different from either of the Rush Island projects at unit one or unit two. Right?

A. In those respects, yes, the projects are different.

…

Q. But you do know that the equipment was different at Port Washington than the equipment replaced at Rush Island in the Rush Island projects. Correct?

A. At least, yes, there are -- in the Venn diagram, there are nonoverlapping components, yes.

Q. Well, we talked a lot about the steam drum replacement and the fact that that was part of the EPA determination for why the project was not routine. Do you recall that?

A. I do.

Q. And that was also part of what the Seventh

Circuit found notable was the unprecedented steam drum replacement. Do you recall that too?

A. I do recall the Seventh Circuit -- is this -- well, remind me, which court case is this again?

Q. The WEPCO case that you brought with you today.

A. The WEPCO case.

Q. We marked it as Exhibit 2.

Okay. Right. Yes. I do recall that there was a portion of the decision that states that there was something unprecedented. I just don't recall specifically if it was about the steam drum.

Q. But you do recall that the Seventh Circuit did discuss the fact that WEPCO couldn't point to any other steam drum replacement. Do you recall that?

A. Yes, I do.

Q. Okay. And at Rush Island there was no steam drum replacement or anything like it in the Rush Island projects, was there?

A. I agree that there was no steam drum repair or replacement.

Q. Of any of the pieces of equipment that were focused on by the courts in WEPCO, was any of that comparable to the components replaced by Ameren Missouri in the Rush Island projects?

A. I don't know.

Q. When you consider the components that were at issue in the Port Washington project and the components that were at issue in the Rush Island projects, is it fair to say that those were different components?

A. Yes. The -- I mean, the ones that we've been talking about, yes, are different.

Q. And is there -- is there anything about the components at the Washington -- Port Washington project that you think are comparable to the component replacements at the Rush Island project?

A. I don't know.

Q. Now, we talked about the cost of the Port Washington project. Do you recall the figure cited by the Court in the Seventh Circuit as $70.5 million?

A. Yes.

Q. And that was in 1988 dollars?

A. Most likely, yes.

Q. Okay. Do you know how that compares to the cost of the -- well, any of the Rush Island projects?

A. No. In terms of -- you mean in terms of the dollars at the time of the Rush Island projects?

Q. Well, you could, you know, talk about it in constant dollars or really dollars as of any date. I guess my question is do you have any comparison that you're prepared to draw for the Commission between the cost of the 70.5 million Port Washington project and the cost of the Rush Island projects?

A. No.

…

Q. So if the 2007 outage, the project at issue there cost 35 million in 2007 dollars, would you agree that's substantially less than 70.5 million in 1988 dollars?

A. That would be about half, so yes, that would be less.

Q. Significantly less?

A. Half, yeah.

…

Q. Okay. Despite all of the differences in costs, size, purpose, components, you recognize those differences exist between the Port Washington project and the Rush Island project?

A. Yes.

Q. Okay. And the purpose included increasing the potential emissions at Port Washington whereas that was not part of the work at Rush Island. You recognize that as well?

A. That I'm a little less clear on, but I understand what you're saying.

Q. Okay. Would it have been reasonable, based upon the distinguishing factors we just talked about for the last few minutes, for the Environmental Services Department at Ameren Missouri to think its Rush Island projects were distinguishable from the WEPCO Port Washington project?

A. Yes. I mean, there's always, what is it, lumbers and splitters, right. There's always a problem with how you distinguish things or how you group things. And so of course you can distinguish the projects and do a finer and finer grain, but you can also compare them.

Q. My question though, sir, is whether, based upon what we've talked about for the last few minutes and these distinguishing factors including but not limited to the fact that the Port Washington project increased the potential emissions, would it have been reasonable at the time for the Environmental Services Department in making it permitting decisions to consider the WEPCO Port Washington project distinguishable from what was being planned for Rush Island?

A. **I think in the respects that we said they were different, yes, it would be reasonable to distinguish the two.**[28]

[28] Seaver Dep., supra, p. 82, l. 9 to p. 107, l. 11 (emphasis added).

Q. What did EPA's subsequent statements about its WEPCo decision tell the utility industry?

A. EPA made clear that large projects, including multi-component life extension projects, could be routine.

After its WEPCo decision, EPA did a survey of life extension projects in the electric utility industry. It identified several, but noted that none appeared to involve the steam drum replacement that had been the focus of the decision to require permitting for the Port Washington Project. EPA told Congress that its survey of utility life extension projects did not detect any violations.

Congress then commissioned a study by its Government Accountability Office on the potential impact of EPA's WEPCo decision on life extension projects in the utility industry. EPA responded to Congress and the GAO that it did not expect that the WEPCo decision would have broad application to utility life extension projects. EPA assumed that every coal-fired unit in the entire electric utility industry would undergo life extension around age 30 and that doing so would not trigger any emissions control requirements under PSD. Congressman Dingell asked EPA to confirm this, which EPA's Assistant Administrator for Air & Radiation did in a letter dated June 19, 1991. In that letter, EPA confirmed that most utility life extension projects would not be like the Port Washington Project, and would not trigger permitting requirements. EPA acknowledged that the aggregation of multiple component replacements into a "life extension project" would still be routine. EPA again confirmed this position on RMRR in the Federal Register in 1992, stating that the RMRR exclusion required analysis of whether the components at issue are of the sort routinely replaced in the industry. And in 1995, EPA's program office again confirmed that the RMRR exclusion would exclude routine capacity restoration projects from NSR permitting requirements. The surrebuttal testimony of Company witness Moor discusses these public statements by EPA in more detail. And we certainly were aware of these public statements, having discussed them frequently at UARG meetings and elsewhere. For example, Schedule SCW-D4, cited by Ms. Eubanks in her Rebuttal Testimony, contains a slide walking through this timeline of EPA's post-WEPCo statements:

** [redacted]:

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted] **

Schedule SCW-D4.

As several courts described it in the 2005-2010 timeframe, EPA "[t]hrough [its] statements in the Federal Register, its statements to the regulated community and Congress, and its conduct for at least two decades . . . has established an interpretation of RMRR under which routine is judged by reference to whether a particular activity is routine in the industry."[29] For these reasons, the District Court for the Eastern District of Kentucky also rejected EPA's narrow, enforcement interpretation of RMRR, United States v. East

[29] United States v. Duke Energy Corp., 278 F. Supp. 2d 619, 637 (M.D.N.C. 2003), *affirmed* United States v. Duke Energy Corp., 411 F.3d 539 (4th Cir. 2005), *reversed on other grounds* in Env't Def. v. Duke Energy Corp., 549 U.S. 561 (2007).

Kentucky Power Coop., 498 F. Supp. 2d 976, 993 (E.D. Ky. 2007), as did courts in Tennessee and Pennsylvania in 2008-2010.

"A fair reading of the EPA's description of how it has defined and applied RMRR during the (then) twenty (20) year history of NSR leads inexorably to the conclusion that, as the EPA said, a facility could spend millions of dollars on equipment replacement or repair without triggering NSR." United States v. Alabama Power Co., 681 F. Supp. 2d 1292, 1307–08 (N.D. Ala. 2008).

Ameren Missouri and the rest of the utility reasonably relied upon EPA's statements that WEPCo would not apply to most large utility projects.

> [T]he court believes the EPA meant what it said when it called the modifications in WEPCo extraordinary and that the EPA did not anticipate bringing additional enforcement actions because of WEPCo. The fact that years passed before it did so speaks for itself. The electric utility industry was reading what the EPA was publishing, *e.g.*, EPA's response to Congressman Dingell's "inquiry."

Id. at 1309. EPA "could not tell Congress it envisioned very few future WEPCO-type enforcement actions on the one hand, and then argue in subsequent enforcement actions that the utility industry was unreasonable in relying on those, or similar, EPA statements." Id. at 1310.

Q. What relevance did WEPCo have to ESD's application of the Missouri SIP to the Rush Island Projects?

A. Large rehabilitation projects will not trigger permitting under the Missouri SIP unless they increase the potential emissions. MDNR's treatment of a "major reconstruction program" at Missouri Public Service's Sibley Generating Station in 1990 makes this perfectly clear. MDNR's investigation of this facility and its program and its conclusion that the program did not trigger any permitting requirements is set forth in

Exhibit 9 to the 2013 deposition of Kyra Moore. I attach a copy of that here as Schedule SCW-S1. Because this provides a concrete example of how we and MDNR considered WEPCo, I will describe the project as set forth in MDNR's files in some detail.

MDNR gathered information from the testimony of Missouri Public Service's Jackson Barry, dated January 26, 1990, about an "ongoing $77 million project to extend the life of the company's 490 megawatt, coal-fired Sibley Generating Station." Schedule SCW-S1 at AM-02317762-MDNR, AM-02317764-MDNR to AM-02317778-MDNR. This "Rebuild Program" was "a major reconstruction program of the three Sibley Generating units." Id. at AM-02317766-MDNR. The Rebuild Program "was initiated to refurbish our primary base load generating plant in order to" allow for "safe and dependable operation" that the Station could not otherwise achieve "without the Rebuild Program." Id. at AM-02317766-MDNR to AM-02317767-MDNR. Each of the boilers on each of the units at Sibley required extensive work For example, studies performed by outside contractors had identified "severe deterioration of the tubes" on the boilers of unit 3, and the company developed a plan "to replace the problem boiler areas and to restore the boiler to a safe and reliable operating conditions." Id. at AM-02317767-MDNR. The Rebuild Program started in 1985, AM-02317770-MDNR, and by the spring of 1990 was expected to have involved the replacement and upgrading of numerous "major systems" for units 1, 2 and 3. Id. at AM-02317769-MDNR to AM-02317770-MDNR. The Rebuild Program included major boiler components such as cyclones, tubes sections (e.g., waterwalls and superheaters), and air heaters. AM-02317794-MDNR. The "complete replacement" of major boiler components was extensive, "requiring a five-month outage." Id. at AM-02317771. The "major projects" were scheduled to continue in 1991 and 1992, including "[r]eplacement of cyclones and boiler tubes on Sibley Units No. 1 and No. 2." Id. at AM-02317774-MDNR. Thus, the Rebuild Program was scheduled to last for at least seven years (1985 to 1992).

MDNR made an "inquiry concerning the work being done at the Sibley Generating Station." Id. at AM-02317793-MDNR. Missouri Public Service responded with a letter to MDNR describing the work as "replacement of worn components and control systems," Id., and identified some of the specific component replacements such as the tube sections (waterwalls and superheaters), major components (cyclones and coal feeders) and auxiliary equipment (air heaters). Id. at AM-02317794-MDNR. Missouri Public Service concluded by setting forth its view that the projects conducted and planned for the Rebuild Program do not trigger "the permitting requirement under 10 CSR 10-6.060"—the very rule ESD relied on in concluding that permitting requirements did not apply to the Rush Island Projects. Id. at AM-02317796-MDNR "Replacement of the components listed is not uncommon for our type of facility and, as such, is considered routine." Id. Moreover, MPS stated, none of the projects in the Rebuild Program would produce "an increase in the capacity to emit pollutants." Id.

In addition to gathering information on the Sibley Rebuild Program, MDNR collected information about EPA's decision on the WEPCo Port Washington Project. Id. at AM-02317779-MDNR to AM-02317792-MDNR.[30] MDNR closed out its "inquiry" into the matter without requiring any permitting, consistent with the position set forth in the February 1990 letter from MPS. Id. at AM-02317793-MDNR to AM-02317796-MDNR. As the "Permit Detail Report" plainly notes, MDNR completed its "inquiry" into the Sibley

[30] It is clear that the pages of EPA's WEPCo letter were out of order in MDNR's file. My Schedule SCW-S1 reflects how the pages were ordered in Exhibit 9 to the Kyra Moore deposition.

Rebuild Program with the finding "No Permit Required." Id. at AM-02317760-MDNR (stating "Comp. Date: 03/30/1990" and "Status: No Permit Required").

Although I was not working with MDNR in 1990, when MDNR reviewed the Sibley Rebuild Program, I was at the 2013 deposition of Kyra Moore where this file was marked as an exhibit and identified and discussed by Ms. Moore. From my review of the MDNR file, MDNR's assessment of the Sibley Rebuild Program and its determination that no permitting was required reflects the broadly held understanding at the time that EPA's WEPCo decision did not apply to projects—even large projects lasting years, involving multiple boiler components, at the cost of over $70 million—if the work would not increase potential emissions.

If Ameren Missouri proposed to do something like the WEPCo Port Washington Project, which *was* expected to increase the hourly potential emissions, that would likely trigger permitting requirements under the Missouri SIP (unless it was considered RMRR). But the Rush Island Projects involved no increase in hourly potential emissions, and under the Missouri SIP and its established interpretation by MDNR, that would not trigger permitting.

Mr. Seaver's contention that WEPCo somehow shows imprudence by Ameren Missouri is dead wrong.

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.	))))))	EF-2024-0021

AFFIDAVIT OF STEVEN C. WHITWORTH

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

Steven C. Whitworth, being first duly sworn on his oath, states:

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

/s/ Steven C. Whitworth
Steven C. Whitworth

Sworn to me this 21st day of March, 2024.

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

Date: 07/15/1998

Department of Natural Resources
Division of Environmental Quality
Permits Detail Report

Report Order:

Selection Criteria:
- Review number 08400003006

Permit

Review #: 08400003006
Permit Type: CP: Sec 7 & 8 & 9 (Unified): Major
Date Rcvd: 02/21/1990
Description:
Program: Air Pollution Control Program
DNR's Staff: Curtit, Karen

Facility

Fac. ID: AP0022400031
Name: Missouri Public Service Co
Location: E WALNUT St
County: Jackson

Status

Start Date: 02/21/1990 **Permit #:**
Comp. Date: 03/30/1990 **Exp. Date:** / /
Status: No Permit Required

Coordination: ☐ APCP ☐ HWP ☐ LRP ☐ PDWP ☐ SWMP ☐ WPCP

Application

Name: Missouri Public Service Co
Address:
Street: **Ph #:** 8167379340
City: Sibley **St:** MO **Zip:** 64088
Eng. Firm:

Permit Timeline

Phase	Group	Step		Date Start	End Date	Days Used	Days Planned
Check Application							
	2 Program						
		2. 1.	Awaiting Completeness Check	02/21/1990	03/03/1990	10	10
		2. 2.	No Permit Required	03/30/1990	03/30/1990	0	0
					Total Days:	10	10
						Status:	Completed

MDNR668351

AM-02317760-MDNR

Schedule SCW-1

Wednesday, September 25, 1996

Cnty	Plnt	Prmt	Description	Final	Test?	Number	Type	Status	NSPS
Facility Name : MISSOURI PETROLEUM PRODUCTS				**County : Pulaski**					
3860	N002	005	Continuous Asphalt Plant	7/1/79		0779-005	M	CI	
Facility Name : MISSOURI PORTABLE STONE, INC				**County : Portable Plant**					
PORT	0038	005	jaw crusher, secondary crusher, 3 deck screen	4/14/92	False	0492-009	C	CI	OOO
PORT	0038	006	Add a tertiary crusher, 2 radial stackers, & increase production to 600,000 TPY	1/27/94	False	0294-014	M	CI	OOO
Facility Name : MISSOURI PORTABLE STONE, INC				**County : Portable Plant**					
PORT	0120	005	Rock Crushing Plant	5/1/80		0580-002	M	CI	
Facility Name : MISSOURI PRECISION CASTINGS INC				**County : Jasper**					
2260	0008	005	sand reclamation system for no bake molding system	1/30/90	False	0190-012	S	CI	
Facility Name : MISSOURI PUBLIC SERVICE CO				**County : Cass**					
0840	0003	005	Peaking turbine	12/1/80	True	1280-006	M	CI	GG
0840	0003	006	improvements to plant may fall under extended life	3/30/90	False		A └ Attainment Major	CN - No permit Required	
Facility Name : MISSOURI PUBLIC SERVICE CO				**County : Jackson**					
2240	0031	005	EXIST;COAL CONVEYOR SYS. AND FLYASH HANDLING SYS.	2/3/93	False	0393-004	D	CI	
Facility Name : MISSOURI ROCK INC				**County : Clay**					
1020	0102	006	a replacement of a triple deck screen	6/1/95	False		M	CN	

MDNR668352

AM-02317761-MDNR

Schedule SCW-S1

0840-0003-006

CASE NO. ER-90-101
MPS EXHIBIT NO.
Section B
Schedule 6
Page 2 of 3

NEWS RELEASE

MISSOURI PUBLIC SERVICE

RECEIVED
... RESOURCES
1990 MAR 29 ...
AIR POLLUTION CONTROL

Missouri Public Service
10700 East 350 Highway
Kansas City, Missouri 64138

CONTACT: Robert W. Phillips
737-9346

MISSOURI PUBLIC SERVICE SEEKS ELECTRIC RATE HIKE

RAYTOWN, MO., November 17, 1989 -- Missouri Public Service, a division of UtiliCorp United (NYSE:UCU), today filed a request with the Missouri Public Service Commission (PSC) to increase its electric rates by $25.5 million, or 12.7 percent, annually.

The average residential customer would pay about $7.11 more on the monthly bill under the proposed tariffs. Missouri Public Service lowered its electric rates nearly 10 percent since the last electric rate increase in July, 1983. If granted in full, the average residential customer's bill would be $1.69 higher than in 1983, or 3 percent increase.

Increased revenues are needed primarily to cover costs associated with an ongoing $77 million project to extend the life of the company's 490 megawatt, coal-fired Sibley Generating Station in northeastern Jackson County, said Missouri Public Service President Fred K. Little. Increasing costs of purchased power capacity and inflation also have contributed to the need for more revenues.

(more)

MDNR668353

AM-02317762-MDNR

Schedule SCW-S1

"Our life extension program will enable us to extend the life of the Sibley plant by 20 years or more at about 7 percent of the cost of building a new coal-fired facility," Little said. "More than half of this request is related to investment in facilities."

The process of submitting testimony in the rate case and review by the PSC staff and commission is expected to take several months. Hearings in the matter probably won't be held until next summer. By law, the commission is required to issue a decision within 11 months of the filing date.

Missouri Public Service provides electricity to about 162,000 customers in more than 150 communities in 23 western Missouri counties. Its electric system extends from Kansas City east to Sedalia, north to near the Iowa border and south beyond Nevada. It also provides gas service to about 40,000 customers.

Missouri Public Service is one of seven gas and electric utility divisions in eight states owned by UtiliCorp, headquartered in Kansas City, Missouri. In addition, UtiliCorp owns a Canadian utility subsidiary in British Columbia and three energy-related subsidiaries.

###

Exhibit NO.	
Issue:	Generating Facilities
Witness:	Jackson E. Barry
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Missouri Public Service
Case No:	ER-90-101

MISSOURI PUBLIC SERVICE

ER-90-101

DIRECT TESTIMONY

OF

JACKSON E. BARRY

January 26, 1990

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI
DIRECT TESTIMONY OF JACKSON E. BARRY
CASE NO. ER-90-101

Q. Please state your name and business address for the record.

A. My name is Jackson E. Barry, and my business address is 10700 East 350 Highway, Kansas City, Missouri 64138.

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

A. I am employed by Missouri Public Service (MPS) as Vice President-Production.

Q. Please describe briefly your responsibilities in that position.

A. I am responsible for the operation and maintenance for all of MPS's electric generating facilities. In addition, I am responsible for engineering, design and construction of all new electric generating facilities including modifications and rebuilds of existing generating facilities. Also, MPS's Environmental Department reports to me on all environmental matters.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor of Science in Mechanical Engineering from the University of Arkansas. I began working for Missouri Public Service in June 1959 as an Assistant Production Engineer. In 1968, I was transferred to the Sibley Generating Station as Assistant Superintendent in charge of the Results Department. In 1972, I was promoted to Station Superintendent and in 1973, I was named Manager of

Production. I was elected Vice President-Production in 1981 which is my present position.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe the Rebuild Program which is underway at the Sibley Generating Station, to explain the need for the proposed Western Coal Conversion Project at that plant and to set forth appropriate in-service criteria for these programs for ratemaking purposes.

Rebuild Program

Q. Please describe what you mean by the term Rebuild Program.

A. The Rebuild Program is a major reconstruction program of the three Sibley Generating units. This program was initiated to refurbish our primary base load generating plant in order to meet the future demand for generation in the MPS system.

Q. Will the Rebuild Program provide any other benefits?

A. Yes. Sibley Unit No. 3 is the largest base load unit in our system to help carry the summer peak load demand. The Sibley Units No. 1 and No. 2 are much smaller in capacity than Sibley Unit No. 3; consequently, these two units are being converted to cycling service in addition to the Rebuild Program. The capacity from the two smaller units will be required during periods of peak loads, emergency conditions, economical sales, outages on Sibley Unit No.3 and will be subject to increased use for base load as the system load demand increases. In addition, the cycling feature of the two small units will permit daily, weekend, or weekly shutdowns to improve the load factor and efficiency for the larger Sibley Unit No.3 during lower load conditions.

Q. Could the Sibley Generating Station continue to operate safely and reliably in 1990 and beyond without implementing the Rebuild Program?

A. No. MPS could not rely on safe and dependable operation from the Sibley Generating Station for the 1990 summer peak load without the Rebuild Program. A recent Boiler Fitness Survey performed by the firm of Babcock & Wilcox along with visual inspections have confirmed that the boiler of Sibley Unit No.3 had severe deterioration of the tubes. This fact was underscored by the large increase in the forced outage rate at the unit in 1989. A plan has been developed to replace the problem boiler areas and to restore the boiler to a safe and reliable operating condition.

In addition to the boiler rebuild work on Sibley Unit No. 3, other major rebuild or replacement work includes the turbine, generator and control systems. These systems had also reached a point of condition which required rebuild and replacement of components to allow the unit to function in a safe and reliable manner in 1990 and beyond.

Q. What analysis did MPS perform to determine the necessary scope of the Rebuild Program?

A. In 1984, we recognized the continued deterioration of these units, sought the advice of the Electric Power Research Institute (EPRI), and determined that a three-phase approach would best define the necessary modifications. Black & Veatch was retained to conduct the first two phases of the Rebuild Program.

Q. Briefly describe the first two phases.

A. Phase I consisted of a study to identify as much of the work scope as possible without the benefit of nondestructive testing (such as x-ray testing, ultrasonic testing or other aids) to determine the condition of materials. The Phase I study included a visit to each of the generating facilities to conduct plant surveys of the units, and the preparation of a report describing plant work scope items and modifications necessary for consideration. Phase II consisted of a study to estimate the total cost of the project based on the scope identified in Phase I.

Q. After the Phase II study was competed were all of the costs for the Rebuild Program quantified?

A. No. We knew that additional items would be developed and identified as detailed testing progressed in Phase III, and we could not predict the costs in Phase II until Phase III was in progress.

Q. Describe briefly Phase III of the Rebuild Program for the Sibley Generating Station.

A. Phase III consists of engineering work performed by Sargent & Lundy Engineers and includes the work scope developed in the Phase I report plus additional work items that were identified from the results of actual tests conducted in the field on equipment that was disassembled and inspected during outages.

Q. Would you identify major systems that will be completed by spring of 1990 for the Rebuild Program, including the dates of completion for these major systems?

A. The following major systems will be completed by the spring of 1990 or have already been completed:

		In-Service
1.	Replace primary superheater on Unit No. 1	05/87
2.	Replace primary superheater on Unit No. 2	02/88
3.	Replace boiler control system on Unit No. 1	11/88
4.	Replace 2400 volt and 480 volt switchgear on Unit No. 2	11/88
5.	Replace high pressure turbine shell and upgrade instruments and controls on Unit No. 2	04/89
6.	Replace boiler control system on Unit No. 2	04/89
7.	Install turbine water induction system on Unit No. 2	04/89
8.	Install new static exciter on Unit No. 2	04/89
9.	Replace unit auxiliary transformer on Unit No. 2	04/89

10.	Replace 2400 volt and 480 volt switchgear on Unit No. 1	05/90
11.	Replace turbine on Unit No. 1	05/90
12.	Install turbine water induction system on Unit No. 1	05/90
13.	Upgrade turbine-generator components on Unit No. 3	05/90
14.	Replace boiler control system on Unit No. 3	05/90
15.	Replace cyclones and boiler tubes on Unit No. 3 boiler	05/90
16.	Install turbine water induction system on Unit No. 3	05/90

Q. What is the total approximate cost of the Rebuild Program for the Sibley Generating Station?

A. The total cost of the Rebuild Program is approximately $75,000,000. Approximately $55,000,000 will have been expended on completed plant by the Spring of 1990.

Q. Is there a difference between the Rebuild Program and a routine maintenance program?

A. Yes. The purpose of a routine maintenance program is to repair various components and parts which have failed while in service and to perform preventative maintenance on parts to allow the equipment to operate until the next scheduled maintenance period.

The Rebuild Program, which started in 1985, is a detailed comprehensive set of plans to look at the total plant from a viewpoint of what is required to restore, rebuild and refurbish the station's systems to a condition that will permit safe and reliable operation for an extended period of time and then to implement those plans. For example, the control systems for each of the three units were replaced in their entirety as part of the Rebuild Program. Under a routine maintenance program, the control systems on each unit would not have been replaced, rather, a calibration check would have been made to tune the controls and there might have been repair or replacement of a switch, fuse, transistor, diode or some other part that was defective as opposed to replacing the complete system.

Another example of the difference between routine maintenance and a rebuild involves the Sibley boilers. The boilers for the Sibley units were given a complete detailed special inspection involving ultrasonic and metallurgical testing. It was determined that the remaining usefulness of the materials was not sufficient to justify repair, but that a complete replacement was necessary. The program is now underway to replace the boiler areas, requiring a five-month outage. With a routine maintenance approach, the boilers would have undergone a basic repair program including deslagging, welding isolated worn areas, shooting studs on tubes as needed, replacing refractory materials at selected areas in the boiler and visual inspections requiring only three weeks of downtime at the scheduled outage. Many other examples exist wherein the scope of

Schedule SCW-S1

work (i.e. replacement versus repair) readily differentiates maintenance from the Rebuild Program.

Q. Has MPS verified that the capitalization of the Rebuild Program is in compliance with the Uniform System of Accounts?

A. Yes. MPS sought and received clarification from the Federal Energy Regulatory Commission that our accounting treatment is in general compliance and appropriate for use.

Q. What criteria has MPS established for placing the projects into service?

A. MPS has developed criteria to assure that systems are functional before they are considered in service. Systems that have been declared in-service have met the established criteria and systems yet to be completed will meet the criteria before in-service is declared.

The in-service criteria developed by MPS for placing these projects into service is as follows:

1. Each project must be identified and in-service completion reports made to ensure the project or projects were placed into service.

2. A project or projects will not be considered in-service and used and useful for the customer until the particular generating unit or units are actually started and placed into service generating power for the customer.

3. A unit must be able to operate at its design capacity

factor for a reasonable period of time.

This criterion will be satisfied if:

$$\text{Design capacity factor} \leq \frac{\text{Energy generated in a continuous 48-hour period (MWH e)}}{\text{Capability rating (MW e) x 48 hours}}$$

If the design capacity factor is not specified, it will be assumed to be 0.6.

Capability rating is the full-load continuous rating of a prime mover or other electrical equipment under specified conditions.

4. A unit must operate at a capacity equal to 90 percent of its capability rating for at least four hours.

5. A unit must have finished the startup test program with all startup test procedures necessary for operation.

6. It is understood that after the unit or units are placed into service generating power for the customer, the unit or units may be removed from service for various economical reasons as required. This action will not be used to cancel or forfeit in-service status.

Q. When will the Commission have an opportunity to review the status of the Rebuild Program?

A. Expenditures associated with the current phase of the Rebuild Program are expected to be completed and in-service by June 1, 1990. This will provide the opportunity for all interested parties to review the in-service reports and the results of the in-service tests, check supporting information, and possibly tour the plant before the Commission renders a final decision in this proceeding.

Q. Please describe the additional systems to be started and completed after completion of systems in the spring of 1990.

A. There will be a few systems remaining to be started and completed in 1991 with completion of the rebuild work in 1992. These systems will be subjected to the same in-service criteria as previously described. Major projects to be completed in 1991 and 1992 include:

1. Replacement of cyclones and boiler tubes on Sibley Units No. 1 and No. 2.
2. Upgrade of boiler insulation on Sibley Units No. 1 and No. 2.
3. Replacement of coal feeders on Sibley Units No. 1 and No. 2.
4. Addition of bulk nitrogen storage systems.
5. Upgrade of ash handling systems.
6. Upgrade of voltage regulator, Sibley Unit No. 3.

Q. Are there any systems identified in this rate case to be included in plant in-service which will not be fully operational until the 1991 and 1992 expenditures detailed above are incurred?

A. No. The systems that have been rebuilt and replaced are required to support the process of generating electricity. The current process of generating electricity is not dependent on future expenditures. All system rebuild work completed through spring 1990 will be required to meet the 1990 summer load requirements.

Western Coal Conversion

Q. Will any portion of the new plant to be used in connection with the coal conversion be in-service by the spring of 1990?

A. Yes. Currently, work is being performed to rebuild the electrostatic precipitator at Unit No. 1. Although the Western Coal Conversion is not estimated to be complete until 1992, this electrostatic precipitator rebuild is necessary currently for the unit to comply with existing opacity limitations and would have been necessary absent the Western Coal Conversion. The rebuild of the electrostatic precipitator, along with other smaller projects, will be in-service by May of 1990 and will comprise approximately $2,000,000 of the adjusted jurisdictional rate base in this proceeding.

Q. Why is MPS entering into a Western Coal Conversion Program?

A. For several months now, MPS has been aware of the momentum generated in Congress to pass an acid rain bill designed to limit emissions of sulfur into the atmosphere. MPS has looked into the various ways available to allow us to comply with any such legislation. Converting to Western coal is the most economical way to lessen the impact of MPS' major generating station on the environment.

Q. What is the schedule for making the conversion?

A. Planning was started in 1989 and various components will be completed throughout 1990, 1991 and 1992 and placed into service. The total cost of the Western Coal Conversion will be approximately $28,000,000.

Q. Please outline the program.

A. The preliminary Western Coal Conversion work will consist of selecting an engineering firm to start the engineering. We will perform additional test burns on other Western coals to gather actual burning characteristics of the fuel which will aid in the selection process of the fuel, prepare specifications for bids, submit designs of the conversions to state agencies for permits, select contractors and issue purchase orders for materials. In 1991, design work will continue, additional specifications will be generated for the conversion and construction work will begin to implement the designs. In 1992, construction will continue until the work is completed during the fall of 1992.

The major work items which we believe will be accomplished during this time frame are rebuilding the electrostatic precipitators on all three units, adding collection fields to the existing precipitators, installing a chemical injection system to all three units, installing necessary control systems for the additions, improving the sootblowing systems on all three units, adding dust collection and handling systems, performing needed coal handling modifications, converting the ash handling system to a dry collection system, modifying the coal bunkers to more safely store the coal inside the plant, adding fire protection systems, adding another unit train to transport the coal and performing various other modifications that will be identified by the engineering firm.

Q. What will be the result of the program?

A. The program will result in reduction of pollution emissions into the atmosphere prior to 1992.

Q. How will this be accomplished?

A. The conversion will be performed on all three units including the coal handling system. Outage schedules will be set to allow the work to progress and at the same time allow units to continue to carry our system load requirement. The 1992 schedule is a very tight schedule allowing the proper time for design, acquisition of materials, and installation of the materials while at the same time maintaining the units in service at the appropriate times. Our units will be scheduled to operate during the summer peaks and the conversion work will be performed during off-peak times. Consequently, systems will be placed into service as soon as schedules and various materials are received which will begin the gradual control of emissions into the atmosphere.

Q. Does that conclude your prefiled testimony?

A. Yes.

Enclosure B

Revised PSD Applicability Determination
Port Washington Power Plant Renovation of Units 1-4

(all emissions calculations are in tons per year)

Pollutant	Actual Emissions Baseline (1)	Estimated Future Actual Emissions (2)	Net Emissions Change	PSD Significance Level	Subject to PSD Review (3)
Particulate matter (4) (5)	328	339	11	25	no
Sulfur dioxide (4)	24,236	18,505	-5,731	40	no
Nitrogen oxides (5)	2,592	3,396	804	40	yes
Carbon monoxide	144	217	73	100	no
Hydroc_bon	17	25	9	40	no

Other Regulated Pollutants: Due to insufficient source specific information regarding emission factors, PSD applicability for PM-10, lead and noncriteria pollutants listed at 40 CFR Section 52.21 (b)(23)(i) and (ii) cannot be determined at this time.

1) Average actual emissions for 2-year period defined by calendar years 1983 and 1984.

2) Calculated by EPA based on the following information submitted by WEPCO:

a. The average, historic-firing rate (approximately 17×10^6 MMBtu per year) for the 2-year period defined by calendar years 1978 and 1979.

b. The emissions estimates for the renovated units based on future coal characteristics (e.g., sulfur and heat content) and actual emissions after pollution controls for particulate.

c. Unit 5 inoperative. Sulfur dioxide removal of 22 and 13 percent at units 1 and 4, respectively, to exclude these units from NSPS requirements for greater control of sulfur dioxide.

3) If new data indicate that annual, historic-firing rates at the Port Washington facility exceeded historic 1978 and 1979 levels, the indicated applicability determination could change.

4) The calculation of estimated, future, actual emissions for this pollutant is based on WEPCO's projection of control technology performance levels and/or fuel sulfur content for post renovation operations. Consequently, EPA's PSD applicability determination is valid only to the extent that the specific particulate and sulfur dioxide emissions factors used for units 1-4 to calculate future emissions (based on particulate and SO_2 control technology performance levels and fuel sulfur and heat content) are made federally enforceable. Otherwise, the calculation of estimated, future, actual emissions for this pollutant will be revised by EPA, based on existing federally-enforceable limits (i.e., applicable SIP, NSPS). The use of current, federally-enforceable emissions factors would result in higher, projected, future emissions and, consequently, could affect the indicated PSD applicability finding.

5) Baseline emissions (actual emissions for 2-year period defined by calendar years 1983 and 1984) have been revised based on additional information submitted by WEPCO.

0840-0003-006

Enclosure A

Revised PSD Applicability Determination
Port Washington Power Plant Renovation of Units 1-5

(all emissions calculations are in tons per year)

Pollutant	Actual Emissions Baseline (1)	Estimated Future Actual Emissions (2)	Net Emissions Change	PSD Significance Level	Subject to PSD Review (3)
Particulate matter (4) (5)	328	323	-5	25	no
Sulfur dioxide (4)	24,236	15,919	-8,317	40	no
Nitrogen oxides (5)	2,592	3,405	813	40	yes
Carbon monoxide	144	217	73	100	no
Hydrocarbon	17	25	9	40	no

Other Regulated Pollutants: Due to insufficient source-specific information regarding emission factors, PSD applicability for PM-10, lead and noncriteria pollutants listed at 40 CFR Section 52.21 (b)(23)(i) and (ii) cannot be determined at this time.

1) Average actual emissions for 2-year period defined by calendar years 1983 and 1984.

2) Calculated by EPA based on the following information submitted by WEPCO:

a. The average historic firing rate (approximately 17×10^{6} Mbtu per year) for the 2-year period defined by calendar years 1978 and 1979.

b. The emissions estimates for the renovated units based on future coal characteristics (e.g., sulfur and heat content) and actual emissions after pollution controls for particulate.

c. Sulfur dioxide controls applied to unit 5 at 75 percent sulfur dioxide removal to comply with NSPS Subpart Da. Sulfur dioxide removal of 22 and 13 percent at units 1 and 4, respectively, to exclude these units from NSPS requirements for greater control of sulfur dioxide.

3) If new data indicate that annual, historic-firing rates at the Port Washington facility exceeded historic 1978 and 1979 levels, the indicated applicability determination could change.

4) The calculation of estimated, future, actual emissions for this pollutant is based on WEPCO's projection of control technology performance levels and/or fuel sulfur content for post-renovation operations. Consequently, EPA's PSD applicability determination is valid only to the extent that the specific particulate and sulfur dioxide emissions factors used for units 1-5 to calculate future emissions (based on particulate and SO_2 control technology performance levels and fuel sulfur and heat content) are made federally enforceable. Otherwise, the calculation of estimated, future, actual emissions for this pollutant will be revised by EPA, based on existing federally-enforceable limits (i.e., applicable SIP, NSPS). The use of current, federally-enforceable emissions factors would result in higher, projected, future emissions and, consequently, could affect the indicated PSD applicability finding.

5) Baseline emissions (actual emissions for 2-year period defined by calendar years 1983 and 1984) have been revised based on additional information submitted by WEPCO.

Table 7

03/29/90

PORT WASHINGTON POWER PLANT
MAY 1989 FORECAST
Units 1 - 5

YEAR	MEGAWATT HOURS GENERATED	CAPACITY FACTOR	FUEL CONSUMPTION COAL (13200 Btu/lb) BURNED TONS
1995	825,288	0.24	365,548
1996	941,779	0.27	415,332
1997	1,081,002	0.31	475,624
1998	1,114,313	0.32	490,868
1999	1,247,296	0.36	546,546
2000	1,349,329	0.38	589,569
2001	1,391,882	0.40	608,621
2002	1,481,464	0.42	646,417
2003	1,420,120	0.41	620,153
2004	1,432,122	0.41	625,174
2005	1,431,412	0.41	624,904
2006	1,460,471	0.42	637,519
2007	1,488,124	0.42	649,133
2008	1,481,623	0.42	646,909
2009	1,463,981	0.42	638,750

PORT WASHINGTON POWER PLANT
UPPER MAXIMUM FORECAST
Units 1 - 5

YEAR	MEGAWATT HOURS GENERATED	CAPACITY FACTOR	FUEL CONSUMPTION COAL (13200 Btu/lb) BURNED TONS
1995	1,074,957	0.31	473,981
1996	1,202,460	0.34	528,838
1997	1,341,074	0.38	587,412
1998	1,390,470	0.40	609,237
1999	1,501,584	0.43	654,718
2000	1,600,500	0.46	696,483
2001	1,651,930	0.47	718,252
2002	1,748,046	0.50	760,000
2003	1,690,000	0.48	735,000
2004	1,690,000	0.48	734,000
2005	1,690,000	0.48	734,000
2006	1,710,000	0.49	741,000
2007	1,720,000	0.49	748,000
2008	1,720,000	0.49	747,000
2009	1,695,000	0.48	737,000

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NSPS for any pollutant and, therefore, is subject to the NSPS requirements for NO_x, SO_2, and PM.

Sincerely,

William G. Rosenberg
Assistant Administrator
for Air and Radiation

3 Enclosures

Schedule SCW-S1

B. Revised Finding

In sum, EPA has considered past operations at WEPCO's Port Washington plant in estimating future actual emissions. Specifically, EPA has relied on the 42 percent utilization level (in terms of heat input) during 1978-1979. The Agency believes this is a reliable indicator of future utilization because it is consistent both with WEPCO's own projections of post-renovation operations and typical industry usage. The Agency has also considered post-renovation emissions rates on the assumption that they will be made federally enforceable. Compared to the 1983-1984 baseline period, those hourly rates are lower for SO_2 and PM, and unchanged for NO_x. The 42 percent estimated post-renovation capacity utilization is substantially higher than the 29 percent utilization level during the baseline period. However, in calculating total annual actual emissions, that increased usage is offset for SO_2 and PM by the decreased hourly emissions rates resulting from improvements to control systems and the use of low sulfur coal. Consequently, WEPCO is not subject to PSD review for those pollutants.

In the case of NO_x, there will be a direct correlation between increased utilization resulting from the renovations and increased actual emissions. Hence, WEPCO is subject to review for that pollutant and must obtain a PSD permit. The company should contact the Wisconsin Department of Natural Resources regarding the processing of a permit application for NO_x. Due to insufficient source-specific information regarding emissions factors, PSD applicability for PM-10, lead, and noncriteria pollutants listed at 40 CFR 52.21 (b)(23)(i) and (ii) cannot be determined at this time. The PSD applicability for these pollutants should also be based on the "actual-to-actual" emissions test described herein.

This PSD applicability determination applies to WEPCO's currently planned renovations to units 1-5 (see Enclosure A), or, if WEPCO no longer wishes to proceed with renovating unit 5, only the renovation of units 1-4 (see Enclosure B). However, a decision to cancel the currently planned renovations to unit 5 could result in a PSD review for that unit should WEPCO reconsider renovating it some time in the future.

It is our understanding that WEPCO proposes to avoid triggering NSPS for SO_2 and PM at units 1 and 4 by using dry sorbent injection and improving the existing ESP's to offset the potential emissions increases of these pollutants. To the extent that the controls are federally enforceable, and no increase in hourly emissions would occur at maximum capacity, WEPCO can use these options to avoid triggering NSPS for PM and SO_2 at units 1 and 4. However, the two units are still subject to the NSPS requirements for NO_x. Unit 5 cannot, however, avoid triggering

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hourly emissions rates. These emissions factors are based on WEPCO's own assumptions regarding future sulfur in fuel and control technology performance levels. However, since these assumptions go beyond current State implementation plan (SIP) requirements, they must be made federally enforceable for EPA to continue to consider them for PSD applicability purposes.

Operational data (i.e., heat input) from the years 1978-1979 show a capacity utilization factor of 42 percent. These data points represent the closest projection of WEPCO's operational characteristics, approximating an "as-new" state, as currently available to EPA. The data currently available to us regarding WEPCO's past operational levels are limited to a 10-year period. The Agency believes that these historical levels of operation are representative of the plant's past operations in an "as-new" condition. In addition, the 1978-79 data points appear consistent with WEPCO's own projection of future operations for the year 2010 (as submitted to the Wisconsin Department of Natural Resources on March 29, 1990) and common capacity levels for the utility industry, in general, for new units. However, by this letter, EPA is requesting that WEPCO submit operational data from previous years (i.e., pre-1978), if such data show heat input levels notably higher than the 1978-1979 levels.

As previously mentioned, to calculate future emissions levels for each pollutant, EPA assumed that the amount of future coal consumed in terms of heat input to the plant would be comparable to WEPCO's annual average 1978-1979 coal-consumption figure. On March 29, 1990, WEPCO submitted to the Wisconsin Department of Natural Resources information which contained estimates of future emissions for different levels of coal and heat input to the plant. The Agency used these estimates to establish future emissions based on 1978-1979 heat-input values. Again, it is important to note that EPA's calculation of "estimated future actual emissions" is based on WEPCO's projection of control technology performance levels and/or fuel sulfur content for post-renovation operations. Consequently, EPA's PSD applicability determination is valid only to the extent that the emissions factors (based on control technology performance levels and sulfur in fuel) used to calculate future emissions are made federally enforceable. Otherwise, the calculation of estimated future actual emissions for each pollutant will need to be revised by EPA based on existing federally-enforceable limits (i.e., applicable SIP, NSPS). The use of current, federally-enforceable emissions in the current SIP would result in higher projected future emissions than assumed in EPA's calculations and, consequently, could affect the indicated PSD applicability finding.

compare representative actual emissions for the baseline period to estimated future actual emissions based on all the available facts in the record. Specifically, in calculating post-renovation actual emissions, this approach takes into account 1) physical changes and operational restrictions that would affect the hourly emissions rate following the renovation, 2) WEPCO's pre-renovation capacity utilization, and 3) factors affecting WEPCO's likely post-renovation capacity utilization.

To quantify WEPCO's estimated future actual emissions after the proposed changes EPA relied heavily on projected and historical operational data (e.g., fuel consumption, MMBTU consumed) representative of the source. Specifically, the Agency considered available information regarding (1) projected post-change capacity utilization filed with public utility commissions; (2) Federal and State regulatory filings; (3) the source's own representations; and (4) the source's historical operating data. As described below, EPA determined an appropriate utilization factor for future operations and combined this with post-change emissions factors (to the extent they are or will be made federally enforceable) to estimate a future level of annual emissions for the purpose of determining whether the proposed physical and operational changes would be considered a major modification for PSD purposes. Where a significant emissions increase is projected to occur, WEPCO could voluntarily agree to federally-enforceable limits on any aspect of its future operation (including physical capacity and hours of operation) to ensure that no significant emissions increase will occur.

IV. THE AGENCY'S REVISED PSD APPLICABILITY DETERMINATION

A. Estimated Future Actual Emissions.

The Agency has revised its October 14, 1989 PSD applicability determination for WEPCO's proposed Port Washington renovation based on a "representative actual" to "estimated future actual emissions" comparison (as outlined above). As previously discussed, estimated future actual emissions projections take into account the likelihood that the plant will operate in the future as it has in the past.

The stated purpose of WEPCO's renovations is to refurbish the power plant units to an "as-new" condition in terms of their capacity, efficiency, and availability. Consequently, EPA has used actual, historical, operational data representative of the plant's past operations, approximating an "as-new" configuration, to calculate "estimated future actual emissions." The Agency has verified these data by comparison to WEPCO's own projections of post-renovation capacity utilization and industry averages.

As to the emissions factors used to calculate future emissions, EPA has used WEPCO's own emissions factors for future

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the renovations. This is the interpretation urged by WEPCO in a February 9, 1990 letter to EPA. Such a calculus will always result in exactly the same level of emissions before and after the physical change, and thus would always exempt "like-kind replacements" from PSD review. In addition, calculating emissions increases using this assumption would flatly contradict the record in this case. The WEPCO has stated that it will greatly increase capacity utilization over both current levels and the baseline levels used in the previous determinations. Capacity utilization in terms of heat input to the plant (based on nameplate capacity) during 1978-1979 was about 40 percent (Record item 7.4, WEPCO Submission, April 19, 1988 meeting with EPA). During the 1983-1984 baseline period, it was approximately 27 percent. Id. It has since declined to less than 10 percent (1988-1989 data). Id. The WEPCO has advised the State of Wisconsin that it intends to return to a forecasted 42 percent utilization level in the years following renovation, with an upper maximum forecast of 50 percent [Letter from Walter Woelfle, WEPCO, to Dale Zeige, Wisconsin Department of Natural Resources, March 29, 1990, Table 7 (enclosed)]. It would be wrong to assume that unit 5 would not be operated at all in the future when an explicit purpose of the renovation is to bring the unit back on line at its original design capacity; moreover, unit 5 is presently inoperative. Most importantly, this methodology is not fairly discernible from any reading of the current regulations. In addition, using "present hours and conditions" would disregard planned changes at WEPCO that will affect the post-renovation hourly emissions rate [e.g., increased capacity, lowering of sulfur content, and enhancement of the electrostatic precipitators (ESP)].

The court upheld EPA's position that increased utilization in the future that is linked to construction or modification activity should not be excluded in determining post-renovation emissions. Nevertheless, the court told EPA not to automatically assume 100 percent utilization in the future when historical data are available. The WEPCO has definite plans to return the plant to historical levels of utilization that are well above baseline levels of utilization, and which could not be physically or economically attained but for the renovation project. Accordingly, EPA believes it is consistent with the court decision for EPA to base its remand decision on these facts and not rely on the present hours and conditions as conclusive of post-renovation emissions. After a thorough review of the possibilities, EPA has concluded that the court intended that estimates of future emissions for WEPCO's "like-kind replacements" should consider historic pre-renovation operating hours and production rates, as well as other relevant factors, in estimating future utilization levels, and should also consider the increased capacity, switching to lower-sulfur fuel, and other changes affecting the hourly emissions rate for PSD purposes. Consequently, for WEPCO's "like-kind replacements," EPA will that the most recent 2 years should be used, but has allowed another period where the source demonstrates that recent operations are abnormal [see 40 CFR 52.21(b)(21)(ii); see also 45 FR 52676, 52718 (1980)]. The WEPCO baseline period is an example of this. In this instance, plant utilization was disrupted by physical problems that led to nonroutine physical changes to remedy those problems. Consequently, EPA determined that a period prior to the onset of such problems was representative of normal operations, and as required by its regulations, used this period to establish the baseline. The period used was also within the contemporaneous period specified in 40 CFR 52.21(b)(3)(ii). It should be emphasized that, in the WEPCO case, the parties and the court agreed that 1983-84 (prior to discovery of steam drum cracks) should be the baseline years (slip op. at 26); these years had an average 29 percent utilization rate. We continue to believe this is the appropriate baseline period for the Port Washington renovation.

B. Calculating Post-Change Emissions Under PSD.

The court concluded that "EPA's reliance on an assumed continuous operation as a basis for finding an emissions increase is not properly supported" (slip op. at 30). Although the court held that EPA cannot, in this case, wholly disregard past operating conditions at the plant, it also held that EPA could not reasonably rely on the company's own unenforceable projection of operating conditions (slip op at 29). The court remanded the question of PSD applicability to EPA for further proceedings not inconsistent with its decision.

Before the court remanded EPA's determination, it attempted to ascertain whether, in fact, the proposed project would be a major modification even using the assumptions least likely to result in an emissions increase. The court felt (and we agree) that such a "best" case scenario for WEPCO would assume that the "present hours and conditions" would not change at all following the renovations (despite, of course, WEPCO's own estimates of at least tripling of utilization over current levels) (slip op. at 31, n. 14). The court, however, lacked the data to make this calculation, so it could not determine whether a major modification would result using a set of assumptions most favorable to WEPCO. Therefore, the court remanded the determination to EPA for further consideration.

A conceivable interpretation of the court's opinion is that EPA <u>must</u> calculate WEPCO's post-modification emissions increases based on "present hours and conditions." However, for the reasons discussed below, EPA believes that this interpretation is incorrect. Under such an interpretation, EPA would determine WEPCO's post-renovation annual emissions in tons per year (tpy) by simply projecting into the future the hours of operation and conditions (i.e., hourly emissions rate) that existed just before

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operational changes at an existing major source which are not specifically "like-kind replacements" in nature, EPA will continue to apply the actual-to-potential test for PSD applicability purposes.

III. THE AGENCY'S RESPONSE TO THE COURT'S REMAND ORDER

A. The PSD Baseline Emissions.

Determining the "baseline" level of actual emissions before a physical or operational change is a necessary first step to determine if emissions increase as a result of the physical change. The Agency's regulations define the baseline for PSD purposes, as follows:

> In general, actual emissions as of a particular date shall equal the average rate, in tons-per-year (tpy), at which the unit actually emitted the pollutant during a 2-year period which precedes the particular date and which is representative of normal source operation. The Administrator shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period [see 40 CFR 52.21(b)(21)(ii)].

The purpose of the definition is to establish a baseline that is "representative" of "normal" source operations prior to the change. The Agency historically has followed a presumption

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circumstances, it would be unreasonable to rely on pre-modification usage patterns to estimate future levels of capacity utilization. Instead, in such cases, EPA believes that it is reasonable to assume that in the absence of federally-enforceable limits on hours of operation or production rates, the new components may result in a substantial increase over historical levels of utilization of the emissions unit following modification [see Puerto Rican Cement, supra, 889 F.2d at 297 ("a firm's decision to introduce new, more efficient machinery may lead the firm to decide to increase the level of production")] and will compare pre-modification actual emissions to post-modification potential emissions. In addition to this circumstance, there are cases in which sources that undergo changes that qualify as add-on control systems would, under certain circumstances, be exempt from new source review. See Letter to Timothy J. Method, Assistant Commissioner, Indiana Department of Environmental Management, from David Kee, EPA Region V, January 30, 1990.

II. THE WEPCO DECISION IN THE CONTEXT OF THE PSD PROVISIONS

The Seventh Circuit held that EPA could not wholly disregard past operating history and automatically apply the actual-to-potential methodology for determining PSD applicability to WEPCO's "like-kind replacements." In describing the WEPCO changes as "like-kind replacements" and limiting its decision to such changes, the court did not dispute the correctness of EPA's application of the actual-to-potential test to the full spectrum of new and modified sources not covered by this subcategory of change. The recent decision in Puerto Rican Cement Co. v. EPA, 889 F.2d 292 (1st Cir. 1989), explicitly upheld EPA's position that the actual-to-potential concept should be applied to "modified" emissions units. The First Circuit case involved the modernization and reconfiguration of existing emissions units [see 889 F.2d at 293 (company planned to "convert kiln No. 6 from a 'wet' to a 'dry' cement-making process, and to combine that with Kiln No. 3")]. A key issue was whether EPA properly held that the "modified" units had "not begun normal operation" and therefore the actual-to-potential concept applied in calculating emissions increases. The First Circuit affirmed EPA's position that the actual-to-potential concept should be applied to the company's "modified" units. Puerto Rican Cement, 889 F.2d at 297. Consequently, the court found that both the language and expressed purpose of the regulations indicate that EPA applied the regulations properly in using the actual-to-potential test for a proposed modification. The Seventh Circuit in WEPCO did not dispute the correctness of EPA's application of the actual-to-potential test to the full spectrum of changes not covered by the subcategory of changes (like-kind replacements) created by the court.[1] Therefore, in the case of nonroutine physical or

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[1] EPA will leave to future case by case applicability determinations what is a "like-kind replacement." But for guidance of the parties, EPA presently considers that only for projects that are genuine "like-kind replacements" can future emissions projections be calculated using "estimated future actual emissions" in lieu of potential to emit. EPA does not consider "like-kind replacements" to mean the entire replacement (or reconstruction) of an existing emissions unit with an identical new one or one similar in design or function. Rather, EPA considers "like-kind replacements" to encompass the replacement of components at an emissions unit with the same (or functionally similar) components. Under this interpretation of the term, new components that perform essentially the same function as old ones will be viewed as "like-kind replacements." In addition, even if the design or purpose of a new component is identical to that of an old one, if the new component is part of a project that will fundamentally change the production process at an existing stationary source, this would be beyond the scope of a "like-kind replacement." Under either of those

renovations proposed by WEPCO were exactly the type of industrial changes that were meant to be addressed by the NSPS and PSD programs. In upholding EPA's finding that a physical change would occur, the court strongly endorsed EPA's reading of the basic congressional intent in adopting the modification provisions of the NSPS and PSD programs, because to rule otherwise "would open vistas of indefinite immunity from the provisions of NSPS and PSD" (slip op. at 11). The court also relied on the reasonableness of EPA's consideration of the magnitude, purpose, frequency, and cost of the work in upholding EPA's finding that the renovations are not "routine" (slip op. at 14-18). In addition, the court rejected WEPCO's argument that the renovations could not be deemed a modification for NSPS purposes because they did not constitute a "reconstruction" under 40 CFR 60.15 (slip op. at 18-20).

2. NSPS Emissions Increase.

The court upheld EPA's decision that there would be an increase in hourly emissions at three of the units, and thus for those three units, WEPCO met the second test for NSPS applicability. The Agency had argued that the regulations require NSPS emissions increases to be determined by comparing the current (pre-change) hourly emissions capacity of each affected facility with the post-renovation hourly emissions capacity of each unit. The Seventh Circuit agreed, and rejected WEPCO's argument that original design capacity or past "representative" capacity no longer achievable at the plant should be used for the baseline emissions rate (slip op. at 20-25).

3. PSD Emissions Increase.

The regulatory preamble to the PSD regulations provides that the set of emissions units that have "not begun normal operations" includes both "new or modified" units (45 FR 52676, 52677, 52718) (1980). Consequently, EPA used the "actual-to-potential" calculus in evaluating WEPCO's life extension project. The court rejected this methodology in the case of WEPCO's "like-kind replacement," asserting that EPA's reasoning was circular (slip op. at 28). [In addition, the court held (slip op. at 27 n. 11) that the exemption in 40 CFR 52.21(b)(2)(iii)(f) for emissions increases due to expanded operations did not apply, because WEPCO's increased operations were directly tied to the life extension project.] Instead, the court ruled that EPA should recalculate post-change emissions considering past operating conditions where it is possible to make a more realistic assessment of future emissions (slip op. at 29-31). Alternatively, the court stated that EPA could conduct new rulemaking to explicitly apply the "actual-to-potential" calculus to "like-kind replacements" (slip op. at 30).

0840-0003-006

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

JUN 8 1990

OFFICE OF
AIR AND RADIATION

Mr. John Boston
President
Wisconsin Electric Power Company
Post Office Box 2046
Milwaukee, Wisconsin 52301

Dear Mr. Boston:

On January 19, 1990, the United States Court of Appeals for the Seventh Circuit in Wisconsin Electric Power Co. v. Reilly, Nos. 88-3264 and 89-1339, issued its decision regarding a challenge by Wisconsin Electric Power Company (WEPCO) to two final determinations issued by the Environmental Protection Agency (EPA). In these determinations, EPA concluded that WEPCO's proposed renovations to its Port Washington power plant would be subject to new source performance standards (NSPS) and prevention of significant deterioration (PSD) requirements.

In its decision, the court upheld all but one of the positions advanced by EPA in the NSPS and PSD applicability determinations. However, the court rejected EPA's position on the issue of whether the "actual-to-potential" method--referred to by the court as the "potential to emit concept"--should be used to calculate emissions increases for PSD purposes in this case. Consequently, the Seventh Circuit vacated and remanded the PSD determination to EPA for further action consistent with the court's decision.

As you know, EPA decided to acquiesce in the court's holding rather than seek rehearing. This letter constitutes EPA's revised PSD applicability determination in response to the court's remand order.

The Agency believes that the court's principal instruction--that EPA consider past operating conditions at the plant when addressing modifications that involve "like-kind replacements"--can be reasonably accommodated within the present regulatory framework without further litigation in this case. The net result of the court's ruling is the recognition of a subcategory of "like-kind replacements" under the "major modification" definition of EPA's new source review provisions.

As explained below, EPA will employ an "actual-to-actual" method to calculate emissions increases for WEPCO's proposed renovations to its Port Washington power plant. The outcome in this case is that WEPCO will not be subject to PSD review for sulfur dioxide (SO_2), particulate matter (PM), carbon monoxide, or hydrocarbons. However, there will be a significant net increase in actual emissions of nitrogen oxides (NO_x), and WEPCO must obtain a PSD permit for that pollutant.

I. BACKGROUND

A. Factual Background.

The WEPCO owns and operates five coal-fired, steam-generating units at its Port Washington facility near Milwaukee. All units had an original design capacity of 80 megawatts when they were placed in service between 1935 and 1950. However, due to age-related deterioration and loss of efficiency, both the physical capability and actual utilization of the plant have declined over time. Unit 5 was shut down completely due to a cracked rear steam drum. Consequently, by 1987, WEPCO was faced with removing the units from service as they reached their planned retirement dates beginning in the early 1990's, unless it undertook a costly "life extension" program to restore the physical and economic viability of the units and extend their useful life for approximately 20 years. The WEPCO proposed such a life extension to include replacement of the steam drums, air heaters, and other major capital improvements totaling over $80 million. It should be noted that this program is not a pollution control project (i.e., it is not intended to add on or improve pollution control systems even though modest improvements to the particulate matter control devices are a part of the program).

In a series of applicability determinations in 1988 and 1989, EPA ruled that the renovations planned under WEPCO's life extension program would constitute a "modification" for purposes of the NSPS provisions of the Clean Air Act (Act), and a "major modification" under the PSD provisions of the Act. Thus, WEPCO would have had to install some level of control equipment or physical capacity restriction to avoid NSPS coverage for three of the five units proposed to be renovated. As to PSD, the company would have had to accept operational restrictions or lower emissions rates to "net out" of review. Regarding SO_2, for example, WEPCO could have almost doubled its projected level of future operations without triggering PSD review. However, WEPCO did not want to be constrained by new source requirements, and so sought review in the Seventh Circuit Court of Appeals.

B. The Court's Decision.

1. Physical Change.

The court unequivocally agreed with EPA that the replacement of steam drums, air heaters, and other major components was a nonroutine "physical change," and thus met the first of two tests for a modification under NSPS and PSD. The Agency found that the

0840-0003-006

MISSOURI PUBLIC SERVICE

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Jackson E. Barry
Vice President—Production

RESOURCES
1990 FEB 21 PM 4: 27
AIR POLLUTION CONTROL

February 16, 1990

Mr. Randy E. Raymond
Deputy Director
Missouri Department of Natural Resources
Air Pollution Control Program
P.O. Box 176
Jefferson City, MO 65102

Dear Mr. Raymond:

This is in response to your inquiry concerning the work being done at the Sibley Generating Station. As you are probably aware, reliability of the unit is of vital importance to power plant operation. Although the output of the three units had not declined, several projects have been undertaken and are planned to maintain an acceptable reliability level. These projects include replacement of worn components and control systems. With the completion of these projects by 1992, we anticipate that the units can be operated through the year 2010 at an acceptable reliability level.

Replacement of the worn components and control systems will not increase the capacity of the units nor result in a significant increase in efficiency. Consequently, there will not be an increase in the actual current capacity to produce emissions.

In addition to the work previously described, we are preparing the plant for a coal conversion. As you know, acid rain legislation appears imminent, and fuel switching to a low sulfur western coal appears to be our lowest cost compliance option. Burning this type of coal, however, requires revamping the coal handling system and upgrading the precipitators. Fuel switching would result in a significant reduction of SO_2 emissions.

A summary of the major projects completed, in progress, or scheduled is listed below for your information. A brief description of the projects, which has been grouped under the categories of boiler, turbine/generator, controls, and balance of plant, is included.

MISSOURI PUBLIC SERVICE

BOILER PROJECTS

Unit #3

* Replace worn cyclones, hot-side tubular air heater, and waterwall tubes.

* Improve boiler penthouse roof design to reduce boiler gas leaks.

Unit #1 & #2

* Replace worn cyclones, primary superheaters, and hot-side and cold-side tubular air heaters.

* Replace drag chain coal feeders and scales with gravimetric coal feeders to reduce maintenance and improve accuracy of coal consumption measurements.

* Replace existing manually controlled valves with automated traps and drain valves.

TURBINE/GENERATOR PROJECTS

Unit #3

* Replace control system with state-of-the-art digital control system to improve load management.

* Replace eroded nozzle block with diffusion coated components to reduce hard particle erosion effects.

* Replace coupling on generator to offset design deficiency which caused torsional vibration induced turbine blade failures.

* Replace supervisory instrumentation to improve operational information.

* Replace defective generator retaining rings per manufacturer's recommendation.

MISSOURI PUBLIC SERVICE

Units #1 & #2

* Replace turbine shells exhibiting thermal cracking due to design deficiencies which have been corrected in modern designs.
* Replace outdated hardware with new generator static excitation equipment to control electric system transient fluctuations.
* Replace control system with state-of-the-art digital control system to improve load management.
* Install lube oil filter system per industry standards to prevent bearing damage.

CONTROLS PROJECTS

Unit #3

* Replace control and data acquisition system with state-of-the-art distributed digital control system.

Unit #1 & #2

* Replace control and data acquisition system with state-of-the-art distributed digital control system.

BALANCE OF PLANT PROJECTS

Unit #3

* Routine retubing of selected feedwater heaters.
* Install additional fire protection system.

Unit #1 & #2

* Replace steam air ejector nozzles with mechanical vacuum pumps to reduce air in the condenser,

MISSOURI PUBLIC SERVICE

thereby minimizing corrosion of the boiler tubing.

* Replace 2400 volt switchgear and motor control centers and upgrade size to accommodate more electrical devices.

* Routine retubing of selected feedwater heaters.

* Install additional fire protection system.

We do not feel that the New Source Performance Standards or the permitting requirement under 10 CSR 10-6.060 is applicable to these projects. Replacement of the components listed is not uncommon for our type of facility and, as such, is considered routine. As mentioned previously, there will not be a net increase in capacity for any of the units resulting from these projects nor an increase in the capacity to emit pollutants. Finally, the total cost of these projects is approximately $70,000,000, which represents an investment of less than eight percent (8%) of the cost of a new replacement facility. Consequently, substantial savings to the ratepayers of Missouri will be realized as a result of these projects.

If you need any additional information or would like to discuss this matter, please do not hesitate to call.

Sincerely,

J.E. Barry

JEB:cah

cc: Fred Little, MPS
John Browning, MPS
Bob Beck, MPS
Pat Lorenz, MPS

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[•] Standard Form [‡]

Phase1-2 # 9

County:	2240
Plant:	0031
Plant Name:	MISSOURI PUBLIC SERVICE CO
Site Name:	SIBLEY GENERATING STATION
Contact:	ROBERT C. BECK
Telephone:	816-650-6196
Plant Address:	33200 EAST JOHNSON RD
City Name:	SIBLEY
Zip1:	64088
Zip2:	
Mailing Street Address:	10700 EAST 350 HIGHWAY
Mailing City Name:	KANSAS CITY
Mailing Zip1:	64138
Mailing Zip2:	
Current Phase I Units:	3 Phase I
Current Phase II Units:	
Orig Phase I Units:	1 Phase I
Orig Phase II Units:	2 Phase II
Date Phase II-I Changed:	Aug 94

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Phase1-2 # 9

County:	2240
Plant:	0031
Plant Name:	MISSOURI PUBLIC SERVICE CO
Site Name:	SIBLEY GENERATING STATION
Contact:	ROBERT C. BECK
Telephone:	816-650-6196
Plant Address:	33200 EAST JOHNSON RD
City Name:	SIBLEY
Zip1:	64088
Zip2:	
Mailing Street Address:	10700 EAST 350 HIGHWAY
Mailing City Name:	KANSAS CITY
Mailing Zip1:	64138
Mailing Zip2:	
Current Phase I Units:	3 Phase I
Current Phase II Units:	
Orig Phase I Units:	1 Phase I
Orig Phase II Units:	2 Phase II
Date Phase II-I Changed:	Aug 94

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