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VIA OVERNIGHT AND ELECTRONIC MAIL

Administrator Lisa P. Jackson
U.S. Environmental Protection Agency
Room 3000, Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Request for Reconsideration and Stay of *Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals,* 76 Fed. Reg. 48,208 (August 8, 2011) (Docket No. EPA-HQ-OAR-2009-0491)

Dear Administrator Jackson:

The operating companies of the American Electric Power System[1] (collectively referred to herein as "AEP"), respectfully request administrative reconsideration of the final rule entitled *Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approval*, published at 76 Fed. Reg. 48,208 (Aug. 8, 2011) (the "Transport Rule"), and a stay of the effective date beyond October 7, 2011, to allow adequate time for reconsideration of the Transport Rule and/or effective judicial review.

Reconsideration is warranted because the Environmental Protection Agency (EPA) materially changed the fundamental requirements of the rule between its original proposal and the final version of the rule, and failed to provide the public with adequate opportunity to comment on the data, assumptions, methodology, legal interpretations and policy considerations on which the final rule is apparently based. States that were initially part of the region covered by the Transport Rule were removed in the final rule, while other states in which AEP operates that were initially subject to only certain portions of the proposed rule became subject to additional or different programs in the final rule. Moreover, all of the state budgets were revised based on new modeling that was never made available for review or public comment. And EPA's preferred option at the time of its initial proposal, which included unrestricted interstate trading for the initial two years of the program, was abandoned for an inflexible system that combines new and different significant reductions in emissions with an implementation date that is less than six months from the public release of the rule. Such an inflexible system requires that

[1] This request is submitted on behalf of AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company.

EPA accurately analyze the performance of individual electric generating units and incorporate local transmission constraints in order to evaluate real-world responses. However, EPA's Integrated Planning Model (IPM), which was used to develop the Transport Rule, simply does not have these capabilities.

As part of its stay request, AEP specifically asks EPA to stay its anticipated action removing allowances from existing Clean Air Interstate Rule (CAIR) allowance accounts, so that during any period for reconsideration or judicial review, the emissions reductions that have been and are being made can continue to contribute to improved air quality across the region. As demonstrated by the modeling submitted by the Midwest Ozone Group during the public comment period (EPA-HQ-OAR-2009-0491-2809), the CAIR reductions and other existing requirements are anticipated to allow all but two areas (whose air quality is dominated by local sources) to achieve the ambient air quality standards targeted by the Transport Rule before 2014. Indeed, more than 80 percent of the areas EPA projected would be in non-attainment in 2012, and upon which the Transport Rule's most imminent reduction requirements are based, already have attained the target standards based on measured air quality data. *Id.* It is essential that EPA not dismantle this existing compliance structure without first affording petitioners an opportunity to seek relief from the unreasonable and infeasible demands and compliance schedule incorporated into the final Transport Rule.

Introduction

On August 2, 2010, EPA published in the *Federal Register* a proposed federal implementation plan to reduce the interstate transport of fine particulate matter and precursors of ozone (the Transport Rule). 75 Fed. Reg. 45,210 (Aug. 2, 2010). The proposal was intended to "identify and limit the interstate transport of emissions of nitrogen oxides (NO_x) and sulfur dioxide (SO_2)" from electric generating units (EGUs) in 32 states in the eastern United States and to assist downwind states in attaining and maintaining compliance with the 1997 ozone and fine particulate matter National Ambient Air Quality Standards (NAAQS), and the 2006 ozone NAAQS. *Id.*

The proposed Transport Rule was crafted to replace CAIR, 70 Fed. Reg. 25,162 (May 12, 2005), which was remanded to EPA by the United States Court of Appeals for the District of Columbia Circuit in 2008. *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008). The court found that EPA did not demonstrate that CAIR would secure the emission reductions in each state necessary to remedy that state's significant contribution to any linked downwind non-attainment area, and suffered from other fundamental flaws in the record. The court ultimately issued a ruling to remand CAIR without vacatur, thus leaving CAIR temporarily in place until EPA promulgated a new rule that would address the defects identified by the court. *North Carolina v. EPA*, 550 F.3d 1176 (D.C. Cir. 2008).

Request for Reconsideration and Stay

Rulemakings that promulgate or revise an implementation plan under Section 110(c) of the Clean Air Act are subject to the requirements of Section 307(d), which states that a notice of proposed rulemaking must contain a statement of its basis and purpose that includes a summary of –

> (A) the *factual data* on which the proposed rule is based;
> (B) the *methodology* used in obtaining the data and in analyzing the data; and
> (C) the *major legal interpretations* and *policy considerations* underlying the proposed rule.

42 U.S.C. § 7507(d)(3). All data, information and documents referred to in the summary must also be included in the docket on the date of publication of the proposed rule. *Id.* As previously explained by numerous commenters on the proposed rule, and further discussed herein due to new deficiencies identified with regard to the final rule, EPA failed to make the required information available in a meaningful way during this rulemaking.

If (1) it was impracticable to raise a comment of central relevance to the outcome of the rulemaking within the period provided for public comment, or if (2) the grounds for objection arose after the period for public comment but within the time specified for judicial review, the Administrator must convene a proceeding for reconsideration, and provide the same procedural rights that should have been afforded and make available all of the information that is required by Section 307(d) at the time the rule was proposed. 42 U.S.C. § 7607(d)(7)(B). The Administrator may stay the effectiveness of the rule during the reconsideration proceeding. *Id.*

Here, as explained in more detail in the sections below, the fundamental factual data underlying the final rule are materially different than the data underlying the proposed rule, the methodology used to analyze the data changed, and the legal interpretations and policy considerations that were used to support critical aspects of the proposal were inexplicably altered in the final rule without notice or opportunity for comment. Under such circumstances, reconsideration is clearly warranted.

In addition, a stay is also warranted because AEP and other affected parties will experience immediate, irreparable harm should the rule take effect prior to the completion of the reconsideration proceeding or effective judicial review. As outlined below, the inaccuracies in and changes between the proposed and final rule create a real risk of non-compliance due to the unrealistic reductions required beginning in 2012. If fuel switches cannot be made, combustion controls cannot be installed, or other measures cannot be undertaken in the time remaining before January 2012, units that provide both needed capacity and critical transmission support services may have insufficient allowances to run as required to assure the stability of the electricity grid. Even if allowances are available, operators are likely to be exposed to the punitive allowance surrender provisions and other enforcement due to the inadequacy of individual state budgets. It is imperative the EPA refrain from removing allowances from the existing CAIR accounts, so that some stability in operations and continued emission reductions can be assured while reconsideration and/or judicial review proceeds.

The following sections outline specific areas where incomplete information was made available by EPA during the rulemaking process or where new information has become available that is of central relevance to the Transport Rule and justifies reconsideration. In each of these areas, it was either impracticable for AEP to raise the specific issues identified during the comment period, or the grounds for objection arose after the comment period closed.

A. Fundamental Changes Were Made Between the Proposed and Final Rules That Were Not a "Logical Outgrowth" of the Proposed Rule

In crafting the proposed Transport Rule's redesign of CAIR's cap-and-trade system, EPA followed a "two-step" process, based largely on extraordinarily complex IPM modeling of the U.S. electric power sector. It relied on the National Electric Energy Data System (NEEDS) database for the unit-level EGU data used to construct the "model" plants that represent existing and planned/committed units in the IPM modeling.[2] First, EPA conducted a "base case" air quality modeling analysis, which assumed that the Transport Rule and CAIR did not exist, to simulate ambient air concentrations for the future years 2012 and 2014. 75 Fed. Reg. at 45,233. The 2012 base case modeling was used to identify projected nonattainment and maintenance areas (*i.e.,* areas that have not attained or are in danger of failing to maintain the NAAQS) and to quantify the projected contributions of emissions from upwind states to those locations. *Id.* States whose contributions to any downwind sites were projected to be greater than 1 percent of the relevant NAAQS were considered significant contributors and thus "linked" to those locations. *Id.* AEP and others commented on the legal and practical defects in this approach to identifying needed reductions. The Midwest Ozone Group (MOG) presented a modeling analysis that demonstrates that the aggressive emission reductions included in the proposed Transport Rule are not necessary to achieve the targeted NAAQS by 2014.[3] MOG has further analyzed the air quality modeling data used by EPA to support the final rule, and confirmed that EPA did not properly consider current air quality data in identifying nonattainment and maintenance areas, and that the vast majority of monitors identified by EPA as nonattainment or maintenance areas are currently in attainment. AEP incorporates by reference the petition for reconsideration submitted by MOG based on that analysis, as if fully set forth herein.

Next, EPA identified the portion of each state's contributing emissions projected to "significantly contribute to, or interfere with maintenance by" another state." 75 Fed. Reg. at 45,233. In this step, EPA identified emissions reductions available from EGUs in each of the upwind states that were "linked" to downwind locations, at "appropriate

[2] EPA, "IPM Analyses of the Proposed Transport Rule," available at http://www.epa.gov/airmarkt/progsregs/epa-ipm/proposedTR.html.
[3] See Alpine Geophysics Report dated Sept. 28, 2010, attached to MOG's Comments on the Transport Rule, EPA-HQ-OAR-2009-0491-2809.

maximum cost thresholds" developed by the agency for annual SO_2, annual NO_x, and ozone-season NO_x. *Id.* EPA compared the 2014 base case modeling against modeling which assumed that EPA's proposed remedy was in place (the "preferred case"), in order to quantify the benefits of the proposed rule. *Id.* at 45,238.

Under the proposed Transport Rule, 32 states were included in one or more of three separate programs to reduce their annual SO_2, annual NO_x, and/or seasonal NO_x emissions to help downwind states achieve compliance with the fine particulate matter and/or ozone NAAQS. *Id.* at 45,215. The proposed rule assigned emissions "budgets" to each state for each pollutant, and allocated emissions "allowances" to sources within each state, beginning in the years 2012 and 2014. *Id.* at 45,290, 45,306. The 2012 emission reductions were intended to reflect continuous operation of installed controls, limited upgrades of combustion controls (for NO_x), and limited fuel switching (for SO_2). *Id.* at 45,276. The 28 states that were to be covered by the annual SO_2 program were divided into two groups, a "Group 1" and a "Group 2" based on their cost curves, with more stringent requirements for the former group phased in over the two periods. *Id.* at 45,306. The 2014 budgets assumed the deployment of cost-effective SO_2 controls throughout the region. Each covered source within the states would be permitted "limited flexibility" to design its own compliance strategy to meet its overall reduction requirement, including intrastate and some interstate trading of allowances, installation of pollution controls, fuel switching, and other emissions reduction options. *Id.* at 45,215. EPA also proposed to account for the inherent variability in power system operations through ''assurance provisions'' based on state "variability limits" which would extend above the state emissions budgets, and impose costly "allowance surrender requirements" to deter exceedances by EGUs. *Id.* at 45,313.

After the publication of the proposed rule in the *Federal Register*, EPA provided only 60 days for the public to review over 250 pages of regulatory text and multiple volumes of supporting documentation, including detailed modeling information, and provide detailed comments. Many comments were submitted, identifying numerous serious errors in the model inputs and assumptions. Many commenters, including AEP,[4] urged EPA to revise the model inputs, rerun the models, and issue a supplemental proposal for public comment including state-level budgets and unit-level allocations prior to finalizing the rule.

After its initial proposal, EPA issued three separate notices announcing that additional information was being placed in the docket for this rulemaking. First, EPA published 3,500 pages of technical data, updating the NEEDS database and notifying the public that a newer version of IPM was available. EPA stated that it would use these new tools to generate additional model runs for the final rule. *Notice of Data Availability Supporting Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone,* 75 Fed. Reg. 53,613 (Sept. 1, 2010). A few select model runs were released at that time, but they did not include any of the corrections that commenters discovered in the original proposal. In addition, EPA provided only 45 days to review and comment on

[4] See attached Exhibit 1, Comments of the AEP Companies on the Proposed Clean Air Transport Rule, submitted October 1, 2010.

this information, and refused to provide any extensions. AEP submitted comments identifying errors in the information included for its units, and requesting additional information and re-proposal of the rule once the errors in the underlying databases were corrected, so that the public would be fully informed about the changes that resulted from correcting these errors.[5]

A second notice was issued on October 27, 2010, including parsed files for the electric generating unit emission inventories and other inputs to EPA's modeling. 75 Fed. Reg. 66,055 (Oct. 27, 2010). AEP submitted comments identifying additional errors in these inventories, which resulted in double-counting emissions and overestimating the contributions of upwind states.[6] Again, no revisions were made in the state budgets based on the corrections made to errors discovered in the previous work, and no detailed assessment of the impact of the changes EPA was making in its analyses was possible.

A third notice was issued in January 2011, including IPM model runs still based on the uncorrected inputs used in the prior runs, this time examining different allocation methodologies and allowance surrender scenarios. 76 Fed. Reg. 1109 (Jan. 7, 2011). AEP's comments on the alternative allocation methodologies were based on its understanding from the proposed rule that EPA was still intending to require minimal, if any, additional emission reductions in 2012, and AEP continued to urge the agency to re-examine its assumptions regarding the feasibility of installing highly effective (and very capital-intensive) emissions control equipment by the beginning of 2014, based on AEP's extensive real-world experience in installing over $7 billion dollars of this equipment since 1990.[7] AEP also urged the agency to abandon its proposed assurance provisions, or substantially increase the flexibility of the trading programs, noting that the agency's own examination of historic variability supported more flexibility from year-to-year.

Instead, in crafting the final rule, EPA updated its models, made some corrections to its inputs and assumptions, and generated never-before-seen scenarios to achieve even more significant reductions in SO_2 and NO_x emissions across a newly-defined region that excluded 5 of the originally covered states, and proposed to expand the program into 6 other states for ozone season NO_x. EPA also altered the programs that would be effective in certain states, limiting the requirements to ozone season-only reductions in Louisiana but imposing very substantial annual SO_2 and NO_x reduction requirements in Texas that were never previously announced. The absolute level of reductions required to be achieved in the states where AEP's facilities are located changed dramatically from the proposed rule to the final rule, and are set forth in the table below.

Comparison of Proposed to Final 2012 Budgets in AEP States

[5] See attached Exhibit 2, Comments of the AEP Companies on the Notice of Data Availability (NODA 1), submitted October 15, 2010.

[6] See attached Exhibit 3, Comments of the AEP Companies on the Notice of Data Availability (NODA 2), submitted November 23, 2010.

[7] See attached Exhibit 4, Comments of the AEP Companies on the Notice of Data Availability (NODA 3), submitted February 7, 2011.

Year and Program	Proposed 2012 SO_2 Budget	Final 2012 SO_2 Budget	Proposed 2012 Annual NO_x Budget	Final 2012 Annual NO_x Budget	Proposed 2012 Seasonal NO_x Budget	Final 2012 Seasonal NO_x Budget
Arkansas	NA	NA	NA	NA	16,660	15,037
Indiana	400,378	285,424	115,687	109,726	49,987	48,876
Kentucky	219,549	232,662	74,117	85,086	30,908	36,167
Louisiana	90,477	NA	43,946	NA	21,220	13,432
Ohio	464,964	310,230	97,313	92,703	40,661	40,063
Texas	NA	243,954	NA	133,595	75,574	63,043
Virginia	72,595	70,820	29,581	33,242	12,608	14,452
West Virginia	205,422	146,174	51,990	59,472	22,234	25,283
Net Impact*		-317,598		11,541		-13,499

* Excludes Texas and Louisiana from annual net calculations due to change in programs.

In addition, EPA revised the "assurance provisions" to limit the amount of interstate trading, doubled the allowance surrenders required if those provisions are exceeded, and made those restrictions effective beginning in 2012. 76 Fed. Reg. at 48,294-96. These provisions severely limit the ability to trade allowances freely among the states subject to the Transport Rule, nearly eliminating the ability to design cost-effective strategies to achieve these significant decreases in emissions in less than 6 months. EPA's justification for this change was based on a limited analysis of "power sector variability" based on year-to-year changes in weather and load. *Id.* at 48,265-66. It did not include any analysis of the flexibility needed to address implementation concerns unrelated to the seasonal and operational variability of electricity production, such as the inability to switch fuels, accommodate large shifts in generation, and other reliability concerns, which were considered in the proposed rule. 75 Fed. Reg. at 45,318. These changes alone make the compliance obligations imposed by the final Transport Rule a proper subject for reconsideration.

Moreover, the intricacy of the rule is buried in thousands of pages of numeric codes and computer files which are unintelligible to an ordinary reader, and the objects of its compliance mandates – the providers of most of the nation's electricity – are the lifeblood of the American economy and provide critical public service. After each issuance of additional data, thousands of manhours were required to review the portions of the data made publicly available. Critical data underlying the final rule were not placed in the public docket but were made available only by special request to EPA and its modeling team. As noted in AEP's comments on October 15, 2010, the complexity of the IPM and EPA's constantly changing assumptions made it critical that EPA release new model inputs and outputs on an *individual unit basis* to assure that the model was accurately capturing real-world constraints on fuel blending, equipment performance, control efficiency, transmission capability and other parameters. EPA failed to do so. As a result, there are several areas where EPA's analysis incorporates unrealistic assumptions and incorrect data upon which affected entities were unable to comment during the rulemaking process.

The increased stringency of the emission budgets, and the elimination of unlimited interstate trading are inconsistent with the fundamental premise of the proposed rule – which was to reflect continuous operation of installed controls, limited upgrades of combustion controls (for NO_x), and limited fuel switching (for SO_2), 75 Fed. Reg. at 45,276, and which, with unlimited interstate trading, would have provided a rational transition from CAIR to a more restrictive cap-and-trade program. At a minimum, restoration of the flexible trading scheme initially proposed is essential if covered sources are to have any real opportunity to achieve the aggressive emission reductions required in the final rule without impairing electric reliability. At a minimum, AEP respectfully requests that if any portion of the Transport Rule takes effect in 2012, the Administrator suspend the effective date of the assurance provisions until 2014 to restore a portion of the flexibility needed in order to reliably transition from CAIR to the Transport Rule.

B. New Information Regarding Localized Transmission Constraints and Impacts on Electricity Reliability Has Become Available

EPA acknowledges in the Final Rule that the IPM modeling tool lacks the precision to forecast unit level operation. 76 Fed. Reg. at 48,285. AEP strongly agrees with this conclusion, and urged EPA repeatedly during the rulemaking process to consider localized transmission constraints and reliability impacts associated with its modeled changes in unit-level generation. AEP's concerns were driven by the fact that many existing units provide localized load rejection and black start capability and are critical to preventing an electrical system brown-out or black-out or restoring the electrical grid following such an event. These units are able to rapidly separate from the electrical transmission grid and operate in an "islanding" condition, until they are advised to reconnect and quickly help restart the grid. To fulfill their role in assuring that system reliability can be maintained, they must be operating at the time a transmission contingency occurs. AEP Comments, Oct. 15, 2010. AEP urged EPA to incorporate realistic constraints in its modeling scenarios to protect the continued operation of these units, or to accurately capture the impacts on reliability, particularly if the units were projected to retire or not to run. *Id.* Because AEP has information only about its own units, it was not in a position to analyze the cumulative impacts of EPA's proposal on the areas in which its units operate, but provided confidential information concerning its units to its regional reliability organizations the Southwest Power Pool (SPP) and PJM, regional entities including Reliability First Corporation (RFC) and SPP Regional Entity (SPPRE), and to the North American Reliability Corporation (NERC), and the

Department of Energy (DOE) related to this rule and other EPA rulemaking activities, and supported a more robust analysis of these potential reliability impacts.

The reduced state emission budgets and the immediately applicable assurance provisions in the final rule *increased* the importance of properly projecting unit level operations, and accounting for these reliability impacts. However, the supply and demand regions in the EPA models underlying the final rule are not state-specific, often encompass a number of states, and recognize only bulk regional transmission constraints. Thus, EPA's conclusion that IPM can be effectively used to establish state-level budgets is also materially flawed. EPA's model runs for the final rule improperly assume that the system can sustain massive shifts in generation from coal-fired to gas-fired units, and from higher-emitting to lower-emitting coal-fired units, as well as significant shifts in generation from state-to-state, without regard to these reliability constraints.

EPA did not perform any analysis to test its model's predictions of how the emission reductions under the final rule would be achieved at the targeted cost against the reality of the operation of the electric grid in recent years. Yet even high-level comparisons of the modeled output to recent operations shows the wide divergence between the modeled cases and real-life operations. The following table shows the changes from the proposed rule to the final rule in EPA-modeled heat input and NO_x emissions during the ozone season (the period in which demand is highest) for the 2012 policy case, and compares the modeled 2012 levels to actual 2010 levels. Calendar year 2010 was chosen because it is the most recent year for which data is available and represents a period when the country is still suffering the impacts of the financial recession, a condition that unfortunately is likely to continue depressing demand for electricity. There are two very important conclusions that can be drawn from this comparison. First, there are significant changes in total 2012 emissions and heat input from the proposed to final rule, on a state-by-state basis. Overall, seasonal NO_x emissions were reduced by more than ten percent below the levels in the proposed rule, and a large portion of that reduction appears to be attributable to reduced energy production across the region. In seven states, the change in ozone season NO_x emissions from the proposed to final rule exceeds the 21 percent seasonal NO_x assurance limit. Any economic recovery or extreme weather will only increase the difficulty of complying with these limits. Because the level of emissions included in the proposed rule's 2012 state budgets was intended to reflect current operations and the limited options that could be implemented within the very short period between the final rule and its effective date, and EPA did not provide a basis to assume that greater reductions could be practically implemented, reconsideration is warranted.

The table also shows that the final rule does not accurately reflect the actual operation of the electric system in 2010, and may be fundamentally flawed due to the model's inability to capture local transmission constraints or other limitations. Notwithstanding these dramatic shifts, EPA never attempted to "backtest" the IPM model versus actual operational constraints.

State Name	Data	2012 Remedy IPM Data Proposed	Final	% Change vs Proposed	2010 Actual	% Change Final vs 2010
Alabama	Summer NOx Emission (MTon)	30	32	7%	27	15%
	Summer Fuel Use (TBtu)	454	452	0%	450	0%
Arkansas	Summer NOx Emission (MTon)	12	15	28%	18	-16%
	Summer Fuel Use (TBtu)	223	170	-24%	189	-10%
Florida	Summer NOx Emission (MTon)	57	28	-51%	37	-26%
	Summer Fuel Use (TBtu)	900	750	-17%	858	-13%
Georgia	Summer NOx Emission (MTon)	32	27	-17%	27	0%
	Summer Fuel Use (TBtu)	460	379	-18%	457	-17%
Illinois	Summer NOx Emission (MTon)	20	21	7%	28	-25%
	Summer Fuel Use (TBtu)	419	443	6%	448	-1%
Indiana	Summer NOx Emission (MTon)	48	47	-2%	49	-5%
	Summer Fuel Use (TBtu)	609	552	-9%	528	5%
Iowa	Summer NOx Emission (MTon)	20	16	-21%	19	-18%
	Summer Fuel Use (TBtu)	201	173	-14%	191	-10%
Kansas	Summer NOx Emission (MTon)	17	13	-19%	22	-40%
	Summer Fuel Use (TBtu)	168	153	-9%	181	-16%
Kentucky	Summer NOx Emission (MTon)	31	35	14%	39	-10%
	Summer Fuel Use (TBtu)	455	414	-9%	432	-4%
Louisiana	Summer NOx Emission (MTon)	17	14	-18%	23	-41%
	Summer Fuel Use (TBtu)	231	248	7%	330	-25%
Maryland	Summer NOx Emission (MTon)	7	7	-5%	9	-29%
	Summer Fuel Use (TBtu)	152	120	-21%	141	-15%
Michigan	Summer NOx Emission (MTon)	26	26	-1%	35	-27%
	Summer Fuel Use (TBtu)	339	290	-14%	374	-22%
Minnesota	Summer NOx Emission (MTon)	15	13	-9%	14	-4%
	Summer Fuel Use (TBtu)	178	162	-9%	156	4%
Mississippi	Summer NOx Emission (MTon)	8	11	31%	16	-34%
	Summer Fuel Use (TBtu)	94	115	23%	205	-44%
Missouri	Summer NOx Emission (MTon)	28	22	-21%	26	-15%
	Summer Fuel Use (TBtu)	336	335	0%	359	-7%
Nebraska	Summer NOx Emission (MTon)	14	12	-14%	16	-25%
	Summer Fuel Use (TBtu)	124	128	3%	108	19%
New Jersey	Summer NOx Emission (MTon)	5	3	-32%	5	-34%
	Summer Fuel Use (TBtu)	124	108	-13%	140	-23%
New York	Summer NOx Emission (MTon)	10	8	-19%	13	-35%
	Summer Fuel Use (TBtu)	296	213	-28%	305	-30%
North Carolina	Summer NOx Emission (MTon)	23	21	-6%	25	-14%
	Summer Fuel Use (TBtu)	392	331	-15%	368	-10%
Ohio	Summer NOx Emission (MTon)	41	35	-15%	48	-27%
	Summer Fuel Use (TBtu)	643	535	-17%	559	-4%
Oklahoma	Summer NOx Emission (MTon)	27	21	-24%	35	-40%
	Summer Fuel Use (TBtu)	349	277	-21%	317	-13%
Pennsylvania	Summer NOx Emission (MTon)	48	50	4%	58	-13%
	Summer Fuel Use (TBtu)	652	576	-12%	627	-8%
South Carolina	Summer NOx Emission (MTon)	14	14	-3%	14	0%
	Summer Fuel Use (TBtu)	223	215	-3%	235	-8%
Tennessee	Summer NOx Emission (MTon)	11	14	27%	15	-2%
	Summer Fuel Use (TBtu)	250	231	-8%	210	10%
Texas	Summer NOx Emission (MTon)	66	63	-6%	68	-8%
	Summer Fuel Use (TBtu)	1,483	1,274	-14%	1,528	-17%
Virginia	Summer NOx Emission (MTon)	13	14	14%	18	-22%
	Summer Fuel Use (TBtu)	196	198	1%	217	-9%
West Virginia	Summer NOx Emission (MTon)	22	23	5%	24	-4%
	Summer Fuel Use (TBtu)	439	397	-10%	333	19%
Wisconsin	Summer NOx Emission (MTon)	15	16	3%	15	9%
	Summer Fuel Use (TBtu)	205	220	8%	223	-1%
TOTAL	**Summer NOx Emission (MTon)**	**1,327**	**1,196**	**-10%**	**1,370**	**-13%**
	Summer Fuel Use (TBtu)	**9,943**	**8,884**	**-11%**	**9,844**	-10%

The data cited above from the proposed Transport Rule is the analysis for the Interstate Trading option, which has the most similarities to the elements EPA ultimately selected for inclusion in the final rule. However, there are key differences between the proposed rule and the final rule, most notably the applicability of the state assurance provisions in the first two years of the program. EPA did not produce a parsed results file from its IPM run for the 2012 policy case in the IPM NODA. Thus, AEP was not able to view or effectively comment on the changes in modeling assumptions and how those changes impact 2012 electricity supply and emissions between the proposed and final rule.

One significant flaw in the underlying modeling is the way in which IPM characterizes dual-fueled units in the SPP region. AEP companies own several units in this area that are permitted to burn both natural gas and oil, but in the modeled output for the final rule, many of the units are listed as "oil" fired units. Due to the higher costs associated with oil-firing, none of these units are projected to operate, even though all of these units were running on natural gas at or near full load during periods of peak demand in recent years. The units in AEP's fleet which are projected not to run in 2012 include Northeastern Unit 2, Riverside Unit 2, Southwestern Units 1 to 3, and Tulsa Units 2 to 4 in Oklahoma, Lieberman Units 1 to 4 and Arsenal Hill Unit 5 in Louisiana, and Knox Lee Units 2 to 5, Lone Star Unit 1 and Wilkes Unit 1 in Texas. All the listed units, with the exception of Knox Lee Unit 5, were projected to operate on oil. Collectively, this represents 2900 MW of idled natural gas-fired capacity, which is needed to operate during peak demand periods in the summer in the Southwestern United States. Such results do not accurately reflect reality, and represent a fundamental flaw in EPA's models.

The impact noted above for AEP's units is not unique. Just recently, SPP completed an analysis of EPA's modeled IPM results for 2012. SPP's analysis tested the reliability impacts associated with the 48 EGUs within SPP that EPA's model assumed will have zero fuel burn (*i.e.*, will not operate) during the ozone season in the 2012 remedy case.[8] All 48 of these units would have been dispatched by SPP during summer peak conditions. According to SPP's models, without the generation from these units, serious violations of the applicable reliability standards are projected during 2012, including the potential of cascading blackouts and shedding of firm power loads. Not only would this scenario place SPP in clear violation of its reliability requirements, thus subjecting it to penalties from the Federal Energy Regulatory Commission, it could result in "significant impacts on human health, public safety and commercial activity" within SPP. *Id.*

Another reliability organization, the Electric Reliability Council of Texas (ERCOT), has prepared a report that was included with the petition for reconsideration submitted by the State of Texas, which concludes that in that region, implementation of the final rule will result in the loss of thousands of megawatts of capacity and that the implementation time frame provided by EPA "provides ERCOT an extremely truncated period in which to

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[8] See attached Exhibit 5, Letter from Southwest Power Pool to Administrator Jackson, Sept. 20, 2011.

assess the reliability impacts of the rule, and no realistic opportunity to take steps that would even partially mitigate the substantial losses of available operating capacity."[9]

The Midwest Independent System Operator (MISO), provided a preliminary analysis on September 28, and has organized a Task Force to further investigate potential impacts associated with the final rule.[10] Among the issues identified for further study are the capability of gas units to furnish the substantially increased requirements due to the restricted availability of coal units, and the failure of the existing analyses to account for forced outages, maintenance requirements, and units that are idled due to lack of allowance availability.

The reliability consequences of the final rule will undoubtedly vary from region to region. But EPA's failure to solicit information about and adequately analyze these impacts in order to understand the effect of its rule on critical public safety services guarantees that neither the industry nor its public service regulators will have the opportunity to assess or adequately prepare for them. As confirmed by these organizations, the time period between the finalization of the Transport Rule and its implementation is simply too short for detailed analysis or responsible action to ensure reliability. Accordingly, the Administrator should grant this petition for reconsideration and immediately stay the implementation of the rule.

At a minimum, the Administrator should solicit information concerning units for which zero heat input or significantly reduced capacity factors were assumed in the analysis supporting the final rule, and provide additional allowances to support normal ozone season operation and/or operation consistent with reliability requirements for the initial allocation period.

B. Incomplete Information about Compliance Options

EPA's modeling analysis on which the final Transport Rule is based incorporates numerous unrealistic assumptions and incorrect data, including mistaken rates of assumed emissions from individual EGUs obtained from the IPM modeling tool. Affected entities were unable to effectively comment on these assumptions and data during the rulemaking process because they were difficult to discover in the limited time made available for public comment, not directly discoverable from the information provided, or only made available in conjunction with the publication of the final rule.

The more stringent state allowance budgets put a premium on ensuring that EPA's model accurately reflects electric sector operations and costs. However, much of the underlying data on unit operation are not readily available to the public. EPA only provides a summary file which contains high-level U.S. estimates for generation, fuel use and emissions. Unit-level data files contain only emission rates, major environmental control

[9] See attached Exhibit 6, *Impacts of the Cross-State Air Pollution Rule on the ERCOT System*, Exec, Summary, Sept. 1, 2011.
[10] See attached Exhibit 7, *EPA Regulation Impact Analysis for the MISO Planning Advisory Committee*, Sept. 28, 2011.

retrofits and heat input. Key attributes such as generation at the unit level, retrofit combustion controls, fuel use by mine source and capital deployed for compliance are not available. As such, identifying improper assumptions is very difficult, particularly as they relate to coal selection and sulfur content. Additionally, there is no way to properly verify that EPA is appropriately reflecting capital for fuel blending or environmental controls.

Many of EPA's incorrect assumptions are related to assumed compliance options for the individual EGUs, in the following particular areas.

1. Availability of Very Low Sulfur Subbituminous Fuels

In its proposed rule, EPA based state-level budgets and unit-level allocations for 2012 on base year model runs and historic information that was intended to capture the operation of existing control equipment up to its design removal efficiency and some additional reductions due to the use of lower sulfur coal. 75 Fed. Reg. at 45,281. AEP provided information in its comments concerning the constraints preventing the use of lower sulfur fuels at several of its units designed to burn bituminous coals, and the unreasonably low emission rates EPA assigned to many of its existing controlled and uncontrolled units.[11] AEP also pointed out that there was not enough information in the docket to properly evaluate this issue on a unit-specific basis, since information about fuel characteristics had to be inferred from the emission rates for SO_2 included in the parsed field of the IPM model runs. *Id.* However, because the proposal allowed unrestricted trading and was premised on state emission budgets that more closely approximated actual projections for AEP's fleet in 2012, the issue was not of material importance.

In the preamble for the final rule, EPA summarized the fuel-switching assumptions that were imbedded in the model runs, many of which increased from the proposed rule. Because the budgets in AEP's states were substantially decreased in 2012, and the option for unlimited interstate trading was abandoned, AEP more carefully examined the availability and suitability of fuel switching. In addition, AEP owns all or part of 4 of the 7 plants identified in EPA's final remedy model runs where retrofitted flue gas desulfurization (FGD) controls are projected to be installed by 2014. 76 Fed. Reg. at 48,282. However, EPA also claimed that compliance could be achieved even if no new FGD retrofits were completed by 2014, and that the more stringent requirements in Group 1 states can be achieved through additional fuel switches, redispatch of existing generation, and optimization of existing controls. *Id.* at 48,279-80. Given these revisions, the availability of fuel switching became of paramount importance to the feasibility of complying with the state budgets in 2012 and 2014.

In the initial proposal, EPA provided the following summary of fuel use for the 28 states originally proposed to be covered by the annual program to reduce SO_2 emissions:

Modeled Coal Use Under Proposed Transport Rule

[11] See Exhibit 2, pp 3-4.

Table 7-10. Coal Use by Sulfur Category in the $PM_{2.5}$ Transport Region for the Base Case and Preferred Approach*
(thousand short tons)

		Lignite	Subbituminous			Bituminous				Total
			High sulfur	Low sulfur	Very low sulfur	High sulfur	High-medium sulfur	Low-medium sulfur	Low sulfur	
2012	Base case	3,911	3,405	125,460	176,479	285,511	106,575	72,952	4,507	778,800
	Preferred approach	3,911	2,143	63,858	246,828	258,847	101,383	89,826	10,518	777,315
2014	Base case	3,883	6,664	110,357	193,885	331,913	69,060	85,248	5,143	806,153
	Preferred approach	3,883	4,823	64,434	242,821	294,305	84,519	91,672	11,558	798,014

*These coal usage results are for the 28 states covered by the rule in the trading program to reduce SO_2 emissions.

When the final rule was issued, a similar summary was issued for the now 23 states covered by the annual SO_2 program. The fuel usage projections for the region covered by the program are not directly comparable due to the elimination of several eastern states from the region, and the inclusion of the state of Texas in the final rule. However, it is striking that, even within the smaller geographic region covered by the final rule, the projected use of "very low sulfur" fuel – which is produced from a very few mines in the Powder River region in Wyoming and Montana – increased even more significantly from the base case to the remedy case in 2012 and 2014:

Modeled Coal Use Under Final Transport Rule

Table 7-9. Coal Use by Sulfur Category in the $PM_{2.5}$ Transport Region for the Base Case and Transport Rule* (million short tons)

		Lignite	Subbituminous			Bituminous				Total
			High sulfur	Low sulfur	Very low sulfur	High sulfur	High-medium sulfur	Low-medium sulfur	Low sulfur	
2012	Base	30	13	145	156	91	211	83	3	732
	TR	25	2	77	255	83	195	74	12	723
2014	Base	37	13	145	154	102	216	71	9	747
	TR	32	2	108	202	88	202	73	18	724

*These coal usage results are for the 23 states covered by the rule in the trading program to reduce SO_2 emissions.
Source: Integrated Planning Model run by EPA, 2011.

Further investigation of the coal supply assumptions underlying the final rule revealed that EPA is projecting that overall *production* of very low sulfur coal from the Powder River region in Wyoming is expected to increase by 20 percent from the 2012 base case to the 2012 policy case, or by roughly *40 million tons*. [AEP analysis of IPM 2012 Remedy Case Results] This level of increased production cannot occur over a period of less than a few months due to the need for additional mining equipment, modifying air and mining permit limitations, and existing rail transport limitations. Even more significant shifts in coal production are expected to occur within the Colorado Green River coal supply region. EPA's remedy case assumes that low sulfur coal production in this region *can be more than doubled (+123%)* in time to comply with the SO_2 emission reductions required by 2012. [AEP analysis of IPM 2012 Remedy Case Results] These critical errors stem from the fact that the coal supply curves utilized by EPA do not impose any timing restrictions on increasing coal production. The coal supply curves used by EPA assume that all coal mines can expand in an almost unlimited way in response to price, and could achieve the same increase in production next year or in 2030. [http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter9.pdf] This is a highly flawed assumption that leads to an over-estimation of the role that lower-sulfur coal can realistically play in meeting near-term emission constraints.

In addition to changes in the total coal supply, changes in *coal consumption patterns* are also not limited. IPM projects major switching of very low sulfur coal supplies on a state-by-state basis by 2012. [AEP analysis of IPM 2012 Remedy Case Results] The following chart shows the percentage change in very low sulfur (0.58 - 0.62 lb-SO2/MMBtu) subbituminous coal consumption in the 2012 policy case as compared to the base case.

State	% Change
Alabama	-88%
Arkansas	-17%
Arizona	-4%
California	-100%
Colorado	-74%
Georgia	46%
Illinois	124%
Indiana	480%
Kansas	85%
Louisiana	-88%
Maryland	70%
Michigan	67%
Minnesota	78%
Missouri	108576%
Montana	-100%
Nebraska	8%
New Mexico	-100%
New York	-98%
Ohio	12%
Texas	-25%
Washington	-79%
Wisconsin	285%
Wyoming	-99%
National	**17%**

Simply put, these results assume that in many western states, including the coal-producing regions of Wyoming, Montana and Colorado, all or nearly all of the currently used very low sulfur coal would be replaced with a higher sulfur product – and that eastern states like Indiana, Illinois, Kansas, Minnesota, Missouri, and Wisconsin can increase their usage by 75 percent or much more. These massive shifts in consumption are not technically feasible due to fuel contracts and transportation constraints, as described in the following section.

These unrealistic coal consumption patterns are likely responsible for the distortion of state budgets and impose significant constraints on the operation of coal units that provide many of the critical grid support services outlined above. Revision of the unit allocations in 2012 is necessary, and supports reconsideration and a stay of the rule's implementation. At a minimum, the Administrator should solicit information concerning units for which infeasible fuel switches were assumed in the analysis supporting the final rule, and provide additional allowances to support normal operation for the initial allocation period.

2. Fuel Supply Constraints and Costs

Reconsideration is also warranted because EPA failed to consider the impact that its reduction of the SO_2 allowance budgets and elimination of interstate trading would have on fuel supply constraints throughout the Transport Rule region. As shown above, EPA projects reductions in usage of about 80 million tons of higher sulfur subbituminous coals, 35 million tons of various grades of bituminous coals, and 5 million tons of lignite beginning in 2012 as a result of the final rule. Shifts of such magnitude in coal deliveries within a few months will disrupt long-term fuel contracts and transportation arrangements, resulting in substantial additional expense not analyzed as part of EPA's cost-effectiveness methodology.

For example, many of AEP's existing fuel and transportation contracts contain minimum delivery commitments that are enforceable through liquidated damages provisions. Since nearly all of AEP's coal-fired facilities are located within states subject to the annual SO_2 program, opportunities to resell the fuel or redirect shipments to facilities outside the region affected by the Transport Rule are limited. Reconsideration is warranted to evaluate the impact of fuel supply constraints on the cost of implementing fuel switches assumed in the final remedy.

In addition, the revised IPM documentation made available in support of the final rule revealed that EPA used EIA Form 423 data on coal purchases to determine the percentage of subbituminous fuels that could be burned at units that currently burn a blend of bituminous and subbituminous fuels. EPA assumes that any unit currently reporting 90 percent or more subbituminous coal on this EIA Form can increase the percentage of subbituminous fuels burned in their units to 100 percent without any additional cost. There are two significant flaws in this assumption. First, EIA Form 423 is used by generators to report coal *deliveries* to units on a monthly basis, not the blend of fuels actually *consumed* at the units. The percentage of a particular coal type delivered to a generating unit can and does vary significantly from month-to-month. Fuel blending typically is performed on site from coal storage piles, which gives the plant operator the flexibility to manage deliveries to accommodate temporary interruptions in production at the mines, transportation issues, or the needs of the generator. The second flaw in this assumption is that increasing the percentage of subbituminous coal cannot be accomplished at zero cost.

For example, the 2012 policy case assumes that all of the units at AEP's Rockport Plant will run on 100 percent subbituminous coal in 2012, based on EIA data showing that 90 percent of the deliveries received at the plant were subbituminous coal during several months in 2008-2010. But the Rockport Units typically consume a 85%/15% blend of subbituminous/bituminous coal. This blend ratio assures that the units operate at or near their design capacity, and that the higher ash and lower heat content of the subbituminous coal does not constrain the units' output. Subbituminous coals also have higher combustible dust hazards, and at very high blends additional fire protection and other modifications are required to address these hazards. The capital costs and impacts on unit output necessary to accommodate a higher percentage of subbituminous coal are unit-specific, and should be accounted for in the IPM inputs to better reflect the feasibility and costs of fuel switching.

At a minimum, however, EPA should correct the effect of this inaccurate assumption by identifying units whose emission allocations are affected by this error, and supplying additional SO_2 allowances during 2012 and 2013 that accurately reflect the degree of fuel blending that can occur without capital expenditures or de-rating of the affected unit.

3. Biomass Use

Based on the IPM outputs, there also appear to be over several hundred coal units that EPA assumes will be burning biomass for a portion of their heat input. There is no easy way to discern the assumed use of biomass in a co-firing application, as EPA does not report these data in either the IPM System Summary file nor in the Parsed File. However, by examining the unaccounted-for heat input, one can begin to identify a number of coal-fired units that EPA assumes may not be burning coal for 100% of their heat input. By reviewing the TR_Remedy_Final.rpe file, we were able to identify at least one AEP unit which is projected as burning biomass for a portion of its heat input, Oklaunion. However, based on a scan of the .rpe file, it is apparent in the modeling results that a great number of other units are also assumed to be using biomass to fulfill a portion of their heat input requirements.

In each of the states in which AEP operates, state agencies typically require performance of test burns to ascertain the impacts of changing the fuel supply for an individual unit. AEP has explored the potential for biomass co-firing at a number of units. In each instance, changes in the material handling equipment would have been necessary, in addition to planning for the delivery and storage of the biomass fuel prior to its introduction into the boiler. Depending upon the volume of material and the methods of delivery, these can require approval from the permitting authorities. In addition, to assure a reliable supply of the target fuel, contracts for its delivery must be negotiated with suppliers. Since most sources of biomass are non-traditional suppliers of woody waste, used oils, and, in some cases, crops, securing a reliable supply of this fuel on a cost-effective basis has been the most challenging part of successfully implementing these changes.

EPA's assumption that even modest increases in use of biomass would be available at hundreds of different locations across the country by 2012 is simply unsupportable. Although the IPM runs limited the amount of this fuel that could be used at any individual source, no consideration was given to the practical restraints on implementing these changes at hundreds of units across the country within the few months available before the 2012 compliance year.

In the IPM outputs for the 2012 final remedy case, Cardinal 3, Clifty Creek 1-6, Clinch River 1-3, Conesville 3, Glen Lyn 5-6, Kammer 1-3, Kanawha River 1-2, Muskingum River 3-5, Oklaunion, Sporn 1-4, Rockport 1-2, Tanners Creek 1-4 and Beckjord 6 (all units that AEP either fully or partially owns or operates) also have some missing coal heat input which is most likely wrongly attributed to biomass. Most of these units are not authorized to burn biomass, and none have the necessary material handling, fuel storage or delivery systems necessary to make its use practicable by 2012. This is a glaring modeling error which affects state budgets and overall program cost. At a minimum, the Administrator should solicit information concerning units for which infeasible biomass utilization was assumed in the analysis supporting the final rule, and provide additional allowances to support normal operation for the initial allocation period. However, given the number and magnitude of the noted errors in fuel supply assumptions, reconsideration and an immediate stay are warranted.

4. Inclusion of Dry Sorbent Injection Systems

EPA projects that 3 GW of capacity within the final Transport Rule will install Dry Sorbent Injection (DSI) technology for compliance, including AEP-owned Clinch River 1-3, Glen Lyn 6, Kanawha River 1-2 and Sporn 1-4 units. AEP does not have plans to install DSI technology on any of these units, and is unconvinced that EPA's assumed SO_2 removal capability can reliably be achieved. Additionally, EPA assumes that fabric filters would be installed in conjunction with the DSI technology, a very costly investment. This assumption of a new control technology to reduce SO_2 emissions was not included in either the original IPM runs done to support the proposed Transport Rule, nor in the updated runs produced in conjunction with the NODA. EPA's assumption that this technology could be used to achieve the required emissions reductions, despite limited actual operating experience within the electric power industry and a complete lack of opportunity for the public to comment on the applicability of this technology for these units, justifies reconsideration of the final rule. At a minimum, units for which a DSI installation was assumed in 2012 should receive additional allocations to support normal operations during the initial allocation period.

5. Low NO_x Burner Use

EPA has concluded that 10 GW of Low NO_x Burners (LNBs) can be installed by 2012. 76 Fed. Reg. at 48,279. "EPA reflects the effects of these installations in the 2012 annual and ozone-season NO_x budgets, which would yield reductions of approximately 28,000 tons of annual NO_x and 14,000 tons of ozone-season NO_x. EPA assumes these controls are cost effective at $500/ton." *Id.* at 48,281. EPA acknowledges that the 6 months available between the issuance of the final rule and the start of the 2012 compliance year is far less than the typical 12 to 16 months for the contractor's portion of the design, engineering, fabrication and installation of these controls, but assumes based merely on two examples that such work can be accomplished in the fall of 2011 and the spring of 2012, so that these controls will be available during the ozone season in 2012. *Id.*

EPA also acknowledges that installation of LNBs will, in most cases, require permitting to accommodate the increase in carbon monoxide emissions that result from the lower combustion temperatures used by this equipment to reduce NO_x formation. *Id.* at 48,302. However, *no allowance* is made to accommodate the applications for, processing of, or receipt of permits prior to commencing construction on these projects. Similarly, no allowance is made for regulatory approvals that might be required by public service commissions or other state or local authorities. *See id.* at 48,281.

AEP's internal analysis of these projects using EPA's own IPM input assumptions for Northeastern Units 3-4 in Oklahoma indicates that reductions achieved through the installation of LNBs would cost more than $1,600 per ton removed. In the final rule, EPA established individual state budgets for ozone season NO_x based not on the results of its NO_x cost curve at $500 per ton, but on the combined run used to analyze the effect of applying all three programs at their respective price breakpoint ($500/ton for seasonal NO_x, annual NO_x, and SO_2 in 2012, and $2400/ton for SO_2 in 2014 in the Group 2 states). This produced an incremental 7,500 tons of seasonal NO_x reductions in 2012, and increased the real cost of seasonal NO_x reductions to $1300/ton in 2012.

EPA provided no justification for this increase in stringency and cost, nor any rationale for ignoring the real time constraints associated with installation of this level of control, and reconsideration is warranted. At a minimum, operators who were assumed to install controls before the ozone season in 2012 should receive an additional allocation for the initial compliance year. (Please note that the example we use above is for a facility in Oklahoma, and we recognize that Oklahoma is included in the supplemental proposal. We encourage EPA to take these comments into consideration as the Agency finalizes that proposal.)

C. FGD Timelines

AEP submitted detailed comments regarding the time required to obtain regulatory approvals, permit, engineer and design, procure materials and construct FGDs, and demonstrated that the average industry experience is well in excess of the 27 months assumed by EPA to support its compliance requirements in the Transport Rule.[12] EPA responded by citing the construction schedules for two new units, and stating its ""belief"

[12] See Exhibit 2, pp. 6-10.

that the imminent deadlines in the Transport Rule will provide the necessary incentive to expedite construction. 76 Fed. Reg. at 48,281.

AEP's experience was supported by numerous other commenters, who also noted that FGD construction schedules must provide sufficient time not only for installation of the actual control equipment, but new stacks (for which the permittee must also perform air quality modeling analyses) and landfill capacity (which requires substantial land acquisition, siting review, and permitting lead time).

EPA also continues to view the Transport Rule in isolation, ignoring the other requirements that will impact this same sector within the same period of time. If EPA's EGU hazardous air pollutant standards (EGU MACT) are finalized as scheduled later this year, the three-year compliance time frame for that program will overlap completely with the time frame required to construct controls to satisfy the Transport Rule. While AEP was projected to complete FGD projects covering XX units at four plants by 2014 under the Transport Rule, AEP has estimated that the combination of the Transport Rule and the EGU MACT will require at least 36 projects at XX plants over the next XX years, in addition to forcing premature retirement of nearly 5,000 – 7,000 MW of capacity.

Reconsideration is warranted on this issue. EPA has acknowledged in the EGU MACT proposal that the three-year compliance time frame provided for EGU MACT is not likely to be sufficient given the competition for qualified labor, equipment, and capital in the electric generating sector. EPA cannot simply ignore the fact that these same pressures will exist during the compliance schedule for the Transport Rule. And while EPA has modeled a "no-FGD" option, the validity of the fuel switching, coal production, equipment performance and cost assumptions underlying that analysis are flawed, as demonstrated above. In addition, the reliability implications of the combined impacts of the Transport Rule and the EGU MACT are likely to be even more severe than those associated with the Transport Rule alone.

AEP respectfully requests reconsideration of the time provided to make additional SO_2 reductions in the Group 1 states. Reconsideration must proceed promptly, however, and the 2014 compliance requirements should be stayed pending completion of reconsideration.

D. New Unit Allocations

Between the final and proposed rule, EPA dramatically reduced the new unit set-aside allocation in Arkansas. The final rule includes a new unit set-aside of only 2 percent of Arkansas's reduced ozone season NO_x budget, a total of 301 ozone-season NO_x allowances, compared to the 500 allowances for eligible new units contained in the proposed rule. EPA changed the method used to establish the allocations and the scope of units participating in the set aside between the proposed and final rule. EPA's method for establishing the new unit set-aside in the final rule for the 2012-2013 allocations is based on a two-step process that examines both the need for a reserve to accommodate "potential" future units (unspecified additions) and "planned" future units (those known units for which substantial progress has been made and which are likely to commence operation during the relevant allocation period). 76 Fed. Reg. at 48,291.

However, EPA's methodology only allocates additional allowances to "planned" units that commence operation between January 2010 and January 2012, a method that ignores the needs of units that are already planned but will commence operation later in 2012 or in 2013. EPA fails to explain how planned units commencing operation during this later period are different from those that will come online by January 1, 2012.

This is particularly troubling because several large and very efficient power plants are scheduled to come online in Arkansas during this period, and should have been considered. A new unit at the Plum Point Power Station commenced operation in 2011 and should have been included in the calculation of an additional new source set-aside in Arkansas. In addition, AEP is constructing a large ultra-supercritical coal-fired power plant, the Turk Plant, which is anticipated to commence operation in October 2012. Turk should have been included in the "planned" new unit allocation. Turk's permitted NO_x emissions alone are over three times the size of the total new unit set-aside, and it is expected to run as a baseload unit during ozone season, making the current set-aside woefully inadequate. This under-allocation presents a situation in which two of the newest and most efficient generators within the state of Arkansas are at risk of exceeding assurance levels due to an insufficient allocation of allowances.

AEP respectfully requests that an additional allocation be made for the new unit set aside in Arkansas that will accommodate the operation of the Turk Plant in 2012 and 2013.

Conclusion

AEP appreciates the ongoing dialog that EPA has maintained since the publication of the final Transport Rule. However, the errors in EPA's data and analyses set forth above demonstrate that there are substantial unresolved issues that preclude effective implementation of the selected remedy within the next few months. AEP respectfully requests that EPA grant reconsideration of the issues identified herein and in the other petitions on file with the Administrator, stay the effectiveness of the final rule, and maintain the CAIR allowances currently in the compliance accounts for CAIR units in order to maintain the continuous improvements in air quality that have occurred as a result of the numerous programs affecting the electric utility generating units across the country. Alternatively, AEP respectfully requests that the effective date of the assurance provisions be delayed from 2012 to 2014, and that the Administrator promptly commence and complete reconsideration and make the other modifications to the program requested herein prior to January 2012.

Respectfully submitted,

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