AEP
AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

Original by Regular Mail
E-mail copy to; a-and-r-docket@epa.gov

EPA Docket Center, EPA West (Air Docket)
Environmental Protection Agency
Air and Radiation Docket and Information Center
Mail code: 2822T
1200 Pennsylvania Avenue, NW
Washington DC 20460

October 1, 2010

Subject: Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone; Proposed Rule

Reference: Docket ID No. EPA-HQ-OAR-2009-0491
FR Vol. 75, No. 147 Monday, August 2, 2010 Notice at 45210

AEP Texas 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, the operating companies of the American Electric Power system (collectively referred to herein as "AEP"), appreciate the opportunity to comment on the "Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone; Proposed Rule" of August 2, 2010 (Proposed Transport Rule or PTR). AEP owns or operates electric generating facilities and serves customers in eleven states. Thus, the operating companies of the AEP system would be directly affected by any regulatory actions applicable to the electric generating unit (EGU) source category, including the Proposed Transport Rule.

AEP is one of the nation's largest electricity generators with nearly 38,000 megawatts (MW) of generating capacity serving more than five million retail consumers in 11 states in the Midwest and South Central regions of our nation. AEP's generating fleet employs diverse energy sources – including coal, nuclear, hydroelectric, natural gas, oil, and wind power. Most importantly, as pertaining to the Proposed Transport Rule, approximately two-thirds of our generating capacity utilizes coal to generate electricity. Given scale and location of these facilities, AEP and its customers are projected to be heavily impacted by this rule.

Background

On July 6, 2010, the U.S. Environmental Protection Agency (EPA or Agency) issued its Proposed Air Pollution Transport Rule, the Agency's most recent attempt at a market-based approach to reduce emissions of air pollutants. The Proposed Transport Rule was published in the Federal Register on August 2, 2010. The proposed rule is intended to replace the Clean Air Interstate Rule (CAIR), which EPA promulgated in 2005, which the U.S. Court of Appeals for the D.C. Circuit in 2008 initially vacated, and then changed its vacatur to a remand that kept the CAIR program in place pending completion of EPA's remand rulemaking. Like CAIR, the Proposed Transport Rule primarily addresses emissions of two pollutants (sulfur dioxide (SO_2) and nitrogen oxides (NO_x)) from electric generating units (EGUs) and is based on the Agency's interpretation and application of section 110(a)(2)(D)(i)(I) of the Clean Air Act ("CAA").

In the Proposed Transport Rule, which is structured as a federal implementation plan (FIP), EPA attempts to redesign CAIR's emissions cap-and-trade system as its proposed response to the decision of the D.C. Circuit in *North Carolina v. EPA,* 531 F.3d 531 (D.C. Cir. 2008). For example, the Proposed Transport Rule: (i) establishes new methods for determining which states should be subject to the program and for calculating statewide emission budgets and unit allowance allocations; (ii) abandons CAIR's use of Title IV allowances for compliance with SO_2 emissions reduction requirements; (iii) creates new NO_x allowance programs that do not involve fuel adjustment factors; and (iv) adopts an aggressive implementation schedule that involves an initial compliance date of January 1, 2012 (May 1, 2012 for the ozone season NOx program), a further SO_2 reduction requirement at the beginning of 2014 for many states subject to the program, and, as a practical matter, a limited role at best for state implementation.

Under the Proposed Transport Rule, states would play a distinctly secondary (or even nonexistent) role in implementation. By framing its program as a FIP and setting deadlines that do not allow enough time for each state to develop its own state implementation plan (SIP) for addressing interstate transport, EPA is effectively preempting state discretion in determining how to meet at least the first (2012) phase of emission reduction obligations. EPA's legal theory for bypassing the states is that, in the Agency's view, they have defaulted on their CAA section 110(a)(2)(D)(i)(I) obligations with respect to the 1997 ozone and fine particulate matter ($PM_{2.5}$) NAAQS and with respect to the 2006 $PM_{2.5}$ NAAQS. But EPA has approved states' plans for meeting those obligations, and the flaws in the CAIR program identified by the D.C. Circuit in the *North Carolina* case were of EPA's making, not the states'. EPA has failed to provide current and specific notification to the states targeted by the proposed Transport Rule of how their current implementation plans fail to meet the requirements of section 110(a)(2)(D)(i)(I).

AEP believes it is particularly important for our company to comment on the relative merits and concerns with various portions of the Proposed Transport Rule. Unfortunately, EPA's Transport Rule as currently written does not appropriately balance environmental and economic objectives. While we commend EPA for retaining some of the flexibility of intrastate and regional emissions trading of SO_2 and NO_x, the timing of the reduction requirements, the relative inflexibility of other provisions of the rule, and the stringency of the emission reductions, particularly as it applies to SO_2, would substantially increase the cost of compliance and could likely have significant adverse impacts on reliability and the regional economy.

AEP participates in and endorses the comments submitted by the Edison Electric Institute, Utility Air Regulatory Group, and the Midwest Ozone Group (MOG).

Comments:

AEP does not believe that the timelines and stringent budgets within this Proposed Transport Rule are necessary. The modeling data developed by the Midwest Ozone Group (MOG) and its Industrial Modeling Coalition used in conjunction with ambient air quality data collected by USEPA show that not only are transport criteria met by the existing CAIR program, but full compliance with the NAAQS targeted by this rulemaking are satisfied for all be a few areas that have ambient concentrations driven by local sources. We believe that EPA should address the specific issues identified by the D.C. Circuit in the *North Carolina* case, while keeping the timing and reductions the same as is defined in CAIR.

The MOG commissioned Alpine Geophysics to perform regular CAMx simulations that examined a 2008 base case along with as business as usual cases for 2014 and 2018. In this exercise, the business as usual case follows the D.C. Circuit's determination in the *North Carolina* case to keep the current CAIR program fully in effect as promulgated until such time as EPA corrects the errors the court found in that rule. That modeling shows similar or better results than the Proposed Transport Rule results in terms of attaining and maintaining the 1997 ozone and PM-2.5 and 2006 PM-2.5 NAAQS, using essentially similar emission inventories.

The MOG modeling shows that by 2018 nearly all areas will be in attainment with the current ozone standard of 75 ppb, not the 85 ppb level used by EPA, with the exception of areas that are part of or adjacent to highly urbanized areas (Bucks County, Pennsylvania, Suffolk County, New York, and Harford County, Maryland). The same can also be shown for PM-2.5 where all but two monitors (Allegheny County, Pennsylvania and Brooke County, West Virginia) that have significant local source impacts are also shown to meet the 35 ug/m^3 standard by 2014 and several other monitors that are close to the limit are significantly impacted by urban emission and have a signature indicative of local source impact (high organic carbon levels) and will not be significantly aided by the reductions from these rules. AEP urges EPA to provide a properly-formulated analysis that demonstrates to the D.C. Circuit that emissions' trading in a regional transport solution is technically supported. The modeling submitted by MOG provides a technical demonstration, absent from the record before the court in the *North Carolina* case, that the emissions trading in the currently-effective CAIR program meets the transport mitigation goals of section 110(a)(2)(D)(i)(I) of the Clean Air Act.

While AEP feels that the stringency of the Proposed Transport Rule is unnecessary, we are also making the following comments on the published proposal. AEP agrees with EPA's selection of the interstate trading option as the proposed remedy option. However, AEP has three major concerns with the Proposed Transport Rule:

- **Unrealistic Deadlines** - The compliance deadlines of 2012 for Phase I and 2014 for Phase II will make it impossible for utilities to comply on time. There is simply not enough time to permit, construct and install Flue Gas Desulphurization (FGD or scrubbers) and Selective Catalytic Reduction (SCR) control equipment or to build replacement capacity (if units are retired) by these deadlines. This is not a matter of conjecture regarding the time needed, as AEP has lengthy experience in the last decade of actual time frames exceeding 3 years to install scrubbers and/or SCRs. EPA needs to provide adequate time for utilities to comply with the rules as well as for states to implement the rules.
- **Flawed Methodology** - The bottom-up methodology used to analyze the impacts of the rules and to determine the degree to which reductions are needed at specific power plants is seriously flawed. At a minimum, EPA must consider the impact of reductions under already existing programs on air quality and not rely on outdated studies of air quality effects to determine necessary actions. Further, EPA must accurately evaluate the cost-effectiveness of controls on utility power plants considering the actual remaining lifetimes of many units is much less than 20-30 years assumed by EPA. EPA must also consider alternative reduction options from industrial and transportation sources which will likely achieve much greater and more cost-effective air quality improvements (both per ton reduced, and even more so per ppb of ozone or PM-2.5 reduced).
- **Incorrect Data** - The NEEDS database lists certain units with inaccurate emission controls. Additionally, the IPM model structure does not take into account all necessary unit specific operating constraints, specifically those relating to fuel suitability. Furthermore, EPA's data on purportedly "actual" costs of scrubbers and SCRs are lower than actual industry and AEP-specific experience.

AEP has organized its comments into three main sections based on the major concerns identified above. The Program Timing section addresses AEP's concerns with actual times required to plan, permit, construct and install controlling equipment in comparison to EPA's compliance deadlines. The Methodology section addresses AEP's key concerns with how the modeling and rulemaking efforts were merged together and makes recommendations for improvements, consistent with the D.C. Circuit Court's decision. The Data and Assumptions section addresses AEP's numerous concerns in the underlying data sets used in development of the rule. The erroneous or inconsistent data points identified have significant impacts upon the structure of the rule, projected costs, allocation of allowances and equity between companies and customers.

1. Program Timing Comments

Phase I SO_2 and NO_x Requirements in 2012 are Too Soon and Infeasible

One of our greatest concerns with EPA's proposed Transport Rule is that the schedule for implementing the new program's more stringent emission caps is too fast. Under the proposal, the Phase I caps apply at the beginning of 2012 and the even more stringent Phase II caps apply at the beginning of 2014.

The 2012 program start date is a major issue for compliance entities as it is anticipated there will be only six to eight months after final rule promulgation until the start of the compliance period. This is not enough time to set up the requisite allowance trading system to accompany the rule. This will create considerable uncertainty as to how the allowance market will function for compliance purposes and lead to excessive speculation and turmoil. Furthermore, the six to eight months is a fraction of the time needed for states to develop their own implementation plans and get them approved. State implementation plans are not only the primary and preferred approach under the Clean Air Act, but also especially vital given the huge financial implications and accompanying decisions that will result from these new regulations. While the EPA claims that the Phase I will require little investment in the way of new controls, its assumption is counterfactual and predicated upon high level modeling and not the actual physical, contractual and financial constraints at these facilities during such a short time frame. This very short time frame is made worse by the constraints placed on emissions trading, assuming that this recommended option is adopted for implementing the reduction requirements.

Additionally, EPA has assumed in setting the 2012 compliance deadline that coal switching could occur by that date and thus drive some emission reductions. While some coal switching may occur, AEP and other large utilities generally procure much of their coal through contracts several years in advance. By the time of final rule promulgation, almost all of AEP's 2012 coal supply will be procured. Fuel switching is therefore an unrealistic model option in 2012, and any post-2012 fuel switching assumed or expected by EPA should take into account existing long term contracts and the full direct and indirect costs of such fuel switching.

Timing of Phase II SO_2 Caps is Too Soon and the Caps are Very Stringent

The SO_2 budget levels in 2014 are significantly more stringent than those in 2012 for about half of the States covered under the Proposed Transport Rule. These States are ones most reliant on coal and that face the major portion of the compliance burden for limiting SO_2 emissions. In particular, the SO_2 budgets in Eastern states which have AEP coal-fired power plants (*i.e.,* Virginia, West Virginia, Ohio, Kentucky and Indiana) are very stringent. The SO_2 tonnages in these states amount to an average emission rate of approximately 0.20 to 0.30 lbs SO_2 per million Btu, which can only be just attained by installing a scrubber. 96.5% is the current maximum level of removal that most retrofit scrubber designs for existing units can reliably and consistently achieve on an annual basis. The proposed Phase II budget levels would require most of AEP's coal-fired power plant units in these states to install FGD, switch to natural gas, or retire early in order to comply. A 2014 deadline for a second phase of SO_2 reductions further complicates the planning and logistical challenges for compliance.

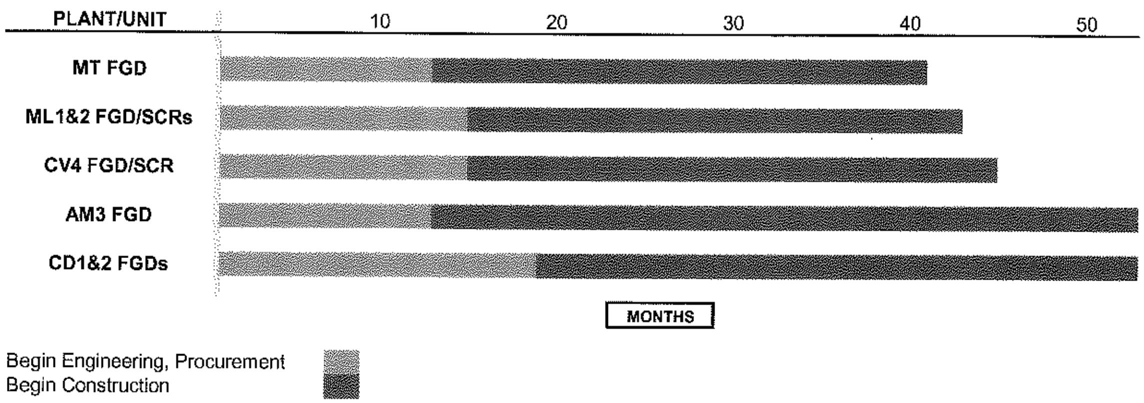
Retrofitting additional scrubbers by the beginning of 2014 throughout the Phase II states is infeasible given that, in our experience, the typical time frame to design, permit, fabricate, and install such major pollution control equipment has taken more than three years. AEP has extensive experience in the retrofit application of FGD technology on coal-fired boilers, having managed the overall engineering, design, permitting, procurement, construction and commissioning of scrubbers on over 10,000 megawatts of capacity. Similarly, AEP has managed the installation of SCRs on approximately 14,600 megawatts of generation, which when combined, provides us a wealth of knowledge related to schedules and resource requirements to implement environmental controls. Couple this with our management of past and current landfill construction programs and we become a uniquely qualified source of experience and expertise in these areas.

EPA assumed that it takes approximately 27 months to build FGD equipment and approximately 21 months to build SCR equipment. Based on these timelines, EPA assumed additional FGD controls could be installed by 2014 and thus SO_2 emissions could be further reduced in 2014 due to the technology. AEP's experience outlined below does not support an assumed 21 and 27-month construction duration for a typical SCR and FGD installation project, respectively. In order to more accurately represent the overall required FGD project duration, one must consider a minimum of three separate and distinct components that influence the time required for the overall project: 1) the FGD construction; 2) landfill construction; and 3) stack construction. Each of these three separate components is discussed below.

Engineering and Construction of the FGD System takes up to 52 months to complete

The complexity of the "construction" of an FGD System is very site-specific which strongly influences the time required for installation. The Front End Engineering & Design (FEED) work required to determine the feasibility of the project, to support the technology selection, and to establish the high level cost estimates requires a 6 to 8 month effort. Following the completion of the FEED effort, and assuming the decision is made to proceed with the project, an additional 6 to 8 months of preliminary engineering is required to advance the maturity of the design to the point that long lead time major equipment orders can be placed and the initial site preparation and underground relocation work ("construction") can commence. Based upon our experience to date and our analyses of the current resources, the subsequent continuation of the detailed engineering for the project, performed in parallel with the site FGD construction effort, including startup and commissioning of the new FGD System, will take 28 to 40 months. This results in an overall project duration from initiation to "first gas" through the new FGD system of 42 to 52 months. The shakedown, debugging, and optimization process after "first gas" through the new system can take up to 6 months. The below chart depicts 6,200 megawatts of our most recent retrofit experience: Mountaineer and Amos Unit 3 (1,300 megawatts each), Mitchell 1&2 and Conesville 4 (800 megawatts each) and

Cardinal 1&2 (600 megawatts each).

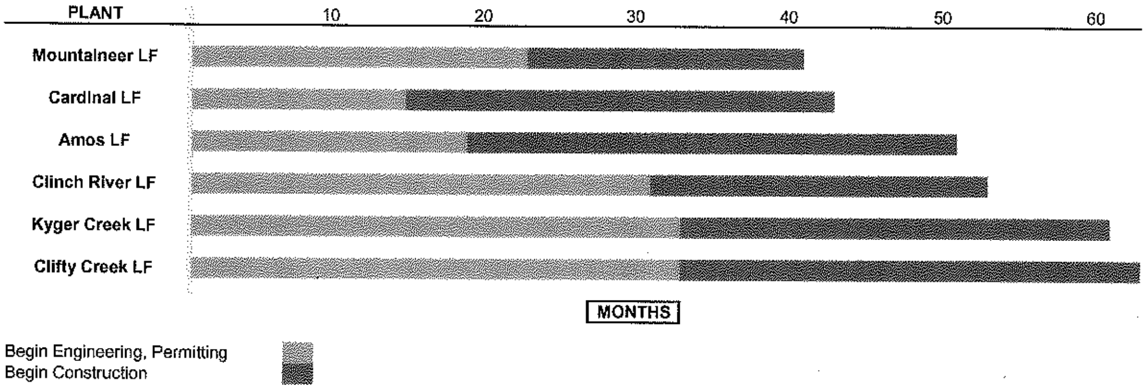


Engineering and Construction of the Landfill takes on average 54 months to complete

Assuming no land acquisition is required, a nominal 20-25 acre landfill, typical of those required for a new FGD system, requires 54 months to complete. (Land acquisition could add 6-12 months to the overall duration.) The first 19 months are utilized to generate the conceptual layout of the proposed landfill, to then perform a detailed site investigation including soil borings, monitoring well(s) installation and barrow area determinations and then to perform the landfill engineering and design in sufficient detail to support the permit application process requirements. Following the submittal of the applications, the review and subsequent approval cycle for the Air Permit, the Corp of Engineers 401 and 404 permits, and the Solid Waste Permit required to commence landfill construction consumes the next 17 months. The next 18 months is spent actually constructing the haul roads, barrow areas and landfill cells to the point of being available for first disposal use.

A nominal 20 to 25 acre landfill is typical in size of those required for 5 years of capacity for the disposal of an FGD system byproduct. When a new landfill can be sited adjacent to an existing landfill, the time required to generate the conceptual layout of the proposed new landfill, to then perform a detailed site investigation including soil borings, monitoring wells and barrow area determinations and then to perform the landfill engineering and design in sufficient detail to support the permit application process requirements is 10 to 12 months. Following the submittal of the applications, the review and subsequent approval cycle for the Air Permit, the COE 401 and 404 permits and the Solid Waste permit required to commence landfill construction can consume the next 6 to 10 months. This cycle duration is highly dependent upon the number of simultaneous applications within the agencies and their staffing levels, and the unpredictable extent of third party opposition. Actual construction of haul roads, barrow areas and landfill cells to the point of being available for first waste disposal results in an overall duration of 40 to 42 months, as shown below from our actual construction of the Mountaineer Plant and Cardinal Plant Landfill projects.

When a new landfill must be located remote to any existing landfill, the overall project schedule is extended by an additional 10 to 20 months, as shown below from our actual construction of the Amos Plant, Clinch River Plant, Kyger Creek Plant and Clifty Creek Plant Landfills. The time required for landfill engineering, permitting, and construction could be lengthened substantially by EPA's coal combustion residuals rule proposed on June 21, 2010 (75 Fed. Reg. 35128).

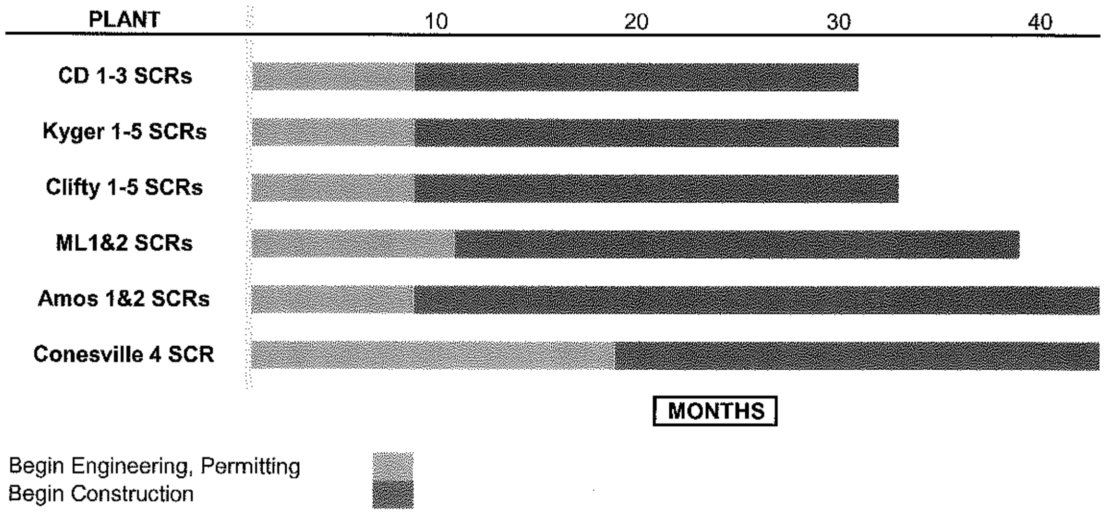


Engineering and Construction of the Stack takes on average 46 months to complete

In addition to the FGD and Landfill construction durations, it should be noted that a typical wet-FGD concrete stack with a single FRP liner, built to GEP height, can take 44-48 months to construct, dependent upon State permitting requirements. (Certain States allow construction of the stack foundation prior to receipt of the air permit.) The first 8 months are consumed performing the air modeling to determine stack location and height. Along with the stack information, additional engineering information needed to support the air permit application is compiled. Review and final approval of the air permit typically takes the 12 months. Upon receipt of the air permit, the stack foundation installation can be accomplished in 4 months (absent severe weather conditions) followed by 24 months required to slip form/pour the concrete shell and install the stack liner. These durations are based upon our actual construction of eight such stacks over the past six years.

Engineering and Construction of the SCR takes up to 42 months to complete

Very similar to an FGD project, the complexity of the construction of an SCR System is also very site-specific, which can significantly effect the time required for installation. The Front End Engineering & Design (FEED) required to determine the feasibility of the project, to support the technology selection, and to establish the high level cost estimates requires a 4 to 6 month effort. Following the completion of the FEED effort, an additional 4 to 6 months of preliminary engineering is required to advance the maturity of the design to the point that long lead time major equipment orders can be placed and the initial site preparation and underground relocation work can commence. In some instances, the analyses and final determination of steam generator pressure part modifications to facilitate SCR operation can extend this engineering effort up to an 18 month duration. Again, based upon our experience to date, the subsequent continuation of the detailed engineering for the project, performed in parallel with the site SCR construction effort, including startup and commissioning of the new SCR System, will take 24 to 36 months. This results in an overall project duration from initiation to "first gas" through the new SCR system of 32 to 42 months. The below chart depicts approximately 8,000 megawatts of our most recent retrofit experience: Cardinal 1&2 (600 megawatts each), Cardinal 3 (635 megawatts), Kyger Creek 1-5 (215 megawatts each), Clifty Creek 1-5 (215 megawatts each), Mitchell 1&2 (800 megawatts each), Amos 1&2 (800 megawatts each) and Conesville 4 (800 megawatts).



Other factors affecting the engineering and construction schedules

In addition to the front end permitting schedule constraints, several other factors strongly influence the overall schedule of work and project durations. During these challenging economic times and the inherent downturn in the number of large, capital intensive projects, domestic suppliers of environmental equipment, materials and services have scaled back production and skilled resources in an attempt to maintain their long term viability. Contrary to the belief of some that this situation would make major components and material more readily available, economic stagnation and uncertainty lead suppliers to scale back, which results in longer lead times for critical system components. As examples, the lead time after receipt of order for limestone ball mills for FGD systems has increased from 70 weeks in 2006 to 90 weeks in 2011. Major electrical transformers are currently quoted at a 40-48 week delivery. Specialty alloy metals necessary for wet FGD vessel fabrication currently require a minimum of 32 weeks for delivery of the raw materials to the fabricators so that they can begin their manufacturing work. When numerous Utilities are forced to move to market simultaneously seeking the same components in a severely constrained timeframe, lead times for practically all significant system components will be further exacerbated.

With today's era of high unemployment, one could surmise that labor availability should not and will not be a constraint to the timely execution of FGD and SCR projects. However, it should be understood that highly skilled labor in specific areas of expertise are required to construct these complex systems. Not every Union Boilermaker can weld exotic metals. In fact, only slightly more than half, approximately 55%, of the union members are currently certified to perform this task. Similarly, FGD systems utilize a significant quantity of Fiberglass Reinforced Plastic (FRP) piping within the processes, which requires unique skills to perform section-to-section joining. Only 15% of the total available union pipefitters are currently certified to perform this task. Numerous other highly specialized skills are required of other individual crafts, and similar availability statistics are valid.

Furthermore, this schedule does not take into account the need for all controls to be permitted, engineered, contracted and constructed simultaneously. AEP acknowledges the total amount of retrofits is likely to be on a scale similar to what was achieved in preparation for compliance with CAIR. Unlike CAIR, the Proposed Transport Rule does not provide the timing for a phased approach to construction given the inability to utilize an existing allowance bank and the proposed tighter timeline for compliance. This means that every unit undergoing a retrofit would have the same timeline for engineering, procurement, construction and operation and thus be concurrently relying on the same specialized segments of the required labor force and material suppliers, greatly straining resources.

In addition to any PSD or state air quality permitting, some state regulations require obtaining public utility commission approval in the form of a certificate of need. These are issued for projects required by regulation and in some instances (i.e. Kentucky), must be issued prior to initiating construction. The process to obtain the approval includes approximately 6-months to prepare the application then an additional 4 to 12 months (depending on the jurisdiction) for the Commission to evaluate the application, obtain public comment and process the order. The application includes detailed cost estimates that are only available after engineering is complete. Where the certificate is needed prior to initiating construction, an additional 4 to 12 months will be added to the engineering time estimates above.

Simply put, EPA needs to provide more time for the full implementation of the Proposed Transport Rule. AEP recommends EPA keep in place for at least several more years the existing CAIR program. The SO_2 and NO_x reduction levels of the CAIR program were set at levels that EPA determined were appropriate to remedy interstate transport problems for both the ozone and fine particulate matter standards. Under this approach, Phase I of the Proposed Transport Rule would not begin until 2015. This schedule would provide additional time for companies to install the new control equipment to meet additional reduction requirements of the Proposed Transport Rule and for States to adopt and begin to implement this new control program. It would also allow EPA time to consolidate and coordinate the several active rulemakings affecting the decision to retire versus investing more in existing generating units for which the costs of the Proposed Transport Rule are most difficult to absorb.

Furthermore, the proposed timeline for implementation is inconsistent with past multi-pollutant reduction programs. Congress, for example, provided almost a decade to implement in two phases the SO_2 and NO_x reductions mandated under the Acid Rain program. Similarly, EPA established a two-phase program for achieving the reduction obligations under the CAIR program. The Phase I deadlines for CAIR allowed almost five years from promulgation of the final rule until the first compliance year for SO_2 and almost four years for NO_x. Similarly, EPA adopted the NO_x SIP-Call program in September 1998, allowed States a full year until September 1999 to submit implementation plans, and did not apply the NO_x control requirements until May 2003, over 4-1/2 years after EPA promulgation of the final rule.

2. Methodology Comments

Aside from our preference to keep the budgets and timelines the same as the existing CAIR program, the proposed remedy option which includes interstate trading of allowances is highly preferred to the other alternative approaches proposed by EPA. The main reason for this preference is that economies of scale are lost when taking a smaller (i.e. state or unit level) approaches to emissions trading or averaging, which will ultimately drive up cost to customers and increase the risk of stranded or misplaced investments. Secondly, administration of the alternative approaches may be more challenging by creating additional allowance markets and/or limitations which need to developed, implemented and monitored. AEP agrees with EPA's selection of the interstate trading option.

IPM Modeling Approach and Inventory Development

AEP has serious concerns with the bottom-up approach used by EPA in apportioning reductions to states and specific units as this requires that both the data and modeling assumptions be highly accurate to ensure an optimal outcome. However, in the case of this rulemaking, the data and assumptions are not representative of the actual economic and operating conditions of the electric generating fleet. Employing a methodology which specifies budgets and allocates allowances on the basis of speculative modeled reductions will lead to costs much higher and disproportionate than optimally needed.

The modeling support for the Proposed Transport Rule does not take into account the reductions that are occurring under the current CAIR program in the absence of this rulemaking. CAIR continues to be in effect until further regulations are promulgated and utilities are currently factoring this into their planning process. Additionally, the IPM modeling did not contemplate the myriad of other regulations (e.g. coal combustion residuals, hazardous air pollutants, cooling water intake) that EPA is currently developing that affect the same electric generating units subject to the Proposed Transport Rule. Planning decisions do not occur in isolation within the electric utility sector, particularly those relating to retirement and retrofit decisions. Given EPA's schedule for rule promulgation, it is arbitrary and irrational to base a rule and allocation system on modeled reductions that do not take into account the effects of the full suite of related new regulations which are currently proposed or publicly announced and soon to be proposed by EPA. AEP and all other utilities must take into account potential outcomes for new regulation in the real world planning process and EPA's modeling efforts should be revised to take into account likely regulatory outcomes as well. As a result of EPA's artificial and myopic IPM modeling approach, combined with data and assumption errors, the IPM modeling relied upon by EPA dramatically underestimates the amount of coal unit retirements due to the proposed rule. Accompanying these coal units retirements will be lost jobs, lost tax revenue and higher energy prices, all presenting major obstacles to an economic recovery. These enormous indirect costs of the Proposed Transport Rule have been arbitrarily ignored by EPA in formulating its proposal.

Additionally, the complexity of the model makes it impossible to review the accuracy of all inputs and outputs of the model with the level of scrutiny required given the enormous financial implications of this model. This frustrates the ability to meaningfully comment on the true basis and purpose of EPA's proposal. Furthermore, EPA has indicated its intention to continue changing the NEEDS database and IPM modeling inputs and outputs without adequate notice and opportunity to comment on those ongoing changes. Therefore, AEP requests any interim model updates which include the incorporation of data corrections or new information be released publicly upon completion to ensure they can be reviewed for accuracy. Additionally, AEP requests that a full suite of IPM results be released on an individual unit basis and not just through the parsed file and grouped model outputs, with an adequate opportunity for review and comment.

The Transport Rule Drastically Limits the Use of Banked Allowances, Resulting in Higher Than Necessary Costs

In the currently-effective CAIR program, EPA currently incentivizes power plants to reduce SO_2 and NO_x emissions more than required in a given year and save or "bank" these emission allowances for use in a later compliance year. Emissions banking allow companies to comply at a lower overall cost because very high cost reductions and expensive pollution control equipment can be delayed until the most optimal time frame by utilizing banked allowances. More importantly, banking provides a net environmental benefit, because more emission reductions and hence environmental improvement occurs sooner.

Under the Proposed Transport Rule, EPA has proposed an entirely new allowance system that would eliminate the use of previously banked Title IV and CAIR SO_2 allowances after the end of 2011. As a consequence, the market price of SO_2 allowances has dropped to nearly zero and the SO_2 market has been effectively eviscerated. In effect, electric companies and their ratepayers and various market participants who have funded extra emission reductions and environmental improvement through advanced pollution control investments over the past several years have been penalized billions of dollars.

To minimize these adverse impacts, AEP recommends that EPA extend the current CAIR rule for several more years before beginning Phase I of the Proposed Transport Rule and allow for banked allowances to be used during this time period. The use of banked allowances could help smooth the transition to any tighter emission caps under a new Transport Rule, substantially reduce the costs of compliance, and help ameliorate unit retirement and system reliability concerns. Also, the continuation of the CAIR program will ensure progress to attaining the air quality goals under the Clean Air Act.

This is confirmed by the fact that the SO_2 and NO_x reduction levels of the CAIR program were set at levels that EPA determined were appropriate to remedy interstate transport problems for both the ozone and fine particulate matter standards.

IPM Modeling Outcomes

In reviewing the various sensitivity cases run using both the older and new version of IPM, AEP is often confused by the resulting model outputs as it pertains to the operation of our generating fleet. For example, in the updated 2012 base case (new IPM v.4.10 Runs) SCRs were listed as installed at Pirkey, Welsh 2-3 and Rockport 1-2 units. While AEP does face some NO_x constraints at Rockport due to the NSR Consent Degree with EPA, it is not projecting additional SCR installations in the near-term. Additionally, Pirkey and Welsh are not subject to any existing NO_x emission constraints and it is unclear why the model would be selecting SCRs as economic control technologies under a business as usual scenario. Furthermore, these SCRs do not appear to be achieving 90% removal in the policy runs, so it is unclear why they are being added. Additionally, the IPM v.4.10 results show SCR installations at Kammer 2-3 and Clinch River 1-3 in the 2014 policy case which are also puzzling. AEP requests that EPA look into the full rationale behind these illogical modeling results and correct any underlying data or modeling errors. These modeling and/or input errors ultimately manifest themselves in the budget development process. As a result, within the proposed Rule, projected base case SCR installations resulted in the NO_x budgets for several AEP units being arbitrarily reduced.

EPA should utilize the most recent approved CAMx Model Version for its Proposed Ambient Air Quality impact analyses

EPA used version 5.01 of the Comprehensive Air Quality Model with Extensions (CAMx) as described in the Technical Support Document for the Proposed Transport Rule – Air Quality Modeling that discussed work performed starting in early 2009 and continuing until the spring of 2010. Version 5.01 of CAMx was the current version of the model at the time the exercise was initiated. Due to enhancements in the vertical transport algorithms that were implemented in version 5.20 of the model, differing results may exist when replication type studies are performed. AEP recommends that modeling relied upon in support of the proposed rule utilize the most current version of the CAMx Model.

The Analyses Supporting the Transport Rule do not Meet the Requirements of the Court Decision Requiring a Full Impact Analysis

EPA has failed to fully examine the impacts of the utility sources in a given state on downwind nonattainment areas. This is important since the control program embodied in the Proposed Transport Rule is solely focused on utility sources while the impacts on downwind areas are based on all sources in the state. When EPA developed the NOx SIP Call Rule in the late 1990's, the analysis performed did take into account all source categories and the rule regulated emissions from all source categories. Further, the states were given some discretion in how the final budgets were distributed to sources, so long as the overall budget was met.

In the Proposed Transport Rule, EPA assumes that a single source category is capable of resolving a state's contribution to downwind nonattainment and maintenance, and should exclusively bear the entire burden of mitigating that impact, even though it has used all source sectors to determine impacts. Making a single source category effectively responsible for resolving the downwind significant transport contribution is fundamentally unfair and technically flawed as shown using data developed by both EPA and the Midwest Ozone Group (as described above). In addition, MOG modeling also demonstrates that the trading program embodied in the existing CAIR program, with a complete and proper technical analysis, can cure the defects in the record found by the D.C. Circuit in the *North Carolina* case.

EPA Failed to Fully Analyze the Available Modeling Output to Determine the Effectiveness of the Transport Rule Remedy

In performing its analysis of the results of the CAMx modeling, EPA has failed to completely utilize the information in the output data. In analyzing the $PM_{2.5}$ modeling data, EPA appears to have properly reconstructed the total mass from the constituent species. However, EPA appears to have then completely ignored the speciated concentrations to determine the potential effectiveness of the solution in the Proposed Transport Rule. EPA came to an erroneous conclusion that all downwind areas can significantly benefit from large utility reductions in all upwind areas where a given state triggers the 1% impact threshold. There are many areas where the total benefit of the utility SO_2 and NO_x reductions will be much less than those that could be achieved from other source categories due to Organic Carbon being much larger contributors than are sulfate and nitrate species. AEP urges EPA to fully utilize the capabilities of the Particulate Source Apportioning Technology (PSAT) algorithms in CAMx. In performing its analysis, EPA could easily develop a series of PSAT runs that would have examined a subset of states in each simulation.

This approach requires more simulations, but the benefits doing them far outweigh the cost of the extra CPU time involved. Such relevant simulations will identify relative contributions of particular sources and identify areas that need local controls to demonstrate attainment even if the out-of-state transported contribution was zero.

Comparison Modeling Supports Attainment using the existing CAIR Regulations

MOG and its Industrial Modeling Coalition commissioned Alpine Geophysics to perform regular CAMx simulations that examined a 2008 base case along with as business as usual case for 2014 and 2018. In this exercise, the business as usual case takes the correct legal interpretation of the final order of the DC Circuit Court of Appeals in the CAIR case that the rule is still fully in effect as promulgated until such time as USEPA corrects the errors the court found in that rule. In examining that modeling, the results show similar or better results than the Proposed Transport Rule results, with essentially similar emission inventories based on different base years.

The MOG modeling shows that by 2018 nearly all areas will be in attainment with the current ozone standard of 75 ppb, not the 85 ppb level used by USEPA, and with the exception of areas that are part of or adjacent to highly urbanized areas (Bucks County, Pennsylvania, Suffolk County, New York, and Harford County, Maryland) or have known local issues (Allegheny County, Pennsylvania and Brooke County, West Virginia) demonstrates that the CAIR pathway with its unfettered trading, that the court ruled was not sufficiently justified, works equally well as the far more costly program proposed by USEPA in the Transport Rule. AEP supports providing a properly formulated analysis similar to that developed by MOG that would demonstrate to the Court that its concern about emissions trading in a regional transport solution is not well founded. The modeling submitted by MOG should offer a foundation for such a demonstration.

USEPA has also failed to recognize that its existing rules and programs for interstate nonattainment areas apply to several of the previously referenced counties that are shown to not reach attainment. These processes, which have been in existence for at least 20 years call for the states directly involved in the nonattainment area to work together to solve the issue. A transport rule helps these areas be assured that the problem is indeed local, and the analysis above shows that this criteria is met.

Budget Allocations and Equity

The allocations as detailed in the proposed remedy are based on the lower of historical or forecast emission levels in 2012 and forecast emissions in 2014. These allocations take into account modeled control equipment installations, dispatch changes, and fuel switching. This system sets a new precedent for a cap-and-trade program by allocating based on what a computer model calculates to be economic. This takes the modeling logic one step too far, given the considerable uncertainty surrounding the economics of utility system future planning decisions. While modeling could be used to specify state or regional permissible emissions, the model outcomes should not be used to drive allocations at the unit level. Rather, unit-level allocations should: 1) be determined by the host states through a state implementation plan; and 2) be based on historical emissions. Taking historical emissions into account is much more equitable in that it does not penalize companies who have invested heavily in controls in advance of future regulations.

AEP is disproportionately affected by the proposed budget allocation methodology as a result of both projected controls and incorrect data. As an example, initial EPA modeling of the interstate trading option indicates that 5.7 gigawatts electric generating capacity within the AEP eastern fleet would install FGD systems as a result of the rule, or 40% of the projected FGD installations from the entire Proposed Transport Rule program. In other words, 40% of the burden of reductions (as dictated by commensurately decreased allocations) for the program has been placed on AEP and its customers even though it is responsible for well less than 10% of covered source emissions, and virtually zero of the contribution to predicted pockets of nonattainment remaining after implementation of the current CAIR program and other existing regulatory requirements.

AEP is also concerned with the use of the lower of historical versus modeled emissions and the discrepancies this has caused. The historical data used for 2012 SO_2 budget development are from the years 2008-2009. Late 2008 and early 2009 happen to coincide with the longest and deepest economic recession since World War II, and represent one of the lowest periods in recent history of utility power plant utilization. Additionally, emissions during this period were exceptionally low as high cost uncontrolled units did not run. Thus, using the portions of 2008 and 2009 as a heat input basis for state and unit level budgets is highly punitive and arbitrary.

Additionally, this budgeting method is punitive to units which had an outage to install controls (as AEP was required to do at a number of its units under its NSR Consent Decree with EPA) which reduced heat input relative to other periods. Furthermore, subsequent corrections to emission rates based on projected control installations is also inaccurate because installations dates are rounded to the nearest years and thus don't consider partial years of operation, resulting in an additional haircut.

Given the aforementioned issues, a more representative historical time perspective should be used to set 2012 SO_2 budgets. We would recommend a three year average from 2006-2008 to capture more typical plant operation. Furthermore, any corrections to unit emission rates for controls should: a) take into account more realistic performance expectations (see NEEDS FGD Removal Assumptions comments); b) adjust for higher sulfur coal use with FGD installations; and c) take into account only partial year operation of control equipment.

Variability Assessment and Assurance Provisions

The assurance provisions attempt to address the D.C. Circuit Court's concern that emission reductions must be guaranteed to take place within upwind states. However, the proposed approach is flawed in that intrastate trading and banking will be severely limited by the lack of compliance flexibility when adhering to state-specific limits. AEP recommends expanding and refining the variability provisions to remove arbitrary restrictions and allow economic solutions. We do not believe assurance provisions should be expanded for use in 2012-2013. We recommend that proposed assurance provisions should be either removed or substantially modified.

The assurance provisions will cause vast differences in state allowance markets as the majority of allowances can only be used within the state to which they were originally allocated, as trading for out of state allowances and exceeding state level allocations in a given year (plus variability limits) will result in significant penalties. We also have significant concern that owners can be held liable for a state exceeding the variability limit if their emissions exceed their plant level budget. This is fundamentally unfair as the flawed modeling and budget system is thereby dictating what actions individual plants must do to remove any chance of penalization in case of a state exceedance. This will dramatically raise the costs of compliance. AEP urges that any assurance based penalties or remedies be handled through a state implementation plan process where liability and equity can be better addressed.

AEP recommends that the proposed one year limit be removed from the rule in favor of a broader three year average, which can provide added flexibility while still achieving the emission reduction goals. However, in the case of retention of either a one year or three year limit, we suggest expanding the limits for variability. Artificially excluding certain years in the baseline calculations for the variability analysis is arbitrary and punitive. 2000 and 2001 were excluded because EPA concluded these were "large, uneven changes in annual heat input from fossil units for some states." In fact, these years were a testament to the variability that can be inherent within the electric generating fleet, policy driven or not. Those two years, along with 2009, which was used in other portions of the rulemaking, should be also included in the variability analysis. However, in absence of a calculation revision, the one year variability limit for all states should be increased to reflect the variability of the most variable state (in the case of the proposed rule calculation, 28%).

Additionally, there was no evidence given supporting EPA's conclusion that heat input variability should serve as a proxy for emissions variability. Generally speaking, emissions can be more variable than heat input as units with full environmental controls tend to be baseload units that run regardless of electric demand. Conversely, uncontrolled units, which are responsible for the bulk of emissions, tend to cycle based on electric demand and thus are subject to greater variation from year to year. In other words, variability in heat input is not linearly correlated with the variability in emissions. EPA needs to revise the variability assessment to take into account increased emission variability.

Another recommended way to broaden the assurance provisions and allow for more economic decisions would be to provide that assurance be viewed on a more pure geographic basis that does not reflect arbitrary state boundaries. As an example the Ohio River serves as partial state boundary for Ohio, West Virginia, Kentucky and Indiana and a large amount of coal fired generation resides on both sides of the river. A plant on one side of the river could be severely impacted by the assurance provisions in one state forcing uneconomic reductions based on its unit-level budget, while a unit on the other side of the river might be able to make a economic reductions at a lower cost and have the identical impact on air quality, but will not do so due to its unit-level budget and lower state emissions. Thus, trading of "state emissions" as counted toward the assurance provisions should be examined as well.

PSD Permitting

EPA concludes in the proposed rule that it is "very unlikely" that pollution control projects would cause greenhouse gas (GHG) emission increases in excess of the PSD emission thresholds in the Agency's June 2010 GHG Tailoring Rule. AEP disagrees with this assessment. As an example, the use of limestone wet FGD systems will increase CO_2 emissions through the plant stack as CO_2 is liberated during the conversion of limestone to calcium sulfate or calcium sulfate. In addition, parasitic load requirements associated with the wet FGD operation (about 3% of output) will further increase GHG emissions levels per unit output. Without a pollution control exemption, a scrubber project could be deemed a non-routine physical or method of operation change for which a detailed emission increase and causation assessment could be necessary. Moreover, such scrubber projects could trigger PSD due to the likely increase in GHG emissions resulting from the scrubber conversion process and increased coal used to generate the extra electricity necessary to operate the scrubber, even assuming the unit operated at existing production levels. In addition, a higher unit dispatch associated with more favorable market economics after an FGD installation could be potentially used as another basis for evaluating the PSD implications of the proposed project. Even if an electric utility can document that the scrubber project has not resulted in a significant GHG emissions increase (which will likely not be a straightforward task), it may be necessary to notify the permitting authority of the proposed project and demonstrate to permitting authorities satisfaction that PSD will in fact not be triggered pursuant to the "reasonability possibility" requirements of existing PSD regulations. Viewed in this context and given the nascent nature of this PSD process as applied to GHG emissions, the permitting timeline for new FGD installations could be greatly extended and subsequently push out the time period in which new controls can actually be installed.

There are multiple ways EPA can craft an appropriate PSD/NSR exclusion for Transport Rule-driven emission control projects. EPA could provide a special definition of baseline actual emissions for such projects (such as the product of maximum actual hourly emission rates for any regulated pollutant multiplied by the maximum actual 12-month heat input for the electric generating unit in question) or a causation determination tied specifically to the Transport Rule (that the Transport Rule rather than the measures undertaken to comply with it are the predominant and relevant cause, for NSR non-applicability purposes, of any emission increases associated with such compliance measures). EPA also has discretion to interpret the term "stationary source" in the definition of "modification" in Section 111(a)(4) of the Clean Air Act that does not impede compliance with timeframes and targets in the Transport Rule.

The Transport Rule Provides No Certainty Regarding Future Reduction Requirements for SO_2 and NO_x Under Currently Planned EPA Rules

EPA has noted in the proposed rule that it plans to further revise the rule and tighten the utility SO_2 and NO_x emissions caps in future rulemakings in order to meet its new fine particle and new ozone standards. Without knowing what levels of reductions will ultimately be required and by when, the investment planning process for the current Proposed Transport Rule is completely untenable. The risk of stranded or unnecessary pollution control costs increases dramatically. Such uncertainty also increases the probability that coal power plant units will be prematurely retired in order to avoid these investment and rate recovery risks. Given the equally effective transport mitigation resulting from the current CAIR program as compared to the Proposed Transport Rule, as demonstrated by the MOG modeling described above, EPA should not change the current

CAIR program until after the transport constraints resulting from the upcoming ozone and PM-2.5 NAAQS revisions are determined by EPA.

Units should be issued allowances in perpetuity to avoid reshuffling of "deck" each time standards are tightened. Utility investments occur over time horizons of 20 to 60 years. Trying to plan in the wake of uncertain standards will quell economic investment and emissions reductions as well as drive up consumer electricity prices. Utilities need certainty that future policy will be based on past precedent to make sound investments. As such the Proposed Transport Rule should contain a concrete pathway as to how future NAAQS will be incorporated into this system.

EPA's Economic Analysis is Flawed and Deficient in Justifying the New Transport Rule

As a general matter, EPA's analysis fails to account for the impact of multiple uncoordinated rules and policies on the investment decisions being made at coal-fired power plants. As noted earlier in this statement, in addition to the proposed Transport Rule, coal-fired power plants face a yet to be determined set of additional SO_2 and NO_x reductions to meet new ozone and fine particulate standards, future mercury and hazardous air pollutant rules, recently proposed ash disposal rules, possible water rules and of course the prospects of the regulation of greenhouse gases under either existing Clean Air Act authorities or federal climate change legislation.

The impact of investments and additional operating costs that are needed to comply with all of these EPA rules and regulations in addition to the proposed Transport Rule is substantial and should be factored in, specifically when considering the retrofit pollution control versus retirement or conversion to gas decision. It is evident that EPA did not do this. In fact, EPA only predicts an additional 1.2 Gigawatts of retirements across the United States due to this rule. AEP alone projects it may have more retirements than EPA's projection for the U.S. in the 2014-2015 time frame.

EPA Should Consider Effects of Current and Future Multi-Pollutant Regulation

The combination of EPA's proposed transport rule and multiple other new air pollution regulations will likely result in a series of relatively inflexible and stringent air pollution regulations with inadequate timelines and high costs. As already noted, in addition to high costs borne by our electricity customers, these rules could also result in many premature plant retirements. This is turn would mean an attendant loss of skilled local jobs in some of the poorest rural counties in industrial states that are still reeling from the effects of the recession.

We expect this transformation of our coal fleet to continue in the coming decade. In addition to EPA's Proposed Transport Rule, we currently have requirements to reduce SO_2 and NO_x emissions further at units that are regulated under the Clean Air Visibility

Rule. We are also moving forward with emissions reduction projects to meet our obligations under the consent decree that AEP entered into with EPA and other litigants related to the New Source Review provisions of the Clean Air Act. While considerable uncertainty exists over the timing and form of other future regulations, we know that EPA is actively pursuing additional programs to reduce emissions, including a new rule to address mercury and other hazardous air pollutants, and the establishment of more stringent national ambient air quality standards. Although we are committed to working with EPA in the development of future control requirements, we have concerns about the time frame for compliance with these multiple and overlapping programs, as well as the stringency and structure of the underlying regulatory requirements. Some of those concerns are:

- The cumulative costs of multiple requirements and their impacts on our customers;
- Immediate deadlines that do not take into account the need for economic recovery in our service territories;
- The risk of stranded investments that may result from installation of expensive pollution control equipment in order to meet near-term environmental regulations which are effectively overridden by future EPA standards;
- Lack of coordination of the control requirements imposed under future regulatory programs;
- Potential adverse impacts on grid reliability due to wide-scale unit outages required to install emission controls as well as a large number of unit retirements within a short compliance time frame;
- The significant new investments that may be required by non-air environmental programs including EPA's recently proposed rule for disposal of coal combustion by products, EPA's revisions to cooling water intake rules, and its initiative to update its steam-electric effluent guidelines; and
- The potential investments required to meet new EPA greenhouse gas regulations and/or potential new federal climate change legislation.
- This cumulative cost exposure is raising significant concerns about the economic viability of a large number of existing coal-fired units, as well as potential impacts to grid reliability and imposition of substantial increases in retail electricity prices on consumers.
- No evaluation of these potential cumulative costs and impacts has been undertaken. Instead, EPA has engaged in only piecemeal examination of individual rules, and ignored the sustained economic pressures created by these increasingly stringent requirements.

3. Data and Assumption Comments

AEP has numerous concerns with the data and assumptions used to support various portions of the Transport Rule. While the NEEDS v.3.02 database was used originally in the Transport Rule development, AEP will provide data comments based off NEEDS v.4.10, which has been indicated under the NODA as the input vehicle for future IPM runs. However, AEP has output driven comments from both versions of IPM, as we remain unsure which underlying errors might have been corrected in the modeling update process. Many of our concerns are directly related to how underlying unit limitations are factored into the modeling, specifically as ultimate allocation and/or potential emission rate limits are proposed to be tied directly to modeled emissions and performance. Furthermore, AEP requests that EPA produce modeling outputs disaggregated and reported at the unit level. It is highly unclear from the parsed data files provided exactly what coal types are being utilized and what constraints individual units are tied to. This level of data is needed to ensure that a proper third-party review can be conducted of the runs used to support the proposed Transport Rule.

At a minimum, EPA should correct the data and assumption issues identified, remodel the air quality impacts assuming a continuation of CAIR-like standards, revise the compliance dates based on reasonable timelines for environmental controls and rerun the economics and subsequent allocations that would result from these changes. A supplemental Transport Rule should then be proposed for comment.

NEEDS Emission Rates

Several of AEP's units are projected to have NOx rates in NEEDS v.4.10 scenarios which are inconsistent with either historical or projected operations. The following units should be corrected as listed in the recommended rates below. The recommended control rates are based on AEP's experience operating these units.

Plant Name	Unit ID	NEEDS Controlled NOx Policy Rate (lbs/mmBtu)	Recommended Controlled Annual NOx Rates (lbs/mmBtu)
Big Sandy	BSU1	0.15	0.46
Cardinal	3	0.02	0.06
Conesville	5	0.31	0.36
Conesville	6	0.31	0.36
Mountaineer	1	0.04	0.07
Oklaunion	1	0.23	0.31

NEEDS Existing Controls

There are several instances where wet scrubbers are incorrectly listed at AEP owned/operated units within the NEEDS v.4.10 database. Kammer Units 1 & 2 are listed as having had a wet scrubber installed in 2007 though no such controls were added or are planned to be added. Additionally there are incorrect references to wet scrubber installations at John E. Amos Unit 1 (2008), Cardinal Unit 3 (2010) and Kyger Creek Units 1-5 (2010). These are projected to have wet scrubber systems come online within the next few years, but not by the dates assumed in the Proposed Transport Rule.

NEEDS FGD Removal Assumptions

EPA's IPM v.4.10 modeling assumed that all new wet FGD systems average 98% SO_2 removal with a floor of 0.06 lb/mmBTU. Additionally, its appears all units with FGD controls installed in 2005 or later were defaulted to the 98% removal criteria based on the lack of more recent data availability within the EIA-767 database. While many new wet

FGD systems might be able to achieve 98% removal or higher on an intermittent basis, 98% SO_2 removal is very difficult, if not impossible, to achieve on most units on a year-round basis due to operational upsets and operating variability. AEP recommends revising the assumptions to show 96.5% SO_2 removal for all new(er) FGD systems.

For other units operating with older FGD systems, targeted SO_2 removal performance based on current operation or design basis is different than the scrubber efficiency listed within the NEEDS database. Scrubber efficiency at Gavin Units 1 &2 should be revised to 94.5% and Dolet Hills Unit 1 revised to 70%. Additionally, the most recent information from Duke Energy on the co-owned Zimmer unit indicates a scrubber efficiency of 93% and should be revised.

NEEDS Missing Units

Two operational AEP units are currently missing from the NEEDS database, the Philip Sporn Unit 5 in Mason County, WV and the Conesville Unit 3 in Coshocton County, OH. EPA should refer to EIA for unit characteristics and incorporate these units into the NEEDS database for purposes of further modeling and allocations.

IPM Environmental Retrofit Capital Costs

AEP is appreciative of the efforts EPA undertook to update the IPM study with new numbers to better reflect the current costs of procuring and constructing pollution controls. While these updated costs are more accurate, they still underestimate cost of controls for many units due to other factors not currently considered within the cost structure.

The ability to retrofit control technologies remains a major issue at some units due to plant layout and design. Most of the newer and easier to retrofit units have already been retrofitted. As such, the next round of units required to retrofit are likely to be significantly more difficult and costly than previous experience would suggest. Between similarly sized units, costs could vary by two times or more based on unit-specific constraints. AEP recommends EPA include unit-specific multiplier as an IPM input parameter to adjust retrofit costs versus perceived difficulty.

It is also apparent that landfill costs were included only as a variable cost within the cost structure for new FGD installations. However, construction of new landfill space to support FGD byproduct disposal are almost always undertaken on-site and require significant capital to be deployed. As such, the initial landfill development cost should be factored into the capital cost of the FGD installation as well as the ongoing variable cost of operation. Landfill development costs are approximately \$5 to \$40 per kW and should be factored into the model as a capital cost. These costs could increase substantially as a result of the coal combustion residuals rule EPA proposed on June 21, 2010.

Because of the low projected capital costs of environmental retrofits, the model is biased in the direction of retrofit versus retire for emissions reductions on uncontrolled units. However, AEP feels that the actual economics, in conjunction with capital requirements to address other forthcoming environmental liabilities, will favor retirement on most uncontrolled units. This will have a definite impact on cost and reliability outcomes.

Transmission/Black Start with Retirements

AEP's current transmission grid restoration plan is built around the control functionality of its smaller subcritical unit turbines successfully load rejecting during a system or national electrical grid emergency. This functionality is premised around our fleet's subcritical generators that are in operation at the time of emergency, needing to successfully separate, or load reject from a voltage decaying grid. Units that have successfully load rejected will remain islanded, only generating enough to support their own auxiliary loads, until at such time, they are advised to re-parallel in a systematic manner in an effort to re-energize the electrical transmission grid. All of AEP's 18 subcritical units capable of automatic load rejection are now being threatened by the currently proposed Clean Air Transport Rule, and thus facing probable unit retirement. The economics of localized transmission constraints and ancillary services provided by ALR and blackstart units should be included in future modeling scenarios and reviewed with increased scrutiny, particularly as individual units are selected for retirement.

IPM Financial Assumptions

AEP has concerns with how capital recovery factors are calculated for use within IPM as they pertain to retrofit decisions on older coal units. Specifically, the model assumes that these retrofit investments would have a book life of 30 years and a debt and depreciation life of 20 years. However, as the majority of uncontrolled units are older less efficient units, an additional 20-30 years of life expectancy is not guaranteed or even likely. Furthermore, uncertainty as it pertains to additional future EPA regulations means that these investment decisions must clear an even higher hurdle of prudency, which would likely result in the investment needing to be recovered over a 10-15 year time horizon.

A similar risk adjustment is already present in the IPM model as investments in new coal are subject to a "Capital Cost Adder for Climate Change Uncertainty" which results in 3% added to the cost of equity and debt. Old coal is not likely to be treated any different than new coal under climate and other EPA regulations and thus any investment in coal technology should be subject to either an adder or an accelerated timeframe for capital recovery.

IPM Coal Suitability

AEP has significant concerns about how various coal types are selected and utilized within the IPM model, ultimately leading to an inaccurate portrayal of the economics and viability of emission reductions through coal switching. In using the parsed IPM output files to back into unit emission rates, it was determined that several of AEP's units are burning coals which they cannot physically use without significant operational limitations or the addition of major capital equipment not currently considered in IPM.

One set of concerns relates to the apparent lack of a minimum coal sulfur content model parameter. Many coal-fired boilers are limited to a minimum specification for coal sulfur content due to their boiler configuration, and their electrostatic precipitator (ESP) and/or air permit limitations. For example, wet-bottom boilers capture the majority of their ash in a molten form within the boiler and require coals with low ash fusion temperatures. For eastern bituminous coal, this property is generally correlated with high sulfur fuels. Other limitations due to ESP performance are also found on both wet and dry-bottom units that were initially designed to utilize higher sulfur coals. Lower sulfur coals do not have the same electrical resistivity properties as higher sulfur coals and thus the ash is harder to collect. Therefore use of low sulfur coals at some units could cause opacity to exceed permitted limits. Given these unit specific operational limitations, the NEEDS database and IPM model structure should be updated to reflect these actual limitations. AEP offers two examples of where the lack of fuel constraints resulted in a modeled operating situation that is not currently feasible.

1. In the recently released IPM runs in conjunction with the NODA, emission rates for the Muskingum River units 1-4 were as low as 1.42 lb-SO_2/MMBtu based on the modeled emissions and heat input. In previous runs used to support the Transport Rule the emission rates were as low as 1.01 lb- SO_2/MMBtu. As these are uncontrolled units, the emission rate is largely indicative of the sulfur content of the underlying fuel. However, low sulfur eastern fuel(s) are not compatible with these wet-bottom boilers due to ash fusion and ESP limitations. These units are currently limited to coal(s) with an SO_2 content of 4.0 lb per mmBTU or above.

2. A similar concern was observed when viewing the model outputs for Kammer Units 1-3. While these units can burn coal with slightly lower SO_2 content than Muskingum River Units 1-4 due to an ability to blend limited portions of PRB, they similarly cannot burn very low sulfur coal. In new NODA IPM runs, one Kammer Unit was exhibiting an emission rate of 1.34 lb- SO_2/MMBtu. In earlier IPM runs the emission rate was as low as 0.95 lb- SO_2/MMBtu. With current blend capability, AEP is only able to achieve emission rates slightly below 2.0 lb-SO_2/MMBtu.

An additional concern related to fuel suitability is based on how the IPM model treats units that can burn subbituminous coal. Many boilers are flagged within the model as having the ability to burn subbituminous coal based on past utilization. While keeping this designation within the model structure is important, not all units that can burn subbituminous coal have demonstrated the ability to burn exclusively subbituminous coal. Many units utilize subbituminous coal for a portion of their coal, but not all of their coal, due to boiler limitations.

For example, AEP-operated Rockport Units 1&2 and Tanners Creek Unit 4 all currently burn a percentage of subbituminous coal due to combination of economics and emission limitations. However, as the boilers were originally designed to burn bituminous coal, 100% subbituminous coal cannot be used without significant changes to unit output and operation. (Generally speaking, we have already pushed the subbituminous portion as high as these boilers will allow). As subbituminous coal has lower energy and higher moisture content than bituminous coal, a larger boiler design is typically needed to produce the same thermal and electrical output. Thus, burning 100% subbituminous coal in a boiler designed for bituminous coal will result in a unit having to be derated, or limited in electrical output. Also, units switching to 100% subbituminous coal will have to undergo more frequent outages related to slag formation and boiler maintenance given the physical properties of subbituminous coal. IPM runs indicating uncontrolled emission rates below 0.60 for Rockport Units 1 & 2 and Tanners Creek Unit 4 suggest that these units are exclusively utilizing very-low sulfur subbituminous coals, as this coal type is the only one capable of meeting this low emission rate. Therefore, output constraints regarding the use of 100% subbituminous fuel and/or maximum blend percentages for the use of subbituminous in boilers currently utilizing blends need to be incorporated in EPA's modeling for the Proposed Transport Rule.

Coal Procurement

In addition to coal limitations, AEP is also concerned about coal flexibility as it pertains to short term shifts in supply. The IPM model was able to optimize coal selection based on relative economics of different coals. However, the modeling does not take into account long-term coal purchase contract obligations and the ability to quickly ramp production up and down. The IPM model allowed full switching to low sulfur coal in 2012, but in the real world, this could not occur. Given that this rule is not going to be finalized until spring 2011, it will be too late to switch coal contracts. Generally, almost all of AEP's coal (like other electric generators) is contracted more than one year in advance. Thus, the IPM model should be recalibrated and constrained to make sure that transitions in coal type occur over a reasonable period.

Conclusion

AEP does not believe that the timelines and stringent budgets within this Proposed Transport Rule are necessary or justified. The modeling data developed by the Midwest Ozone Group and EPA's own data show the NAAQS attainment and maintenance targeted by this Proposed Transport Rule will be satisfied with the existing CAIR program. EPA should address the specific issues of the D.C. Circuit in the *North Carolina* case while keeping the timing and reductions the same as is defined in the current CAIR program.

In summary,

1. The Proposed Transport Rule does not result in ozone or PM-2.5 NAAQS attainment and maintenance benefits by 2015 beyond those assured by the existing CAIR program.

3. The Proposed Transport Rule neglects to consider utility system planning factors that affect unit retirement decisions and deadline-driven resource and skilled labor shortages, and the consequences to electrical system reliability and functionality in the event of a national or regional grid emergency.

4. The series of rulemakings aimed at the same electric generating units subject to the Proposed Transport Rule creates an unreasonable and unnecessary moving target that increases costs to electric consumers and threatens very large stranded or misplaced investments at a time of tight capital markets and the recent recession.

5. EPA has understated the direct costs of complying with the budgeted caps, ignoring some of the significant direct costs, including output capacity deratings, and landfill development. EPA has also ignored entirely the enormous indirect costs of its caps, including the indirect costs of fuel switching, unit retirements, and increased energy costs to consumers.

For all of these reasons and the additional reasons detailed in the comments, EPA should limit the current rulemaking to providing enhanced technical support for the current CAIR provisions as amended to include narrow corrections specifically required by the *North Carolina* decision, and otherwise continue to rely upon the current CAIR program budgets, deadlines, trading, and banking until 2015. EPA should address the post-2015 period in a revised proposal that takes into account the states' primacy for SIP formulation, and that takes into account the transport implications of EPA's new ozone and PM-2.5 NAAQS revisions and utility HAP rules, at a minimum.

Should you have any questions or need clarification regarding these comments, please direct them to Jeff Novotny at 614-716-1294 or to me at 614-716-1268.

Respectfully submitted,

John C Hendricks for John McManus

John M. McManus
Vice-President Environmental Services
American Electric Power,

cc: Office of Information and Regulatory Affairs
Office of Management and Budget (OMB)
725 17th Street, NW
Washington, DC 20503
ATTN: Desk Officer for EPA

By e-mail to Sam Napolitano – napolitano.sam@epa.gov