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/DC)
Environmental Protection Agency
Air and Radiation Docket and Information Center
Mail code: 2822T
1200 Pennsylvania Avenue, NW
Washington DC 20460
Docket ID No. EPA-HQ-OAR-2009-0234

August 4, 2011

Subject: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units (76 Fed. Reg. 24976 (May 3, 2011)

Reference: Docket ID No. EPA-HQ-OAR-2009-0234

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 National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units proposal of May 3, 2011 (the "EGU-MACT Rule"). AEP owns or operates electric generating units ("EGUs") in ten states, including 54 electric generating units that fire coal and oil. Thus, the operating companies of the AEP system will be directly affected by any regulatory actions applicable to the EGU source category, including the proposed EGU MACT rule.

On June 9, 2011, AEP released a preliminary analysis of the impact that the proposed EGU-MACT rule will have on AEP's fleet, in conjunction with several other current EPA rulemakings (Coal Combustion Residual Rule, Clean Air Transport Rule, 316(b) Water Intake Rule). The analysis showed that over 5,900 MW of coal-fired units will be retired resulting in the net loss of 600 jobs, and that AEP will be required to invest between \$6 - 8 billion to add environmental controls, upgrade existing controls, and build new generation, increasing customer bills by 10 – 35%. The potential impacts on the reliability of the grid are significant, particularly in the Midwest. The retirements and retrofits are in addition to the more than $7.2 billion that AEP already has invested since 1990 to reduce emissions. While AEP supports regulations that achieve long-term environmental benefits, the company has determined that the proposed EPA rules do not provide enough time to permit, engineer, procure, and construct the necessary retrofits to meet the 2014 Clean Air Transport Rule and EGU-MACT Rule deadlines.

AEP is providing the following comments on EPA's proposal (76 Federal Register 24976) to develop maximum achievable control technology ("MACT") standards for hazardous air pollutant ("HAP") emissions for EGU's. In addition, except as otherwise stated in these individual comments, AEP endorses and incorporates by reference the comments submitted by the Utility Air Regulatory Group ("UARG"), the Midwest Ozone Group ("MOG"), the Edison Electric Institute ("EEI"), the Coal Utilization Research Council ("CURC"), and the Electric Power Research Institute ("EPRI") on this proposal.

Section 1: General Comments

I. EPA Has Not Provided a Sufficient Basis for its Determination that It Is Appropriate and Necessary to Regulate Emissions of Hazardous Air Pollutants from the Fossil Fuel-Fired Electric Utility Steam Generating Source Category

Section 112(n)(1)(A) of the Clean Air Act ("CAA") was included in the Clean Air Act Amendments of 1990 to provide EPA with an alternative means of examining emissions of HAPs from electric utility generating units and approaching the regulation of those emissions through "alternative control strategies," if warranted. EPA has turned the statutory language on its head, claiming that the undefined terms in the statute both vest it with broad discretion to exercise its regulatory authority, and are so prescriptive that they compel the regulatory results set forth in this proposed rule. EPA cannot have it both ways.

UARG's comments present a detailed history of the regulatory development of the current proposal, and demonstrate that EPA's proposed action contravenes Congressional intent in several important respects. AEP also submitted comments on EPA's 2004 proposal to issue standards under Section 112 (d), which chronicle how the studies EPA was directed to undertake by Congress do not provide an adequate basis for regulating even mercury emissions from coal-fired generators or nickel emissions from oil-fired generators, let alone support the more comprehensive proposal issued in May of this year. AEP's 2004 comments are attached hereto as Attachment A, and incorporated herein by reference.

EPA has provided no reasoned justification to revert to a mechanistic application of the regulatory development process in Section 112 (d), and regulate not only mercury emissions from coal-fired utility boilers, but the entire suite of HAPs from coal- and oil-fired utility boilers. The findings made in the Utility Study show that utility emissions of mercury are dwarfed by emissions from natural and other man-made sources around the globe, and that totally eliminating utility emissions of mercury will not advance the public health in any way. No additional studies have been performed which call this conclusion into question. Instead, EPA claims it has discretion to consider not only utility emissions, but emissions from multiple sources in determining whether it is "necessary and appropriate" to regulate utilities. And EPA claims that not only should it examine the potential impacts on public health, but that potential environmental impacts also justify regulation of utility emissions. Such assertions ignore the plain terms of Section 112(n)(1)(A), and render EPA's proposed action arbitrary and capricious.

The plain language of this section requires EPA to answer one question and one question only: After all other sections of the 1990 Clean Air Act Amendments have been fully implemented, is there any hazard to public health that can reasonably be anticipated to occur as a result of emissions of HAPs by EGUs? Based on all of the work completed by several different Administrations over decades since the passage of the 1990 Amendments, the answer is clearly "No." All of the studies and analyses presented in the current proposal do no alter this conclusion. They simply attempt to substitute a different question for the one Congress asked the agency to answer.

Moreover, EPA compounds the flaws in its analyses by failing to recognize that additional requirements imposed by the CAA since the completion of these studies have contributed to further reductions in mercury emissions, so that any perceived threat associated with utility emissions has been mitigated further over time. EPA claims that its current regulatory effort must ignore the numerous ways in which emissions have been reduced, and that it could not be expected to "project into the future" but must consider only those emissions reductions that would have otherwise occurred at the time it was required to submit the initial report to Congress. Such an interpretation flies in the face of the plain language requiring EPA to "reasonably anticipate" the health effects that might occur "*after* the imposition of the requirements" of the 1990 Amendments. 42 U.S.C. § 7402(n)(1)(A). Given the continuing reductions that have been achieved and that will be imposed through other EPA initiatives, mercury, acid gas, and particulate emission reductions will also continue to occur, further undermining EPA's purported reasoning.

EPA then asserts that a finding with respect to a single HAP is justification for the entire suite of HAP emissions, even though specific investigations have been undertaken and fully support the opposite conclusion. Congress gave EPA discretion to propose "alternative control strategies" and did not confine the agency to strict compliance with the mandates in Section 112(d). EPA has failed to take advantage of the latitude conferred on the agency by Congress. Without considering alternatives, EPA's action is incomplete, and must be remanded for further consideration to satisfy the requirements of Section 112(n)(1)(A).

II. The Promulgation of the Cross State Air Pollution Rule Renders the MACT Rule Unnecessary

Recently EPA finalized the requirements of the Cross-State Air Pollution Rule (CSAPR), formerly know as the Clean Air Transport Rule, which replaces the requirements of the Clean Air Interstate Rule (CAIR). The implementation of the CSAPR, if feasible, beginning in 2012 will achieve many of the same air quality goals EPA has used to justify the EGU-MACT Rule. The extreme reductions required by CSAPR can only be achieved through the installation of the same highly efficient control devices that the MACT rule will require for control of HAPs. The promulgation of the HAP rule will simply eliminate any flexibility in achieving these goals by imposing unit-by-unit or facility-by-facility control requirements, resulting in duplicative and inefficient regulation with a negligible effect on air quality. The benefits attributed to the EGU_MACT rule should not include any of the reductions that will be achieved through the CSAPR. However, EPA's current regulatory analysis double counts the benefits of $PM_{2.5}$ reductions. The CSAPR reductions need to be included in the baseline, before EPA assesses the necessity of the EGU-MACT rule.

III. Health Impacts Used to Justify the Rule Are Not Based on Reductions of HAPs and Rely on Invalid Assumptions.

The health benefits claimed by EPA in the preamble to the rule are not from the control of HAP emissions; rather, the benefits are attributed primarily the control of sulfates and nitrates that are precursors to the formation of secondary condensable particulate matter ("PM"). As noted above, this amounts to double counting the PM reductions that were already used to justify the CSAPR, and fails to comply with the clear direction given by Congress in Section 112(n)(1)(A), that EPA shall regulate EGU HAP emissions only if it is *necessary and appropriate to reduce HAP emissions from those sources*. EPA should provide a health impact analysis based on the HAPs that the rule is intended to control. Based on the information in the rulemaking docket, the total quantifiable health benefits associated with the reduction of HAPs through the EGU-MACT are $4.1 – 5.9 million, and are subject to multiple sources of uncertainty associated with the levels of mercury deposition, the amount of bio-available methyl-mercury present in particular watersheds, and the actual rates of exposure due to repeated fishing activity and consumption. These limited an uncertain benefits do not justify the extraordinarily high costs of compliance with the proposed rule.

Further, the vast majority of $PM_{2.5}$ reductions predicted as a consequence of the EGU_MACT occur in areas of the United States that are either currently classified as attainment for $PM_{2.5}$ or that will achieve attainment through continued efforts to comply with CAIR or implementation of the CSAPR. Areas that attain the national ambient air quality standards (NAAQS), by definition, have achieved and are maintaining a level of air quality that protects the public health with an adequate margin of safety. 42 U.S.C. §7409(b)(1). Accordingly, further reductions in $PM_{2.5}$ should not produce significant additional human health benefits. In addition, the primary studies relied on by EPA base their predicted estimates of health outcomes on incremental improvements in air quality at levels significantly higher than current air quality. EPA should revise its concentration-response calculations to include only studies which have relied on data from within the last three years, as this data is truly reflective of current conditions.

Finally, even if it were appropriate to consider the potential benefits of criteria pollutant reductions in the context of this rulemaking, which AEP does not concede, AEP disagrees that "there is no clear scientific evidence that would support the development of differential effects estimates by particle type." The two studies referenced by EPA in making this claim, Pope and Laden, simply rely on data collection and subsequent modeling that treat all PM emissions the same; they do not support a conclusion that all PM has the same impact. In fact, recent work by EPRI and others support the opposite conclusion - that not all PM components have equal health significance. There is mounting evidence that inorganic ions (e.g. sulfate and nitrate) play a less significant role than other compounds, such as organic carbon and other trace elements, based on

EPRI's review of component-based research on concentration-response. AEP requests that EPA revisit the science of particulate matter speciation and health response before promulgating the final rule or projecting health benefits associated with PM reductions to ensure that a fair cost benefit analysis is being conducted.

IV. EPA Has Ignored Basic Information About How a Coal-based EGU Actually Operates

The proposed rule ignores basic information about how coal-fired generation technologies actually operate and for how state agencies have established air permits for new coal-based generation units. EPA should consider factors, such as the ones described below, in developing the final rule.

a. Coal-based electric generating units use a variety of technologies that differ in design and performance based on the coal consumed, and experience a wide range of operating conditions.

The design of a coal-based generating unit is driven by the characteristics of the coal supply. A wide variety of combustion technologies and unit designs have been deployed and are available that contribute varying strengths with respect to unit efficiency, system performance, expected emissions profile, and commercial maturity. In general, combustion technologies for coal-based units can be classified as pulverized coal, fluidized bed, and coal gasification. Further, the fuel type selected, anticipated emissions profile and chosen combustion technology drives the selection of emission controls, such as wet vs. dry flue gas desulfurization or selective catalytic vs. selective non-catalytic reduction systems. All of these design differences, and subsequent operating variables and emissions performance, are a result of varying coal characteristics. These differences were recognized in prior EPA rulemakings, and have consistently been used to create different categories and subcategories of units and tailor emission standards. A similar approach should have been used in the current EGU-MACT rulemaking.

An individual coal-based generating unit is not a steady-state operation. The efficiency, performance, and emissions profile will vary across the range of operating conditions expected over the life of the unit, including startup, shutdown, and load changing operations. Other influences impacting operations include ambient conditions, the age of equipment, and changes in coal characteristics. All of these considerations, along with others highlighted in the following sections, point to the complexity and variability of operating scenarios that EPA must consider in developing the final rule.

b. A variety of factors influence the quantity of potential emissions to be controlled and the performance of the emissions control equipment, and EPA has not adequately accommodated these factors in establishing the EGU-MACT limits.

A number of factors, known and unknown, controllable and uncontrollable, influence the potential emissions from coal-based generating units. The emissions control process (and safe operation of the unit itself) is complex - it is not as simple as turning on a switch to reduce emissions. The process becomes even more complex when attempting to reduce emissions of trace constituents that are being controlled as co-benefit of other installed systems that were not specifically designed for that purpose. For most of the HAPs subject to limitations under the proposed rule, little or no historic operating data is available. All of the data collected through the Information Collection Request (ICR) issued to support the proposed rule was collected during stable full-load operations. Many of the constituents are inherently variable within coals commonly used at the same unit. Under the proposed rule, an operator is likely to be in the unenviable position of testing below a limit one time and then testing above the limit the next without knowing what actions to take to change the emission rate.

The levels established in the EGU-MACT for new and existing units are so low that they do not accommodate the full range of unit operating conditions, and currently available monitoring methods lack the precision and accuracy necessary to confidently assure compliance. An appropriate regulatory approach should not be one whereby compliance is subject to chance. EPA should design the final rule with greater flexibility so sources can reliably demonstrate compliance, such as through reexamination of the sources of uncertainty and recalculation of the limits, longer averaging times, additional options for averaging with other units, as well as development of work practice standards for known periods when controls do not operate, such as start-ups and shutdowns, or design of emission rates that can actually be achieved across the whole range of operations a unit would experience. As an example of the scope of issues that can impact emissions, below is a summary of some of the issues that could impact the performance of particulate control by an electrostatic precipitator (ESP):

- Mineral constituents of ash: the chemical makeup of the ash affects the resistivity of the ash, which impacts the ESP control efficiency.

- Sulfur content of fuel: some sulfur in fuel is converted to SO_3, which can improve ESP efficiency to a point, but can be reduce performance at very high levels.

- Loss on ignition (unburned carbon in the fuel): high unburned carbon affects overall unit efficiency, and impacts ESP performance because of changes in ash properties.

- Flue gas temperature and stratification issues: high temperature results in higher actual gas flow and therefore higher velocity through air pollution control equipment – higher velocities can affect removal rates significantly. Higher gas temperatures can also affect resistivity of flyash and therefore ESP efficiency.

- Boiler slagging: Relatively minor fuel changes can also affect slagging and fouling within the boiler, which can raise outlet temperatures. Changing coal characteristics can impact ESP performance as the ash concentration in flue gas going to the ESP increases.

- Coal fineness: Coal fineness impacts the combustion characteristics, unit efficiency, flue gas characteristics, and ESP operations. Changes in pulverizer performance due to normal operating variables (load conditions, age of equipment, etc.) and differences in coal characteristics (grindability, etc.) impact the fineness of coal combusted. For example, a coal with a lower grindability will be harder to grind, which can require more air to deliver coal to the burners and larger coal particles being combusted. Larger coal particles can contribute to concerns regarding slagging, greater loss on ignition, and higher temperatures.

- Moisture (wet coal and/or moisture getting into flue gas path) – moisture can affect ESP operation significantly. For example, moisture can make ash sticky and harder to rap off of ESP plates. Moisture can also create issues with the flue gas approaching its dew point, which causes concerns regarding ESP corrosion and performance.

- Air in-leakage – casing leaks can allow ambient air to get into the flue gas path – this can cause localized corrosion, increased gas velocities (overall), and localized areas of extremely high velocity/low temperature, all of which can impact ESP performance.

These and similar issues for other types of control equipment have not been adequately analyzed in designing the EGU-MACT standards. Because the MACT standards must be designed to accommodate the worst foreseeable operating conditions, EPA should re-evaluate these sourcesd of variability and recalculate the EGU-MACT limits.

c. The quantity of trace constituents varies significantly and EPA has not adequately accommodated this variability in establishing the EGU-MACT limits.

Coal is not a homogeneous substance, but rather is comprised of a suite compounds (including many trace constituents to be regulated by the proposed rule) that vary in concentration not only from region to region in the United States, but also within these individual regions and even within an individual coal mine or seam. The potential emissions from coal combustion and the performance of emissions control systems is a complex process driven, in part, by the concentration, ratio of, and interactions between these various compounds in coal. The United States Geological Survey maintains an extensive database of information U.S. coals, which highlight the variability of trace constituents in coal.

Using mercury as an example, consider the map below from a 2003 USGS Report[1], which depicts the significant variability of coal mercury concentrations in various regions of the country. This range of concentrations, especially in context with the interaction of mercury with other coal compounds and the fact that most EGU's consume coal blends from multiple mines, points to the challenges in designing emission control systems to effectively reduce trace concentrations of mercury across a range of operating conditions.

[1] 2003. Geologic Studies of Mercury by the U.S. Geological Survey. U.S. Geological Survey Circular 1248.

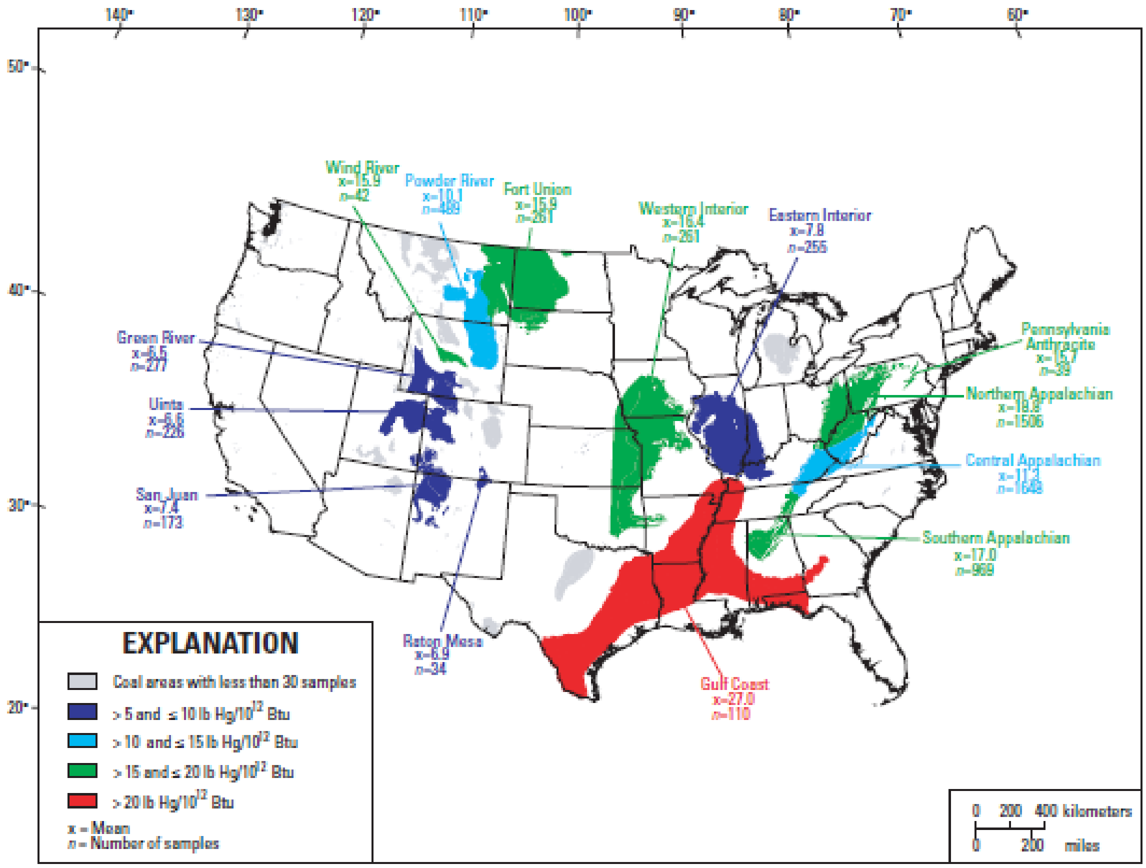


Figure 9. Distribution of mercury in coal fields in the United States. Data are given on an equal energy basis, in which mercury concentration is converted to weight percent and divided by Btu.

Similarly, consider the variability of trace concentrations of arsenic in coal throughout the United States as summarized in the following table from a USGS report title "Arsenic in Coal"[2]:

Table 1. Comparison of average arsenic content in U.S. coals by basin and calculated average powerplant input loadings of arsenic.
[Data from Bragg and others, 1998. ppm, parts per million; Btu, British thermal unit; lb, pound]

Coal basin	Arsenic (ppm)			Calorific value (Btu/lb)			Arsenic input loadings (in 10^3 lbs per 10^{12} Btu)		
	Median	Mean	Number of samples	Median	Mean	Number of samples	Median	Mean	Number of samples
Appalachian, Northern	16	28	1,607	12,570	12,440	1,500	1.3	2.3	1,500
Appalachian, Central	7.8	22	1,742	13,360	13,210	1,643	0.6	1.7	1,643
Appalachian, Southern	29	71	974	12,850	12,760	968	2.2	5.8	968
Eastern Interior	10	19	289	11,510	11,450	255	0.92	1.7	255
Fort Union	4.2	8.5	280	6,340	6,410	257	0.7	1.4	257
Green River	1.2	4.8	391	9,950	9,560	264	0.13	0.44	264
Gulf Coast	2.2	3.2	141	6,440	6,470	110	0.34	0.54	110
Pennsylvania Anthracite	3.2	8.1	51	12,860	12,530	39	0.25	0.79	39
Powder River	1.6	4.2	602	8,050	8,080	486	0.2	0.5	486
Raton Mesa	0.99	1.4	40	12,500	12,300	34	0.073	0.1	34
San Juan River	0.92	2.5	185	9,380	9,640	169	0.095	0.26	169
Uinta	0.7	1.5	249	11,290	10,820	222	0.074	0.14	222
Western Interior	14	21	286	11,320	11,420	261	1.2	1.9	261
Wind River	2.4	7	41	9,630	9,570	41	0.25	0.75	41

[2] Arsenic in Coal. US Geological Society. Feb 2006. Fact Sheet 2005-3152.

USGS has also discussed the variability of trace elements in coal in context with the Clean Air Act. A paper titled *Trace Elements in Coal: A USGS Perspective of the Clean Air Act* by R.B. Finkelman,[3] USGS, demonstrates the range of trace element concentrations between different regions of the country, between different areas of the same coal, and within the same coal seam itself. All of this data reaffirms the fact that coal is not a homogeneous substance and that its inherent variability must be accommodated in establishing the MACT standards for trace element emissions. The following tables from the *Trace Elements in Coal* report further demonstrate that this variability affects most of the targeted trace metals considered by EPA in this rulemaking, not just mercury and arsenic. Additional subcategories, more flexible limits and longer averaging times should be provided, and any limit must be based on the highest concentration of the target substance normally found in coals combusted by EGUs.

Table 1. Variation of potential air toxics among coal basins. (Values are arithmetic means in parts-per-million on a whole-coal basis; figures in parantheses are number of samples.)

Element	Appalachian basin (4,700)	Interior Province (800)	Gulf Coast lignites (200)	Fort Union lignites (350)	Powder River basin (800)
Antimony	1.4	1.5	1.0	0.69	0.57
Arsenic	35.0	20.0	10.0	11.0	5.6
Beryllium	2.5	2.4	2.4	1.0	0.84
Cadmium	0.1	4.2	0.55	0.16	0.16
Chromium	17.0	19.0	24.0	6.4	8.5
Cobalt	7.2	10.0	7.2	2.4	2.3
Lead	8.4	40.0	21.0	4.8	5.5
Manganese	29.0	78.0	150.0	83.0	63.0
Mercury	0.21	0.15	0.22	0.14	0.12
Nickel	17.0	27.0	13.0	4.1	6.4
Selenium	3.5	3.2	5.7	0.82	1.1
Uranium	1.7	3.1	23.0	1.8	1.6

Table 2. Variation of potential air toxics among coal beds in the Appalachian basin. (Values are arithmetic means in parts-per-million on a whole-coal basis; figures in parentheses are number of samples.)

Element	Meigs Creek coal bed (54)	Redstone coal bed (80)	Pittsburgh coal bed (194)	Lower Freeport coal bed (119)	Lower Kittanning coal bed (219)	Sewell coal bed (73)
Antimony	0.3	0.7	0.6	1.2	0.9	1.1
Arsenic	6.7	29.1	20.4	37.3	25.2	11.1
Beryllium	1.4	1.6	1.4	2.7	2.6	2.2
Cadmium	0.08	0.07	0.11	0.11	0.14	0.10
Chromium	16.4	13.8	14.7	17.4	16.8	11.8
Cobalt	3.2	3.5	4.6	7.6	6.7	8.0
Lead	5.3	4.0	4.9	10.4	10.6	5.5
Manganese	30.8	46.3	31.9	42.8	27.2	18.5
Mercury	0.12	0.22	0.18	0.34	0.24	0.16
Nickel	9.5	9.5	10.7	20.4	20.5	18.9
Selenium	2.9	2.4	1.9	5.0	4.3	2.4
Uranium	1.8	1.7	1.1	1.7	1.8	1.4

[3] www.anl.gov/PCS/acsfuel/preprint%20archive/Files/39_2_SAN%20DIEGO_03-94_0519.pdf

Table 3. Lateral distribution of potential air toxics within the Pittsburgh coal bed from Ohio, Pennsylvania, and West Virginia. (Values are arithmetic means in parts-per-million on a whole-coal basis.)

	Sample					
Element	1	2	3	4	5	6
Antimony	0.4	1.4	0.4	0.4	1.4	0.3
Arsenic	13.3	75.1	15.0	9.6	79.8	10.0
Beryllium	1.1	1.2	1.6	1.4	1.0	0.3
Cadmium	0.10	0.07	0.14	0.06	0.09	0.04
Chromium	14.4	9.3	10.1	10.3	9.2	10.2
Cobalt	2.8	3.1	11.8	2.7	4.9	1.7
Lead	3.6	3.7	1.5	3.8	6.9	1.0
Manganese	17.8	19.1	55.1	19.7	25.6	25.3
Mercury	0.10	0.22	0.60	0.16	0.28	0.22
Nickel	7.1	6.3	20.9	9.0	9.5	4.3
Selenium	1.5	3.4	3.0	0.9	1.7	1.0
Uranium	0.8	0.3	2.0	0.9	1.4	2.4

Table 4. Variations of potential air toxics from the top to the bottom of a set of bench samples from the Pittsburgh coal bed in Ohio. (Values are in parts-per-million on a whole coal basis. Total thickness of the bed is 52.5 inches.)

	Sample						
	top 1	2	3	4	5	6	bottom 7
Element							
Antimony	0.6	0.2	0.2	0.2	0.3	0.3	0.4
Arsenic	10.4	12.6	4.9	6.3	8.2	31.9	12.8
Beryllium	3.0	1.5	0.8	0.7	1.6	1.3	3.4
Cadmium	0.10	0.09	0.03	0.05	0.08	0.08	0.09
Chromium	30.4	7.4	6.9	9.8	32.7	11.8	12.5
Cobalt	9.2	2.2	1.6	2.1	6.6	1.3	3.3
Lead	8.7	1.6	1.3	1.4	5.5	1.5	5.1
Manganese	12.6	10.3	8.8	7.34	24.8	8.4	13.7
Mercury	0.24	0.29	0.10	0.14	0.20	0.19	0.05
Nickel	16.6	5.8	2.9	4.7	21.3	5.9	13.7
Selenium	8.5	3.3	1.1	1.5	2.2	0.9	0.9
Uranium	2.0	0.3	0.3	0.4	1.3	0.3	0.6

d. EPA should consider the full range of operating conditions that might be expected over the life of a unit in establishing the final rule.

As discussed in the previous sections, the potential emissions from a coal-based generating unit are influenced by a number of varying factors (unit design and performance, coal quality, varying trace metal concentrations, etc.). When emission limits become so stringent that they are below the levels that can be measured with current testing methodologies, as some of the liits in the current proposal are, the ability to effectively manage known and controllable variables in operating conditions, potential emissions, and fuel quality is effectively eliminated. Equally importantly, the risk of non-compliance due to unknown and uncontrollable variables, especially for elements present in trace quantities for which no detailed operational history exists, is significantly increased.

State agencies have recognized the impact of these factors and issued air permits that allow units to maintain operating flexibility and reasonably demonstrate compliance. For example, state agencies have designed permits with limits or work practice standards that are applicable to specific coal types and/or operating scenarios. In many cases, permits have been designed that exempt specific operating conditions, such as startup, shutdown, and malfunction operations, from the emission limits designed for normal operations. Particularly in the case of EGUs where control equipment is subject to known operational limits (like safe operating temperatures in the flue gas before electrostatic precipitators can be energized or ammonia injection for a selective catalytic converter can commence) the case for the development of work practice standards is strong. EPA's proposed limits do not provide sufficient flexibility to allow compliance demonstrations to be made during reasonably foreseeable operating scenarios, and must be re-evaluated.[4]

In summary, EPA should give greater consideration to the diversity of issues that impact the emissions from coal-based generating and to the process that state agencies have undertaken to issue air permit limits so that the final rule contains MACT standards are practical and achievable.

V. MACT Standards Should Reflect the Level of Emissions Control Achieved in Practice by Actual Units Across a Wide Range of Operating Conditions

EPA has proposed MACT standards for certain individual HAPs and for certain surrogate emissions representing groups of HAPs, based on the performance of a different set of units for each different HAP standard. This approach creates a fictitious "best performing" unit that does not represent the actual performance of any one unit, and which employs a one-size-fits-all methodology that inappropriately ignores known variability with respect to coal quality, combustion conditions, and emissions control technologies. Further, EPA's methodology fails to provide appropriate consideration of the potential impact on the ability to effectively control other HAPs when choosing the "best performing" results for a given HAP. This results in different units being used in each of the three HAP or HAP surrogate classes as the best performing 12 percent of sources. This approach results in the establishment of emission limits that are not indicative of what a single source has demonstrated or could demonstrate to be achieved or achievable in practice. Compliance with such emission limits, therefore, has not been demonstrated by any single source in operation and is not "achievable."

The EPA should have followed the language of CAA §112(d)(3) for setting new source MACT limits, which directs the EPA to use a single "source" in its analysis to set the MACT limits. AEP encourages the EPA to re-evaluate the emissions data for HAPs in their entirety to develop emission limits that can be met by the best performing units in accordance with the CAA language.

Additionally, the MACT limits were set based on data obtained during full load steady-state testing taken at a single point in time. As such, the limits were not based on the full range of operating conditions including changes in operating variables (i.e. unit load, ambient conditions, age of equipment, fuel variability causing changes in control equipment operations, etc.) that a unit experiences as a normal course of operation. An emissions rate limit based on a "best

[4] See Appendix D for example permit conditions.

performing" unit must take into account the variability that a unit experiences in operation and emissions, especially when attempting to regulate substances present in trace quantities and for which control performance can more strongly be influenced by unknown and uncontrollable factors. As the data relied upon by EPA does not encompass this variability, the agency needs to either obtain additional data to establish standards that can be achieved on an ongoing basis by the best performing units, or revise the standards to address these concerns. As discussed in Section 6 - IV below, numerous state agencies have performed Section 112(g) case-by-case MACT determinations and have concluded that "achieved in practice" represents the best performance that is achievable based on range of reasonably expected operating scenarios that might occur over the life of a unit. These agencies determined that data from a single stack test or from a limited number of stack tests that occurred under the same operating conditions is not sufficient to determine achieved in practice.

Section 2: Concerns Regarding the Standard Setting Process

I. EPA Should Establish Additional Subcategories for EGU's

AEP encourages EPA to fully use all of its available discretion, as provided for in the Clean Air Act, in establishing subcategories and designing appropriate MACT limits. CAA Section 112 grants the EPA much latitude in establishing "categories and subcategories" to distinguish between classes, types, and sizes of sources within a source category when determining MACT standards. Subcategorization is the one avenue that Congress gave to the EPA to be able to craft regulations that make sense for differing types of sources. EPA chose to take a very limited view of subcategorization in the proposed rule, which is contrary to what Congress intended when the CAA was passed into legislation.

Coal characteristics drive the design and operation of boilers, as well as the selection and performance of associated emissions control equipment. The proposed rule is insufficiently structured to appropriately address the range of coal types, unit designs, and equipment performance capabilities of coal-based electric generation processes. Further, the EPA has ignored the technical feasibility, and potentially exorbitant costs of boiler modifications and control technology retrofits by not considering the impacts of coal rank on unit design and performance. Such distinctions were taken into account in determining emission rates for the acid rain program and the prior mercury proposals issued by the agency, and should not be ignored in this rulemaking. To address these concerns regarding the substantial differences in emission characteristics and heating value for the various coal ranks on the emission reductions that can be achieved in practice, EPA should establish separate subcategories and corresponding separate MACT standards for bituminous, sub-bituminous, and lignite coals. As discussed in Section 6 - III below, numerous state agencies have performed Section 112(g) case-by-case MACT determinations and have determined that such subcategorization is technically and legally appropriate.

In addition to subcategorization for coal rank, the EPA should recognize that many smaller coal- and oil-fired units are operated primarily during periods of peak electrical demand. A separate, subcategory based on boiler size and/or capacity factor would also follow the direction provided to the EPA by Congress to distinguish between sizes of sources. The emissions profiles for the smaller peaking units are different from the base load units, and the EPA should account for these differences in setting MACT standards. A maximum size of 250 MW and a 25% capacity factor should be utilized in setting a limited use subcategory to be applicable to smaller units, below which, only work practice standards should apply to the units.

In addition, there are numerous older boilers that are devoted to similar peaking or occasional use as they near the end of their useful lives. The limited use category could also be applied to any units 50 years or older for which a retirement date has been established based on the approved depreciation schedules on file with a public utility regulatory commission or similar binding commitment. A limited use subcategory for any older oil and coal units that are also willing to accept a limitation to a 25% capacity factor will help to ensure the reliability of the electrical system, as well as limiting the overall emissions of HAPs associated with these units. This subcategory should be allowed to expire after 6 years. The inclusion of the limited use subcategory would provide ample time for replacement power to be constructed, transmission reinforcements and upgrades to be designed and put in place, or allow for other measures to be taken, as appropriate, and in coordination with the reliability organizations and regional transmission operators, and would alleviate grid reliability concerns associated with abrupt mass coal-fired generation retirements at the same time. AEP announced plans to retire 5,900 MW of generation as an outcome of this rule and other EPA requirements. By providing flexibility with the limited use provision, EPA would recognize the reliability issue that exists, while still guaranteeing significant emissions reductions. There is precedent for a limited use subcategory in the Industrial Boiler MACT rule, and similar justification is present within the category of utility units. The inclusion of the limited use subcategory would provide flexibility to the industry in being able to balance the retirement of units with the needs for grid reliability.

In addition, AEP supports the provision mentioned in the preamble for those units that are capable of firing dual fuels. A 10% capacity factor for oil-firing as a limited use category for dual-fired units should be included in the final rule. Dual fuel-fired units need the flexibility to deal with supply constraints that can affect these units, and for which their dual fuel firing capability was designed. AEP believes that a 10% exemption for oil-firing of dual fuel units is consistent with the manner in which these units operate and will provide a cost effective manner of dealing with their HAP emissions.

The current definition for a low emitting EGU (LEE) should be expanded to include provisions for a mass emissions threshold to qualify for LEE status for all regulated HAPs, not solely mercury. The LEE definition for each constituent should be set as the product of (0.25) x (average previous 3-year capacity) x (unit design heat input) x (HAP limit). Units would gain operational flexibility if they were able to monitor their emissions to stay beneath a yearly mass emissions threshold to qualify for LEE status instead of the rate based method proposed for HCl and PM.

Finally, EPA should continue with the precedent it has set in past MACT rulemakings by allowing for an area source subcategory. Congress has given EPA the ability to subcategorize area sources because of their low HAP emissions and low potential impact on human health. EPA should move area sources away from the stringent MACT limit setting approach under section 112 and set generally available control technology (GACT) limits for area sources.

II. EPA Should Establish MACT Standards Based on Annual Averages

EPA should use an annual averaging period for HAP emission standards. Annual averaging would be consistent with other EPA rulemakings for EGU's (i.e. Acid Rain program and CSAPR). In fact, as part of the previously proposed Clean Air Mercury Rule, EPA established annual emission limit for mercury after a rigorous review of the science related to potential exposure and health effect risks. EPA has not demonstrated why a 30-day average would be more appropriate in this proposed rulemaking for any of the emissions being regulated, but particularly for mercury emissions. Mercury is the only HAP for which EPA estimated a potential health benefit. EPA determined that the propose rule would provide up to $4.1 – 5.9 million dollars of potential annual benefit. Since the mercury risks of concern are associated with bio-accumulative factors that occur from potential long-term exposure, an annual limit is most appropriate for balancing mitigation of those concerns with compliance flexibility. As mass emissions of the pollutants are the key issue with these HAPs, use of an arbitrary short-term rate and short averaging period (i.e., 30-day rolling average) does not allow enough operational flexibility to address process issues or startup and shutdown operations.

The MACT data set consists solely of full load steady-state testing taken at a single point in time and does not encompass the full range of operating conditions including changes in operating variables (i.e. unit load, ambient conditions, age of equipment, fuel variability causing changes in control equipment operations, etc.) that a unit experiences as a normal course of operation. EPA can help alleviate some of the effect of variability on unit emissions, that was not accounted for in ICR testing, by allowing annual averaging while still achieving the same emission reductions. AEP encourages the EPA to move the averaging compliance time to an annual period to more adequately address variability that was not captured in steady-state full load ICR testing as well as providing sources with greater operational flexibility while still maintaining the same overall reduction in HAPs emissions.

III. The Emissions Averaging Provisions Should be Applied on a Mass Emission Basis.

While AEP supports the EPA's attempt to afford some flexibility in meeting the MACT limits through emissions averaging, AEP requests that EPA provide a mechanism in the final rule for a mass based emissions average at individual facilities, including adjacent facilities under common control. The proposed emission rate averaging plan does not provide much flexibility because the emission rate limits are so low and averaging times are so short. In order for a source to take advantage of these provisions, at least one unit would need to achieve a rate substantially lower than the MACT limit. There is no evidence that such rates are achievable for any existing units. A mass-based plan that applies the final MACT emission rate limits to the design heat input for all sources present at a facility on the date that the rule is finalized would achieve the EPA's mission to reduce HAP emissions, while also providing units a much greater level of flexibility and also allow for more cost-effective reductions. The mass based plan would provide each facility a total annual mass emission limit for HCl, PM, and Hg that could then provide flexibility for the source to operate its units in the most cost-effective way to meet that facility-wide limit. By utilizing a mass based approach, it becomes possible to "bank" the total allowable mass in order to provide more compliance flexibility for units that operate at a very low capacity factors and that otherwise may be prematurely retired. The proposed HAPs to be regulated are trace elements in coal, and of concern because of the potential impacts of their long-term accumulation in the natural environment. Thus, the greater concern is the total mass that is emitted, not the short-term emissions rate. A unit could have its annual mass limit set as a multiple of its design heat input, the HAP limit for each constituent, and the average capacity factor for the unit for the previous 3 years. All units at a facility would be able to aggregate their mass emission limits to have a single facility wide limit. This approach would still achieve all of the emission reductions that EPA claims in the rule, but it would achieve these reductions in a manner that is much more flexible for industry.

Additionally, the averaging provisions should not be limited to units at a facility, but should be expanded to include adjacent units that have controlled access within a common fence line. Due to many factors, including dates of construction and unit acquisitions, not all of AEP's units are classified as being at the same facility even though they share contiguous property inside the same fence line. EPA can provide additional flexibility and cost savings on emission reductions by clarifying the definition to include adjacent units within a common fence line.

IV. EPA Should Recalculate and Re-Propose the PM Limits

The ICR database is comprised of filterable PM tests that were performed utilizing a variety of sampling and analysis methods. Methods 5 and 29 were conducted at different units and used in the same floor analysis. AEP compared Method 29 filterable PM data against historical Method 5 compliance data and noticed that the Method 29 results are an order of magnitude lower than the Method 5 data. AEP performed subsequent side-by-side testing utilizing both methods simultaneously and again saw the order of magnitude disparity in the methods. The results of the side-by-side testing of the methods were summarized in a white paper by EPRI that is being included as Attachment B to these comments.

EPA should conduct an analysis for the filterable PM MACT floor using either the Method 5 or the Method 29 data. It is inappropriate to derive a PM MACT standard by mixing data from the two methods as they are not equivalent methods. The PM limit is set by the lower data obtained using the Method 29; however, compliance will be determined by Method 5 for the filterable PM option, which tends to yield higher results. EPA is setting a standard that will make an already difficult limit to achieve even more difficult to meet. With the known disparity in results, it is arbitrary and capricious for EPA to establish a limit based on test results using one test method, but require compliance demonstrations to be made using a different method with an inherent high bias. EPA should recalculate a PM limit based on a like-method comparison and re-propose the rule. Additionally, EPA should use an average of the test series instead of the lowest from the runs.

III. EPA Should Use Filterable PM as a Surrogate Instead of Total PM

EPA has not been able to demonstrate that total PM is a more appropriate surrogate for non-Hg metals than filterable PM. Based on EPRI's analysis of the data, the addition of condensable PM does nothing to strengthen the relationship between filterable PM and non-Hg metals. The analysis for a filterable PM limit should be based solely on Method 5 test data collected during the ICR and compliance should be determined from a Method 5 stack test.

Further, using total PM as a surrogate has numerous technical challenges that demonstrating continuous compliance using a filterable PM limit does not. Filterable PM can be measured continuously through a PM CEMS monitor. The variability of condensable PM in the flue gas is enormous and the test methods for condensable PM are still incapable of accurately measuring the condensate in a replicable fashion routinely. The study that AEP conducted, in conjunction with EPRI, showed that the Method 202 may not be accurate in stacks with FGD. More study is required to understand the limitations with the measurement of condensables and to construct a test method that will be accurate and repeatable for in-stack measurements.

V. EPA Should Amend the Filterable PM Unit-Specific Limit to Give Sources Credit for Low PM Emissions

If EPA maintains a total PM standard, the site-specific filterable PM limit derived from the performance test total PM should be amended to be calculated as the total PM limit minus the condensable test result to arrive at a site-specific filterable limit. This method would not punish units that are well controlled by forcing those units to adhere to an even stricter filterable limit than their counterparts. Under the EPA proposal, units that employ a baghouse will be out of compliance as often as units equipped with precipitators due to the tighter unit-specific PM limit that would be established as a result of the required performance stack test. For example, a unit equipped with a baghouse may have emissions during the performance testing of 0.008 lb/mmBTU for filterable PM and 0.012 lb/mmBTU for condensable PM thereby passing the performance test. The unit would then have to meet a 0.008 lb/mmBTU limit on its PM CEMS. A unit equipped with an electrostatic precipitator may have emissions during the performance test of 0.02 lb/mmBTU for filterable PM and 0.01 lb/mmBTU for condensable PM, thereby passing the performance test. This unit would then have a 0.02 lb/mmBTU limit on its PM CEMS. The baghouse is doing a much better job of controlling PM, but the manner in which the proposed rule governs ongoing operations does not give the unit with the baghouse credit for its low emissions. The limits for the baghouse unit should be calculated as the proposed Total PM limit, 0.03 lb/mmBTU, less the condensable fraction, 0.012 lb/mmBTU, to give the source its filterable PM CEMS limit of 0.018 lb/mmBTU. This approach would meet the spirit of the proposed rule by limiting a source to the MACT floor, while giving the source credit for good performance.

VI. EPA Should Allow for a Startup and Shutdown Work Practice Standards

EPA failed to properly account for periods of startups and shutdowns in developing the proposed MACT standards. Stack testing during the ICR was done exclusively with the units at normal operating loads. By setting a limit to include startups and shutdowns, but having limits based solely on full load, steady-state test data, EPA is violating the requirements of the CAA to set achievable standards. It is impossible for EPA to declare that the MACT floor calculations include variability adjustments to reflect periods of startups and shutdowns when EPA possesses no test data to support this declaration. None of the data collected was representative of any startup/shutdown periods, and some of the control equipment vital to achievement of the proposed standards is constrained by the need to safely operate systems within manufacture specifications, as well as the need to achieve stable operating temperatures or other conditions that are not present during startup and shutdown periods. Startups and shutdowns routinely occur as a part of normal plant operations; however, the equipment performance and associated emission rates during these periods are not similar to those during steady-state full load operation. The different operating regime during these startup/shutdown periods was recognized by the EPA in the response to comments for the final IB MACT rule and is equally applicable in this rulemaking. Unit processes, including control equipment, may not operate at all, or at peak efficiency, until the unit achieves certain temperatures (increase in products of incomplete combustion, control devices not operating properly) or process rates. The increase in actual emission rate could greatly skew the average emission rate over the proposed averaging periods, particularly in units with a low capacity factor. Should startups and shutdowns not be excluded from the averaging period, the inclusion of these periods would have a much greater effect on peaking units, which by their nature will experience more startups and shutdowns. Accordingly, if EPA appropriately sets the standard, this influence must be taken into account in developing the limits, or these periods should be governed by work practice standards. Furthermore, EPA would be following its own precedent by excluding periods of startups and shutdowns from being counted towards emission limits as established in numerous other rulemakings.

AEP is in support of the proposed affirmative defense for malfunctions. Sources need the protection from exceedances caused by circumstances beyond their control.

VII. EPA Should Not Include a Beyond-the-Floor Limit for Mercury.

EPA has proposed a beyond the floor mercury limit for subcategory 2, new and existing EGUs designed to burn a virgin non-agglomerating coal having a calorific value (determined on moisture and mineral matter-free basis) of less than 8,300 Btu/lb in a unit with a furnace height-to-depth ratio of 3.82 or greater. EPA justifies its approach to going beyond the floor for these units by stating: “EPA believes that the control level being achieved is still not that which could be achieved if ACI were used to its fullest extent.” However, EPA fails to provide any support for this claim and thus it is purely speculative. Due to this unsubstantiated claim and lack of health benefits, AEP believes that EPA must rely on the MACT floor for subcategory 2 units.

In its beyond the floor compliance option analysis, EPA assumes that all units could achieve the same emission rate as the best controlled similar source using a combination of ACI and fabric filters. While EPA’s modeling and inputs may support this conclusion, the underlying variability in fuel, boiler, control and performance makes such an assumption overly simplistic and inaccurate in terms of real-world implementation. Furthermore, EPA portrays “cost-effectiveness” in terms of $/lb-Hg removed, but this is a meaningless metric unless EPA can justify that the benefits exceed that cost. In fact, IPM modeling indicates the annual cost of beyond the floor would be $86.7 million. However, the EPA cost number as previously determined in setting the beyond the floor limit was only $70.2 million, suggesting the even EPA cannot say with any certainty how much this standard will cost. Additionally, these cost numbers are an order of magnitude higher than the direct benefits of ALL mercury reductions associated with the entire MACT rule of only $4.1-5.9 million. Thus, it is obvious that the health benefit of only addressing a small subset of the mercury emissions is much less, and the projected costs are an order of magnitude higher than the total benefit from ALL mercury reductions under the rule.

AEP is also concerned with the IPM analysis suggesting that units will fuel switch to meet the beyond the floor standard. This is unrealistic for several reasons. First, pursuing a fuel switch option could change the subcategory of the unit from subcategory 2 to subcategory 1 and thus subject it to a more stringent Hg MACT limit. Second, fuel switching costs used by EPA do not appear to account for all required coal conversion activities and projects. One very large associated project not included in the cost analysis was new coal unloading and coal yard facilities to accommodate sub-bituminous coal. Sub-bituminous is likely to be delivered by rail instead of truck or conveyor, which is the predominant delivery method for lignite fuel. Additional facility upgrades, which were not included in the scope of EPA's cost estimate, include dust collection, new coal conveyers, fire protection, ventilation, ESP performance and water cannons to handle the new fuel, soot and ash characteristics. These costs and the impacts of fuel switching on the overall efficiency and performance of the unit are substantial and should be analyzed and included in a reexamination of the cost and technical feasibility of pursuing a beyond the floor approach. EPA should make a positive determination, in the final rule, that this type of fuel switching would not redefine the subcategory.

VIII. EPA has Omitted Crucial Data from the IPM Model Inputs

While EPA has made significant efforts to update inputs to the IPM model, AEP feels other significant revisions are still needed. As an example, the estimates on SCR costs are still well below industry estimates for installed costs and should be raised at least 20%. Also, based on the supplemental IPM documentation, it is not clear that EPA is correctly accounting for AFUDC and owner's costs on fabric filter retrofits. The illustrative data table in the supplemental documentation does not match the data as presented in the Sargent and Lundy cost model described in Appendix 5-5. Additionally, costs for ACI and DSI do not appear to include transfer, handing and storage facilities. These costs are significant components for these types of projects, particularly for larger units which may need rail facilities. Thus, the ACI and DSI capital costs should include the cost of these necessary ancillary systems. All of these oversights, errors and omissions should be addressed prior to any additional IPM modeling.

The proposed construction costs for environmental controls are based on current market conditions and do not take into account the supply constraints that will be present in the markets as a result of this rule and others. Virtually all the equipment and engineering services for power plants comes from the same small group of viable suppliers. As there are relatively few reputable firms who deal with this type of work, resources will be stretched as all utilities will be competing for the same resources in order to meet the same compliance deadline. This will drive up the cost of engineering, design, and labor associated with emission control retrofits or new replacement generation, while limiting the number of such projects that can feasibly be completed prior to the rule becoming effective. Additionally, the raw material markets will be stressed as steel and other key commodities will be placed in higher demand, which are already showing price increases and signs of high demand due to the rebuilding efforts in Japan. EPA needs to evaluate the supply chain impacts of the rule to more accurately portray costs and include a feedback mechanism in its modeling efforts.

It is also unclear how EPA made some conclusions regarding which units would have to add fabric filters to meet the PM standard. EPA concluded that 49 GW of additional capacity would have to add fabric filters to comply with the PM portion of the rule and "based on ICR data and existing pollution controls, EPA estimates that approximately 54 GW of existing capacity without fabric filters may not require this retrofit." EPA provides no documentation or support for these conclusions on the implementation of control technology to meet the PM limits. Therefore, AEP requests that EPA present full emission data and projections, along with conclusive results as to which technologies, controls and units are likely to meet the HAPs standards without the use of a fabric filter and which are not. This is a critical piece to determining the overall cost of the rule in the regulatory review process.

Additionally, AEP is concerned that the gas supply curves utilized within the EPA model are too short on supply and inelastic in the near-term. This is based on comparison with data from EIA's 2011 Annual Energy Outlook. AEP requests that EPA coordinate assumptions with EIA on gas prices, as well as other energy industry cost inputs, so that more accurate IPM modeling can be used to develop the final rule.

AEP feels very strongly that EPA reached an incorrect conclusion that gas prices have the most significant impact on unit retirements. While gas prices play an important role in determining the economics of electric power markets and ultimate decisions on generation capacity, the most relevant impact to existing coal units is their exposure to future environmental constraints and potential expenditures. These regulatory uncertainties dwarf any variability in gas pricing. As such, EPA needs to constrain its model with likely future environmental policy actions. These constraints include Coal Combustion Residuals (CCR) regulation, revised National Ambient Air Quality Standards (NAAQS), regulations surrounding cooling water intake impingement and entrainment (316(b)), regional haze implementation, and GHG regulations. EPA must include an approximation of these factors in its analysis to match with the actual planning processes of the utility industry. Without such analysis, EPA will dramatically understate the impact of the individual rule being proposed.

As an example of EPA understating potential cumulative impacts on the utility industry as a result of the IPM modeling, IPM model results of the HAPs MACT case indicated that Northeastern units 3-4, located in Oklahoma, would be able to comply with the MACT rule through the use of dry sorbent injection. However, in March 2011 EPA issued a Federal Implementation Plan which would require FGDs to reduce SO_2 making the HAPs scenario proposed by EPA unrealistic. EPA needs to reevaluate its modeling with correct inputs based on the totality of all current rulemakings including FIPs.

Section 3: Implementation Concerns

I. EPA Should Provide Certainty to Sources that Adequate Time Will Be Available to Install Controls.

EPA can provide greater assurance that a blanket one year extension will be provided for the completion of major retrofits. As the rule currently stands with a three year compliance timeframe, utilities will simultaneously be seeking regulatory approvals from a variety of agencies that have limited resources to assure that timely implementation of emission controls can occur. These approvals include permission from Regional Transmission Operators for major tie-in outages, cost-recovery approval from state utility commissions for regulated utilities, as well as necessary environmental permits needed to commence construction. Engineering and design of FGD's, DSI systems, and baghouses will not be complete far enough in advance of the compliance date to allow the number of outages to be managed by the compliance date. By granting a blanket one-year extension, utilities will have certainty in planning and budgeting further in advance, thereby allowing even the most ambitious compliance strategies to be implemented in a timeframe that is realistic with respect to regulatory approvals and technically feasible in terms of design and construction schedules. The proposed rule will result in a significant number of unit retirements and a significant number of extended forced outages for units to install additional emission controls. This loss of available generating capacity in the compressed implementation timeline afforded by the proposed rule, coupled with the inability to construct new generation assets within that timeline, creates significant concerns regarding grid reliability. This can be alleviated by giving utilities certainty upfront that additional time will be available for major retrofit installations.

EPA should also decouple the requirement to have replacement power constructed at the same site as a prerequisite to gain an additional year extension. It may not be feasible to construct replacement power at the same site due a number of issues, including siting issues, modeling concerns related to recently implemented NAAQS, proximity to natural gas pipelines, etc. EPA should grant the extension for any plant that will be retired when replacement power comes online. The extension should also apply if transmission improvements are needed, additional gas supply lines must be constructed or replaced, or if required state and federal regulatory approvals to retire the capacity cannot be obtained.

II. EPA has not adequately studied the reliability impacts associated with not just this rule, but all rules that EPA is currently promulgating

AEP believes that EPA is dramatically understating the potential reliability impacts associated with this MACT rule. The heart of this underestimation is the major disconnection between EPA's modeled scenarios using IPM and the real constraints electric generators must use in their planning processes. The main issue is IPM models the MACT rule in isolation from future regulations, instead of making a realistic attempt to quantify environmental and other risks faced by the electric power sector as part of the model's decision logic. As such, the model has a completely unrealistic bias towards preserving coal-fired generation as potential future costs due to GHG regulation, cooling water intake structure requirements and other environmental regulations are not factored into the investment decisions. These regulations will have significant impacts on the amount of capital utilities are willing to invest in older units given likely future requirements or expenses and should be taken into account in subsequent modeling.

Another issue potentially affecting reliability is that the MACT limits set a very high standard for compliance with minimal consideration of potential, and likely, variation. Thus, any upset or variation in operation, process or fuel specification could result in a unit having to be derated or taken off line to remedy the situation. These activities would have a negative impact on reliability and should be more thoroughly examined.

EPA notes that before the final rule, they will work with "DOE and FERC to identify any opportunities offered by the authorities and policy tools at the disposal of DOE and/or FERC" to protect reliability. This language suggests that EPA has not consulted with DOE and FERC to date, which suggests that the necessary rule coordination or harmonization is not occurring. Furthermore, the statement implies that EPA only sees flexibility on the part of DOE and FERC to protect reliability and that adding this flexibility into the MACT rule itself, or other proposed rules for that matter, is not a concern for EPA, which goes directly against the Executive Order.

AEP has been involved in a series of meetings with PJM, SPP, EPA, DOE, FERC, and NERC to discuss the impacts of this and other EPA rulemakings on the reliability of the transmission system as well as to discuss ways that EPA can provide flexibility to ensure reliability. AEP suggests that EPA closely examine all of the publicly announced implementation plans from utilities to assess the accuracy of the data EPA is relying on to make the claim that grid reliability is not an issue. These data must take into account actual and planned future regulations and their impact on the electric sector, as well as resulting rate and reliability impacts. Only in viewing a comprehensive and holistic analysis of the electric sector can there be a reasonable discussion of the reliability impacts. This type of cross-functional analysis should include the most specific localized or unit level reliability analysis possible in order to pick up key ancillary services important to grid stability.

III. EPA has failed to address regulatory concerns associated with Executive Order 13563

AEP has significant concerns relating to the promulgation of this rule as it relates to Executive Order 13563, "Improving Regulation and Regulatory Review," issued January 18, 2011. The Executive Order defined central principles for regulatory review including "propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs," "to impose the least burden on society," to promote "coordination, simplification, and harmonization" of regulatory actions and use of flexible approaches. The proposed rule does not live up to the language and intent of the Executive Order.

EPA has failed to demonstrate that the direct benefits of the MACT rule will outweigh the costs. EPA calculates only \$4.1-5.9 million in benefits from the Hg reductions and \$0 in monetized benefits from direct reductions of other HAPs. At the rule's projected cost of more than \$10 billion annually, these direct benefits hardly outweigh the added societal cost. In a flawed attempt to justifying the rule under these remarkably unbalanced conditions, EPA characterizes collateral reductions of fine particulate matter ($PM_{2.5}$) as producing monetary benefits. However, regulation of $PM_{2.5}$ is covered under health based standards in other areas of the Clean Air Act, deriving a benefit under this rule is simply the use of imprudent accounting practice.

The MACT rule also fails to take into account "coordination, simplification and harmonization" with other regulations. As an example, EPA does not take into account the effect of this rule coupled with future requirements surrounding Coal Combustion Residuals (CCR), revised National Ambient Air Quality Standards (NAAQS), regulations surrounding cooling water intake impingement and entrainment (316(b)) and GHG regulations that will also be affecting sources in upcoming years and will in fact be proposed by EPA. With this failure in intra-agency coordination, EPA gives affected units and facilities little planning certainty, which will lead to uneconomic decisions forcing increases in electricity costs and a pronounced impact on the economy. Additionally, the subsequent analysis of the rule does not take into account "the costs of cumulative regulations" as directed by the executive order. Particularly disturbing is EPA's interpretation that the Executive Order enables future regulations to consider the impact of the MACT rule, but made no effort within the MACT rule to consider future regulations.

EPA also chose not to use its full available authority and discretion under the Clean Air Act in promoting flexibility within the proposed HAPs regulations. By starting with an emission dataset that intentionally included only the best performing units, it ignored the potential for subcategorization amongst different boiler configurations, sizes, ages, fuel types and existing control technologies to provide compliance flexibility. There is extreme variability in capability and costs associated with reducing emissions in the broad category of utility boilers and thus additional flexibility through subcategorization needs to be examined and should be provided. Other areas where flexibility could be improved include the source averaging provisions and the requirements for monitoring and verification of compliance.

In addition, recent EPA statements directly contradict the tight timeframes under which this rule is being promulgated. The Industrial Boiler MACT rule has been reconsidered due to the enormous number of public comments and problems associated with the rule as proposed and these issues were recognized in press releases by EPA. EPA should prevent a similar situation with this rule and fix known issues with the data before re-proposing the rule.

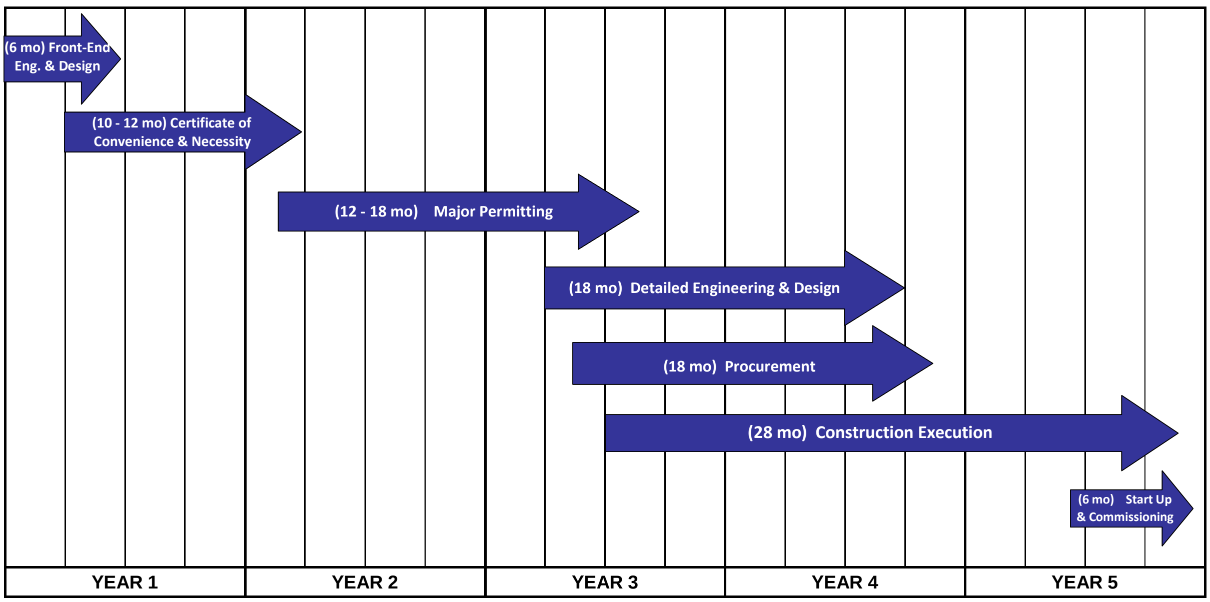
IV. EPA has underestimated the time frame associated with construction control equipment

EPA claims "units that choose to install dry or wet scrubbing technology should be able to do so within the compliance schedule required by the CAA as this technology can be installed within the 3-year window." AEP completely disagrees with this statement. AEP has previously indicated in Congressional testimony and in comments to EPA, that the timeline for FGD construction is much longer than three years, particularly once the required permitting and regulatory approvals are factored in. The proposed rule says these factors can be excluded from construction timelines as these processes can be started in advance of a rule based on preliminary assumptions of regulations. This is simply not true. Going into the regulatory approval and permitting process, significant money and resources must be utilized to help provide regulators with a required level of certainty as to the scope and cost of the project before proceeding. These dollars cannot be prudently spent, on the ratepayers or shareholders behalf, prior to obtaining a reasonable certainty as to the ultimate timing and stringency of a regulation. In the case of this rule, very little certainty can be offered at this point as there are fundamental areas of deficiency in the rule.

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. A typical FGD retrofit timeline is provided below.

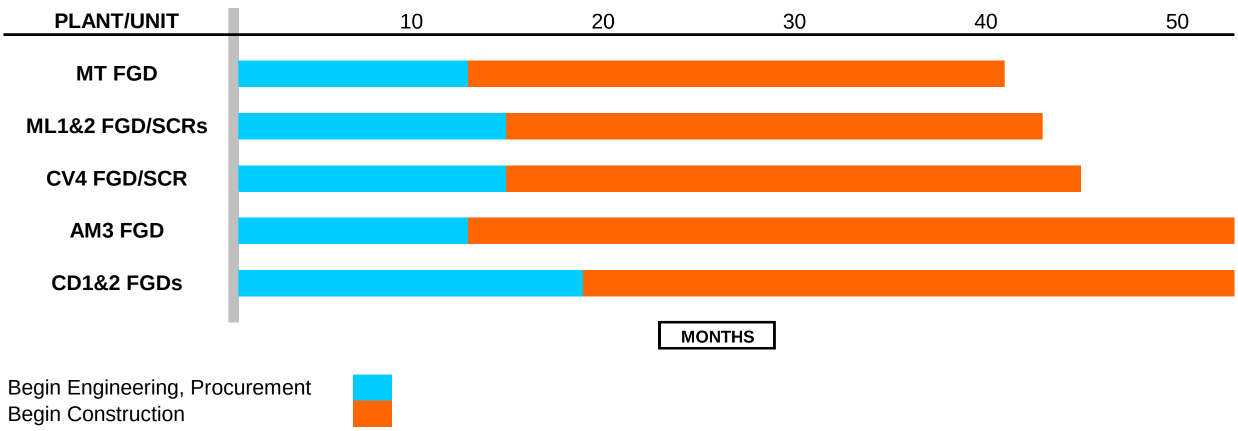
Typical FGD Retrofit Timeline:



- Timeline milestone lengths are based upon actual AEP construction experience
- Timelines could be longer if the support system becomes strained from multiple companies facing similar compliance deadlines

The below chart depicts 6,200 MW of AEP's most recent FGD retrofit experience: Mountaineer and Amos Unit 3 (1,300 MW each), Mitchell 1&2 and Conesville 4 (800 MW each) and Cardinal 1&2 (600 MW each). It is important to note that none of these installations required AEP to receive a Certificate of Convenience prior to construction. In states that require a Certificate of Convenience, these construction timelines can be lengthened by up to a year.

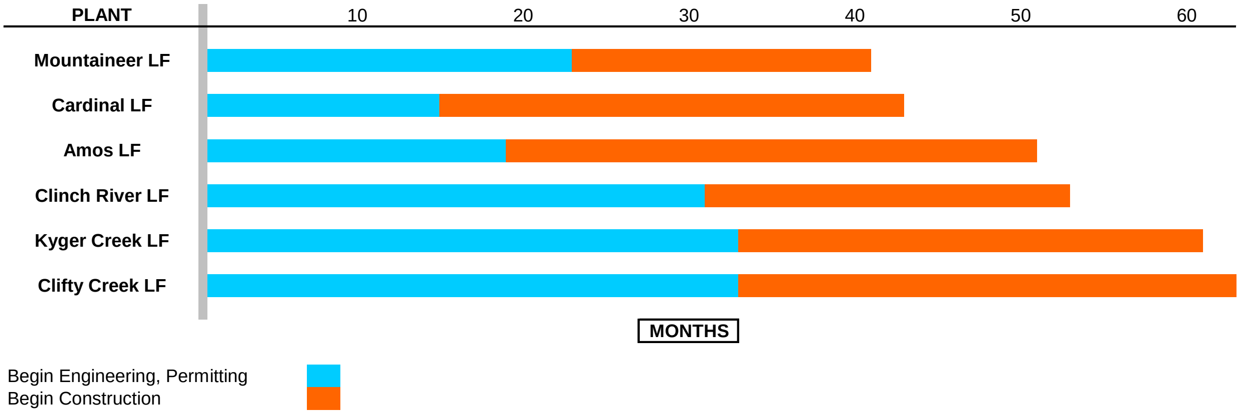
AEP Actual FGD Construction Timelines



<u>Engineering and Construction of the Landfill takes on average 42 - 54 months to complete</u>
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 borrow 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, borrow 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 land acquisition, engineering, permitting, and construction could be lengthened substantially by EPA's coal combustion residuals rule proposed on June 21, 2010 (75 Fed. Reg. 35128).

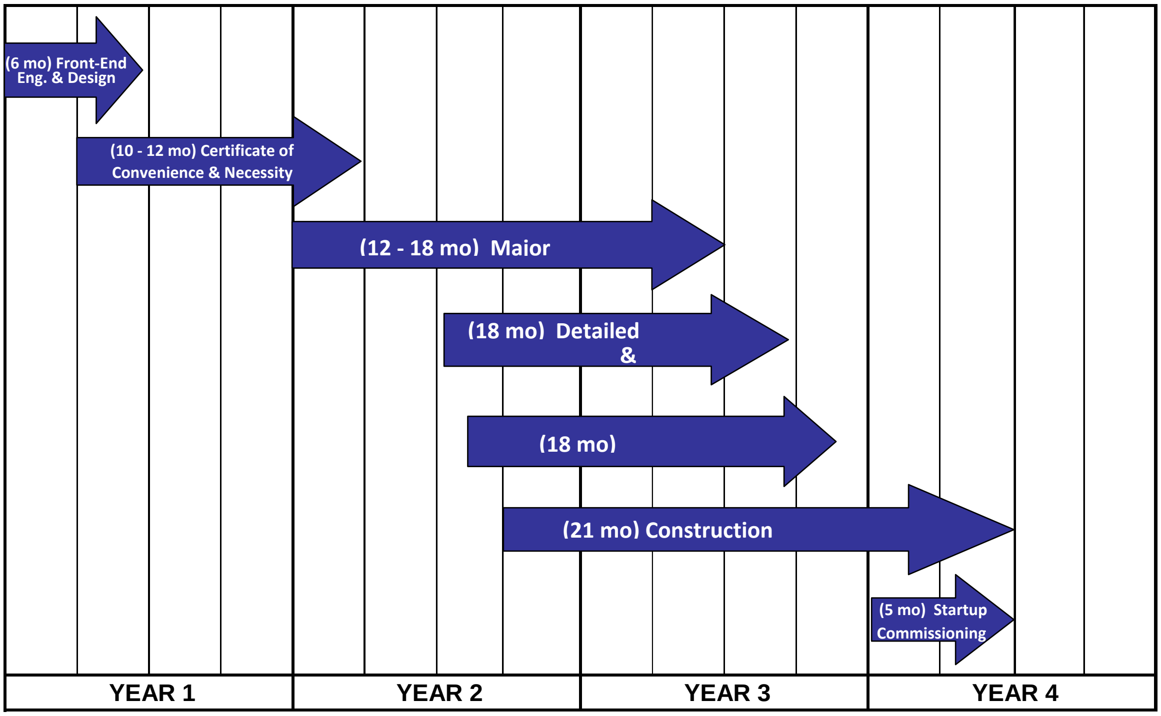
AEP Actual FGD Related Landfill Construction Timelines



<u>Engineering and Construction of a Fabric Filter takes on average 42 months to complete</u>

The complexity of the "construction" of a fabric filter is site-specific, which strongly influences the time required for installation. The FEED work required to determine the feasibility of the project and to establish the high level cost estimates requires a 6 to 8 month effort. An additional year may be added to this process should a Certificate of Convenience be required by the state that the unit is located. 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 including startup and commissioning of the new Fabric Filter, will take approximately 42 months. A typical Fabric Filter retrofit timeline is provided below.

Typical Fabric Filter Retrofit Timeline:



- Timeline milestone lengths are based upon actual AEP construction experience
- Timelines could be longer if the support system becomes strained from multiple companies facing similar new build requirements

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. The total amount of retrofits is likely to be on a much larger scale than what was achieved in preparation for compliance with CAIR. Additionally, unlike CAIR, the proposed MACT 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.

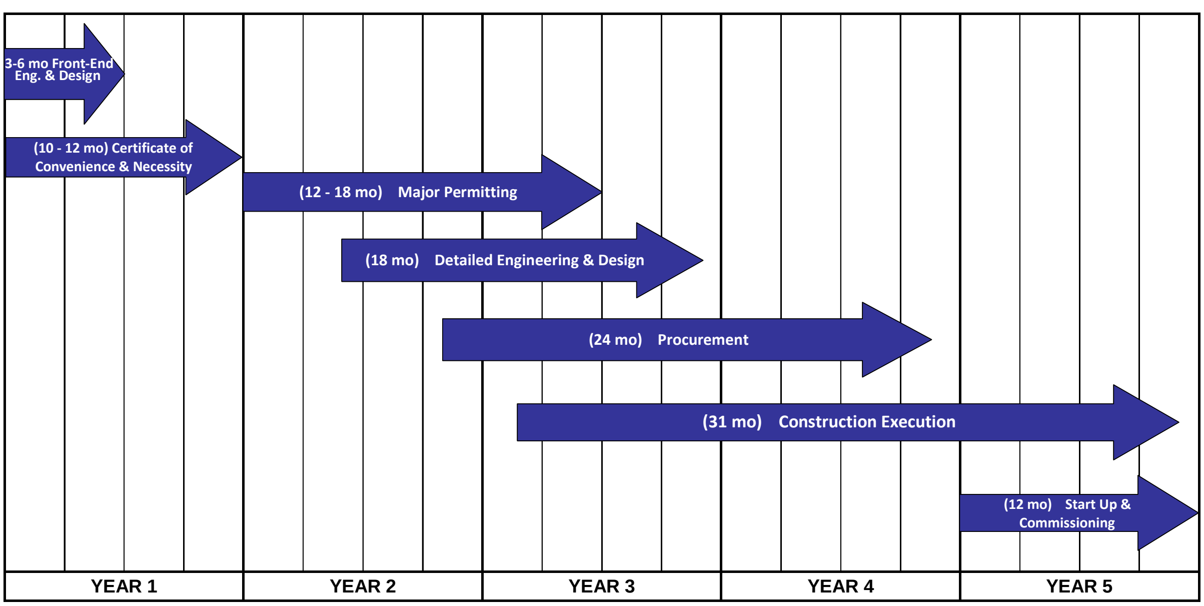
In addition to any PSD or state air quality permitting, some state regulations require obtaining public utility commission approval in the form of a certificate of need. These are issued for projects required by regulation and in some instances (i.e. Kentucky), must be issued prior to initiating construction. 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 significant basic 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

The EPA's assertion that three years is enough time for FGD installations is simply unrealistic and not consistent with the broad experience of AEP (or the utility industry) over recent years. EPA's position is premised based only by reference to a single memo. However, the use of a single memo to make such a robust claim is extremely problematic and flawed in its applicability to this rule. The letter from David Foerter, the executive director of the Institute of Clean Air Companies (ICAC), to Senator Carper describes the timelines associated with emission control construction. However, ICAC does not represent an unbiased or impartial source, but rather is a group of companies that stand to substantially benefit from generating units adding emissions controls as quickly as possible. Thus, it is in their best interest to make a claim of a short construction timeline to sway environmental policy. Furthermore, the letter indicates that "design and construction of a large 'wet' scrubber system <u>may</u> take 36 months to complete." The use of the word "<u>may</u>" does not indicate a fixed 36 month period for completion, nor does this statement consider time associated with permitting, regulatory approval, testing and start-up periods. Thus, this letter clearly does not support a 36 month compliance window or that a full project cycle for a new FGD system is 36 months. AEP also has similar concerns regarding the overly ambitious and unrealistic timelines presented for dry scrubber and dry sorbent injection systems in the letter from Mr. Foerter.

For a regulation that will have such broad-ranging, significant impacts to the health and economy of the United States in terms of the viability of the coal-utility industry, cost-impacts to rate payers, and reliability of electric transmission grid, it is imperative that EPA not rely upon limited, and potentially biased, information from sources such as vendors or other interest groups, without support or documentation, as rational for installation timelines, costs or performance of technologies. Therefore, EPA should significantly expand the quantity and quality of their review so that accurate, realistic, and broadly-accepted expectations of the cost, development timeline, and performance of emission control systems can be properly considered in the decision-making process for the final rule.

AEP appreciates that EPA includes construction of on-site replacement power as an eligible activity for a compliance extension should units be retired and replaced. However, the reference to "on-site" replacement generation is too limiting as existing sites, among other technical factors, may not have easy access to natural gas supply, which will be the likely fuel source for much of the replacement generation. Additionally, replacement generation may be added at a single larger site to replace retired generation at number of smaller sites. Thus, AEP requests that ANY capacity being added to off-set unit retirements automatically be eligible for the compliance exemption. As noted in the figure below, the construction timeline for a new combined cycle unit is similar to that for retrofitting an FGD system on an existing unit, and thus also could not be completed within a three year window.

Typical Combined Cycle Retrofit Timeline:



- Timeline milestone lengths are based upon actual AEP construction experience
- Timelines could be longer if the support system becomes strained from multiple companies facing similar new build requirements

V. EPA vastly overestimates the job creation capabilities of this rule

Based on AEP's experience, EPA has misrepresented the true employment impacts associated with the MACT rule. EPA has projected a net increase in employment based on a narrow view of employment that is only associated with installation and operation of new pollution control equipment. This ignores the largest employment impacts -- those associated with the impacts to other economic sectors, whereby the resulting higher electricity rates make domestic manufacturers less competitive leading to fewer jobs and less discretionary income for all Americans. A recent macroeconomic study conducted by NERA indicated that 1.44 million job-years would be lost as a result of the Cross State Air Pollution Rule and MACT rule. This is in stark opposition to EPA's claim that jobs will be created.

EPA's jobs analysis significantly under estimates the job impacts even within the electric sector, as incorrect assumptions within IPM modeling lead to the conclusion that more coal units will adding controls than actually will. In fact, there will be a large number of coal unit closures associated with this rule which will result in lost jobs. The likely replacement generation for retired units will be new natural gas combined cycle units, which employ 75% less people per megawatt of capacity than coal. AEP has announced that it will lose approximately 600 jobs due to unit closures from this rule and other EPA rulemakings. It is impossible to analyze this rule by itself without looking at the impact of all other EPA rulemakings.

Before finalizing this rule, EPA must examine and identify the full U.S. employment impacts of the rule by utilizing a robust macroeconomic model. This is consistent with supporting the notion that the rule costs must not outweigh the benefits.

Section 4: Compliance and Monitoring Issues

I. Dry Sorbent Injection is an Unproven Control Technology and its Benefits for HAPs Control are Overstated

AEP is troubled by EPA's assumption that dry sorbent injection ("DSI") could be used in a wide-spread fashion to control acid gas emissions from coal-fired units. Currently, very few coal-fired units utilize DSI for any purpose. No units have been identified that employ DSI specifically for HCl control. Given the lack of practical experience in the utility industry with DSI as an HCl control and uncertainties regarding its potential performance, EPA should revisit the application and performance attributes of this technology, which the agency currently projects will be installed on 56 GW of capacity for acid gas control. Otherwise, the agency risks understating the potential costs associated with this rulemaking and the number of induced unit retirements.

EPA's dry sorbent injection technical assumptions are equally concerning. EPA's source data for DSI HCl removal capability is a main supplier of the technology and sorbent. The *Documentation Supplement for EPA Base Case v4.10_PTox − Updates for Proposed Toxics Rule* states: "The corresponding HCl removal effect is assumed to be 90%, based on information from Solvay Chemicals (H. Davidson, *Dry Sorbent Injection for Multi-pollutant Control Case Study*, CIBO IECT VIII, August, 2010)." Solvay Chemicals Inc. holds numerous patents and considerable intellectual property relating to the use of Trona and other sodium-based sorbents to remove SO_2, SO_3 and other acid gases and will substantially financially benefit from any regulation requiring DSI technology. Additionally, the reference document referred to by EPA is not a detailed technical analysis, but rather a 13 slide presentation, which refers to a **single test case**, on one unit, over a three week period and lacks any technical specifics which would be required to extrapolate applicability and performance elsewhere. For a regulation that will have such broad-ranging, significant impacts to the health and economy of the United States in terms of the viability of the coal-utility industry, cost-impacts to rate payers, and reliability of electric transmission grid, it is imperative that EPA not rely on limited information from vendors or interest groups, without support or documentation, as rational for installation timelines, costs or performance of technologies. Therefore, EPA should significantly expand the quantity and quality of their review so that accurate, realistic, and broadly-accepted expectations of the cost, development timeline, and performance of emission control systems can be properly considered in the decision-making process for the final rule. The fact that EPA allows DSI to be used in conjunction with existing ESP systems in its modeling without regards to size or performance is troubling. In fact, EPA assumed in the recently finalized Cross State Air Pollution Rule that DSI could only be used in conjunction with a fabric filter.

The assumed SO_2 removal of 50-70 % with DSI is not specifically supported by the S&L study other than indication it was based on commercial testing. The notion of commercial testing does not indicate that this technology has been implemented or routinely utilized at a full scale. It certainly does not automatically imply "commercial acceptance" either. This is particularly troubling as the technical support document notes that "information and data provided by others may not have been independently verified by S&L." In other words, this data could have come directly from the Solvay presentation as well. Additionally, while the S&L study differentiates amongst SO_2 removal efficiency by particulate removal type, it fails to comment on the role that other factors including injection location and fuel type have on potential dry sorbent performance. Additionally, S&L analysis does not account for the potential cost premiums affected units could pay for being forced to rely on this single vendor (Solvay) for this "key cost saving technology." In addition, these "testing" reports do nothing to evaluate or discuss potential operational concerns with respect to DSI processes, such as the reliability of injection systems, impacts to existing unit performance (e.g. DSI related plugging, corrosion, heat transfer, efficient impacts, etc.), or potential upgrades that may be necessary to particulate control technologies. AEP has installed trona injection systems on over 10,000 MW of coal-fired units and has experience with the operation of DSI as well as the issues caused by DSI injection. Trona injection can be utilized for some SO_2 removal, however, the quantities of trona required for the removal efficiencies claimed by EPA would be far too expensive and logistically cumbersome to maintain to render DSI too costly to retrofit on smaller units as a cost effective solution to the MACT limits. The O&M involved with maintaining the system due to nozzle pluggage and antagonistic effects on electrostatic precipitators would make achieving not just the HCl limit, but also the PM limit very difficult to achieve over a short 30-day operating period. EPA needs to revisit the performance and applicability of DSI based on commercially operating facilities with the recognition that facility operators must be involved in the review process.

II. EPA Should Alter the Continuous Compliance Demonstration Requirements.

It is not clear in the proposed rule that installing and operating CEMS for the regulated HAPs and surrogates will relieve a source of the burden of also monitoring compliance with operating limits on control equipment based on a performance stack test. EPA should require no additional proof of compliance if a properly calibrated and installed CEMS is employed. EPA should revise the format of both the regulatory language and supporting tables in the final rule to clarify its intent as it relates to CEMS used for demonstrating compliance.

HCl CEMS currently are not commercially available or adequate for in-stack measurements at coal-based EGU's, and are not anticipated to be available by the compliance date of the rule. As a result, sources will be forced to either take a fuel limit or an operating parameter limit. The fuel analysis limit is impractical because of the inherent variability of chloride concentrations in coal, both between various ranks of coal and within the same coal category. It will be impossible to control fuel deliveries in such a manner as to negate the possibility of burning coal with chlorine content above that which was used during compliance testing.

Operating limits for emissions control equipment based on a point-in-time stack test does not recognize the inherent variability of chloride concentrations in coal or the complex balancing act that plant operators must continuously perform to safely meet emission limits for, not just HAPs, but all regulated emissions. As currently proposed, units would be constrained by unachievable operational parameters because the set of operating limits that a unit measures during its first performance test would be its maximum operating limits. Subsequent performance tests would further ratchet down operating parameters until they are no longer achievable during a 30-day or annual averaging period. In other words, the ongoing process having to perform stack tests to demonstrate compliance with a previous stack test results will in effect drive the emission limit to zero over time as units have no choice but to test lower. As this process occurs, the result of stack testing is left to chance by the increasing influence of unknown and uncontrollable factors.

At some point, even if emission testing suggests non-compliance, facilities will be left in the unenviable position of not knowing what actions to take in order to further reduce emissions.

Control equipment operating characteristics during full load testing is not representative of the range of operating characteristics that a source can reasonably be expected to experience. These include differences related to fuel variability, unit load conditions, age of equipment, ambient environmental conditions, as well as difference related to startup, shutdown, and transient operations. As a result, parametric operating limits developed based on a single compliance test are only representative, and potentially only applicable when the unit is in that same mode. The data from that single test (or set of test) is grossly insufficient to characterize all other operating scenarios, and certainly inappropriate for use in establishing limits with unlimited applicability to source operations. With operating limits changing every 2 months based on performance testing, sources will have no confidence that they will be able to demonstrate compliance over the full range of operating conditions that is normal for the source, and permitting authorities will have an impossible task to track different sets of operating limits for each unit in their jurisdiction. Table 7 of the proposed rule should be amended to allow for a source to work with its permitting authority to develop a compliance plan that mimics what is currently contained in their Compliance Assurance Monitoring plans for PM, and develop a similar plan to assure compliance with the HCl limits. Historically, such compliance plans have effectively been developed by state agencies and implemented by the regulated community. Providing such flexibility in the final rule will enable state agencies to build on this experience and develop monitoring plans that effectively address unit-specific operating characteristics. In this manner, EPA would be recognizing that sources know best how to operate and what parameters should be monitored and controlled to ensure and verify compliance.

As proposed, the performance testing requirements for those sources without CEMS will be cumbersome, expensive, and unrepresentative of the range of expected unit operations. For low load units, frequent performance testing could require operation of the unit when it would not normally otherwise be operated. For such low capacity units, testing should be required annually for each of the stacks, instead of every other month as currently proposed. AEP has determined that it could not complete such testing at all of its units within a two month period due to lack of test crews, unit scheduling, scheduled maintenance, and other considerations. EPA's assertion that most units will choose to install CEMS is faulty based on the current lack of commercially acceptable HCl CEMS technologies and the relative infancy of PM CEMS. The CEMS systems may also not be adequate to measure emissions as low as the EPA has proposed with this rule. EPA should consider the frequency and types of monitoring appropriate for various subcategories, including an exemption for low capacity factor and LEE units.

III. The Proposed Parameters for Control Devices Are Not Adequate for all Types and Designs of Each Control Device.

The proposed rule lays out a method to establish site specific operating limits for various types of control equipment in Tables 7 and 8. For example, a wet scrubber would be required to meet site-specific operating limits for pressure drop and liquid flow rate for compliance with the PM standard. AEP has concerns with parameters being prescribed for sources on a one-size-fits-all basis, and whether it is even necessary for such parametric limits if CEMS are being used to demonstrate compliance. As an example of prescribing parameters to demonstrate compliance consider pressure drop and liquid flow rate, which may not be applicable to all types of wet scrubbers. Furthermore, the parameters may not be directly related to the emissions reductions that the equipment is obtaining. Pressure drop is not a direct measurement of emissions, and will naturally vary with load. A pressure drop that is specified for full load will not be applicable to all loads and fuels. Liquid flow rate is also a function of load and the ability to measure it accurately may be a problem. The same issues are encountered when using these parameters as a metric for demonstrating continuous compliance with the HCl limits. AEP proposes that sources be given the ability to work with the appropriate permitting authority to develop site-specific parameters for wet scrubbers that are adequate to ensure compliance while also giving flexibility to the source in how the emission limits are met. AEP would like to reiterate that a PM CEMS should be adequate in determining compliance without being required to monitor site-specific control device operating limits.

For electrostatic precipitators, a site-specific secondary power input is proposed by EPA. This parameter fails to take into account which fields are being powered and where in the precipitator they are located. The appropriate secondary power will also vary with fuel and load making a minimum level set at a full load test inadequate to assure compliance at all loads. AEP has Compliance Assurance Monitoring (CAM) plans in Title V permits for our units that were specifically developed to assure particulate limit compliance through the measurement of opacity. While opacity also is not a direct measurement of particulate, permitting authorities do recognize that it is an indicator of control device performance, and there is a wealth of existing information and approved plans that have formally documented the appropriate use of this indicator in an ongoing monitoring program. Sources should be able to rely on this existing frame work, and to work with permitting authorities to develop a set of parameters that make sense for the facility and its control configuration.

Setting a minimum sorbent injection rate for dry scrubbers or DSI removes all of the flexibility that a unit has to meet all of its obligations. Sorbent may be injected for reasons other than HAPs control during test conditions based on atmospheric conditions that would necessitate more injection for SO_3 control. Sources would then have that injection rate as a minimum injection rate until the next performance test. With an HCl or mercury CEMS, there is no reason for any site-specific limit. Without CEMS, setting a minimum injection rate will potentially hurt units as they attempt to balance their PM limit with the minimum injection of sorbent necessary to control mercury or HCl. Sources should be able to maintain the flexibility necessary to meet all of their emissions obligations.

IV. EPA Cannot Rely on Unproven HCl Monitoring Technology.

HCl is not routinely monitored by electric generating units, and there is little stack test data beyond that collected by EPA during the ICR process. No HCl continuous monitors were used to collect any of the data used by EPA to establish the HCl standard, and there is no information about HCl emissions at conditions other than the limited data available for normal full load operations. Nevertheless, EPA proposes to rely on continuous HCl monitors as its preferred monitoring method for MACT compliance.

It is imprudent for the EPA to set forth a monitoring standard for which there has been very limited experience in the relevant industry and for which the technology has not been commercially developed. EPA states that FTIR has been shown to be adequate for in-stack measurements. However, FTIR has been shown to be unreliable in stack applications, especially at emission rates as low as the EPA has proposed. Given these (and other) uncertainties regarding FTIR performance, EPA should not dictate FTIR as the technology to be utilized. AEP does support SO_2 as a surrogate for HCl at scrubbed units. If EPA establishes additional subcategories, including alternative strategies for unscrubbed units, AEP requests that EPA expand the use of SO_2 as a surrogate parameter for unscrubbed units and units operating with other controls, including DSI and dry scrubbers.

When non-regulatory standards are quoted (Voluntary Consensus Standards), the year of publication needs to be included as part of the rule. Future changes to the standards will cause confusion if the version of the year is not delineated by including the year for reference. Modifications to the standards can significantly affect compliance strategies.

NIST traceable standards are still not available. This is something the industry has been waiting on for years and it is still not final. Gaseous oxidized standards traceable to NIST are also not available. Agreed to standard mercury vapor pressure curves are still not available. All of these issues need to come to a final conclusion before this rule should be implemented. Without them there will be non-uniform reporting of emissions.

HCl CEMS have been considered by various state environmental agencies in the air permitting process for a number of recent new coal generation projects. A variety of concerns have been expressed by agencies regarding the use of HCl CEMS. For example, consider the following excerpts from state agencies in their Response to Comments document that supported the issuance of final air permits:

> "The biggest concern over the use of HCl CEMS is that they are not commercially available and demonstrated in practice. They are used especially on incinerators or other combustion sources where the fuel has a high concentration of chlorine. The problem is with the level of detection. The outlet HCl emissions from a coal-fired power plant are very low in comparison to other sources with high chlorine emissions. Thus, the detection range for coal-fired power plants on the CEMS are lower than the methods provided by EPA to ensure accurate data collection...... At this time, the CEMS are not able to accurately measure HCl and HF emissions on a continuous basis from a coal-fired power plant. Therefore, Plant Washington will not be required to install CEMS for HCl and HF emissions."[5]
> -- Georgia Department of Natural Resources (April 2010)

> "One of the concerns associated with using continuous HCl monitoring is the low HCl concentration expected in the exhaust of Cliffside 6. The expected HCl concentrations are lower than the EPA's performance specification for allowable drift, making it highly unlikely that such a monitor would provide accurate or meaningful data. The State believes that current monitoring requirements, which include a combination of fuel

[5] GaDNR Response to Comments document. Final Air Permit #4911-303-0051-P-01-0. April 8, 2010. p. 147.

sampling and analysis; frequent stack testing; and emission control monitoring provides sufficient assurance that the actual emissions will remain well below the major source threshold."[6]
--- North Carolina Department of Environment and Natural Resources (June 2009)

"A comment was also made that the Department should require an HCl CEMS to be installed. Even though HCl CEMS are currently a monitoring option (not a requirement) in the Hospital/Medical/Infectious Waste Incinerators New Source Performance Standard,281 the Department is not aware of any HCl CEMS installed and operated on a utility boiler and has no data to determine their performance. The group commenting did not provide any data on HCl CEMS used in practice."[7]
-- South Carolina Department of Health & Environmental Control (December 2008)

V. EPA Should Incorporate the Monitoring Refinements Developed for CAMR.

EPA solicited comments during the CAMR rulemaking from industry related to the monitoring aspects of the rule. EPA took industry comments under advisement and released a rule that addressed many of the issues raised. However, EPA appears to have overlooked many of the issues that were resolved in that earlier rulemaking process. AEP is attaching its 2005 CAMR comments to further address issues that had previously been addressed in the previous CAMR rulemaking. For example, comments related to RATA testing and the number of runs required, NIST traceability (or the lack thereof), or the use of single traps if one trap analysis fails, were all previously successfully addressed.

The proposed rule does not address the handling of negative values. AEP recommends that negative values be rounded to zero and use an associated code to indicate the change. This is similar to how Part 75 handles negative data. If instrument drift and allowable calibration error tolerances are included, it is possible to be within the analysis tolerance and read a legitimate negative value.

AEP recommends the use of Part 72 definitions for CO_2 and flow range determination and the definition for zero gas. AEP believes Part 72 is more accurate and provides harmonization between the two rules.

AEP proposes an additional option be available for measuring moisture. If the stack is saturated, a source should be able to use temperature, absolute pressure, and a psychrometric chart to measure moisture. The temperature and pressure transmitters can be calibrated with NIST traceable equipment. A RATA could be performed, but AEP believes that this would be unnecessary. During periods when the stack is not saturated, default factors listed in the rule could be used.

The use of diluent capping during periods of startup/shutdown is appropriate. A table should be included in the final rule listing the appropriate CO_2 diluent values. The value that was chosen for O_2 is not appropriate. AEP recommends the use of the diluent cap values as already defined

[6] Letter from D. Freeman (NCDENR) to S. Meiburg (USEPA). June 8, 2009. p. 1.
[7] SCDHEC Response to Comments document. Final Air Permit #1040-0113-CA. December 16, 2008. p. 119.

in Part 72 of 5% for CO_2 and 14% for O_2 for coal-fired EGU's. This would enable harmonization between the two rules and provide adequate margin in the data. Additionally, the equivalent values for reporting lb/MWe is too low and should be changed to 10%.

VI. EPA Should Propose to Use ECMPS for all Reporting.

Reporting associated with the proposed rule should be subject to further rulemaking to specify precisely how it can be implemented using ECMPS. ECMPS is currently being used successfully by industry and the infrastructure is already in place, thereby reducing costs. Industry personnel have been trained for the constituents that are already being reported by ECMPS so the learning curve will be very short and will allow a rather seamless transition to HAPs reporting. However, AEP recommends that EPA invite industry involvement as was used during the initial development process of ECMPS, to enable a smooth transition in dealing with the numerous monitoring requirements that will impact every coal- or oil-fired EGU stack as a result of the EGU-MACT proposal. EPA should develop the tool, then propose its use in a separate rulemaking. Numerous times industry has been stuck with software implementations that are not ready. Issues with software should be handled in advance of it being required for compliance with a rulemaking.

VII. EPA should amend the coal sampling procedures

While AEP believes that CEMS should be more than adequate for the demonstration of compliance, if EPA moves forward with the fuel analysis provisions of the rule, substantial changes need to be made. The proposed rule requires affected sources to conduct stop belt sampling or to pull samples from the coal piles during testing. Stop belt sampling is neither safe to conduct due to stored energy in the conveyor belts, nor is it representative of a unit's operation. A unit may have to reduce process rate due to a decrease or a lag in the time that the fuel is being delivered.

Sampling from the coal pile will not gather coal samples that are representative of what is being burned. AEP has coal piles that are greater than 15 acres in area, which contain coals from a variety of suppliers and mines. Gathering five samples uniformly spaced at a depth of 18 inches will not adequately represent what is being burned during the test period.
AEP suggests that the EPA specify a number of representative fuel samples during the testing, while allowing the sources the flexibility to safely and accurately determine the best method for collecting such a sample.

Section 5: New Coal-Based Generation Project will Effectively be Eliminated

I. The proposed rule will effectively eliminate the development of new coal-based electric generation projects in the United States.

In the context of new coal generation, EPA's proposed MACT for new EGU's may effectively eliminate coal as a fuel in the future. The scope and stringency of the proposed rule would result in a technology, operation, financial, and regulatory risk profile for new coal generation projects that will be too significant to justify the investment.

In developing the proposed rule, EPA considered data supplied for coal-based generation units listed in the 2007 EIA-860 report.[8] The most recent version of the EIA-860 report indicates that over the past decade at least 40 new coal-based generation units have been built or are actively under construction.[9] Collectively, these units are utilizing the most advanced combustion technologies available, are subject to EPA's New Source Performance Standards ("NSPS"), are deploying Best Available Control Technologies ("BACT"), and are having to meet Section 112(g) case-by-case MACT requirements.

And yet, despite using the most efficient and advanced combustion technologies available, despite being equipped with state-of-the-art emission controls, despite being subject to the most stringent emission limits ever established for coal-generation units, and despite the separately reached conclusions on performance from a broad number of state environmental agencies, project developers, and equipment suppliers, **none** of these 40 new coal-generation units can meet all the proposed new source MACT standards with the requirements in their existing air permit. In fact, not one of the 40 can meet the new generation mercury limit, which is orders of magnitude lower in most cases. Further, a **majority** (35 of 40) cannot meet the proposed existing source MACT standards. Tables 5-1 through 5-3 at the end of this section summarize how existing air permit limits for these units compares to the proposed MACT standards.[10]

To meet the proposed new source MACT limits, owners would have to operate well beyond manufacturer performance guarantees, accept emission limits that are so low that numerous unknown and uncontrollable variables would influence compliance, and utilize compliance testing methods with suspect accuracy and reliability. Additionally, such low emission limits, associated work practice standards, and frequency of required testing would significantly restrict operating flexibility. Combined, the impact of these issues on the technology capabilities, economic viability, and compliance risks for a new process would be so significant that the development of new advanced coal-based generation projects would be extremely limited, and would effectively eliminate coal as an option for future electric generation.

In the preamble of the proposed rule, EPA notes, in the context of fuel switching, that

> "...we [EPA] would still not adopt this fuel switching option because it would effectively prohibit new construction of coal-fired EGUs and we do not think that is a reasonable approach to regulating HAP emissions from EGUs."[11]

EPA's position is valid considering the fact that coal-based generating technologies not only provides nearly half the energy supply of the United States, but also provides an affordable, reliable, and sustainable source of energy that is irreplaceable by available alternatives.[12] The U.S. Department of Energy projects that "coal continues to account for the largest share of electricity through 2035."[13] Secretary of Energy Steven Chu has spoken to the continued

---

[8] Federal Register. Vol .76. No. 85. May 3, 2011. p. 25022.
[9] See Appendix B.
[10] Ibid.
[11] Federal Register. Vol 76. No. 85. May 3, 2011. pp. 25048-25049.
[12] U.S. Energy Information Administration. Form EIA-923: "Power Plant Operations Report." www.eia.gov. Accessed June 1, 2011.
[13] U.S. Energy Information Administration. Annual Energy Outlook 2011. April 2011. DOE/EIA-0383(2011)

importance of coal by noting that:

> "prosperity depends upon reliable, affordable access to energy. Coal…is likely to be a major and growing source of electricity generation for the foreseeable future..."[14]

> "The world will continue to rely on coal-fired electrical generation to meet energy demand."[15]

Even with EPA's statement regarding a reasonable regulatory approach and the recognized importance of coal as a continuing part of the energy portfolio of the United States, the proposed rule will significantly handicap and, in effect, eliminate the development of new coal generation projects. EPA should reassess their methodology for establishing new source MACT standards in the final rule and establish practical, common-sense limits that are technically and commercially achievable, and that provide legitimate public health benefits.

[14] U.S. Secretary of Energy Steven Chu. "Memorandum". October 12, 2009.
[15] Statement of Secretary of Energy Steven Chu before the Senate Committee on Appropriations Subcommittee on Energy and Water Development. May 18, 2011.

Table 5-1 Summary of Recent Coal-Based Electric Generation Projects (2001 to present)

Utility ID	Plant Code	State	Plant	Gen ID	Project Status	Year I/S	Air Permit #	112(g) Limits	Nameplate Capacity (MWh)	Design Heat Input (mmBtu/hr)	Unit Type	Fuel Type	Startup Fuel	Emission Controls Include: (from air permit)			
EIA-860	EIA-860	EIA-860	EIA-860	EIA-860	EIA-860	EIA-860	Permit	Permit	EIA-860	Permit	EIA-860	EIA-860	Permit	NOx	SO2	PM	Other
5416	2721	NC	Cliffside	6	UC	2012	04044T29	no	800	7,850	PC	Bit	oil	SCR	DFGD; WFGD	FF	---
15466	470	CO	Comanche	3	UC	2010	04PB1015	yes	856.8	7,421	PC	Sub	NG	SCR	DFGD	FF	SI
17543	130	SC	Cross	3	I/S	2007	0420-0030-CI	yes	591	5,400	PC	Bit; PC	oil	SCR	WFGD	ESP	---
17543	130	SC	Cross	4	I/S	2008	0420-0030-CI	yes	652	5,700	PC	Bit; PC	oil	SCR	WFGD	ESP	---
17828	963	IL	Dallman	4	I/S	2009	4110050	yes	280	2,440	PC	Bit	NG	SCR	WFGD	FF; WESP	---
1307	56609	WY	Dry Fork Station	01	UC	2011	CT-4631	no	390	3,801	PC	Sub	---	SCR	DFGD	FF	---
15470	1004	IN	Edwardsport	CT1, CT2, ST	UC	2012	T083-17006-00003	no	793.7	4,212	IGCC	Bit	IGCC	IGCC	IGCC	IGCC	IGCC
20847	56068	WI	Elm Road Generating Station	1	UC	2010	03-RV-166-R2	yes	615	6,180	PC	Bit	oil	SCR	WFGD	FF; WESP	---
20847	56068	WI	Elm Road Generating Station	2	UC	2010	03-RV-166-R2	yes	615	6,180	PC	Bit	oil	SCR	WFGD	FF; WESP	---
5580	6041	KY	H L Spurlock	3	I/S	2005	V-06-007R3	yes	329.4	2,500	CFB	Bit; WC; TDF	oil	SNCR	DFGD	FF	---
5580	6041	KY	H L Spurlock	4	I/S	2009	V-06-007R3	no	329.4	2,800	CFB	Bit; WC; WDS	oil	SNCR	DFGD	FF	---
16233	55749	MT	Hardin Generator Project	UNT1	I/S	2006	3185-04	no	115.7	1,304	PC	Sub	NG	SCR	DFGD	FF	ACI
10000	6065	MO	Iatan	2	UC	2010	012006-019	no	914	8,100	PC	Sub	oil	SCR	WFGD	FF	---
16604	7097	TX	J K Spruce	2	UC	2010	70492	no	820	8,000	PC	Sub	NG	SCR	WFGD	FF	---
17698	56564	AR	John W Turk Jr	1	UC	2012	2123-AOP-R0	yes	609	6,000	PC	Sub	NG	SCR	DFGD	FF	ACI
12686	57037	MS	Kemper County	1A	UC	2014	1380-00017	no	839.8	6,350	IGCC	Lig	IGCC	IGCC	IGCC	IGCC	IGCC
55924	56671	WV	Longview Power LLC	MKA01	UC	2011	R14-0024	---	807.5	6,114	PC	Bit	---	SCR	WFGD	FF	SI
14127	6096	NE	Nebraska City	2	I/S	2009	CP09-001	yes	738	6,478	PC	Sub	oil	SCR	DFGD	FF	---
19323	6180	TX	Oak Grove	OG1	UC	2010	76474	??	916.8	8,970	PC	Lig	NG	SCR	WFGD	FF	SI
19323	6180	TX	Oak Grove	OG2	UC	2010	76474	??	878.6	8,970	PC	Lig	NG	SCR	WFGD	FF	SI
55995	56456	AR	Plum Point Energy Station	STG1	UC	2010	1995-AOP-R3	yes	720	7,960	PC	Sub	---	SCR	DFGD	FF	ACI
15330	55856	IL	Prairie State Generatng Station	PC1	UC	2011	01100065	yes	800	7,450	PC	Bit	NG	SCR	WFGD	ESP;WESP	---
15330	55856	IL	Prairie State Generatng Station	PC2	UC	2012	01100065	yes	800	7,450	PC	Bit	NG	SCR	WFGD	ESP;WESP	---
3593	55076	MS	Red Hills Generating Facility	RHGF	I/S	2001	0400-00011	no	513.7	4,950	CFB	Lig	NG	---	LSI	FF	---
19323	52071	TX	Sandow Station	5	UC	2010	83346	---	661.5	5,920	CFB	Lig	oil	SNCR	LSI; FGD	FF	---
55861	56611	TX	Sandy Creek Energy Station	S01	UC	2012	70861	no	1008	8,185	PC	Sub	NG	SCR	DFGD	FF	---
54885	3130	PA	Seward	FB1	I/S	2004	PA-32-040B	no	585	5,064	CFB	WC; Bit	oil	SNCR	DFGD	FF	---
17833	6195	MO	Southwest Power Station	ST2	UC	2011	122004-007	no	300	2,724	PC	Sub	NG	SCR	DFGD	FF	---
7570	56786	ND	Spiritwood Station	1	UC	2010	07026	no	99	1,280	CFB	Lig; Sub	NG	SNCR	LSI; DFGD	FF	---
24211	8223	AZ	Springerville	3	I/S	2006	32008	yes	450	4,200	PC	Sub	oil	SCR	DFGD	FF	---
24211	8223	AZ	Springerville	4	I/S	2009	32008	yes	450	4,200	PC	Sub	oil	SCR	DFGD	FF	---
11249	6071	KY	Trimble County	2	UC	2010	V-08-001R2	no	834	6,942	PC	Bit; Sub	oil	SCR	LI; WFGD	ESP; FF; WESP	ACI
49896	56224	NV	TS Power Plant	001	I/S	2008	AP4911-1349	no	242	2,030	PC	Sub	oil	SCR	DFGD	FF	ACI
19876	56808	VA	Virginia City Hybrid Energy Ctr	1	UC	2012	11526	yes	668	6,264	CFB	Bit; WC; WDS	oil	SNCR	LSI; DFGD	FF	ACI
12341	1082	IA	Walter Scott Jr Energy Center	4	I/S	2007	03-A-425-P2	no	922.5	7,675	PC	Sub	oil	SCR	DFGD	FF	ACI
20860	4078	WI	Weston	4	I/S	2008	03-RV-248	yes	595	5,173	PC	Sub	NG	SCR	DFGD	FF	SI
8245	60	NE	Whelan Energy Center	2	UC	2011	58048C02	no	220	2,211	PC	Sub	---	SCR	DFGD	FF	---
19545	55479	WY	Wygen 1	0001	I/S	2003	30-205	no	88	1,014	PC	Sub	---	SCR	DFGD	FF	---
19545	56319	WY	Wygen 2	0001	I/S	2008	CT-3030A3	no	95	1,300	PC	Sub	---	SCR	DFGD	FF	---
19545	56596	WY	Wygen 3	5	UC	2010	CT-4517	no	100	1,300	PC	Sub	---	SCR	DFGD	FF	---

**See Appendix B for background information on the table.

Table 5-2 Proposed New Source MACT Standards vs. Recent Coal-Based Electric Generation Projects

		Can existing air permit limits meet the proposed new source MACT standards for the following?							
			Acid Gases		Non-Hg Metals			
		Mercury	HCl	SO2	Total PM	ALL Individual Metal Limits	Total Non-Hg Metals	Can air permit limits meet ALL of the proposed new source MACT standards?
Plant	Gen ID	lb/GWh limit	lb/GWh limit	lb/MWh limit	lb/MWh limit	lb/GWh limit	lb/MWh limit	
Cliffside	6	no	no	no	no	no	not determined	NO
Comanche	3	no	no	no	no	---	not determined	NO
Cross	3	no	no	no	no	no	not determined	NO
Cross	4	no	no	no	no	no	not determined	NO
Dallman	4	no	no	no	no	no	not determined	NO
Dry Fork Station	01	no	---	no	no	---	not determined	NO
Edwardsport	CT1, CT2, ST	no	---	no	no	---	not determined	NO
Elm Road Generating Station	1	no	no	no	no	no	not determined	NO
Elm Road Generating Station	2	no	no	no	no	no	not determined	NO
H L Spurlock	3	no	no	no	no	no	not determined	NO
H L Spurlock	4	no	no	no	no	---	not determined	NO
Hardin Generator Project	UNT1	no	no	no	no	---	not determined	NO
Iatan	2	no	---	no	no	no	not determined	NO
J K Spruce	2	no	no	no	no	no	not determined	NO
John W Turk Jr	1	no	no	no	no	no	not determined	NO
Kemper County	1A	no	---	yes	no	---	not determined	NO
Longview Power LLC	MKA01	no	yes	no	no	no	not determined	NO
Nebraska City	2	no	no	no	no	---	not determined	NO
Oak Grove	OG1	no	no	no	no	no	not determined	NO
Oak Grove	OG2	no	no	no	no	no	not determined	NO
Plum Point Energy Station	STG1	no	no	no	no	---	not determined	NO
Prairie State Generatng Station	PC1	no	no	no	no	no	not determined	NO
Prairie State Generatng Station	PC2	no	no	no	no	no	not determined	NO
Red Hills Generating Facility	RHGF	no	---	no	no	---	not determined	NO
Sandow Station	5	no	no	no	no	no	not determined	NO
Sandy Creek Energy Station	S01	no	no	no	no	no	not determined	NO
Seward	FB1	no	---	no	no	---	not determined	NO
Southwest Power Station	ST2	no	no	no	no	no	not determined	NO
Spiritwood Station	1	no	---	no	no	---	not determined	NO
Springerville	3	no	---	no	no	no	not determined	NO
Springerville	4	no	---	no	no	no	not determined	NO
Trimble County	2	no	no	no	no	no	not determined	NO
TS Power Plant	001	no	no	no	no	no	not determined	NO
Virginia City Hybrid Energy Ctr	1	no	no	yes	no	---	not determined	NO
Walter Scott Jr Energy Center	4	no	---	no	no	no	not determined	NO
Weston	4	no	no	no	no	no	not determined	NO
Whelan Energy Center	2	no	no	no	no	---	not determined	NO
Wygen 1	0001	no	---	no	no	---	not determined	NO
Wygen 2	0001	no	---	no	no	---	not determined	NO
Wygen 3	5	no	---	no	no	---	not determined	NO

1. "---" indicates that the air permit does not contain a limit for that emission.
2. See Appendix B for details on this table.

Table 5-3 Proposed Existing Source MACT Standards vs. Recent Coal-Based Electric Generation Projects

		Can existing air permit limits meet the proposed existing source MACT standards for the following?												Can air permit limits meet ALL of the proposed existing source MACT standards?
				Acid Gases				Non-Hg Metals						
		Mercury		HCl		SO2		Total PM		ALL Individual Metal Limits		Total Non-Hg Metals		
Plant	Gen ID	lb/GWh limit	lb/TBtu limit	lb/MWh limit	lb/mmBtu limit	lb/MWh limit	lb/mmBtu limit	lb/MWh limit	lb/mmBtu limit	lb/GWh limit	lb/TBtu limit	lb/GWh limit	lb/TBtu limit	
Cliffside	6	no	no	yes	yes	yes	yes	yes	yes	no	no	not determined		no
Comanche	3	no	no	yes	yes	yes	yes	yes	yes	---	---	not determined		no
Cross	3	no	no	no	no	yes	yes	yes	yes	no	no	not determined		no
Cross	4	no	no	no	no	yes	yes	yes	yes	no	no	not determined		no
Dallman	4	yes	yes	no	no	yes	yes	yes	yes	no	no	not determined		yes
Dry Fork Station	01	no	no	no	no	yes	yes	yes	yes	---	---	not determined		no
Edwardsport	CT1, CT2, ST	yes	no	no	no	n/a	n/a	yes	yes	---	---	not determined		no
Elm Road Generating Station	1	no	yes	no	no	yes	yes	yes	yes	no	no	not determined		yes
Elm Road Generating Station	2	no	yes	no	no	yes	yes	yes	yes	no	no	not determined		yes
H L Spurlock	3	no	no	no	no	yes	yes	yes	yes	no	no	not determined		no
H L Spurlock	4	no	no	yes	yes	yes	yes	yes	yes	---	---	not determined		no
Hardin Generator Project	UNT1	no	no	yes	yes	yes	yes	yes	yes	---	---	not determined		no
Iatan	2	no	no	no	no	yes	yes	yes	yes	no	no	not determined		no
J K Spruce	2	no	no	yes	yes	yes	yes	yes	yes	no	no	not determined		no
John W Turk Jr	1	no	no	yes	yes	yes	yes	yes	yes	no	no	not determined		no
Kemper County	1A	no	no	no	no	n/a	n/a	yes	yes	---	---	not determined		no
Longview Power LLC	MKA01	no	no	yes	yes	yes	yes	yes	yes	no	no	not determined		no
Nebraska City	2	no	no	yes	yes	yes	yes	yes	yes	---	---	not determined		no
Oak Grove	OG1	no	no	no	no	yes	yes	no	no	no	no	not determined		no
Oak Grove	OG2	no	no	no	no	yes	yes	no	no	no	no	not determined		no
Plum Point Energy Station	STG1	no	no	no	no	yes	yes	yes	yes	---	---	not determined		no
Prairie State Generatng Station	PC1	no	no	no	no	yes	yes	yes	yes	no	no	not determined		no
Prairie State Generatng Station	PC2	no	no	no	no	yes	yes	yes	yes	no	no	not determined		no
Red Hills Generating Facility	RHGF	no	no	no	no	no	no	yes	yes	---	---	not determined		no
Sandow Station	5	no	no	yes	yes	yes	yes	yes	yes	no	no	not determined		no
Sandy Creek Energy Station	S01	no	no	yes	yes	yes	yes	no	no	no	no	not determined		no
Seward	FB1	no	no	no	no	no	no	yes	yes	---	---	not determined		no
Southwest Power Station	ST2	no	no	yes	yes	yes	yes	yes	yes	no	no	not determined		no
Spiritwood Station	1	no	no	no	no	yes	yes	no	yes	---	---	not determined		no
Springerville	3	no	no	no	no	no	no	no	no	no	no	not determined		no
Springerville	4	no	no	no	no	yes	yes	no	no	no	no	not determined		no
Trimble County	2	yes	yes	yes	yes	yes	yes	yes	yes	no	no	not determined		yes
TS Power Plant	001	no	no	yes	yes	yes	yes	yes	yes	no	no	not determined		no
Virginia City Hybrid Energy Ctr	1	yes	yes	no	no	yes	yes	yes	yes	---	---	not determined		yes
Walter Scott Jr Energy Center	4	no	no	no	no	yes	yes	yes	yes	no	no	not determined		no
Weston	4	no	no	yes	no	yes	yes	yes	yes	no	no	not determined		no
Whelan Energy Center	2	no	no	yes	yes	yes	yes	yes	yes	---	---	not determined		no
Wygen 1	0001	no	no	no	no	yes	yes	yes	yes	---	---	not determined		no
Wygen 2	0001	no	no	no	no	yes	yes	yes	yes	---	---	not determined		no
Wygen 3	5	no	no	no	no	yes	yes	yes	yes	---	---	not determined		no

**See Appendix B for details on the table; "---" indicates that the air permit does not contain a limit for that emission.

Section 6: EPA should consider the practical, achievable 112(g) case-by-case MACT standards that have been established for recently permitted coal-based EGU's as appropriate rates for new EGUs.

Since the EGU source category was established, dozens of Section 112(g) case-by-case MACT analyses have been performed for new coal-based generation projects. Lessons learned from Section 112(g) case-by-case MACT determinations for new coal-based generation projects offer practical perspectives on the capabilities of the most advanced emission control technologies available, as well as noteworthy methodologies applied by state agencies for establishing MACT standards. The content of the individual analyses, the process by which state agencies made final MACT determinations, and 112(g) limits established in final air permits offer important lessons learned that EPA should consider in developing the final rule.

I. Existing 112(g) limits, representing the most advanced controlled and the most stringently regulated coal-units, cannot meet the proposed MACT standards.

The following analyzes 112(g) case-by-case MACT limits established for coal-based generating units to determine whether these units, representing the best in class in terms of advanced combustion processes, emission control systems, and stringency of air permits, could meet the proposed MACT standards.

In developing the proposed rule, U.S. EPA considered data obtained through a 2010 Information Collection Request made to all potentially affected units. The list of potentially affected units was derived from the 2007 version of Energy Information Administration (EIA) Form 860 – "Annual Electric Generator Report."[16] The 2009 EIA-860 report (most recently available) and individual project air permits were used to identify units for this analysis. The analysis also considers 112(g) limits established for other projects that are not listed in the EIA-860 report because they have been cancelled or have only recently been permitted.

The analysis considers the 112(g) limits established by 15 different state environmental agencies for 27 new coal-based generating units. **None** of 112(g) limits can meet any of the proposed new source MACT limits. It most cases, the proposed MACT standards are orders of magnitude lower than 112(g) limits established for these 27 units. Further, a **majority of units** (20 of 27) have 112(g) limits that **cannot meet** the proposed existing source MACT limits for each category of HAPs (mercury, acid gases, and non-Hg metals). Tables 5-4 through 5-6 below summarize this comparison to the proposed MACT standards.[17]

[16] See Federal Register. Vol 76. No. 85. May 3, 2011. p. 25022.
[17] See Appendix C.

Table 5-4: Example 112(g) Case-by-Case Analysis for Coal-Based EGU's

Plant	Unit	State	Project Status	Air Permit Status	Air Permit #	Air Permit Date	Nameplate Capacity (MWh)	Design Heat Input (mmBtu/hr)	Unit Type	Emission Controls Include: (from air permit)			
										NOx	SO2	PM	Other
AMP-Ohio	1&2	OH	cancelled	draft	P0104461	04/30/09	2 x 480	2 x 5,191	PC	SCR	WFGD	FF, WESP	---
Comanche	3	CO	construction	final	04PB1015	02/22/10	856.8	7,421	PC	SCR	DFGD	FF	SI
Big Cajun II	4	LA	cancelled	draft	2260-00012	05/07/09	705	6,566	PC	SCR	WFGD	FF	SI
Cross	3	SC	operating	final	0420-0030-CI	02/05/04	591	5,400	PC	SCR	WFGD	ESP	---
Cross	4	SC	operating	final	0420-0030-CI	02/05/04	652	5,700	PC	SCR	WFGD	ESP	---
Dallman	4	IL	operating	final	4110050	08/10/06	280	2,440	PC	SCR	WFGD	FF; WESP	---
Elm Road Generating Station	1	WI	construction	final	03-RV-166-R2	09/04/08	615	6,180	PC	SCR	WFGD	FF; WESP	---
Elm Road Generating Station	2	WI	construction	final	03-RV-166-R2	09/04/08	615	6,180	PC	SCR	WFGD	FF; WESP	---
H L Spurlock	3	KY	operating	final	V-06-007R3	04/27/10	329.4	2,500	CFB	SNCR	DFGD	FF	---
Intermountain	3	UT	cancelled	final	AN0327010-04	10/15/04	950	9,050	PC	SCR	WFGD	FF	---
James DeYoung	10	MI	active	final	25-07	02/11/11	78	865	CFB	SNCR	LSI	FF	SI
John W Turk Jr	1	AR	construction	final	2123-AOP-R0	11/05/08	609	6,000	PC	SCR	DFGD	FF	ACI
Karn-Weadock	new	MI	deferred	final	341-007	12/29/09	930	8,190	PC	SCR	WFGD	FF	SI
Limestone	3	TX	active	final	79188 HAP14	12/10/09	800	8,000	PC	SCR	WFGD	FF	SI
Nebraska City	2	NE	operating	final	CP09-001	12/14/09	738	6,478	PC	SCR	DFGD	FF	---
Pee Dee	1&2	SC	cancelled	final	1040-0113-CA	12/16/08	2 x 660	2 x 5,700	PC	SCR	WFGD	FF	---
Plant Washington	1	GA	active	final	4911-303-0051	04/08/10	850	8,300	PC	SCR	WFGD	FF	ACI
Plum Point Energy Station	1	AR	construction	final	1995-AOP-R3	01/11/08	720	7,960	PC	SCR	DFGD	FF	ACI
Prairie State Generatng Station	1	IL	construction	final	01100065	04/28/05	800	7,450	PC	SCR	WFGD	ESP;WESP	---
Prairie State Generatng Station	2	IL	construction	final	01100065	04/28/05	800	7,450	PC	SCR	WFGD	ESP;WESP	---
Springerville	3	AZ	operating	final	32008	07/11/06	450	4,200	PC	SCR	DFGD	FF	---
Springerville	4	AZ	operating	final	32008	07/11/06	450	4,200	PC	SCR	DFGD	FF	---
Trailblazer	1	TX	active	final	84167 HAP13	12/14/10	900	8,307	PC	SCR	WFGD	FF	ACI
Virginia City Hybrid Energy Ctr	1	VA	construction	final	11526	06/20/08	668	6,264	CFB	SNCR	LSI; DFGD	FF	ACI
Weston	4	WI	operating	final	03-RV-248	04/28/07	595	5,173	PC	SCR	DFGD	FF	SI

Notes:

1. Data supplied by air permits and 2009 EIA-860 report (accessed 05/23/10 at: www.eia.doe.gov/cneaf/electricity/page/eia860.html) unless noted.
2. Air permit applications provided design heat input values for Plum Point 1 (dated April 16, 2002) and John W. Turk Jr (dated August 2006).
3. Design heat input value equals the combined total for units with two boilers: Va. City (2 x 3,132)
4. Net Capacity listed for AMP-OH and Plant Washington.
5. See Appendix C for definition of acronyms used in table.

Table 5-5: 112(g) Limits vs. Proposed New Source MACT

		Can 112(g) limits meet the proposed new source MACT standards?						
			Acid Gases		Non-Hg Metals			
		Mercury	HCl	SO_2	Total PM	ALL Individual Metal Limits	Can the 112(g) limits meet ALL of the proposed new source MACT standards?	Can the 112(g) limits meet ANY of the proposed new source MACT standards?
Plant	Unit	lb/GWh limit	lb/GWh limit	lb/GWh limit	lb/GWh limit	lb/GWh limit		
AMP-Ohio	1-2	no	no	no	no	---	no	no
Big Cajun II	4	no	no	---	no	---	no	no
Comanche	3	no	no	---	no	---	no	no
Cross	3	no	no	no	no	no	no	no
Cross	4	no	no	no	no	no	no	no
Dallman	4	---	no	---	---	---	no	no
Elm Road	1	no	no	no	no	---	no	no
Elm Road	2	no	no	no	no	---	no	no
H L Spurlock	3	no	no	no	no	no	no	no
Intermountain	3	no	no	no	no	no	no	no
James DeYoung	10	no	no	---	no	---	no	no
John W Turk Jr	1	no	no	---	no	---	no	no
Karn-Weadock	new	no	no	---	no	---	no	no
Limestone	3	no	no	---	no	---	no	no
Nebraska City	2	no	no	no	no	---	no	no
Pee Dee	1-2	no	no	no	no	---	no	no
Plant Washington	1	no	no	no	no	---	no	no
Plum Point	1	no	no	no	no	---	no	no
Prairie State	1	---	no	---	---	---	no	no
Prairie State	2	---	no	---	---	---	no	no
Springerville	3	no	---	---	---	---	no	no
Springerville	4	no	---	---	---	---	no	no
Trailblazer	1	no	no	---	no	---	no	no
Virginia City	1	no	no	---	no	---	no	no
Weston	4	no	no	no	no	no	no	no

Note:

1. "---" indicates that the air permit does not contain a 112(g) limit for that emission.

Table 5-6: 112(g) Limits vs. Proposed Existing Source MACT

		Can 112(g) limits meet the proposed existing source MACT standards?										Can current permit limits meet ALL of the proposed MACT standards?
		Mercury		Acid Gases: HCl		Acid Gases: SO_2		Non-Hg Metals: Total PM		Non-Hg Metals: ALL Individual Metal Limits		
Plant	Unit	lb/GWh limit	lb/TBtu limit	lb/MWh limit	lb/mmBtu limit	lb/MWh limit	lb/mmBtu limit	lb/MWh limit	lb/mmBtu limit	lb/GWh limit	lb/TBtu limit	
AMP-Ohio	1-2	no	no	no	no	yes	yes	yes	yes	---	---	no
Big Cajun II	4	yes	yes	no	no	---	---	yes	yes	---	---	no
Comanche	3	no	no	yes	yes	---	---	yes	yes	---	---	no
Cross	3	no	no	no	no	yes	yes	yes	yes	no	no	no
Cross	4	no	no	no	no	yes	yes	yes	yes	no	no	no
Dallman	4	---	---	no	no	---	---	---	---	---	---	no
Elm Road	1	no	yes	no	no	yes	yes	yes	yes	---	---	yes
Elm Road	2	no	yes	no	no	yes	yes	yes	yes	---	---	yes
H L Spurlock	3	no	no	no	no	yes	yes	yes	yes	no	no	no
Intermountain	3	yes	yes	---	---	yes	yes	yes	yes	no	no	yes
James DeYoung	10	yes	yes	no	no	---	---	yes	yes	---	---	no
John W Turk Jr	1	no	no	yes	yes	---	---	yes	yes	---	---	no
Karn-Weadock	new	yes	yes	yes	yes	---	---	yes	yes	---	---	yes
Limestone	3	no	no	no	no	---	---	yes	yes	---	---	no
Nebraska City	2	no	no	yes	yes	yes	yes	yes	yes	---	---	no
Pee Dee	1-2	no	yes	no	no	yes	yes	yes	yes	---	---	yes
Plant Washington	1	yes	yes	yes	yes	yes	yes	yes	yes	---	---	yes
Plum Point	1	no	no	no	no	yes	yes	yes	yes	---	---	no
Prairie State	1	---	---	no	no	---	---	---	---	---	---	no
Prairie State	2	---	---	no	no	---	---	---	---	---	---	no
Springerville	3	no	no	---	---	---	---	---	---	---	---	no
Springerville	4	no	no	---	---	---	---	---	---	---	---	no
Trailblazer	1	no	no	yes	yes	---	---	yes	yes	---	---	no
Virginia City	1	yes	yes	no	no	---	---	yes	yes	---	---	no
Weston	4	no	no	yes	no	yes	yes	yes	yes	no	no	no

Note:

1. "---" indicates that the air permit does not contain a 112(g) limit for that emission.

II. The proposed New Source MACT standards do not represent rate that have been achieved in practice and are orders of magnitude lower than any of the 112(g) case-by-case MACT limits established for the most advanced units in the United States coal fleet

The 112(g) permit requirements established in recent years for new coal-based generation projects represent the most stringent emission limits to have ever been established for such sources. Numerous state agencies have made such 112(g) determinations after extensively considering project specific factors such as unit design information, fuel and operating variability, and the actual performance of similar sources. As a result, these agencies established 112(g) limits that meet MACT requirements, which provide the maximum level of control **and** that are practical and achievable over the life of the unit. These units are the most advanced to have ever been developed and are representative of future new coal generation projects. Despite the stringency their 112(g) limits, none can meet any of the proposed new source limits. In most cases, the comparison is not even close as the proposed MACT standards for new sources are orders of magnitude lower than the 112(g) limits established by multiple state agencies. The following are examples that highlight how stringent (and unrealistic) of the proposed MACT standards for new coal generation projects:

Mercury:
- None of the 112(g) limits can meet the proposed new source mercury standard
- The new source mercury MACT standard is 1 to 4 orders-of-magnitude lower than all of the 112(g) limits identified for mercury
- A majority of the 112(g) mercury limits are based on 12-month averages (and which is consistent with prior EPA proposals), not a 30-day average as proposed by EPA

HCl:
- None of the 112(g) limits reviewed can meet the proposed new source HCl standard
- The new source HCl MACT standard is 1 to 3 orders-of-magnitude lower than all of the 112(g) limits identified for HCl

SO_2:
- None of the 112(g) limits reviewed can meet the proposed new source SO_2 standard
- The new source SO_2 MACT is 40 to 450% lower than all of the 112(g) limits identified for SO_2 as a surrogate for certain HAPs

Total PM:
- None of the 112(g) limits reviewed can meet the proposed new source total PM standard
- The new source total PM MACT standard is an order-of-magnitude lower than all of the 112(g) limits identified for total PM as a surrogate for certain HAPs

Individual Metals:
- A majority of the 112(g) permit reviewed did not contain limits for individual metals, but instead relied upon PM as a surrogate

EPA should refine their standard setting methodology so that the final rule contains standards provide the maximum level of control and that are practical and achievable. This would include a review of air permits and associated technical support documents so that proper consideration is given to the range of unit operations and the capabilities of emission control equipment and compliance demonstration methods. To assist in this process, Appendix D contains the air permit documents considered in AEP analysis of emission limits in Appendices B and C.

III. State agencies have established final 112(g) MACT limits based on the use of subcategories with respect to combustion technologies and coal type.

State agencies have established final 112(g) MACT determinations based on coal type subcategories in order to address the substantial differences in emission characteristics and heating value for the various coal ranks on the emission reductions that can be achieved in practice. As an example, consider the following statements from state agencies regarding the issue of subcategories and similar sources:

> South Carolina Department of Health & Environmental Control:
> "The Department has relied on that proposed MACT standard in justifying its decision to subcategorize by coal rank, thus defining a "similar source" for the Pee Dee plant as a unit that solely burns bituminous coal. There has been no other information presented to indicate that coal rank does not impact emissions, design, capacity and control technology such that it could not be eliminated as a subcategory. The EPA states that coal rank (anthracite, bituminous, subbituminous, lignite and waste coal) has a significant impact on overall plant design, and design and operation of control equipment."
>
> "...the Department determined that based on the definition of similar source as "comparable in emissions" and "similar in design and capacity," FBC units were not a similar source to PC units..... The Department has determined that the design and capacity differences between FBC and PC units are substantial and have thus eliminated FBC units from the same similar source category as PC units.....Based on all supporting information, including information on impacts to mercury emissions, the Department has determined that FBC units are not similar sources to PC units."
>
> "The EPA, in its 2004 proposed Utility MACT, subcategorized by coal rank. The EPA went to great length to justify its determination of this subcategorization. The Department has relied on that proposed MACT standard in justifying its decision to subcategorize by coal rank, thus defining a similar source as a unit that solely burns bituminous coal. There has been no other information presented to indicate that coal rank does not impact emissions, design, capacity and control technology such that it could not be eliminated as a subcategory. In its 2004 proposed Utility MACT, the EPA stated that coal rank (anthracite, bituminous, subbituminous, lignite and waste coal) has a significant impact on overall plant design, and design and operation of control equipment." [18]
>
> Texas Commission on Environmental Quality:
> "As explained below, the permit limits for CFB units and for units firing petroleum coke, bituminous coal, or "waste coal" (i.e. coal mine tailings) are not considered similar units to

[18] SCDHEC Response to Comments document. Final Air Permit #1040-0113-CA. December 16, 2008. p. 98-103.

Tenaska's sub-bituminous fired PC unit."[19]

Virginia Department of Environmental Quality:
"In determining MACT for VCHEC, DEQ determined "similar source" to be circulating fluidized bed (CFB) boilers, because the CFB design is unique in its ability to burn the combination of fuels proposed for this project (run of mine coal, waste coal or "GOB", and a maximum of 20% biomass in the form of waste wood)."[20]

Arkansas Department of Environmental Quality:
"....the coal type and boiler type have the most influence on the controls used. In this case a similar source was defined as the coal type (sub bituminous) and the boiler type, pulverized coal. ...It is apparent that the inherent differences in the properties of different types of coal significantly affects the design characteristics of any proposed plant. ...the Department is satisfied that limiting the consideration of similar sources to PC plants burning sub-bituminous coal was appropriate based on the definition of similar source."[21]

IV. State agencies have recognized that coal-based generating units are not steady-state operations by establishing final 112(g) MACT limits that are applicable to specific operating conditions as opposed to a one-size-fits-all regulatory standard.

State agencies have performed Section 112(g) case-by-case MACT determinations and concluded that "achieved in practice" represents the best performance that is achievable based on range of reasonably expected operating scenarios that might occur over the life of a unit. These agencies determined that data from a single stack test or from a limited number of stack tests that occurred under the same operating conditions is not sufficient to determine achieved in practice. The following are examples of statements from state agencies regarding the issue of achieved in practices:

South Carolina Department of Health & Environmental Control:
"The MACT limit is based on the emission limit achieved in practice by the best controlled similar source. Achieved in practice is not necessarily the achieved emission rate during one source test. Because of many variables, the emission level achieved on a single or even several stack tests may not be possible with continual operations. Emission variability will occur over time because of changes in fuel characteristics as well as operational changes over the life span of the unit. As discussed previously, achieved in practice has been interpreted to mean to set the MACT floor at a level that is a reasonable estimate of the performance of the best controlled similar unit under the "worst foreseeable circumstances." To further support the need for variability in determining the MACT emission limitation, rather than the use of one stack test, the EPA was clear in the 2004 proposed Utility MACT that variability had to be accounted for based on variations in the performance testing, and mercury and chlorine content of the coal."

"The MACT emission limitation for new sources is based on the emissions achieved in practice by the best controlled similar source, that is, the MACT "floor."...The Department

[19] TCEQ Response to Comments document. Final Air Permit #84167. December 2010. p. 32.
[20] VDEQ Response to Comments document. Final Air Permit #11526. June 16, 2008. p. 4
[21] ADEQ Response to Comments document. Final Air Permit #2123-AOP-R0. November 5, 2008. pp. 82-87.

determined that the floor must account for variability, especially for the variability in the mercury content of coal that could be purchased...In determining "achieved in practice" it is appropriate and reasonable to account for variability. The EPA states that variability in the mercury content of the coal and control device performance "have a significant impact on the determination of the level of emission limitation actually being achieved...it is essential ...[to] be able to [account for] variability."

"The Department determined that the variability of mercury in bituminous fuel had to be accounted for in order to develop a MACT emission limitation that could be achieved under the "worst foreseeable circumstances," meaning that it was appropriate to not only account for coal that was burned at that specific facility, but to account for coal that could be burned in the future."[22]

Michigan Department of Environmental Quality:
"In addition, the MACT emission limits need to account for variability in fuels and corresponding performance in the pollution controls to assure the emission limit represented by the best controlled similar source can be achieved consistently. To ensure the MACT emission limits are based on realistic operation rather than solely on test results from stack tests performed under optimum conditions, the MDEQ included a margin of compliance in calculating the limits.... The MACT emission limit should not be set at the lowest single test result ever achieved by a source category. The emission limit takes into account the fuels, operating scenarios, and the performance of control devices in order to set a limit that can be achieved in practice on a continuous basis while still meeting the maximum achievable control technology requirement."[23]

"For the MACT determination and limits, all possible fuel combinations had to be evaluated and an emission limit assessed for continuous compliance under all operating scenarios. This is a flexible approach using a broad analysis to derive an emission limit...In addition, the MACT emission limits need to account for variability in fuels and corresponding performance in the pollution controls to assure the emission limit represented by the best controlled similar source can be achieved consistently. To ensure the MACT emission limits are based on realistic operation rather than solely on test results from stack tests performed under optimum conditions, the DNRE used safety factors in calculating the limits...Stack testing is a measure of performance, but the MACT emission limit should not be set at the lowest single test result ever achieved by a best controlled similar source, and when working with small sets of source test data to assess an emission limit, an appropriate safety factor needs to be assessed...The MACT determination was based on the maximum achievable control for the types of fuels proposed to be combusted while maintaining fuel flexibility as a practical consideration."[24]

Georgia Department of Natural Resources:
"The MACT emission limit should not be set at the lowest single test result ever achieved by a source category. The emission limit takes into account the fuels, operating scenarios, and

[22] SCDHEC Response to Comments document. Final Air Permit #1040-0113-CA. December 16, 2008. pp 96-104.
[23] MDEQ Response to Comments document. Final Air Permit #341-07. Dec. 29, 2009. p. 72.
[24] MDEQ Response to Comments document. Final Air Permit #25-07. February 11, 2011. pp. 44-49.

the performance of control devices in order to set a limit that can be achieved in practice on a continuous basis while still meeting the maximum achievable control technology requirement." [25]

Virginia Department of Environmental Quality:
"The permitting agency has more discretion in establishing a numerical emission limit for mercury than suggested by the commenters. The agency must consider whether the limit established is achievable in practice over the lifetime of the facility being constructed. Test results from similar facilities must be reviewed to determine whether they are replicable and sustainable."

"Results from the short term testing should be taken into consideration for establishing a numerical emission limit, but it is appropriate to also apply a margin of safety to ensure that the limit established is achievable and sustainable throughout the life of the permitted equipment."

"The emission limit proposed for VCHEC, like the emission limit established by Pennsylvania DEP for the not yet operational Robinson facility, is higher than the short term emission rate measured at Reliant, in order to ensure that the emission standard is achievable under the most adverse circumstances which can reasonably be expected to occur over the life of the equipment."

"Very limited data available from testing at one facility (Reliant Seward) indicates that this level of emissions may be achieved on a short term basis but does not provide sufficient data to demonstrate that the limit is achievable in practice over the lifetime of the facility..."[26]

Arkansas Department of Environmental Quality:
"Achieved in practice is not necessarily the limit achieved in one stack test. To be considered achieved in practice, the limit must be achieved on a long term basis, not just in an initial or one time 3 hour stack test.... Achieved in practice is not the absolute lowest emission rate ever achieved by a source. It is the emission rate that a source can achieve on a continuous basis.... Use of different tests on different sources would not be appropriate in establishing an achieved in practice rate for a source."[27]

---

[25] GaDNR Response to Comments document. Final Air Permit #4911-303-0051-P-01-0. April 8, 2010. p. 115.
[26] VDEQ Response to Comments document. Final Air Permit #11526. June 16, 2008. pp. 5-7.
[27] ADEQ Response to Comments document. Final Air Permit #2123-AOP-R0. November 5, 2008. pp. 84-92.

Section 7: Existing units using state-of-the-art generation technologies and emission controls cannot meet the proposed MACT standards

I. The most recently developed new coal-based generation units (those constructed over the past decade) represent the state-of-the-art in terms of the emissions profile that can be achieved by the most advanced technologies available. EPA should consider the air permits for these units so that the final rule contains standards that are practical and achievable by even the most advanced technologies.

Since 2001, 40 coal-based electric generation units have been commissioned or, at present, are undergoing active construction. These units represent the most efficient and lowest emitting coal-based EGU's ever to have been built.[28] Further, the expanding scope and complexity of regulatory requirements, the maturation of emission control technologies, and increased input from external groups have resulted in these units being subject to the most stringent air permit limits ever established.

In developing the air permits for these units, state agencies considered vendor information, fuel data, variable operating conditions, as well as the performance and air permit limits of other operating units. This in-depth evaluation by state agencies has enabled practical, achievable air permits to be established that protect public health and that accommodate the range of operating scenarios expected over the life of the unit.

Although these 40 units comprise approximately 4% of the existing coal fleet in the United States, they establish an expected baseline of performance for future units. If any group of units could be expected to be able to meet the proposed MACT standards, it would be this group of 40, which represent the newest and best-performing units. However, based on a review of air permits, 35 of 40 <u>cannot</u> meet the proposed existing source MACT standards, and <u>none</u> can meet the proposed new source standards.[29] In part, this reflects the difference between a state agency permitting a unit on a project-specific basis with consideration all operating conditions and a broad-brush regulatory approach for all units based on snap-shot-in-time stack test data for a limited number of units.

EPA should refine their standard setting methodology so that the final rule contains standards that are practical and achievable. This would include a review of air permits and associated technical support documents so that proper consideration is given to the range of unit operations and the capabilities of emission control equipment and compliance demonstration methods. To assist in this process, Appendix D contains the air permit documents considered in AEP analysis of emission limits in Appendices B and C

---

[28] See Appendix B.
[29] Ibid.

Section 8: IGCC Concerns

I. IGCC processes should be exempted from the proposed NESHAP for coal- and oil-based EGU's.

IGCC processes are inherently different from other methods of coal-based electric generation and more similar to natural gas combined cycle units in terms of design and emissions. In fact, several coal-based gasification projects are being developed to produce synthetic natural gas that will compete with natural gas suppliers in marketing to combustion turbine generators and other industries.

Combustion turbines for IGCC units are typically designed to fire natural gas or syngas, and are typically equipped with the same dry low NO_x burners and water injection emission controls used for natural gas units. The IGCC heat recovery steam generator is typically designed with duct burners that utilize natural gas. Because of the similarities of natural gas combined cycle and IGCC units, both are currently subject to the same NESHAP listed under 40 CFR 63 Subpart YYYY, which notes the following:

> **§ 63.6080 What is the purpose of subpart YYYY?**
> Subpart YYYY establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines located at major sources of HAP emissions, and requirements to demonstrate initial and continuous compliance with the emission and operating limitations.
>
> **§ 63.6085 Am I subject to this subpart?**
> You are subject to this subpart if you own or operate a stationary combustion turbine located at a major source of HAP emissions.
>
> (a) Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function, although it may be mounted on a vehicle for portability or transportability. Stationary combustion turbines covered by this subpart include simple cycle stationary combustion turbines, regenerative/recuperative cycle stationary combustion turbines, cogeneration cycle stationary combustion turbines, and combined cycle stationary combustion turbines. Stationary combustion turbines subject to this subpart do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.
>
> (b) A major source of HAP emissions is a contiguous site under common control that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

Therefore, because of the similarities to natural gas combined cycle units and the applicability of Subpart YYYY, EPA should exempt IGCC processes from the final rule.

II. EPA's use of data from the only two IGCC units operating in the United States misrepresents the design and potential performance of future IGCC units. If the final rule remains applicable to IGCC units, then EPA should consider a broader scope of IGCC technologies, the inherent uncertainties with technology development, and the use of first-of-a-kind technologies for new IGCC units.

a. IGCC technology is not a one-size fits all process design.

The term IGCC represents a broad range of process designs that incorporate varying gasification technologies, syngas cleanup methods, power generation strategies, and other plant systems. The scope of process differences reflects the impact of coal quality variables on design features, as well as the immaturity of the technology. Only two commercial-scale IGCC units are operating in the United States (Polk and Wabash). As presented below, the design and performance of these two units are not representative of all IGCC technologies.

The Department of Energy through the National Energy Technology Lab (NETL) has been actively involved in IGCC development for decades. NETL maintains an extensive library of information on gasification and IGCC technologies. The following from NETL highlights some of the design options for IGCC processes.

Gasification Technologies[30]
Gasification involves the oxidation of coal into a syngas that can be used for power generation or processed into synthetic fuels or chemical feedstocks. Design options include the method of coal injection into the gasifier (dry-feed or slurry-feed) and the type of oxidant used (oxygen or air). Gasifiers can be broadly classified into three categories (entrained-flow, fluidized-bed, and fixed-bed). Various gasifier technologies are summarized below, each has its own unique set of design and operating variables:

Gasifier Category	Gasifier Process	Coal feed to Gasifier	Oxidant	
entrained-flow	GE Energy	slurry-feed	oxygen-blown	Polk
entrained-flow	ConocoPhillips E-Gas	slurry-feed	oxygen-blown	Wabash
entrained-flow	Shell	dry-feed	oxygen-blown	
entrained-flow	Uhde - Prenflo	dry-feed	oxygen-blown	
entrained-flow	Siemens	dry-feed	oxygen-blown	
entrained-flow	MHI	dry-feed	air-blown	
fluidized-bed	KBR TRIG	dry-feed	air-blown oxygen-blown	
fluidized-bed	High Temp. Winkler	dry-feed	air-blown oxygen-blown	
fluidized-bed	U-Gas	dry-feed	air-blown oxygen-blown	
fixed-bed	Lurgi	dry-feed	oxygen-blown	
fixed-bed	BGL	dry-feed	oxygen-blown	

30 www.netl.doe.gov/technologies/coalpower/gasification/gasifipedia/4-gasifiers/4-1_types.html.

Syngas Cleanup Systems[31]

A range of syngas cleanup systems have been identified by NETL, most of which have yet to be demonstrated on a commercial-scale coal-based IGCC unit. These systems can be categorized as particulate removal systems, acid-gas removal systems, and other syngas cleanup processes.

Particulate Removal Systems:

Category	Process	
dry particulate removal	cyclone technology	
dry particulate removal	candle filters	Wabash
wet particulate removal	water scrubbing	Polk

Acid-Gas Removal Systems:

Category	Solvent	Common Name	
chemical solvent	Monoethanolamine	MEA	
chemical solvent	Diglycolamine	DGA	
chemical solvent	Diethanolamine	DEA	
chemical solvent	Diisopropanolamine	DIPA	
chemical solvent	Hindered Amine	Flexsorb SE	
chemical solvent	Triethanolamine	TEA	
chemical solvent	Methyldiethanolamine	MDEA	Polk; Wabash
chemical solvent	Potassium Carbonate	Hot Pot	
physical solvent	Methanol	Rectisol	
physical solvent	Methanol and toluene	Rectisol II	
physical solvent	Dimethy ether of poly ethylene glycol	Selexol	
physical solvent	N-methyl pyrrolidone	Purisol	
physical solvent	Polyethylene glycol and dialkyl ethers	Sepasolv MPE	
physical solvent	Propylene carbonate	Fluor Solvent	
physical solvent	Tetrahydrothiophenedioxide	Sulfolane	
physical solvent	Tributyl phosphate	Estasolvan	

Other Syngas Cleanup Processes:

System	
COS hydrolysis	Polk; Wabash
Water-gas shift reactors	Polk; Wabash
Activated carbon bed	

Power Generation Strategies

Options available for IGCC power generation could impact the emissions profile for the unit. With respect to the combustion turbines, the scope of considerations include the type (manufacture and vintage) of turbine deployed, co-firing options with natural gas, the use of low NO_x burner technologies and/or water injection. In regards to the heat recovery steam generator (HRSG), consideration includes duct-firing capabilities and the use of SCR or oxidation catalyst technologies, which to date have yet to be demonstrated on a coal-based IGCC unit. The future

[31] www.netl.doe.gov/technologies/coalpower/gasification/gasifipedia/5-support/5-4_cleanup.html

use of hydrogen-based combustion turbines will also impact the emissions profile.

Summary
In summary, a suite of IGCC design options are being developed for a variety of coal types and operating scenarios. To date, commercial-scale IGCC technology has been demonstrated at only two units in the United States. The design of these two units represents only a small fraction of the IGCC technologies and coal types that could be used in the future. Further, most of the syngas cleanup technologies presented have yet to be utilized on a coal-based IGCC process, such that their performance and their ability to meet the proposed MACT standards is unknown. In developing the final rule, EPA should consider the wide-range of IGCC design options and the many unknowns with respect to unit performance and the capabilities of syngas cleanup systems.

b. Future IGCC units will represent first-of-a-kind technologies that pose inherent performance risks

Although the use of IGCC in the United States has been very limited, research and development related to commercial-scale IGCC processes has been extensive. The design of future IGCC units will utilize first-, second-, and nth generation of technologies and process integrations that create inherent uncertainties with respect to equipment performance and reliability. It also creates uncertainty with respect to the emissions profile for these future units, especially with respect to the emission of compounds present in trace concentrations. In developing the final rule, EPA should consider the risks associated with the use of first-of-a-kind technologies at future IGCC units.

c. The proposed MACT standard does not sufficiently addresses the unique operating conditions associated with IGCC units resulting in a range of uncertainties regarding the applicability of and compliance with the proposed requirements.

IGCC processes are inherently different from other methods of coal-based electric generation and more similar to natural gas combined cycle units in terms of design and emissions. If IGCC units are not exempted in the final rule, then the standards should be revised to address the unique characteristics of IGCC processes. Issues that would need to be addressed include:

- operating scenarios when coal-based syngas is not consumed by the combustion turbines, but by other process systems, such as a flare, thermal oxidizer, etc.

- operating scenarios when the combustion turbines are firing only natural gas or co-firing natural gas and coal-based syngas

- operating scenarios when the combustion turbines are consuming coal-based syngas and natural gas is combusted in duct burners in the heat recovery steam generator

- operating scenarios when coal and other carbonaceous compounds (petcoke, biomass, municipal solid waste, etc.) are simultaneously being gasified to produce a syngas

- combustion turbines that use synthetic natural gas (coal-based syngas) that is produced offsite by another facility

- the applicability work practice standards, which as proposed are designed to address the unique design and operating characteristics of IGCC processes

- the applicability of fuel sampling requirements....gasifier feedstock sampling, raw syngas sampling, clean syngas sampling, syngas fired in the combustion turbines, syngas fired in a flare, processed syngas fired in thermal oxidizer, etc.

- clarify the use of heat input and generation output terminology to account for (1) differences between coal-based (gasifier feedstock-based) and syngas-based heat input; and (2) differences between syngas-based and natural gas-based output during co-firing operations.

Section 9: Conclusion

In conclusion, AEP appreciates the opportunity to comment on the proposed rule, which will have broad-ranging, significant impacts to the health and economy of the United States in terms of the viability of the coal-utility industry, cost-impacts to ratepayers, and reliability of the electric transmission grid. As EPA considers comments and performs additional analyses to develop the final rule, it is imperative that EPA work closely with regulated entities and establish standards that address legitimate health concerns, are realistically achievable by existing and new coal-based EGU's, and that provide a reasonable timeline for sources to install applicable emission controls.

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

Respectfully submitted,

John M. McManus

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

cc: Mr. Peter Tsirigotis, Director, Sector Policies and Programs Division (without attachments)
Mr. William Maxwell, Energy Strategies Group (without attachments)
Dr. Robert Wayland, Leader, Combustion Group (without attachments)