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Power by Association℠

Edison Electric Institute

Thomas R. Kuhn
President

August 3, 2011

The Honorable Regina A. McCarthy
Assistant Administrator for the Office of Air and Radiation
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Dear Administrator McCarthy:

The Edison Electric Institute (EEI) appreciates the opportunity to provide the attached comments to the Environmental Protection Agency (EPA) on the proposed rule addressing hazardous air pollutants for electric utility steam generating units (Docket No. EPA-HQ-OAR-2009-0234). EEI's member companies are strongly committed to further emissions reductions and continued environmental protection as an integral component of generating electricity.

EEI, working with our CEOs, engaged in a thorough analysis of the proposed rule to provide constructive, consensus-based comments to EPA. Our comments seek to improve many technical aspects of the rule and ensure that utilities have sufficient time to make critical investments in control technologies and replacement facilities.

We urge the Administration to use all of the flexibility tools currently available under the Clean Air Act to address both timing and technical issues to hold down costs to consumers and avoid possible reliability impacts in some areas.

EEI's member company CEOs and I look forward to discussing our comments with you and others in the Administration.

Sincerely,

Thomas R. Kuhn
Attachment
TRK:ffk

cc (w/att):
Administrator Lisa Jackson
White House Chief of Staff William Daley

Edison Electric Institute

COMMENTS ON NATIONAL EMISSIONS 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

Docket Nos. EPA-HQ-OAR-2009-0234; EPA-HQ-OAR-2011-0044

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COMMENTS ON NATIONAL EMISSIONS 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

Docket Nos. EPA-HQ-OAR-2009-0234; EPA-HQ-OAR-2011-0044

August 3, 2011

The Edison Electric Institute (EEI) submits these comments on the proposed rule entitled *National Emissions 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* issued by the Environmental Protection Agency (EPA or Agency) in Docket Nos. EPA-HQ-OAR-2009-0234; EPA-HQ-OAR-2011-0044. 76 *Fed. Reg*. 24976 (May 3, 2011). The proposed rule would create national standards under Clean Air Act (CAA or Act) section 112 that require all units to achieve the maximum degree of reductions in emissions of hazardous air pollutants (HAPs). This standard for setting emissions reductions standards commonly is referred to as the "Maximum Achievable Control Technology" or MACT standard. The proposed Utility MACT is the first time that EPA would regulate HAPs emissions from electric utility steam generating units (EGUs) under CAA section 112.

EEI is the association of shareholder-owned electric companies, international affiliates and industry associates worldwide. Our U.S. members serve 95 percent of the ultimate customers in the shareholder-owned segment of the industry, and represent approximately 70 percent of the U.S. electric power industry. EEI member companies have a critical interest in the proposed rule, which will require the installation of new emissions controls and upgrades of current emissions controls at most coal- and oil-based power plants over the next few years.

I. Executive Summary

America's electric generation fleet—including coal-based power plants, which still produce nearly half of the nation's electricity—has become increasingly cleaner over the last two decades, and this transition is expected to continue apace over the next decade.

The power sector has invested tens of billions of dollars to achieve substantial air emissions reductions. Electric utilities have reduced annual emissions of sulfur dioxide (SO_2) by about 70 percent since 1990, from almost 16 million tons to about 5 million tons in 2010.[1] Similarly, utilities have reduced nitrogen oxide (NO_x) emissions by about 70 percent from 1990 to 2010 (from 7 million to 2 million tons), a reduction that has far outpaced that of other industrial emitters.[2] These SO_2 and NO_x reductions also have led to substantial co-benefits in the reductions of other emissions, including mercury and other HAPs. Moreover, the power sector

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[1] Further progress in reducing SO_2 emissions will come from the new Cross-State Air Pollution Rule (CSAPR); the final Utility MACT; revised national ambient air quality standards (NAAQS) for SO_2 and particulate matter (PM) and associated new transport rules; and regional haze regulations.

[2] This compares to a 36-percent decline in total U.S. NO_x emissions from 1990 to 2008. Further progress in reducing NO_x emissions will come from the CSAPR; the final Utility MACT; revised NAAQS for ozone, nitrogen dioxide and PM and associated transport rules; and regional haze regulations.

has slashed these air emissions while electricity consumption rose 38 percent over the same period (1990-2010).

In addition, utilities have been taking steps to address mercury emissions. As a result of mercury control programs in about 20 states, the Clean Air Mercury Rule (CAMR) (which was vacated by a federal appellate court in 2008) and other EPA mandates, EEI estimates that about half of the total mercury in the coal used to generate the nation's electricity is currently controlled.

EEI's member companies are proud of their achievements in reducing air and other emissions over the last several decades. Going forward, our members are strongly committed to further emissions reductions and continued environmental protection as an integral part of generating electricity. This includes reducing the mercury emissions, non-mercury HAPs (including acid gases) and non-mercury metals emissions that are the subjects of this rulemaking. Moreover, about 30 gigaWatts (GW) of coal unit retirements out to 2022 have been announced in the last 18 months. We share EPA's objective of industry compliance with reasonable environmental regulations and urge that it be accomplished in a cost-effective and flexible manner.

With respect to the proposed Utility MACT rule, we are encouraged that EPA has demonstrated solid judgment in several of the proposed standards by incorporating some key elements of flexibility—such as the use of surrogates, work practice standards for organic HAPs and dioxins, and emissions averaging—to help companies meet these aggressive standards. EPA should include these provisions in the final rule.

Nonetheless, there are a number of areas where the proposed standards (including many of the compliance, testing and monitoring requirements) could benefit from additional flexibility afforded EPA under the Act that would help to reduce the costs of compliance and achieve desired emissions reductions without implications for local reliability. For example, EPA takes steps to provide critical flexibility by providing for the use of surrogates to demonstrate compliance, proposing work practice standards where appropriate and allowing for emissions averaging. We commend EPA's inclusion of these key elements of flexibility. However, EPA often undercuts the utility of these flexibility mechanisms by placing unnecessary restrictions and requirements on them, without obtaining additional environmental or health benefits. Similarly, EPA's proposed compliance testing and monitoring program is complicated, confusing and costly, without any demonstration as to why some requirements are necessary or how they would ensure better compliance than a less complex program.

These comments identify areas in which EPA, working within CAA parameters, should improve the substantive requirements of the proposed rule and provide additional flexibility in the implementation of the rule. With our proposed modifications, EPA can both obtain sensible emissions reductions and save valuable economic resources.

Our overarching concern is the timeframe for implementation of, and compliance with, the proposed rule. EEI believes that units designated for shutdown and not installing pollution control equipment, being replaced or repowered, or awaiting a transmission upgrade should be shut down no later than three years after the effective date of the final rule. The permitting authority should extend this date only if the appropriate regional transmission

organization (RTO), the North American Electric Reliability Corp. (NERC) or the appropriate state commission confirms that the continued operation of the unit is required for reliability purposes and the utility demonstrates that the reliability problem is being diligently addressed.

However, a large number of units installing pollution control equipment, being replaced or repowered, or awaiting transmission upgrades need more than three years. We agree with the recent policy resolution by the National Association of Regulatory Utility Commissioners (NARUC) that "a retrofit timeline for multimillion dollar projects may take up to five-plus years" and that "[t]imelines may also be lengthened by the large number of multimillion dollar projects that will be in competition for the same skilled labor and resources."[3] While EPA acknowledges in the proposal that more than three years may be required for some units to comply—and, importantly, suggests a willingness to consider unit-specific extensions—**we urge EPA, as authorized by CAA section 112(i)(3)(B), to extend the compliance deadline for one year for all units that are installing pollution control equipment, being replaced or repowered, or expanding transmission capacity for reliability purposes**. We believe that the number of units needing additional time is sufficiently large that a unit-by-unit review of the need for an extension actually would delay overall compliance and that allowing more time up front will help protect reliability and achieve compliance in the most cost-effective way.

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[3] NARUC Policy Resolution ERE-5, "*Resolution on Increased Flexibility for the Implementation of EPA Rulemakings*," adopted by the Board of Directors on July 20, 2011 (NARUC Resolution).

In addition, because some units may require more than four years to achieve compliance, we are urging the President to issue an order under CAA section 112(i)(4) to allow additional time in instances where:

- **The utility is continuing to take diligent, good-faith measures to achieve compliance;**
- **The needed technology is not available; and**
- **The appropriate RTO, NERC or appropriate state commission certifies that an extension of time is necessary to address reliability issues or is consistent with the applicable state-approved integrated resource plan (or similar state process), which may take into account the potential reliability and economic impacts of compliance decisions.**

Our position is consistent with the NARUC policy resolution addressing EPA rulemakings, which states that "flexibility with the implementation of EPA regulations can lessen generation cost increases" and encourages the "use of all available tools that provide flexibility in EPA regulation requirements reflecting the timeline and cost efficiency concerns embodied in this resolution to ensure continuing emission reduction progress while minimizing capital costs, rate increases and other economic impacts while meeting public health and environmental goals."[4]

Moreover, EEI's position comports with the President's recent Executive Order on Improving Regulation and Regulatory Review, which includes provisions directing regulatory agencies to promulgate rules that promote implementation flexibility so as to impose the least burden on society.

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[4] *Id.*

The remainder of our comments identifies areas in which EPA should improve the substantive requirements of the proposed rule and provide additional implementation flexibility.

1. Besides the compliance timeline, many of EEI's members are most concerned about EPA's decision to use total particulate matter (PM) as the surrogate for the non-mercury metals standard. EEI supports EPA's use of alternative surrogates for non-mercury metals, but opposes using **total** PM as a surrogate and believes that the **filterable** PM standard that EPA uses in the final industrial Boiler MACT rule and in other CAA rules regulating PM emissions is the appropriate standard. EPA should establish a single, category-wide filterable PM emissions standard and designate filterable PM—not total PM—as a surrogate for the non-mercury metals standard. EPA has not justified the use of a total PM standard or demonstrated that a total PM standard is consistent with the requirements of the CAA. There is little data on historical condensable PM emissions, and EPA's Information Collection Request (ICR) data are not comparable. Total PM—the sum of filterable PM and condensable PM—cannot be directly measured. There are practical and analytical problems with condensable measurement methodologies. Further, there is no scientific justification for including condensable PM in the first place, as EPA's assumption that selenium emissions are correlated with condensable PM has been shown to be incorrect, whereas an association between filterable PM and selenium has been shown. In addition, EPA's requirement of unit-specific operating limits is inconsistent with the CAA statutory provision that a MACT standard must be the "average" of top-achieving units.

2. Dry sorbent injection (DSI) will be a useful and cost-effective control tool for many units, but it is not a viable option for all coal-based units for compliance with the acid gas standard. In

many circumstances, EPA's analysis of DSI significantly underestimates the time needed for, as well as the cost of, compliance in many circumstances. First, DSI could have limited application as a compliance option due to operational impacts and cost considerations that EPA has not taken into consideration. Second, the use of DSI could impact beneficial use of fly ash, resulting in increased disposal volumes, costs and loss of revenue. Third, DSI is not a viable option for eastern bituminous coals, which require the use of wet flue gas desulfurization (FGD); compared to DSI, wet FGD is more costly and takes more time to implement, leading to timing concerns for compliance. Many companies will need more than the three years and will spend more than EPA estimates to achieve compliance.

3. The mercury standard must be recalculated because it was not established as the average of the best-performing 12 percent of existing sources, but rather was based on an unrepresentative sample group. EPA erred in establishing the mercury standard by using a data set different than the 127 units used to calculate the other MACT standards, particularly since the ICR stack emissions data that EPA collected are adequate to calculate the mercury standard correctly. As part of the recalculation process, EPA should create a separate subcategory for circulating fluidized bed (CFB) units, whose mercury emissions are statistically different from conventional boilers.

4. EPA's approach to basing new unit standards on a hypothetical "ideal" unit that has never operated is inconsistent with CAA section 112(d)(3). MACT standards for new units must be measurable, achievable and based on technology at existing sources. Many companies believe it would be extremely difficult to permit and build a new facility that could meet all of the

proposed limits. Accordingly, EPA should revise the new source MACT limits based on the actual emissions achieved under all operating conditions by the best-performing units whose limits can be measured by current technology.

5. While EEI supports EPA's consideration of a limited-use subcategory for oil-based units that operate a limited amount of time per year, we urge the Agency to establish work practice standards in lieu of emissions limits for these units, similar to the approach used in the final industrial Boiler MACT rule.

6. Many of the proposed measures for demonstrating compliance impose unnecessary burdens and excessive costs in contravention of the President's recent Executive Order No. 13563. As a result, EEI strongly recommends that EPA reconsider and remove the restrictive requirements discussed below.

7. EEI urges EPA to allow work practice standards to apply during periods of startup and shutdown (SS), as the agency has done in the final industrial Boiler MACT rule. EPA provides no justification for the disparate treatment of similarly affected units, and the Agency's rationale for imposing numeric emissions limits instead of work practice standards appears to be based on incorrect, overly broad assumptions about utility operations. For example, EPA acknowledges that it is infeasible to test and monitor emissions from utility boilers during SS, but it provides no explanation as to why utility boilers are subject to more rigorous numeric standards while similar commercial and industrial boilers are subject to work practice standards. Finally, neither the

discussion of CAA section 112(h) in the *Sierra Club* decision nor the decision itself constrains EPA's ability to choose to use work practice standards in lieu of numeric standards.

8. EEI urges EPA to allow broad emissions averaging as an alternative compliance mechanism to provide regulatory flexibility and decrease costs as it has done in other contexts. Emissions averaging maintains overall compliance with EPA's final standards while reducing compliance costs. It is consistent with the stated objectives of Executive Order No. 13563. Since averaging would be appropriate any time that it can be shown that the total quantity of a particular HAP emitted by averaged units does not exceed the emissions that would be achieved if the MACT limit were applied to each unit individually, EPA should:

- Allow emissions averaging across all affected units (both coal and oil) on a facility basis, including both new and existing units and where averaged units share a common stack.
- Allow broader emissions averaging where it can be demonstrated that public health and environmental benefits are preserved.

9. Many of EPA's proposed compliance, testing and monitoring requirements are confusing, inflexible or costly and would yield little benefit. For example, EPA unnecessarily proposes to require stack testing to demonstrate continued compliance, even when continuous emissions monitoring systems (CEMS) are used. In addition, the PM CEMS compliance approach proposed by the Agency is unworkable and internally inconsistent with existing EPA requirements (*i.e.*, PS-11). Finally, the alternative fuel analysis provisions should apply to all affected liquid oil-based EGUs. Revisions should be made to the monitoring requirements for PM, mercury, hydrogen chloride (HCl) and SO_2, as well as to the requirements for oil-based units. These include:

- EPA should state clearly what monitoring, testing and operating parameter limits apply as a function of each option.

- The final rule should be clear in stating that if an owner/operator elects direct (CEMS) monitoring of a regulated HAP or its surrogate, then fuel sampling, parameter monitoring, *etc.* are not required.

- For those units that opt to demonstrate compliance by performing ongoing stack tests, EPA should specify stack emissions performance testing only for those methods that are necessary to measure the regulated HAP in terms of the emissions standard, not including surrogates.

- EPA should allow reasonable, flexible alternative compliance demonstration options, including less frequent periodic stack tests.

- Mercury and HCl CEMS limitations must be revised.

- EPA should use existing performance specifications (*e.g.*, for SO_2 CEMS) that have historically proven to provide quality accurate emissions data, rather than attempt to add on additional performance tests that will not improve data quality or accuracy.

- Several oil sampling requirements need clarification or modification.

10. EEI also encourages EPA to recognize investments made for emissions reductions consistent with state HAPs regulations.

II. EPA Should Designate Filterable PM And Not Total PM As A Surrogate For The Non-mercury Metals Standard.

The proposal recommends total PM—filterable PM, *i.e.*, fine particulate emissions ($PM_{2.5}$), plus condensable PM—as a surrogate for measuring non-mercury metals, with alternate surrogates of total metals or individual metals. Besides the compliance timeline, many of EEI's members are most concerned about EPA's decision to use total PM as the surrogate for the non-mercury metals standard. EEI supports EPA's use of alternative surrogates for non-mercury metals, but opposes using **total** PM as a surrogate and believes that the **filterable** PM standard that EPA uses in the final industrial Boiler MACT (Boiler MACT) rule[5] and in other CAA rules regulating PM emissions (*i.e.*, PM NAAQS) is the appropriate standard.

The Utility MACT is the first rule that would require condensable PM emissions to be monitored and controlled. Owners and operators of EGUs subject to the proposed Utility MACT have little historical experience measuring and monitoring condensable PM emissions and little historical data about continuous condensable PM emissions. **In short, there is a great deal of uncertainty as to the data that EPA used to establish the total PM standard, what the total PM standard actually requires and how to demonstrate compliance.**

The use of total PM, instead of filterable PM, is troubling for a number of reasons. EPA states that total PM is an appropriate surrogate because units that use wet scrubbers cannot use the test method for measuring filterable PM. *See* 76 *Fed. Reg*. 25039. While this may be true, CAA section 112(d)(3) requires that standards be set based on the "average emission limitation achieved by the best performing 12 percent of the existing sources," not on what test methods are applicable to a subset of affected units. EPA has not demonstrated that the proposed total PM standard complies with this requirement and has not provided sufficient justification for why total PM is an appropriate surrogate for non-mercury metal emissions.

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[5] The Boiler MACT required only filterable PM as the surrogate for non-mercury metals. S*ee National Emissions Standards for Hazardous Air Pollutants from Industrial, Commercial and Institutional Boilers and Process Heaters*. 76 *Fed. Reg*. 15608 (Mar. 21, 2011). On the same day that the final rule was issued, EPA announced a reconsideration of certain parts of the Boiler MACT. *See National Emission Standards for Hazardous Air Pollutants; Notice of Reconsideration*, 76 *Fed. Reg*. 15266 (Mar. 21, 2011). In the *Notice of Reconsideration*, EPA identified the issues in the final Boiler MACT rule for which the Agency will provide additional opportunity for public comment and reconsideration. This list of issues is limited and does not include the issues raised by EEI in these comments.

A. Filterable PM Is an Appropriate Surrogate for Non-mercury Metals.

Comments to be submitted by the Electric Power Research Institute (EPRI) in this docket provide detailed analysis justifying the use of filterable PM as an adequate surrogate for all non-mercury metals. As the EPRI comments observe (at 2-12), EPA is attempting to improve the surrogacy relationship between selenium and a PM surrogate by proposing a MACT limit that includes condensable PM. However, the extent to which selenium is captured in sampling apparatus for condensable PM is unknown. *Id.* No test data are available for the exact condensable PM method that is required for compliance with the proposed MACT limits, making the merits of including condensable PM in the total PM limit difficult to assess. Most importantly, EPRI's review of the EPA ICR data shows that selenium emissions do not have a strong correlation with condensable PM emissions. The percentage of condensable PM varies across the entire spectrum from 0 percent total PM to 100 percent total PM. In fact, EPRI's analysis shows that filterable PM and total PM correlate equally well with non-mercury metals. *Id*. Accordingly, there appears to be no scientific justification for EPA to depart from the Agency's commonly used filterable PM standard and impose a total (filterable plus condensable) PM requirement in the first place.

B. Total PM Should Not Be Used due to Concerns with Measuring Condensable PM and Problems with Compliance Monitoring.

EPA attempts to justify the total PM standard as appropriate because many existing units already have installed wet FGD systems, which make it difficult to measure filterable PM. *See* 76 *Fed. Reg*. at 25039. However, there are practical and analytical problems with EPA's rationale.

Total PM cannot be directly measured. Total PM emissions are the sum of filterable PM and condensable PM measurements, but as EPRI notes in its comments, there are concerns with measuring condensable PM. Adding a condensable PM measurement to the filterable PM sampling train increases the total variability and reduces the sensitivity of the combined measurement system. *See* EPRI comments at 2-15. As indicated in EPRI's comments, research has shown that the condensable PM measurement method may not be accurate under flue gas conditions associated with wet FGD systems. *Id.* EPA's approach fails to recognize these issues.

In addition, there are uncertainties associated with how filterable PM was measured for the ICR. EPRI's analysis of the ICR data, specifically the conflicting methodologies that EPA required to measure filterable PM, suggests that some of the data are not comparable. Consequently, it is uncertain what the actual emissions of filterable PM are from EGUs. *See* EPRI comments at 2-16.

Finally, establishing a total PM limit raises serious concerns for compliance monitoring since PM CEMS measure only filterable PM. See discussion in section XI, *infra*.

C. EPA Must Revise Other PM Requirements.

1. EPA's requirement of unit-specific operating limits is inconsistent with the CAA statutory provision that a MACT standard must be the "average" of top-achieving units.

EPA creates additional hurdles to using total PM as a surrogate by requiring that unit-specific operating limits be used to demonstrate compliance with the proposed total PM limits. To demonstrate compliance with the total PM limit, the proposed rule requires an initial compliance stack test for PM to be performed that includes both the filterable and condensable fractions, and this total must be less than 0.030 lb/mmBtu. The proposed rule further requires that the filterable fraction level be established as an "operation limit" that cannot be exceeded. *See* 76 *Fed. Reg.* at

25105. The practical effect of this compliance requirement is that the proposed total PM limit could actually be stricter than the 0.030 lb/mmBtu standard in the proposed rule. Moreover, a utility would not know the actual total PM standard that a given unit needs to meet until an initial compliance test is conducted more than three years in the future after any new PM control equipment has been designed and constructed.

More importantly, under CAA section 112(d)(3)(A), MACT standards are applicable to categories or subcategories of sources and must be determined by EPA based on its assessment of the "average" of the best-performing 12 percent of the existing sources for which EPA has information. Accordingly, MACT standards cannot be unit-specific and set by a single test. Even assuming for the sake of argument that EPA is not bound by the statutory language and has discretion to set MACT standards in a different way, it should adopt a more flexible approach than unit-specific operating limits in accordance with the flexibility precepts of the President's recent executive order. See discussion in section VIII, *infra*.

In short, even if there were a rational basis for EPA to use a total PM standard, the way that it has chosen to measure compliance is both unnecessarily onerous and inconsistent with the requirements of the CAA.

2. EPA failed to address cumulative effects of using multiple pollution control devices in determining MACT levels applicable to PM levels.

In proposing total PM as a surrogate, EPA also fails to consider or address the antagonistic effects that adding multiple different pollution control devices can have on an EGU's HAPs emissions. This is particularly relevant with the PM limit. To illustrate, the 131 best-performing units from the EPA ICR database for total PM include 47 units that have a fabric filter installed, but no scrubber. These existing units would not be able to comply with this proposed rule without adding a scrubber or some type of sorbent injection to control hydrochloric acid emissions. Adding these HCl control technologies will increase the total PM emissions of these units. Because a fabric filter-alone configuration would not meet all MACT limits (since EPA has relied on PM emissions data that could not exist under its suite of HAPs limits), these units may not be the best-performing units.

Accordingly, EPA should establish a single, category-wide filterable PM emissions standard.

III. DSI Is A Useful Technology But Is Not A Viable Option For All Coals For Compliance With The Acid Gas Standard, And EPA's Overly Optimistic Analysis Of DSI Significantly Underestimates The Time Needed For Compliance As Well As The Cost Of Compliance.

The proposal adopts an HCl numeric emissions limit as a surrogate for acid gases—HCl, hydrofluoric acid (HF), hydrogen cyanide and chlorine. *See* 76 *Fed. Reg*. at 25038. EPA proposes an alternate surrogate of SO_2 if a unit is using a CEMS to demonstrate compliance with SO_2 limits. EEI supports the proposed surrogate and alternative for acid gas emissions. Utilities already monitor SO_2 emissions continuously under the Acid Rain Program, and the control technology that removes SO_2 also is effective at removing acid gas emissions.

A. DSI Is an Important, but Not Universal, Compliance Option due to Operational Impacts and Cost Factors that EPA Has Not Taken into Consideration.

EEI members agree that DSI is a viable technology that will facilitate compliance with the acid gas standard in certain applications. DSI has been used in several countries for many years as a control technology to capture a range of gaseous pollutants. DSI is currently being used by electric utilities in the United States to capture SO_2 and to mitigate the effects of sulfur trioxide. However, the limited experience with testing DSI for controlling acid gas emissions from coal-based power plants in this country indicates that it may be an option for select units burning select fuels, but it is not a universal option for all coal units.

The proposal states that plants can control acid gases, as represented by HCl, by injecting a sodium-based powder (Trona or sodium bicarbonate) into the flue gas duct of a power plant upstream of a baghouse for particulate control. The powder adsorbs the acid gases and the resulting product is then removed from the flue gas in the baghouse. 76 *Fed. Reg*. at 25014. EEI has significant concern with EPA's assertion that DSI will allow all utility units to achieve HCl reductions, consistent with the proposed acid gas standard. The preamble to the proposed rule states, "EPA does not project use of wet scrubbing technology to meet the requirements of this proposed rule…" 76 *Fed. Reg.* at 25054. EPA concludes that DSI will be used primarily to comply with the acid gas MACT standard. Specifically, EPA projects the installation of 56 GW of DSI and 25 GW of dry scrubbers.

These determinations directly affect EPA's estimates of the cost and timing of installing controls to comply. EPA acknowledges that if DSI does not achieve HCl reduction on the levels that EPA projects, utilities will have to install dry or wet scrubbers to come into compliance. 76 *Fed. Reg.* at 25054. Moreover, given the cost differential between DSI and wet scrubbing, utilities would close more units if DSI does not prove to be a viable compliance option. For these reasons, the role that DSI can play is extremely important to a full understanding of the likely cost, impact and timeframe for complying with the proposed rule.

EEI members agree that DSI can be used for compliance at **many** units cost effectively, but strongly disagree with EPA's assumption that DSI and dry scrubbers will be the compliance method for acid gas control at **all** units. First, DSI has not been widely demonstrated in practice. Out of 131 units that define the HCl floor, only 15 units currently use DSI, and only five of those units use DSI **without** FGD.[6]

Second, DSI has a relatively high variable cost (which ranges widely between $4/megaWatt-hour (MWH) to $15/MWH). There are currently only a few suppliers of DSI; specifically, the primary supply of Trona is located in the western United States. Getting the supply of Trona to units in the eastern United States could make the delivered cost for Trona reach $200/ton. The ongoing operational costs for DSI, including costs to ship and store large amounts of chemical sorbent, can approach the annualized cost of a wet scrubber.[7]

Third, units using DSI are likely to need a particulate control device downstream. The sorbent is removed by a PM control device such as a baghouse or electrostatic precipitator (ESP). EPA acknowledges that DSI is most useful with a baghouse.[8] A baghouse typically takes at least 36 months to install, and costs are about $200/kiloWatt (KW). Similarly, UBS Investment Research notes that "implementing an ACI system…could require the installation of a baghouse,

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[6] FBR Capital Markets, Energy & Natural Resources (Apr. 13, 2011).
[7] Bipartisan Policy Center (BPC), Environmental Regulation and Electric System Reliability 15 (June 2011) (BPC Report), *available at* http://www.bipartisanpolicy.org/library/report/environmental-regulation-and-electric-system-reliability.
[8] See EPA, Regulatory Impact Analysis of the Proposed Toxics Rule: Final Report 7-7 (Mar. 2011) (RIA).

a substantial capital commitment."[9] However, there are indications that these issues may not be present with an ESP.

Fourth, DSI may interfere with ACI used for mercury emissions control. Testing at We Energies' Presque Isle Power Plant to demonstrate the Toxecon™ configuration showed that Trona injection also reduced mercury capture by ACI to the point where the process could not meet its 90-percent mercury reduction goal.[10] (*See* EPRI comments for more detail on Trona interference with ACI.) However, NRG Energy's Huntley and Dunkirk plants in New York currently are using Trona and ACI effectively. These examples illustrate the plant-specific applicability of DSI technology, as the Presque Isle, Huntley and Dunkirk plants all burn Powder River Basin coal.

B. The Use of DSI Could Impact Beneficial Use of Fly Ash, Resulting in Increased Disposal Costs and Loss of Revenue.

The use of sodium-based DSI also could impact the marketability and beneficial use of fly ash in important industry segments, including the concrete, wallboard and asphalt products industries as well as road and bridge construction. UBS reaches a similar conclusion, noting that "a material disadvantage resulting from the use of TRONA and ACI relates to limitations on the ability to beneficially reuse fly ash."[11] Currently, approximately 134 million tons of coal combustion residuals (CCRs) are generated annually, of which approximately 56 million tons, or about 41

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[9] UBS Investment Research, "A Closer Look At EPA's HAPs MACT Regs" 7 (Apr. 26, 2011).
[10] See Department of Energy/National Energy Technology Laboratory, Toxecon™ Retrofit for Mercury and Multi-Pollutant Control on Three 90-MW Coal-Fired Boilers (DOE/NETL-2011/1450) (Oct. 2010).
[11] UBS, *supra* n.9, at 5-6.

percent, are recycled in a variety of applications.[12] The loss of these important beneficial uses will cause CCRs to be disposed of instead of being beneficially used, causing significant and new economic and operational burdens on electric generation facilities. For affected companies, **EPA has not considered the full costs of disposal and loss of revenue from beneficial use of fly ash in the proposed rule.**

The problem arises because for fly ash to be used in certain applications, it must meet product specifications. Sodium-based injection technologies may cause fly ash to exceed the available alkali criteria established by the American Association of State Highway and Transportation Officials for concrete. Sodium-based dry sorbents are soluble and contribute greatly to the available alkali content. As a result, fly ash produced with emissions controls systems employing sodium-based DSI technologies may no longer be suitable for use in the ready-mix concrete industry.

In addition, the use of sodium-based DSI also increases the solubility of certain other constituents in the fly ash, which would potentially make it unsuitable for other established and environmentally beneficial uses, including for mine reclamation.

Specifically, establishment of emissions control technologies predicated on sodium-based DSI as EPA assumes in the proposed rule will likely mean that at least 12 million tons of fly ash will be diverted on an annual basis from its beneficial use in the cement/concrete industries to CCR

[12] See American Coal Ash Association, 2009 Coal Combustion Product (CCP) Product and Use Survey.

disposal units. Coal-based facilities will need to accommodate these additional volumes of CCRs through expansions of existing disposal units, construction of new units or both. The design, planning, permitting and construction of this additional disposal capacity can take many years and cost millions of dollars per unit. EPA's optimistic projections about the cost and usefulness of DSI have not taken into account the additional construction and disposal costs that coal-based generating units will have to incur to dispose of additional CCRs that will be diverted from the beneficial use market as a result of the contemplated emissions control technologies underlying the proposal.

There may be mechanisms to avoid compromising the quality of the fly ash that would preclude its availability for replacement for Portland cement or in concrete applications. These may include the injection of the sorbent in a manner so that it is not intermingled with the fly ash, *i.e.*, downstream of the baghouse or ESP, or it could involve the separation of the sorbent from the combined sorbent-fly ash mixture. However, we are not aware of any currently available technologies that would accomplish the latter option.

C. DSI Is Not a Viable Option for Eastern Bituminous Coals, which Would Necessitate Wet FGD for Compliance, Resulting in Additional Cost and Timing Concerns for Compliance.

Companies that burn primarily eastern bituminous coals do not believe that DSI will meet the acid gas MACT standard, and believe that they will have to install wet FGD for compliance. This is because the higher chlorine content found in these coals necessitates a more aggressive control technology to remove higher levels of HCl. Several energy market analysts share this view. Bernstein Research states, "SO2 scrubbers are likely to be required to control HCl emissions at plants burning eastern bituminous coals" and that "virtually all coal produced in the

Appalachian and Interior regions, accounting for some 45% of U.S. coal production, produced HCl emissions that cannot be controlled to the level required by the EPA using dry sorbent injection."[13] UBS states, "TRONA is not necessarily an economic solution for coals with greater than 2lb/MMbtu SO2" and that "the economic case remains favorable to install a scrubber over TRONA should generators burn higher sulfur coals." [14] Currently about 23 percent of all bituminous coal-based plants is unscrubbed.

To comply, these companies may have to install a wet FGD. Installing a wet FGD will present major challenges due to its cost and time needed for installation:

DSI	wet FGD
\$50/KW	\$400/KW and up
9-18 months to install	current installations have taken up to 60 months

The estimated cost and likely timeframe for installing wet FGD conflict with EPA's assertions about cost and that all companies will be able to install, retrofit and upgrade all of the emission controls needed for compliance within three years.

Most companies' actual experience with emissions control retrofits indicates that a timeline of five years is becoming the norm, for the following reasons (which EPA did not consider in reaching the conclusion that DSI can be installed within three years):

- Permits are routinely contested, leading to delays through additional administrative review or review by the Environmental Appeals Board, or both.

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[13] Bernstein Research, "U.S. Utilities: Why EPA's Acid Gas Emissions Limits Will Force Eastern Coal Burning Plants to Install Costly SO_2 Scrubbers" 1-3 (March 22, 2011).
[14] UBS, *supra* n.9, at 1-3.

- Equipment procurement contracts are not signed until regulatory permits are approved, yet EPA fails to mention or account for this delay in its estimate of the time required to install controls.

- Timelines that may be applicable today—when DSI is purchased and installed on a sporadic basis—may well be inapplicable in a situation where numerous companies are facing similar compliance deadlines. Under the proposed rule, multiple companies would be attempting to install the same type of technology within limited operational periods (spring and fall). Nevertheless, in the preamble EPA does not take this reality into account and instead contends that DSI and wet and dry scrubbing technologies can be installed within three years.

- The detailed requirements and public process involved with prevention of significant deterioration (PSD) permitting will in and of itself add length to the overall schedule for installing DSI. Obtaining a PSD permit will become a critical path item.

These factors demonstrate that many companies will need more than the three years and will spend more than EPA estimates to come into compliance.

IV. The Mercury Standard Must Be Recalculated Because It Was Not Established As The Average Of The Best-performing 12 Percent Of Existing Sources.

A. EPA Erred in Using a Different and Inappropriate Data Set in Establishing the Mercury Standard than It Used for the Other MACT Standards.

EPA used a different methodology to set the MACT floor for mercury than for other HAPs. CAA section 112(d)(3)(A) specifies that when EPA determines the MACT floor for existing units, it must not be less stringent than the "average emission limitation achieved by the best performing 12 percent of the existing sources (for which the Administrator has emissions information)." In order to inform this rulemaking, EPA issued an ICR that required the industry to conduct more than $100 million of stack sampling for HAPs emissions and emissions of possible HAPs surrogates. EPA stated in its Supporting Statement for the ICR:

> For 3 of the HAP groups or individual HAP, to the extent the Agency can establish that it has in fact collected data from all of the existing sources that represent the best

> performing 12 percent of the existing sources, we intend to use data from sources representing the best performing 12 percent of **all** sources in any category or subcategory to establish the CAA section 112(d) standards.[15]

The MACT floors for HCl and PM emissions were based on an analysis of 131 units—12 percent of the fleet of coal-based units. EEI agrees with and supports EPA's use of 131 units to determine the MACT floors for these pollutants.

However, EPA took a different approach with respect to mercury. EPA used only 40 units to determine the MACT standard for mercury. As EPA states in the preamble to the proposed rule:

> For Hg from coal-fired units, we used the top 12 percent of the data obtained because, even though we required Hg testing for the units testing for the non-Hg metallic HAP, we did not believe those units represented the top performing 12 percent of sources for Hg in the category at the time we issued the ICR and we made no assertions to that effect.

76 *Fed. Reg*. at 25023.

This approach is inconsistent with the clear requirements of the Act. A review of the mercury ICR data shows that the best-performing units were indeed tested during the ICR and that EPA should have used 127 units to set the MACT floor. That EPA does not like the data obtained from these 127 units is not a legally sufficient reason not to use it, as required by CAA section 112(d)(3)(A). The fact that EPA "did not believe" or "made no assertions" regarding the data is an insufficient basis to exclude the data. EPA's decision to use a subset of the data, and the basis for that decision, are inconsistent with the CAA.

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[15] Supporting Statement for OMB Review of EPA ICR No. 2362.01, Part B, at 2-3 (Dec. 24, 2009) (emphasis in original); *see also* Response to Comments Received on Proposed Information Collection Request 12-13 (Nov. 10, 2009), *published at* 74 *Fed. Reg*. 58012 (2009).

Consistent with the CAA, EPA should use data from the best-performing 12 percent of existing sources to determine the mercury standards. Once this regulatory floor is established, EPA could consider more stringent "beyond the floor" options, only after taking into consideration cost, energy and environmental impacts, as the Agency did when establishing the mercury standard for lignite units in the proposed Utility MACT. *See* 76 *Fed. Reg*. 25046-47. EPA's approach to setting mercury standards can and must comport with the requirements of the Act.

B. The ICR Stack Emissions Data Set Is Adequate to Calculate Correctly the Mercury Standard.

EPA's assertion that the ICR data obtained did not represent the top 12 percent of sources for mercury also is unsupported by the data itself. It is clear that the Part III stack emissions testing, upon which EPA bases the proposed non-mercury standards, included units with the lowest mercury emissions. ACI has been installed on coal-based EGUs for the sole purpose of controlling mercury emissions. EPA's spreadsheet of the **Part II** ICR data lists 45 EGUs as having installed ACI. Of these units, 33 reported **Part III** mercury test results. If the Part III testing for mercury truly had been random, only 15 percent of all units with ACI would have been selected for Part III testing, or seven units (45 x .15 = 6.75). In fact, 73 percent of the units with ACI (33/45) were required to conduct Part III mercury testing. This inordinately high percentage of ACI-equipped units required to conduct Part III testing is not random; rather, it demonstrates EPA's intent to require Part III emissions testing at units that it believed had the lowest mercury emissions.

Another indication that the ICR testing was improperly aimed at obtaining mercury emissions information from the lowest-emitting units is the large number of units equipped with baghouses that were required to test for mercury. Plants equipped with baghouses have long been known to have better than average mercury removal because as ash builds up on the filter bags, any unburned carbon in the ash acts like a carbon bed that adsorbs mercury from the gas stream. Of the 127 units with the lowest mercury emissions, 120 are equipped with fabric filters.[16]

In summary, EPA erred in not using 127 units to calculate the MACT floor for mercury emissions from existing sources, while it appropriately used that data set for other HAPs. EPA must comply with CAA MACT floor requirements and recalculate and re-determine this standard.

C. EPA Should Establish a Subcategory for Circulating Fluidized Bed Units, which Are Fundamentally Different from Conventional Boilers, to Allow More Flexibility in Meeting the Mercury Standard.

In addition to other changes advocated by these comments, EPA should create a new subcategory for CFB units. CFB units employ fundamentally different processes than pulverized coal (PC) boilers. CFBs combust relatively large coal particles in a bed of sorbent or inert material. CFBs operate at lower temperatures than conventional boilers and have much longer fuel residence times. The design, construction and operation of CFBs are different than conventional boilers. Conventional boilers pulverize coal to a very fine particle size to maximize combustion efficiency and minimize unburned carbon. CFBs tend to burn larger-size coal particles at a lower degree of combustion efficiency. As a result, CFBs typically have higher levels of unburned carbon present in the ash, which promotes more efficient mercury removal. Accordingly, analysis by EPRI indicates that mercury emissions of CFB boilers and PC boilers

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[16] Supporting Statement for OMB Review of ICR No. 2362.01 (OMB Control Number 2060-0631), Attachment 11 (Dec. 24, 2009).

are statistically different, with emissions from CFBs significantly lower than those from PC boilers. *See* EPRI comments at 2-18. This statistically significant difference in the mercury emissions profiles for these two distinct boiler technologies argues in favor of the creation of a separate subcategory for CFBs, as there is no control technology that PCs could install that would result in emissions reductions similar to those achieved by CFBs. Accordingly, **EPA should use the authority contained in CAA section 112(d)(1) to create a separate subcategory for CFB units.**

EEI supports EPA's decision to create a separate subcategory for units burning coal with less than 8,300 Btu/lb coals. Boilers designed to burn these coals (typically lignite) are significantly different than the design of plants burning coals with higher heat content. These coals also are different in composition than other coal types.

V. Work Practice Standards Are Appropriate To Address Emissions Of Organics and Dioxins.

EPA has proposed to establish work practice standards for EGUs to address any emissions of organic HAPs and dioxins. This would require an annual performance test program. EEI agrees with and supports EPA's decision to set work practice standards for these pollutants.

Results of sampling for organics and dioxins during the ICR showed there were far more "non-detectable" observations than actual detected values. The high number of measurements at or below the detection limit makes setting a MACT limit impossible for these HAPs because, by definition, a measurement at or below the detection limit has more error associated with it than the value measured. CAA section 112(h) provides discretion to EPA to set work practice standards in lieu of emissions limits if the Administrator finds it is not feasible to prescribe or enforce an emissions standard. The high percentage of non-detectable measurement for organics and dioxins shows that it is infeasible to either prescribe or enforce emissions standards for these pollutants.

However, the requirements for complying with the proposed work practice standards as described in section 63.10021(a)(16) and Table 3 of the proposal are much more rigorous than procedures established under previous national emissions standards for HAPs. Revisions to the work practice standards are necessary in order to avoid potential impacts on availability of EGUs due to prolonged and more frequent outages.

The decision to propose work practice standards for organic HAPs and dioxins is correct, but EPA should consider revising the work practice standards to make them consistent with historical utility procedures and schedules.

VI. MACT Standards For New Units Must Be Based On Technology At Existing Sources, Not On A Hypothetical "Ideal" Unit That Has Never Operated.

A. EPA's MACT Standard-setting Approach for New Sources Is Flawed.

The proposed MACT standards for new units are very stringent—one to three orders of magnitude more strict than for existing units. It appears that the limits were created by EPA selectively choosing the best-performing elements from among a group of plants, and that the new source MACT limits have not been achieved in practice by any single unit. As a result, there is no single existing unit that could meet these standards, and no new unit—including new integrated gasification combined cycle (IGGC) units—could be designed to meet these standards. This would impose an inappropriate standard, at variance with and inconsistent with the clear requirements of CAA section 112(d)(3).

EPA followed a process where each of the proposed new source MACT limits were derived by determining a MACT floor for each HAP or HAP surrogate for each subcategory of sources. 76 *Fed. Reg*. 25401. This fails to consider the overall effect of using multiple control technologies simultaneously, even though such analysis is essential since each technology affects the operation and effectiveness of other control technologies. The result is a set of MACT floors that do not represent the emissions controls achieved by an **actual**, best-performing unit. Instead, such floors reflect the performance of a hypothetical, ideal unit that practically does not—and we submit, could not—exist in the real world.

EPA's approach for setting new source MACT limits violates the express language of section 112(d)(3). CAA section 112(d)(3) requires that emissions limitations for new units should not be less stringent "than the emissions control that is achieved in practice by the **best controlled similar source**" (emphasis added). Section 112(a) defines major and area sources as any "stationary source located within a contiguous area and under common control." Accordingly, this language directs EPA to use a single "source" to set new source MACT limits. It does not direct EPA to use a collection of different "sources" to set the lowest possible emissions limit for each HAP for new sources. Taken together, these statutory provisions reveal a clear congressional intent that MACT standards promulgated under section 112(d) must be based on the actual performance of an actual source or sources. These requirements are clear and practical. They do not allow MACT standards to be based on a hypothetical, ideal unit, nor do they allow the "emissions control" achieved by the best sources to be determined using a pollutant-by-pollutant approach on a shifting group of best-performing units.

B. Compliance Standards Must Be Measurable and Achievable, Yet EPA's New Source MACT Standards Could Not Be Proven by Existing Technology.

In order for a utility to comply with the proposed rule's emissions limits, there need to be test methods available that can measure the HAPs or surrogates accurately at those stack gas concentrations. EPRI's comments explain that the procedures used by EPA to calculate the new source MACT standards produce an emissions value below the actual capacity of the test method.

The practical effect of the new source mercury limit is that it could not be measured: It is below the detection limit of any current or planned instrument. Even if a new unit could meet the limit, there is no way to assess compliance. The limit for PM is extremely low as well. No vendor of particulate controls has guaranteed that its respective technology would meet the PM limit. Finally, the HCl limit is equivalent to 99.95-percent control, which cannot be achieved with current technology and cannot be measured with any available CEMS. *See* EPRI comments at 2-12.

EEI agrees with EPRI's recommendations that 1) EPA reassess the data used to calculate the new source MACT limits, and 2) the resulting emissions limits should be measurable with acceptable precision in actual field samples, based on standard methods in a competent laboratory, with a sampling duration that is practical for routine stack testing.

Many companies believe it would be extremely difficult to build and permit a new facility that could meet all of the limits. In order to preserve the option for companies to build coal-based plants in the future, and, consistent with CAA section 112(d), EPA should set the new source MACT limits based on the actual emissions achieved under all operating conditions by the best-performing units and whose limits can be measured by current technology.

VII. EEI Supports EPA's Concept To Create A Limited-use Subcategory For Oil-based Units, But EPA Should Establish Work Practice Standards In Lieu Of Emissions Limits.

EPA is considering a limited-use subcategory to account for liquid oil-based units that only operate a limited amount of time per year on oil and are inoperative the remainder of the year. 76 *Fed. Reg.* at 25027. EEI supports the creation of such a subcategory, and urges EPA to set work practice or operational standards (*i.e.*, tune up) instead of numeric emissions limits for limited-use oil-based units. This approach is similar to the final Boiler MACT rule.

The subcategory should:

- Include both forms of oil (*i.e.*, distillate and residual) used to generate electricity.
- Allow these units to be operated up to a maximum of 876 hours (10-percent capacity factor equivalent) per year, where:
  - If the maximum operating limit is exceeded during any given year, it is the owner's responsibility to meet any environmental emissions compliance standards or request a waiver for a special circumstance, *e.g.*, late season hurricane recovery or curtailment of natural gas supply.

Currently, the proposed rule treats oil-based units differently (*i.e.*, more stringently) than the Boiler MACT, which provides a limited-use subcategory. The Boiler MACT defines limited use as "any boiler…that burns any amount of …liquid…fuels, has a rated capacity of greater than 10 MMBtu per hour heat inputs, and has a federally enforceable limit of no more than 876 hours per year of operation." 76 *Fed. Reg.* 15608, 15684. Further, the Boiler MACT rule states that such units would be regulated "with a work practice standard that requires a biennial tune-up, which will limit HAP by ensuring that these units operate at peak efficiency during the limited hours that they do operate." *Id.* at 15634.

Electricity generated from oil-based units contributes a relatively small percentage of the total generation and installed capacity on a national basis and also contributes a *de minimis* amount of emissions. Consequently, creating a limited-use subcategory for oil-based units will have a negligible impact on overall emissions. Data from the Energy Information Administration (EIA)[17] support this statement, indicating that:

- 38,937 out of 3,950,331 thousand MWH of generation came from oil, or 0.986 percent of all generation.
- There were 56,781 MW of installed oil capacity out of a total installed capacity of 1,025,400 MW, or 5.54 percent of all installed capacity.
- Calculating from the above metrics, the average capacity factor for all oil generation in 2009 was 7.83 percent.[18]

Note that on a regional or market basis, the percentage of oil-based generation/installed capacity as well as the capacity factor can be higher or lower than the national averages.

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[17] EIA, Electric Power Annual 2009, ES-1, available at: http://www.eia.gov/cneaf/electricity/epa/epa_sum.html.
[18] Calculation: (38,937,000 MWH/(56,781 MW x 8,760 hours)).

There are 4,055 oil-based generating units in operation or on standby mode, and 89 percent of these units have nameplate capacities of 25 MW or less.[19] According to EIA 2008 data, petroleum-fired units contributed 3 percent of the total SO_2 emissions and 2.2 percent of the NO_x emissions of the power sector.[20] Such units run on distillate fuel oil, residual fuel oil or some combination.

Due to the already high levelized cost of generation for these units ($187.54/MWH, 10-percent capacity factor, on average),[21] the units operate and are dispatched primarily during times of peak load/peak demand or in emergency situations, such as hurricane recovery, curtailment of natural gas due to natural disaster disruptions, *etc*. The levelized cost of generation for these units is significantly higher than most other forms of electricity generation, such as a coal ($94.80/MWH), natural gas combined cycle ($66.10/MWH) and advanced nuclear ($103/MWH).[22] Retrofitting these units with an ESP would increase the already high levelized cost of generation another 7 percent ($200.32/MWH on average) with very little environmental benefit.[23]

The other factor that supports creation of a limited-use subcategory for oil-based units is the fact that, because these units operate so few hours during a given year, they only have a limited number of hours over which to amortize any retrofit capital expense. It is not possible to recover

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[19] Ventyx 2011.
[20] EIA, Electric Power Annual 2008, Electricity, available at: http://www.eia.gov/electricity/data.cfm. Note that the petroleum-fired category in EIA includes distillate fuel oil, residual fuel oil, petroleum coke, jet fuel, kerosene and waste oil.
[21] See Appendix 1 to these comments.
[22] See Appendix 2 to these comments.
[23] See n.19, *supra*.

the capital cost of the necessary controls over the remaining life of an oil-based unit with a capacity factor at or below the 10-percent limit proposed by EPA. When determining whether it is appropriate to create a subcategory under CAA section 112(d)(2), EPA is allowed to take into account the cost implications of achieving emissions reductions. The Agency is further authorized to utilize "work practice, or operational standards" when promulgating standards for such a subcategory. CAA § 112(d)(2)(D).

Unless the separate limited-use subcategory proposed by EPA is promulgated in the final regulations, these units would not be retrofit, and instead would be shut down by their owners. However, as already noted, these oil-based units are critical to the generation fleet to provide electricity during times of peak load or in emergency situations, and their forced retirement could lead to near-term, local energy supply problems and major cost increases.

VIII. The Proposed Measures For Demonstrating Compliance Impose Unnecessary Burdens And Excessive Costs In Contravention Of The President's Recent Executive Order.

The first part of our comments addressed the proposed Utility MACT standards. The balance of our comments will address implementation and compliance issues (including testing and monitoring requirements) before concluding with timeline and other issues.

In addition to the concerns noted previously about the ways in which some of the proposed standards were set, EEI has concerns about some of the proposed implementation requirements, which are very complicated in some cases and lack flexibility in others. This lack of implementation flexibility will impose increased costs without necessarily ensuring any additional environmental benefits. The President's recent Executive Order on Improving Regulation and Regulatory Review,[24] which directs agencies to tailor their regulations to impose the least burden on society, requires EPA to fashion the Utility MACT rule more flexibly and to take into account the cost implications to utilities, our customers and the economy of not maximizing opportunities to utilize available flexibility tools.

That order is explicit about the need for flexibility in regulation:

> Section 4. Flexible Approaches. Where relevant, feasible, and consistent with regulatory objectives, and the extent permitted by law, each agency shall identify and consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public. . . .

Such flexibility in compliance options is particularly warranted where, as here, the costs of compliance to utilities, the public and the economy are high. Given this presidential mandate, and the wide flexibility afforded by the CAA once appropriate standards are set, **EEI urges EPA to reconsider and remove the many unnecessarily restrictive requirements that we discuss below**.

IX. EPA Should Allow Work Practice Standards For Periods Of Startup And Shutdown As The Agency Has Done In The Boiler MACT Rule.

In other rules, EPA has differentiated between periods of startup and shutdown (SS) and periods of normal operation, providing work practice standards to minimize emissions during SS periods. Significantly, EPA did this in the Boiler MACT rule. In that rule, it found the use of work practice standards in lieu of numeric emissions limits appropriate and necessary in recognition of

[24] Exec. Order No. 13563 (Jan. 18, 2011), *published at* 76 *Fed. Reg.* 3821 (Jan. 21, 2011).

the infeasibility of appropriate testing and monitoring during SS periods. *See* 76 *Fed. Reg.* at 15613.

Despite the obvious similarities between the sources regulated by the Boiler MACT and those utility boilers that would be regulated by the proposed rule, EPA proposes very different regulatory treatment here. For utility boilers, EPA proposed numeric emissions limits that must be met at all times, including during SS periods. *See* 76 *Fed Reg*. 24976, 25028. **EPA provides no justification for the disparate treatment of similarly affected units, and the Agency's rationale for imposing numeric emissions limits instead of work practice standards appears to be based on incorrect, overly broad assumptions about utility operations. Consequently, EPA should adopt a different approach and instead provide for work practice standards to apply during SS periods.**

EPA's rationale for not allowing a different standard to apply during SS periods appears to be based on at least three assumptions: 1) SS periods "are all predictable and routine aspects of a sources operations" (*id.* at 25028); 2) the form of the standard, which allows for a 30-day average, provides sufficient flexibility to accommodate SS emissions; and 3) EGU emissions during SS periods will not be greater than during normal operations since EGUs typically utilize different fuels during such periods. These assumptions are not applicable for all units under all operating conditions and cannot provide a rational basis to support the imposition of numeric standards instead of work practice standards during SS periods.

First, EPA is incorrect that SS periods are "predictable and routine." Planned outages to support routine maintenance and repair or transmission upgrades may be predictable and routine, but these are not the only reasons why a SS period may be necessary. For example, utility units—including coal-based units—are being required more regularly to cycle operations to support the integration of variable resources, particularly wind, into the grid. Increased cycling stresses baseload units, which operate most efficiently and effectively in a steady state. As a consequence, more frequent unit "trips" (*i.e.*, unplanned outages) are likely. While the overall impact of this cycling is to reduce **overall** emissions because fossil units are being used less, increased trips lead to increased emissions of criteria air pollutants from the units cycling to accommodate renewables.[25] In these cases, the relatively small emissions increase during SS is likely to be dwarfed by the emissions avoided when renewable facilities are operating. Accordingly, EPA's failure to allow use of work practice standards during these periods would serve to punish, rather than reward, those units that are required to undergo more frequent cycling to accommodate renewable resources. EPA should not penalize practices that foster the emissions benefits associated with increased operation of variable, renewable resources, which will far exceed those that would be realized by imposing numeric standards during SS periods.

EPA's second assumption—that providing a 30-day averaging period will smooth out any emissions increases associated with infrequent SS periods—is predicated on infrequent SS periods of short duration. The frequency and duration of SS periods varies for different types of units and different fuels. **EPA's assumption that 30-day averaging addresses this is**

[25] *See, e.g.*, Bentek Energy, LLC, How Less Became More: Wind Power and Unintended Consequences in the Colorado Energy Market (2010), *available at* http://www.bentekenergy.com/WindCoalandGasStudy.aspx.

unsupported in the record by data from actual unit operations. Accordingly, EPA has not demonstrated that 30-day averaging will enable affected units to comply with a continuously applied MACT standard.

Similarly, EPA has not provided any support for its third assumption, that the use of a different fuel for SS would serve to minimize emissions during these periods. Depending on the fuel used, emissions may be greater during SS periods because emissions controls do not operate at peak performance until steady-state operations are achieved.

A. EPA's Proposed SS Provisions Deviate from Past Agency Practice Without Justification.

As noted, EPA's proposed approach in this rulemaking is in contrast to the approach the Agency took in the Boiler MACT. In that rule, EPA required sources during SS periods to meet a work practice standard "which requires following the manufacturer's recommended procedures for minimizing periods of startup and shutdown." *See* 76 *Fed. Reg*. at 15613. In finalizing separate work practice standards to apply during SS periods, EPA determined it was not technically feasible to complete stack testing: "in particular, to repeat the multiple required test runs – during periods of startup and shutdown due to physical limitations and the short duration of the startup and shutdown period." *Id.* EPA also expressed concern that testing requirements themselves could actually serve to increase emissions artificially. *Id*. at 15642.

The boilers and emissions control equipment employed at commercial and industrial generating units and utility generating units are substantially similar. Accordingly, utility boilers have the same issues as large commercial and industrial boilers with respect to emissions testing requirements, but EPA does not directly address these concerns in the proposed rule. Instead, EPA proposes to account for the variable conditions that can occur during SS periods by using a default value and specifying an electrical production rate for such periods. *See* 76 *Fed. Reg*. at 25028. In proposing these default values and production rates, EPA tacitly acknowledges that it is infeasible to test and monitor emissions from utility boilers during SS. However, the Agency provides no explanation as to why utility boilers are subject to more rigorous standards than similar commercial and industrial boilers. EPA also does not explain how the proposed default values were calculated or why they would be appropriate and accurate proxies for emissions during SS periods.

B. Work Practice Standards for SS Periods Would Be Consistent with the Requirements of CAA Section 112(h).

Under section 112(h), work practice standards are appropriate when it is not feasible in the judgment of the Administrator to prescribe or enforce an emissions standard. Section 112(h)(2) states that it is "not feasible to prescribe or enforce an emission standard" in any situation in which the Administrator determines that "the application of measurement methodology…is not practicable due to technological and economic limitations." Given that the Agency already has deemed that it is not technically feasible to measure emissions directly during SS periods, the standard set out in section 112(h) has been met.

Accordingly, EEI urges EPA to provide for work practice standards to apply during SS periods.

C. EPA Is Not Required to Adopt its Proposed Approach for SS Periods.

In proposing the Utility MACT standards and finalizing the Boiler MACT standards, EPA cites the same decision of the U.S. Court of Appeals for the D.C. Circuit. In both rulemakings, EPA indicates that *Sierra Club v. EPA*[26] requires that sources must comply with CAA section 112(d) emissions standards at all times. *See* 76 *Fed. Reg.* at 15613; 76 *Fed. Reg.* at 25021. In the Boiler MACT, EPA cited this precedent and then exercised its authority under CAA section 112(h) to implement a work practice standard to address SS periods. However, in the proposed Utility MACT rule, EPA uses the same precedent to come to the conclusion that continuously applicable numeric standards are required at all times.

The *Sierra Club* decision does not dictate this disparate result.[27] In *Sierra Club*, the court rejected EPA past practice that effectively provided no standard during SS periods, finding that the imposition of a general duty to minimize emissions was not a section 112-compliant standard.[28] However, the court did not find that numeric emissions limits under section 112(d) were required during SS periods. The court merely cited arguments raised by petitioners that noted that the availability of CAA section 112(h) is constrained by the definitions contained in that subsection. This reference does not in and of itself support the conclusion that section 112(h) work practice standards are impermissible in this rulemaking.

Work practice standards, which are explicitly authorized under CAA section 112(h), would satisfy the requirements of *Sierra Club* by ensuring that some enforceable standard applies to SS periods. **Neither the discussion of CAA section 112(h) in *Sierra Club* nor the decision itself**

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[26] 551 F.3d 1019 (D.C. Cir. 2008) (*Sierra Club*).
[27] *Sierra Club* is also inapplicable to any decision by EPA not to allow for differentiated standards during SS periods under a CAA section 111 new source performance standard (NSPS).
[28] The court stated that "[b]ecause the general duty is the only standard that applies during [SS and malfunction (SSM)] events – and accordingly no section 112 standard governs these events – the SSM exemption violates the CAA's requirement that some section 112 standard apply continuously." 551 F.3d at 1028.

constrains EPA's ability to promulgate alternative standards under this subsection. Accordingly, EPA is not required to apply numeric emissions standards to SS periods and can choose to use work practice standards in lieu of numeric standards.

X. EPA Must Allow Broad Emissions Averaging As An Alternative Compliance Mechanism To Provide Regulatory Flexibility And Decrease Costs.

EEI appreciates and supports EPA's proposal to allow emissions averaging. Averaging is an important flexibility tool that will help reduce the costs of compliance in a manner consistent with CAA section 112 and the President's executive order. As EPA has noted, the proposed rule "includes an emissions averaging compliance option because emissions averaging represents an equivalent, more flexible, and less costly alternative to controlling emissions points to MACT levels." 76 *Fed. Reg.* at 25053.

According to EPA, the decision to allow emissions averaging is based on the Agency's general policy of allowing flexible compliance approaches. The Agency asserts that it is "permissible to establish within a NESHAP a unified compliance regimen that permits averaging within an affected source across individual affected units subject to the standard under certain conditions" and that such an approach can promote "least cost" compliance while maintaining a workable and enforceable standard. *See id*.

In the proposed rule, EPA does not refer to the President's recent executive order, but emissions averaging is consistent with this directive, which requires each agency to "tailor its regulations to impose the least burden on society, consistent with obtaining regulatory objectives, taking into account, among other things, to the extent practicable, the costs of cumulative regulations."

Indeed, the order indicates that each agency "must" take this action along with other actions specified in the order. *See id*. In this case, emissions averaging not only is permitted by law, but also, if properly constructed, could be the least burdensome means to achieve EPA's regulatory objective.

However, EPA has proposed to allow averaging as a means to demonstrate alternative compliance with the MACT standards only in limited circumstances. *See id*. These limits undercut the effectiveness of this important regulatory flexibility tool. EEI believes that averaging could be allowed more broadly, consistent with the Act and EPA's emissions reductions goals.

A. EPA's Proposed Limits on Averaging Add Unnecessary and Costly Complexity.

EPA's emissions averaging proposal is available only to owners and operators of existing units at the affected source that are within a single subcategory. 76 *Fed Reg.* at 25053. Emissions averaging would not be permitted for new sources, between existing sources and new sources, between sources in different subcategories, or for sources subject to the NSPS for PM. *Id.* **Emissions averaging would even not be allowed in instances when a unit shares a common stack with units from different subcategories.** *Id*. at 25054. These limitations undercut the utility of emissions averaging in reducing compliance costs and providing regulatory flexibility.

EPA states that the Agency has "concluded that a limited form of averaging could be implemented that would not lessen the stringency of the MACT floor limits" and alludes to concerns that emissions averaging will result in unspecified implementation and enforcement issues. *See id*. at 25053. EPA does not provide any details as to why it has determined that a broader approach to averaging would have the effect of lessening the MACT floor, nor does it enumerate any of the implementation or enforcement issues that could arise from allowing emissions averaging in any of the scenarios that the proposed rule bars. This lack of information deprives owners and operators of affected sources the opportunity to assess, comment on and address EPA's concerns.

To support this limited approach to emissions averaging, EPA cites past rulemakings in which emissions averaging was limited similarly to the proposed rule.[29] However, EPA provides no discussion of why such limits were appropriate and necessary in other MACT rules or what characteristics of the sources regulated by those rules are comparable to the Utility MACT such that similar treatment is warranted. Moreover, EPA appears to assume, without discussion, that the limits applied to emissions averaging in past rulemakings create enforceable "criteria" that must be satisfied by this proposed rule that applies to utility generators. *See id*.

As EPA notes in the proposed rule, averaging multiple units' emissions is appropriate when the practical outcome is equivalent to compliance with the MACT floor limits by each discrete unit. *See id.* Accordingly**, averaging would be appropriate any time it can be shown that the total quantity of a particular HAP emitted by averaged units does not exceed the emissions that would be achieved if the MACT limit were applied to each unit individually.** This is a common-sense limitation on averaging that ensures that the public health benefits of a proposed

[29] Later in this section of the preamble, EPA notes that the emissions averaging provisions in this proposed rule are based in part on a national emissions standard for organic HAPs from the synthetic organic chemical (SOC) manufacturing industry. *Id*. at 25054. EPA does not state why limits deemed necessary in the context of HAPs from SOC manufacturing are appropriately applied to electricity generation.

rule are attained and the requirements of CAA section 112 are met. EPA has not explained why any of the additional proposed limits—a ban on averaging across units of different subcategories at a single facility and averaging across new and existing units, a ban on averaging emissions from units sharing a common stack, and a ban on averaging if a unit is subject to the PM NSPS—are needed if the owner or operator of affected units at a facility can demonstrate that total averaged emissions do not exceed the limits that would be applied to individual units.

EPA also has not demonstrated that limiting the use of emissions averaging would obviate the unspecified implementation and enforcement issues that EPA suggests are of concern. In fact, EPA fails to recognize the compliance and enforcement difficulties that would be created by imposing some of the proposed limits on averaging. For example, it would be substantially more complicated and expensive to segregate, measure separately and monitor the emissions of units that share a common stack to determine that each is in continuous compliance with the MACT standard for a particular pollutant than to allow these units to use averaging by measuring common emissions from the stack.

Accordingly, because EPA unequivocally has the authority to broaden the proposed approach to emissions averaging and has not demonstrated why the proposed limits on averaging are necessary or appropriate, it should:

- **Allow emissions averaging across all affected units (both coal and oil) on a facility basis, including both new and existing units and where averaged units share a common stack.**

- **Allow broader emissions averaging where it can be demonstrated that public health and environmental benefits are preserved.**

B. The CAA Provides Flexibility in Allowing Emissions Averaging.

The CAA does not mandate that EPA apply MACT standards on an individual unit basis. Instead, CAA section 112(d)(1) provides that EPA shall promulgate regulations "for each **category or subcategory of major sources** and area sources of hazardous air pollutants . . . ." (emphasis added). Moreover, CAA section 112(d)(2) standards are applicable to "new or existing **sources**" (emphasis added). On its face, the CAA authorizes EPA to regulate "major sources" broadly and does not direct the Agency to promulgate standards that are applicable unit-by-unit or facility-by-facility. Consequently, in promulgating any final rule, EPA should allow the emissions averaging alternatives outlined above. This would include the ability to average emissions across a facility.

C. EPA Has Previously Implemented CAA Section 112 Standards in a Flexible Manner.

As the Agency noted in 2004, "EPA has under the authority of section 112(d) established affected source-wide emissions averaging provisions that do not necessarily require each regulated source to apply controls." 69 *Fed. Reg*. 4652, 4662 (2004). EPA has exercised this flexible authority in various forms and on many separate occasions. For example, final standards for wood manufacturing operations allowed facilities to use one of four methods to demonstrate compliance. In that rulemaking, EPA provided additional flexibility to use emissions averaging in the final rule, expanding upon the averaging allowed under the proposed rule. EPA stated:

> The proposed rule did not allow facilities to use a combination of add-on control device and averaging. One commenter pointed out that this should also be a compliance option. In some facilities, emissions from only one or two finishing lines will be directed to the control device. The emission reductions from these lines will typically be much greater than the reductions required for a facility using compliant coatings. These facilities would like to be allowed to average those "overcontrolled" finishing lines with uncontrolled lines. The EPA believes this is consistent with the regulatory negotiation agreement and with the CAA, both of which state that a facility should be able to use any

> compliance method that they can demonstrate achieves an equivalent level of reductions. Therefore, EPA has included this compliance option in the final rule.

60 *Fed. Reg*. 62930, 62933 (1995).

In establishing final MACT standards for primary lead smelting facilities, EPA promulgated standards to limit metal HAP emissions from process sources, process fugitive sources and fugitive dust sources at primary lead smelters. To address these various separate sources, EPA promulgated a "plant wide" emission limit where the aggregated lead emissions from nine different sources were required to meet a combined standard of 500 g/Mg of lead produced. *See* 64 *Fed. Reg*. 30192, 30195 (1999). EPA instituted similar "facility-wide" standards with respect to iron and steel foundries. *See* 69 *Fed. Reg*. 21906 (2004).[30]

Similarly, the 2004 final rule for plywood and composite wood products (*see* 69 *Fed. Reg*. 45944 (2004)) defined the affected source subject to MACT standards as "the combination of all [plywood and composite wood products] manufacturing operations . . . located at a major source facility" and allowed an emissions averaging compliance option. *Id*. at 45948. In discussing this option, EPA stated:

> Emissions averaging is a means of achieving the required emissions reductions in a less costly way. Therefore, if you operate an existing affected source, for each process unit you would choose to comply with the emissions averaging provisions instead of the production-based compliance options or add-on control system compliance options . . . .

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[30] The rule defined "iron and steel foundry" as a **facility or portion** of a facility that undertakes certain actions resulting in "final or near final shape products for introduction into commerce" (emphasis added).

See id.[31] Although this rule was remanded after judicial review,[32] the emissions averaging provisions were not invalidated.[33]

D. EPA Previously Proposed Emissions Averaging for EGUs.

In its 2004 proposed CAA section 112 standards for EGUs, EPA included an option for affected units to utilize emissions averaging. *See* 69 *Fed. Reg*. 4652 (2004). In describing this action, EPA stated:

> In past MACT rulemakings and with respect to source categories other than Utility Units, EPA has not resolved whether a system-wide or pooled performance standard is permitted under section 112(d). However, EPA has under the authority of section 112(d) established affected source-wide emissions averaging provisions that do not necessarily require each regulated source to apply controls . . . .
>
> The proposed rule would also allow emissions averaging as a compliance option for existing coal-fired units located at a single contiguous plant. The owner/operator could elect to establish an overall Hg limit for an emissions averaging group using the procedures in the proposed rule and comply with that limit during each 12-month compliance period. The emissions averaging compliance approach is also applicable to coal-fired Utility Units subject to the Hg emission limits for new affected sources as long as they meet the new source limits.

Id. at 4662.

Although EPA did not finalize this proposal, the rationale for affording this compliance option remains valid. **First, it demonstrates that EPA believes that the CAA authorizes it to**

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[31] The Agency stated that "[e]missions averaging is a system of debits and credits in which the credits must equal or exceed the debits. . . Under the emissions averaging provisions, you would determine the required mass removal (RMR) of total HAP from debit-generating process units for a 6-month compliance period. . . One hundred percent of the RMR for debit-generating process units would have to be achieved or exceeded by the [actual mass removal] of total HAP achieved by credit-generating process units." *Id*. at 45950.

[32] *Natural Resources Defense Council v. EPA*, No. 04-1323 (D.C. Cir. June 19, 2007).

[33] EPA has used facility-wide averaging in other CAA section 112 rules as well. *See, e.g.*, 40 C.F.R. Part 63, Subpart LL (Primary Aluminum Reduction Plants); 40 C.F.R. Part 63, Subpart CC (Petroleum Refineries); and 40 C.F.R. Part 63, Subpart JJJ (Group IV Polymers and Resins).

promulgate MACT standards to control emissions from sources; this can be done broadly, *e.g.*, on a category or subcategory basis. Second, the structure of the utility industry, where multiple units may be co-located or in close proximity to one another, leads to the conclusion that emissions averaging is not only reasonable, but also the most appropriate approach to regulate individual units. Third, providing for emissions averaging will serve to reduce compliance costs while maintaining overall compliance with EPA's final standards. Such action also would be consistent with, and further the stated objectives of, Executive Order No. 13563.

XI. EPA's Proposed Compliance, Testing And Monitoring Requirements Are Inflexible And Costly And Would Yield Little Benefit.

EEI has numerous concerns regarding the monitoring and compliance provisions of the proposed rule, such as:

- Although EPA provides a number of compliance options, each option presents a number of issues. There are numerous inconsistencies between rule provisions and between the rule and the preamble. Many provisions state that requirements apply "as applicable," but few provisions clearly state to which EGUs or options the requirement applies.

- The monitoring requirements for emissions, fuel sampling and operational data are not clearly defined for each of the available options for determining compliance with the various emission standards. **For example, EPA proposes to require stack testing to demonstrate continued compliance, even when CEMS are used.**

- For EGUs that do not choose to use a surrogate, EPA proposes to require testing for surrogates anyway.

- Frequent periodic stack sampling and other performance testing required to demonstrate compliance with numerical emissions limits could be unnecessarily restrictive and expensive to perform.

- Technical concerns with CEMS include demonstrated performance at the proposed emissions limits and operational reliability.

A. Some Monitoring and Compliance Requirements Are Confusing and Are Not Justified.

Inconsistencies abound in the proposal, and few provisions clearly state to which EGUs or options the requirement applies. It seems that certain requirements (*e.g.*, unnecessary parameter limits which are not meant to apply when CEMS are used) are unintended and that regulatory language needs to be made consistent with EPA intent. Requiring excessive testing is inconsistent with Executive Order No. 13563, as discussed elsewhere in these comments, which requires agencies to tailor regulations to impose the least burden on society, consistent with obtaining regulatory objectives.

1. Units with CEMS should not be required to perform fuel sampling, or parameter monitoring, nor take on fuel or operational limits.

The most likely coal-based configurations able to comply with EPA's proposed rule will 1) opt for the total PM limit and utilize PM CEMS for continuous filterable PM measurements; 2) employ some combination of wet or dry scrubbing, and/or DSI, for acid gas control and elect to use already installed SO_2 CEMS; and 3) directly monitor mercury using either a mercury CEMS or a sorbent trap monitoring system. For the above-described scenario in which either all of the regulated HAPs or their surrogates are continuously monitored, **no** additional burdens (*e.g.*, coal sampling, operating parameter limits, *etc.*) should be imposed. EEI believes that EPA understands this logic, but the manner in which the proposed rule is drafted is very unclear. For example, proposed section 63.10007(c) states:

> (c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at the maximum normal operating load while burning the type of fuel or mixture of fuels that has the highest content of chlorine, fluorine, non-Hg HAP metals,

> and Hg, and you must demonstrate initial compliance and establish your operating limits based on these tests.[34]

While proposed section 63.10007(c) continues beyond the above-quoted passage, there is no indication that not every affected facility is subject to the requirements. EPA should revise the section 63.10007 language to make it clear that fuel sampling and operating parameter limits **do not apply** when either all of the regulated HAPs or their surrogates are continuously monitored.

Proposed section 63.10008 lays out in detail a fuel sampling and analysis regimen. Granted, proposed section 63.10008(a) contains an “as applicable clause,” but its meaning is never explained. However, none of the fuel information is meaningful or relevant when either all of the regulated HAPs or their surrogates are continuously monitored.

EEI assumes that the purposes of the fuel input limits are to ensure that EGUs that are not otherwise monitoring compliance with the relevant standard continuously (*e.g.*, EGUs not using CEMS or sorbent trap monitoring systems) repeat the relevant performance test if their fuel characteristics change such that compliance with the applicable limit at the current level of control is no longer assured. However, since all EGUs are required to demonstrate initial compliance with each emissions limit “through performance testing,” and the proposed rule defines “performance testing” to include the first 30 operating days of CEMS data, the proposal appears to require that EGUs meet fuel input limits regardless of the “performance testing” option that they choose. **There is no logical rationale for requiring sources that establish**

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[34] 76 *Fed. Reg.* at 25107.

compliance with the non-mercury metal limit using PM as a surrogate and PM CEMS, with the HCl limit using HCl CEMS or an SO_2 CEMS, or with the mercury limit using mercury CEMS or a sorbent trap system, to comply also with fuel input limits for metals, chlorine or mercury.

Under the proposal, units that demonstrate compliance "through performance testing" must establish site-specific operating parameter limits during the three-run performance test for each applicable control device as described in proposed Table 5. Proposed §§ 63.10007(c), 63.10011(b). Thereafter, units must maintain those parameters consistent with the established limit. Proposed § 63.10021(a)(1), Tables 4 and 8. For example, the parameters to which the minimum operating limits apply include: pH, liquid flow-rate, and pressure drop for wet scrubbers; sorbent injection rate (and carbon injection rate)[35] for dry scrubbers; and secondary power input for ESPs at units with a wet scrubber. *Id*. The rule essentially appears to require all EGUs to develop parameter operating limits for all applicable controls in Table 7 regardless of whether they monitor emissions with CEMS or a sorbent trap monitoring system. **This is illogical, and EPA has provided no justification for this approach.**

2. Testing for surrogates should not be required.

For units that opt to demonstrate compliance with the non-mercury HAP metals or HCl emission standards by performing ongoing stack tests, EPA is requiring sampling not only for the pollutants in question (*i.e.*, non-mercury HAP metals or HCl), but also for pollutants that have

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[35] Although most of the provisions addressing dry scrubbers do not refer to carbon injection rate, the term "minimum sorbent injection rate" is defined to include test average "activated carbon" injection rate as well. Proposed § 63.10042. EPA should be clear regarding application of these requirements.

been identified as potential surrogates. If a utility has chosen to demonstrate ongoing compliance by directly measuring the regulated HAP, it is superfluous to require any further testing not associated with determining the regulated HAP emissions in terms of the given emissions standard. For units that opt to demonstrate compliance by performing ongoing stack tests, EPA should specify stack emissions performance testing only for the methods that are necessary to measure the regulated HAP in terms of the emissions standard.

For example, proposed section 63.10006(h) requires EGUs "without SO2 CEMS but with installed systems that use wet or dry flue gas desulfurization technology" to conduct "all applicable performance tests for SO2 and HCl emissions" at least every year and to "conduct SO2 emissions testing" at least every month. EPA must make clear that these provisions do **not** apply to EGUs with HCl CEMS. **There is no basis for testing of the surrogate SO_2 at a unit that is complying with the HCl standard or for HCl emissions testing at a unit with HCl CEMS.**

3. The proposed frequency of repeating performance testing is excessive and should be revised.

For units that opt to demonstrate compliance with the non-mercury HAP metals or HCl emission standards by performing ongoing stack tests, EPA requires that performance testing be repeated on a bimonthly (for units with emission controls) or monthly (for units without emission controls) basis. This requirement would create an impossible burden to test and maintain economical operations for those units. Considering the fact that EPA has based the emissions standard for both non-mercury HAP metals and HCl primarily on the averages of one set of tests performed at multiple units, it cannot justify the need to repeat the performance testing on such a frequent basis. For units opting to comply with the non-mercury HAP metal or HCl emission standards, the testing frequency should be increased to a minimum of once every four unit operating quarters, but no less than once every eight calendar quarters (based on the Relative Accuracy Test Audit frequency requirements in section 2.3.1.1 of Appendix B of 40 C.F.R. Part 75). An operating quarter would be defined as a calendar quarter with 168 or more unit operating hours, which is the same definition that is used in 40 C.F.R. Part 75.

The testing guidelines in section 63.10006(n) provide time ranges for conducting the ongoing performance tests for the various compliance options. These ranges are specified in terms of days, months and years. Since it is unclear whether EPA is referring to calendar or operating days, it is important to clarify these requirements. EEI strongly believes the preferred option should be in terms of operating days or operating quarters. These terms are used routinely by utilities to manage emissions program schedules, and they will give utilities the necessary flexibility for performing the required tests.

B. PM Monitoring Requirements Should Be Revised.

EPA's proposed rule would require the use of PM CEMS for continuous compliance if the owner/operator elects the total PM option instead of complying with either the total non-mercury or individual metal HAP limits. While the PM CEMS approach is much less burdensome than frequent stack testing coupled with rigid operating parameter limits, as mandated for either of the other two options (*i.e.*, total non-mercury or individual HAP metals), commercially available PM CEMS—especially those that are based on the principle of light scattering—do not provide a direct measure of PM emissions. (By direct measure, we mean that the instrument should measure the mass of PM and the volume of flue gas from which that mass of PM was sampled.) Instead, EPA Performance Specification 11 (PS-11) requires that PM CEMS be correlated to a series of manual stack testing results, and the permissible “tolerance” between PM CEMS readings and corresponding stack test values allowed by PS-11 is significant.

As noted above, PS-11 requires that the PM CEMS output be correlated to a series (minimum of 15) of manual stack testing runs. Two of the principal “performance” criteria are based on the filterable PM emissions limit. It is literally impossible to demonstrate compliance with PS-11 in the absence of a defined filterable PM emissions limit. Accordingly, **the PM CEMS compliance approach proposed by the Agency is simply unworkable and internally inconsistent with existing EPA requirements (*i.e.*, PS-11).**

C. Mercury Monitoring Requirements Should Be Revised.

Although EEI supports the option for use of mercury CEMS, the accuracy of mercury CEMS at or near the concentration of the proposed existing source limit is questionable. Mercury CEMS will not be a viable option at the proposed level of the new source limit. The main issues limiting the accuracy and reliability of mercury CEMS are the high relative uncertainty of National Institute of Standards and Technology (NIST)-traceable calibration gases and the lack of any NIST-traceable calibration gases at the equivalent proposed emissions standard concentration level. Also, mercury CEMS have had persistent issues in the sample transport of mercury from the stack effluent through the sample conditioning system (*i.e.*, sample probe, filters, $Hg^{2+} \rightarrow Hg^0$ converters) to the measurement cell. Electric utilities that installed and certified mercury CEMS in preparation to comply with the since-vacated CAMR have had continued difficulty in maintaining the systems, and in some cases they have abandoned them altogether. When responding to a question for the EGU ICR, EPA in essence acknowledged the inability of current mercury CEMS technology to make accurate low-level mercury concentration measurements. Question Test-002[36] on the Electric Utilities ICR webpage for Frequently Asked Questions asked if certified mercury CEMS data could be submitted in lieu of Method 30B test results. EPA's response was:

> EPA agrees that a company may use data from a Hg CEMS in lieu of conducting (Method 30B) performance testing to satisfy this utility MACT ICR project provided: 1) the CEMS has undergone all of the applicable requirements and procedures of 40 CFR part 75, Appendix A (Specifications and Test Procedures), including all of the ongoing QA/QC procedures (e.g., the weekly system integrity checks); and 2) the source's average Hg emissions concentrations are greater than 1.0 microgram per cubic meter.

The proposed emissions limit for existing units has an equivalent concentration of approximately one microgram per cubic meter (1 μg/cm). **Without further investment in developing mercury CEMS technology to address issues with the availability of NIST-traceable calibration gases at the appropriate concentration levels and sample transport, the only viable option for electric utilities for meeting the continuous mercury measurement requirement is to install, certify and operate a mercury sorbent trap-based monitoring system meeting the specifications in Performance Specification 12B. Accordingly, these requirements should be revised.**

D. HCl and SO_2 Monitoring Requirements Should Be Revised.

Although EEI supports the option for use of HCl CEMS and urges EPA to complete work on a reasonable performance specification, EEI is concerned that HCl monitors face a number of critical issues that need to be addressed before they become an acceptable compliance measurement device:

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[36] https://utilitymacticr.rti.org/FAQ/FAQEmissionsTesting.aspx.

- The proposed HCl emission limit for existing coal-based EGUs is at or near the detection limit for current HCl CEMS technology.

- EPA does **not** have a performance specification that is specific for non-Fourier Transform Infrared-based HCl monitors. Table 5 lists Performance Specification 6 (PS 6) as an applicable performance specification. However, PS 6 is written for the certification of systems used to measure pollutant emissions in units of mass per unit of time.

- EPA protocol gases are not widely available and are expensive relative to traditional CEMS calibration gases. Lowest available concentrations are significantly higher than proposed limits.

Given that HCl CEMS will not be a viable option in the near term for electric utilities, EEI believes that the bulk of utilities will use SO_2 monitors installed downstream of a wet or dry scrubber or DSI system to comply with the HCl monitoring requirements in the proposed rule. Any pollution control device designed to reduce SO_2 emissions will effectively control HCl emissions. Consequently, the most attractive alternative for meeting the HCl monitoring requirements will be the use of SO_2 continuous monitoring.

The use of continuous monitors to measure stack SO_2 concentrations downstream of an SO_2 pollution control device has been successfully used by the electric utility industry for more than 20 years. Utilities have used SO_2 monitors to demonstrate compliance with provisions in the Acid Rain Program since 1993, and the monitoring requirements in Appendices A and B of 40 C.F.R. Part 75 have served to assist utilities in reporting an accurate accounting of the stack SO_2 emissions.

It is confusing why EPA has proposed additional quality assurance (QA) requirements for SO_2 monitors being used to demonstrate compliance with the proposed MACT emissions standards.

In proposed section 63.10010(e)(6), EPA has added several problematic additional QA requirements for SO_2 CEMS that are not currently specified in Appendices A or B of 40 C.F.R. Part 75. **This should be reconsidered**.[37]

Finally, during discussions with EPA staff, it has been stated that DSI and CFB are examples of add-on controls eligible for using SO_2 as a surrogate for acid gas emissions. Further, SO_2 CEMS

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[37] Section 63.10010(e)(6)(i) – The proposed Utility MACT rule would require the SO_2 CEMS to pass a seven-day calibration error test for units with spans less than or equal to 50 ppm. It is unclear whether the specifications in Part 75 or PS 2 are applicable. Under Part 75 requirements, the seven-day calibration error specification is a difference of less than or equal to 2.5 percent of span or ±5 ppm. Using the Part 75 specifications, current SO_2 CEMS should be able to easily meet the alternative ±5 ppm requirement. If the PS 2 specifications are to be applied, then the specification is restricted only to the drift requirement of 2.5 percent of span. This will make passing the seven-day calibration error test significantly more burdensome. Regardless of which specification is used, neither will improve the overall quality or accuracy of the collected data, since these are only implemented for initial certification or recertification events. In other words, there is little a utility can do to upgrade its SO_2 CEMS to meet this requirement.

Section 63.10010(e)(6)(ii) – The proposed Utility MACT rule would require the SO_2 CEMS to pass a linearity test for units with spans less than or equal to 30 ppm. This will be an additional QA requirement for many existing systems that have SO_2 CEMS installed downstream of a wet or dry scrubber. It will add significant cost to update software to integrate the new procedure, and potential costs to add the necessary hardware to existing systems to accommodate the new calibration gas cylinders. It also will increase calibration gas costs, not only in the capital cost of purchasing the additional calibration gases but also in monthly demurrage fees.

Section 63.10010(e)(6)(iii) – This provision may require utilities to add a fourth calibration gas to the linearity sequence in order to have a calibration gas "nominally at a concentration level equivalent to the applicable emission limit." If a utility is required to include a fourth calibration gas level to the linearity check procedure, an additional cost in terms of hardware and software upgrades to integrate the fourth linearity calibration gas into the calibration system will be incurred by the utility. This requirement is unnecessary and will not improve the quality of SO_2 data being collected. Current guidelines in 40 C.F.R. Part 75 ensure that the majority of emission measurements made by an SO_2 CEMS fall within a certain percentage of the monitor's calibrated span. Users are required to evaluate the span of the SO_2 CEMS on annual basis, which has proved sufficient in maintaining the overall integrity and accuracy of the SO_2 emissions being reported. At a minimum, EPA should quantify the term "nominally" (*e.g.*, a calibration gas within ±20 percent of the equivalent concentration level).

should be allowed to be used as a surrogate for HCl for IGCC units since FGD is not needed for those units and HCl CEMS are not a proven compliance monitoring technology. Such details need to be clearly defined in the final rule.

E. Requirements for Oil-based Units Should Be Revised.

1. The alternative fuel analysis provisions should apply to all affected liquid oil-based EGUs.

In the summary of the proposal, EPA states:

> (6) For limited-use liquid oil combustion units, we are proposing that those units be allowed to demonstrate compliance with the Hg emission limit, the HAP metals, or the HCl and HF emissions limits separately or in combination based on fuel analysis rather than performance stack testing, upon request by you and approval by the Administrator. Such a request would require the owner/operator to follow the requirements in 40 CFR 63.8(f), which presents the procedure for submitting a request to the Administrator to use alternative monitoring, and, among other things, explain why a unit should be considered for eligibility, including, but not limited to, use over the previous 5 years and projected use over the next 5 years. Approval from the Administrator would be required before you could use this alternative monitoring procedure.

76 *Fed. Reg*. at 25031.

This states that this provision applies only to limited-use oil units and not other affected oil units. But the provisions of the proposed rule itself (sections 63.10005(c) and 63.10006(s)) appear to indicate that owners/operators of all affected liquid oil-fired units may perform fuel analyses to demonstrate initial and continuous compliance with applicable emission limitations, as an alternative to performance stack testing. The final rule should clarify that the alternative to use fuel testing to demonstrate initial and continuous compliance applies to **all** affected liquid oil-fired EGUs, not only limited-use units.

2. Continuous compliance demonstration requirements should be revised.

The proposed rule prescribes:

> For liquid oil-fired EGUs with non-Hg HAP metals control devices, you must conduct all applicable performance tests for individual or total HAP metals emissions according to Table 5 and §63.10007 at least every other month.

Proposed § 63.10006(f).

> For liquid oil-fired EGUs without non-Hg HAP metals control devices, you must conduct all applicable performance tests for individual or total HAP metals emissions according to Table 5 and §63.10007 at least every month.

Proposed § 63.10006(g).

It is impractical and unnecessary to require performance stack testing of affected oil-fired EGU emissions on a monthly or every other month basis. Testing requirements of this nature and frequency would be unnecessarily restrictive and expensive to perform. This requirement would require units to be brought on line in many cases just for the sake of performing stack tests, which would result in an increase in emissions and be environmentally detrimental. Instead, affected liquid oil-fired EGUs should not be required to perform stack performance testing to demonstrate continuous compliance with emission limits any more frequently than on an **annual** basis.

Proposed section 63.10006(s) states, "If you demonstrate compliance with the Hg, individual or total non-Hg HAP metals, HCl, or HF emissions limit based on fuel analysis, you must conduct a **monthly** fuel analysis according to §63.10008 for each type of fuel burned" (emphasis added). Such testing requirements would be unnecessarily burdensome, costly and impractical. Requiring fuel analysis to be performed **on each shipment of oil received** should be adequate to demonstrate compliance.

F. Summary

In summary, numerous clarifications and modifications are needed in the final rule:

- EPA should state clearly what monitoring, testing and operating parameter limits apply as a function of each option.

- The final rule should be clear in stating that if an owner/operator elects direct (CEMS) monitoring of a regulated HAP or its surrogate, then fuel sampling, parameter monitoring, *etc.* are not required.

- For those units that opt to demonstrate compliance by performing ongoing stack tests, EPA should specify stack emissions performance testing only for those methods that are necessary to measure the regulated HAP in terms of the emissions standard, not including surrogates.

- EPA should allow reasonable, flexible alternative compliance demonstration options, including less frequent periodic stack tests.

- Mercury and HCl CEMS limitations must be revised.

- EPA should use existing performance specifications (*e.g.*, for SO_2 CEMS) that have historically proven to provide quality accurate emissions data, rather than attempt to add on additional performance tests that will not improve data quality or accuracy.

- Several oil sampling requirements need clarification or modification.

XII. EPA Should Exercise Available Authority to Extend MACT Deadlines For Units hat Are Being Replaced Or Repowered Or Awaiting A Transmission Upgrade.

EPA should not divorce the proposal and finalization of the Utility MACT from the larger context of the ongoing transformation of the U.S. generating fleet. This transition has already begun and will lead to a generation fleet in 2020 that is substantially cleaner and more modern than the fleet in 2010. The drivers for this change include: new and more stringent EPA regulations, including this proposed rule; current low-cost and prospects for abundant supplies of natural gas; and increasingly stringent state-level renewable mandates, as well as state and regional programs to reduce greenhouse gas (GHG) emissions. In response to these and other drivers, about 30 GW of coal unit retirements out to 2022 have been announced in the last 18 months.

The trend towards increasingly cleaner generation is evident in the recent EIA projections. In EIA's Annual Energy Outlook 2011 reference case, emissions from the U.S. electric power sector are projected to fall between 2010 and 2020 by 37.5 percent for SO_2, 23 percent for NO_x and 33.8 percent for mercury.[38] See Table 1 below. And, because EIA's reference case generally assumes that current laws and regulations remain unchanged throughout the projections, these calculated improvements will be greater once additional regulations are promulgated.

TABLE 1: Power Sector Emissions, 2010-2020

Electric Power Sector Emissions	2010	2020	% Change, 2010-2020
Sulfur Dioxide (million tons)	5.89	3.68	-37.5%
Nitrogen Oxides (million tons)	2.57	1.98	-23%
Mercury (tons)	40.51	26.82	-33.8%
Source: EIA, Annual Energy Outlook 2011, Reference Case Scenario ref2011, Datekey d020211a, compiled from Tables 8, 18, *downloaded at* http://www.eia.gov/forecasts/aeo/excel/yearbyyear.xls.			

As indicated in section I above, EPA and state permitting agencies should utilize all of the implementation alternatives provided in CAA section 112 to ensure an orderly transition of the fleet with minimal impacts on local reliability. The BPC reached similar conclusions in its recent analysis, recommending that "where appropriate, EPA should use flexibility inherent in its

[38] EIA, Annual Energy Outlook 2011, Reference Case Scenario ref2011, Datekey d0202011a, compiled from Tables 8, 18, *available at* http://eia.gov/forecasts/aeo/excel/yearbyyear.xls.

existing authority to address cost and reliability concerns" and that "where needed and allowed by statute, EPA and state permitting agencies should grant utilities time extensions—with as much notice as possible—to install pollution control technologies and to build the new capacity required to achieve compliance."[39] The BPC concluded that "a rapidly shifting market and regulatory environment will create planning challenges for the electric power industry. The compliance deadlines of the Utility Air Toxics Rule, in particular, will accelerate and concentrate the decision-making timeframe for plant retirements, retrofits, and new infrastructure into a short period over the next few years."[40]

The Southwest Power Pool (SPP) already has filed comments in this docket encouraging "EPA to work with generation owners to develop flexible compliance schedules to ensure equipment installation is completed in a timely, safe, reliable and cost-effective manner without an arbitrary deadline…Such an approach would also ease concerns over grid instability caused by mass outages on generators to install the required equipment."[41] *See also* Midwest Independent Transmission System Operator, Inc. Filing to Enhance RAR By Incorporating Capacity Market Mechanisms; FERC Docket Nos. ER08-394-004 to -005; ER08-394-021 to -022; ER08-394-028 to -029; and ER11-__-000, Tab D at 5 (July 20, 2011) (affidavit of Moeller, Clair J.) ("The compliance timelines associated with many of these rules could adversely impact MISO's reliability by accelerating fossil-fueled resource retirements, in part, because it may be economically challenging for owners of such resources to bear the upgrade costs that will be

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[39] BPC Report, *supra* n.7, at 4, 39.
[40] *Id.* at 5.
[41] SPP Comments, filed in Docket Nos. EPA-HQ-OAR-2009-0234 and EPA-HQ-OAR-2011-0044 (July 19, 2011).

required in order to come into compliance with such rules and regulations, particularly if the resource is toward the end of its useful life.").

A. Except for Units that Will Be Shut Down, Utilities Should Be Afforded a Categorical One-year Extension of Time under the CAA.

CAA section 112(i) provides existing affected sources three years to comply with the final rule, but the Act permits EPA to extend this for one year and the President to extend it even longer.

Options for compliance with the final rule include shutdown, installation of pollution control equipment, replacement or repowering, and expansion of transmission capacity needed for reliability purposes.

EEI believes that units designated by owners or operators for shutdown, and not being replaced or repowered or not waiting a transmission upgrade, should be shut down no later than three years after the effective date of the final rule. The permitting authority (state or EPA) should extend this date only if 1) the appropriate RTO, NERC or the appropriate state commission confirms that the continued operation of the unit is required for reliability purposes, and 2) the owner of operator of the unit demonstrates that the reliability problem is being diligently addressed.

EEI appreciates that EPA suggests a willingness to grant (and encouragement to state permitting agencies to grant) one-year extensions on a unit-specific basis. *See* 76 *Fed. Reg*. at 25055. However, the number of units likely to need extensions is sufficiently large that a unit-by-unit review of the need for an extension actually would delay overall compliance. Therefore, EEI urges EPA to authorize a categorical extension of an additional one year for compliance except for those units that will shut down (without causing a reliability problem). There are approximately 1,350 coal and oil boilers affected by the proposed Utility MACT standards.[42] It is unlikely that EPA and state permitting agencies can act on all requests for extensions on a case-by-case basis within the three-year compliance window. This lack of certainty could lead to delays in installing controls. To provide certainty and ease a tremendous administrative burden, EPA should grant a fourth year for compliance for those units installing controls or taking other actions to comply in the final rule.

Moreover, granting a fourth year in the final rule (except for those units that will close down) is consistent with past EPA precedent. In a MACT rule affecting only 20 marine terminals, EPA granted a blanket fourth year to all sources, noting concerns about these sources' ability to design and install control technologies in the three-year window provided by the CAA.[43] For the proposed Utility MACT—a rule that could affect 67 times as many sources—there are far greater concerns about the ability to design, procure, install and test controls in three years. This point is echoed in the recent NARUC policy resolution, which notes that "a retrofit timeline for multimillion dollar projects may take up to five-plus years" due to "multiple regulatory requirements," such as regulatory approval, front-end engineering, permitting, construction and startup.[44]

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[42] An additional 900 boilers are affected by the Boiler MACT.
[43] *See Federal Standards for Marine Tank Vessel Loading Operations and National Emissions Standards for Hazardous Air Pollutants for Marine Tank Vessel Loading Operations*, 95 *Fed. Reg*. 48388, 48392 (1995).
[44] NARUC Resolution, *supra* n.1.

As explained in more detail below, some owners or operators of units will not be able to comply within three years, contrary to the Agency's overly optimistic timing assumptions. In discussing the possibility of EPA granting one-year extensions to allow the completion of on-site replacement capacity or installation of controls, the BPC similarly "agrees that this [one-year extension] would be an appropriate and beneficial interpretation of the Clean Air Act waiver authority. The states or EPA, as applicable, could and should use this waiver authority to allow an extra year for those electric generating units unable to complete control installations or build on-site replacement capacity in time, particularly where reliability is a concern."[45]

Because some owners or operators of units may require more than four years to achieve compliance, EEI separately plans to urge the President to issue an executive order using the CAA "exemption" authority provided by CAA section 112(i)(4) to allow additional time. Section 112(i)(4) provides that the President may grant a two-year "exemption" (*i.e.*, extension) on finding that "the technology to implement such standard is not available and it is in the national security interest of the United States to do so." EEI believes that an extension of time for an owner or operator of a unit should be granted under this delegated authority when 1) the utility is continuing to take diligent, good-faith measures to achieve compliance; 2) the needed technology is "not available"; and 3) the appropriate RTO, NERC or the appropriate state commission certifies that an extension of time is necessary to address reliability issues or is consistent with the state-approved integrated resource plan (or similar state process), which may take into account the potential reliability and economic impacts of compliance decisions. A utility obtaining any extension of time shall report on its progress as required by the permitting

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[45] BPC Report, *supra* n.7, at 29.

authority. The term "available" could be interpreted to encompass both technological and economic feasibility, consistent with the interpretation of that term in the context of "best available control technology" for PSD permitting. Similarly, it is widely understood, most recently in discussions about the importance of cybersecurity in our electricity infrastructure and the importance of national security and defense facilities having secure, reliable electric service, that the provision of reliable, cost-effective electricity is critical for national security.

B. EPA's Conclusion that All Units Can Comply Within Three Years Is Based on Overly Optimistic Assumptions.

In the proposed rule, EPA states that "we believe that the compliance schedule established by the CAA can be met." 76 *Fed. Reg*. at 25054. Central to EPA's confidence that timing is not a compliance issue for existing units is the value of "proper planning." *Id*. EPA states that "proper planning" would entail starting to plan before the proposed rule is finalized.

However, EPA's reliance on "proper planning" to ensure timely compliance with the final rule fails to address how these plans become reality. The crux of any concerns expressed about a unit's—or the power sector's—ability to achieve timely compliance is the challenge of making these plans a reality. Even when compliance strategies are well planned, they still take time to implement.

In order to facilitate the proper planning that the Agency emphasizes is necessary to ensure compliance (as discussed above), EPA should provide in the final rule a blanket one-year extension for those units that will comply by installing emissions controls, repowering or implementing transmission upgrades. This will provide critical certainty that utilities need to plan and implement compliance strategies. In addition, it will save utilities the time it will take to seek this extension on a case-by-case basis (as EPA proposes), thereby fostering faster compliance.

To support its assertion that quick compliance is possible, EPA includes an extended discussion about the speed at which certain controls can be installed, the widespread use of DSI because it can be installed more quickly than other compliance options and the potential for energy efficiency to offset the costs of compliance. In general, EPA's assumptions about each of these issues are overly optimistic. EEI will address several of these issues in turn.[46]

1. "Installation of controls" requires more than just construction.

In the proposed rule, EPA notes that vendors believe that various control technologies could be **installed** within the three-year deadline. *See* 76 *Fed. Reg.* at 25054 n.172. Clearly, the vendors are using "install" in the most limited sense to include only the physical construction of the controls. However, the reality of installation encompasses more than the physical construction of the technology and its integration into an existing unit. In many cases, the installation of controls may require an array of required state and CAA permits, including PSD permits, which can take permitting agencies more than a year to issue once a final, complete application is made. Indeed, physical installation is the last step in the process, following siting, permitting and financing, all of which take time. Significantly, NARUC agrees. The recent NARUC policy

[46] In addition to the assumptions addressed below, EPA made other arguments to support the Agency's conclusion that three years is sufficient time for compliance. Specifically, EPA notes that two utilities committed to actual capital projects in advance of the final Clean Air Interstate Rule (CAIR), which facilitated early compliance. *See* 76 *Fed. Reg*. at 25056. These examples are misleading. Under CAIR's cap-and-trade program design, each affected state was given an allowance budget, which it allocated to individual units/utilities. If the controls installed early did not achieve the reductions mandated by the final rule, the utility was allowed to go to the market and purchase any allowances needed to cover emissions above the standards. This is not the case for MACT regulations.

resolution found that retrofits may take "up to five-plus years," considering that they not only need to address compliance with multiple regulatory requirements, but require "several steps that may include…[u]tility regulatory commission approval, front-end engineering, environmental permitting, detailed engineering, construction and startup."[47]

EPA cannot rely on the narrowest definition of what it means to "install controls"—which does not address, at minimum, the Agency's own permitting requirements and requirements recognized by utility regulatory commissions—to support its claim that compliance can easily be achieved within three years.

Building new transmission or transmission upgrades may be required to ensure continued reliability as a result of unit closures. EPA notes that "recent experience" indicates that transmission upgrades necessitated by plant closures can also occur in less than three years." *Id*. at 25055. EPA provides no detail to support this assertion. EPA does not say in what state this occurred, how much advance notice the transmission provider had about the plant closure, how quickly the required permits were obtained, what kind of transmission was built or how much it cost.

While planning, procurement and construction of new transmission may indeed take three years or less, EPA has failed to consider that siting and permitting can take substantially longer and are the necessary predicates to being able to build new transmission. As a general matter, the fact

[47] NARUC Resolution, *supra* n.1.

that one transmission project was completed in three years does not provide EPA a reasonable basis to conclude that all other transmission upgrades could be completed on a similar schedule. In recent experience, there are examples of new transmission lines that took almost 17 years to build, from siting to construction. While an extreme example, it serves as a counterpoint to EPA's anecdote of a single transmission project that took only three years to build. In the experience of EEI's shareholder-owned utilities, which invested more than $55.3 billion in transmission infrastructure improvements between 2001 and 2009, the entire process of siting, planning, permitting and constructing transmission generally takes more than three years, and typically four to eight years.[48] This often can be the case for projects in major load centers and densely populated or geographically complex regions (waterways, wetlands, mountainous terrain, *etc*.) where siting, permitting and construction complications could arise.

In his partial dissent in a recent order on transmission planning and cost allocation, Commissioner Philip Moeller of the Federal Energy Regulatory Commission (FERC) said that state laws and federal agency inaction can result in significant delays in the siting of important transmission projects.[49] Specifically, he noted that an RTO had approved a new transmission line in 2007, but that the line currently is delayed by the National Park Service and is not expected to be in service until 2014 at the earliest.

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[48] *See* EEI, Transmission Projects at a Glance (March 2011), *available at* http://www.eei.org/ourissues/ElectricityTransmission/Documents/Trans_Project_lowres.pdf, for a discussion of transmission projects in various planning stages across the United States. This report demonstrates that many of these projects took between four to eight years, from initiation to in-service date.

[49] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051 (July 21, 2011) (Moeller, P., dissenting in part).

EPA touches on, but does not fully address, the fact that this rule will require an unprecedented number of near simultaneous installations of controls. While EPA acknowledges that the control technology industry would have to "ramp up quickly" (76 *Fed Reg.* at 25055), the Agency does not address the fact that manufacturing delays related to the increased volume of orders could slow down the installation of necessary controls. The Agency also does not appear to take into consideration that this volume of control installations could slow down permitting and restrict access to financing, and may be delayed due to labor resource issues. NARUC also raises these concerns in its policy resolution on EPA regulations, which states that "timelines [for retrofit projects] may also be lengthened by the large number of multimillion dollar projects that will be in competition for the same skilled labor and resources."[50] The BPC noted that "managing a large number of pollution control retrofits in a relatively short period could also be a challenge."[51]

2. Consistent with CAA section 112, EPA must allow utilities to determine the best, most cost-effective compliance approach for affected units.

EPA says that it assessed the feasibility of installing controls within the statutory deadline for compliance, but this assessment appears to have been limited to a particular suite of controls that EPA prefers—in particular, DSI. EPA appears to have focused on controls that the Agency already has determined may require less time to install, rendering the Agency's analysis a self-fulfilling prophecy. *See* 76 *Fed. Reg.* at 25054.

As discussed in section III above, DSI will be an important, low-cost compliance option for many units. But given the diversity of affected units in terms of size, location, operating

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[50] NARUC Resolution, *supra* n.1.
[51] BPC Report, *supra* n.7, at 5.

characteristics, boiler type, fuel used and controls already installed, there are many different compliance options that a unit owner or operator may pursue that could result in compliance with the MACT standards. NARUC clearly agrees.[52] In this context, basing compliance timing assumptions on a single control technology would be unreasonable.

Moreover, this approach would be inconsistent with the requirements of CAA section 112(d), which compels the Agency to set emissions standards, not technology standards. Owners and operators of affected units have the right to determine which compliance options—including which suite of controls—they will use. EPA's attempts to deprive utilities of these choices to support the Agency's assessment that compliance within the deadline is easily achievable are contrary to the statute. Consistent with the requirements of section 112, EPA must afford utilities the flexibility to determine the best, most cost-effective compliance approach for each affected unit and allow sufficient time for compliance, as long as the utility is working diligently to meet the statutory deadlines.

The preamble to the proposed rule states, "EPA does not project use of wet scrubbing technology to meet the requirements of this proposed rule…" 76 *Fed. Reg.* at 25054. EPA concludes that DSI will be used primarily to comply with the acid gas MACT standard. Specifically, EPA projects the installation of 56 GW of DSI and 25 GW of dry scrubbers to comply. As noted

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[52] NARUC Resolution, *supra* n.1 ("There are many strategies available to States and utilities to comply with EPA's regulations, including retrofits and installation of pollution control equipment, construction of new power plants and transmission upgrades to provide resource adequacy and system security where needed when power plants retire, purchases of power from wholesale markets, demand response, energy efficiency, and renewable energy policies. . . .").

previously, these determinations directly affect EPA's estimates of the timing and cost of installing controls to comply with the proposed rule.

If DSI does not work as EPA projects, utilities will have to install dry or wet scrubbers to come into compliance, which EPA acknowledges as an alternative compliance option. *Id.* Moreover, given the cost differential, utilities would be likely to close more units if DSI does not work as EPA expects. For these reasons, the role that DSI can play is extremely important to a full understanding of the likely cost, impact and timeframe for complying with the proposed rule.

Some EEI members have concerns regarding EPA's assumption that DSI and dry scrubbers will be the compliance method used for acid gas control. The key drawbacks of DSI were discussed in section III, *supra*. Because of these drawbacks, EPA's assumption that DSI can achieve compliance for a majority of units is not justified.

No utility would choose a more expensive option unless it was deemed necessary to ensure compliance. Obviously, as a potentially lower-cost (in terms of capital expenditures, if not operation and maintenance costs) technology that may be faster to install, utilities will seriously consider DSI as a compliance option for many units. However, there is some question as to the overall cost effectiveness of DSI. The BPC notes that "capital costs for an alternative, dry sorbent injection, are significantly lower. On a levelized cost basis, however, the difference is far less significant. . .[T]he on-going costs for dry sorbent injection, including costs to ship and store large amounts of chemical sorbent, approach the annualized cost of a wet scrubber."[53]

Furthermore, DSI may not work for all units. For example, companies with units that primarily burn eastern bituminous coals do not believe that DSI will meet the acid gas MACT standard, and as a consequence believe that it will be prudent to install wet FGD for compliance. This is because the higher chlorine content found in these coals necessitates a more aggressive control technology to remove higher levels of HCl. Installing a wet FGD will present major challenges due to, among other things, the time needed for installation—from procurement and permitting through construction. While DSI may take less than two years to install, recent control technology installations have taken up to five years. As a consequence, many companies with units that burn coal with higher chlorine content believe that EPA's assertion that **all** companies would be able to install, retrofit and upgrade all of the emission controls needed for compliance within three years to be overly optimistic.

Moreover, companies may elect to install wet FGD to assure compliance not only with this proposed rule but also with future expected emissions limits on SO_2. As a consequence, installing wet FGD may take a longer time to install and may be more expensive, but it will provide superior, long-term environmental benefits. EPA should seek to encourage the prudent investment in the most efficacious controls, even if they may take longer to install.

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[53] BPC Report, *supra* n.7, at 15.

3. State demand-side efficiency measures

In the proposed rule, EPA spends a considerable amount of effort discussing a sensitivity analysis that found that a combination of state investment in demand-side efficiency and appliance standards could lead to additional retirements of affected units and drive down the costs of compliance with the proposed rule. EPA hopes that this study will "provide PUCs with both the motivation and the justification for providing utilities with the financial and regulatory support they need to begin planning as early as possible for compliance and incorporate in their plans the kinds of energy efficiency investments needed to achieve both compliance and cost-minimization." 76 *Fed Reg.* at 25057.

Energy efficiency measures may reduce demand for electricity and bring down the price of electricity, but, as EPA notes, the final decision regarding which sorts of demand-side efficiency measures will be required and what regulatory treatment these will receive rests with the states, not utilities. *Id*. Utilities may work with states on these measures. More importantly, utilities have no control over whether end-use customers will respond appropriately within a relatively short timeframe to change their behavior sufficiently to affect compliance plans. While utilities have and do commit tremendous resources to demand-side and customer-based efficiency activities, and may choose to include efficiency as part of an overall compliance strategy, the timing of achieving efficiency gains is not so quick or obvious so as to justify retaining a three-year compliance timeframe or significantly reducing compliance cost estimates.

XIII. <u>EPA Should Recognize Investments Made For Emissions Reductions Consistent With State HAPs Regulations.</u>

In the proposed rule, EPA notes that a number of states and localities proactively have developed plans to address a suite of environmental issues, an aging generation fleet and electric reliability. These include plans requiring installation of pollution controls, retirement of older units and increasing renewable generating capacity. *See id*. at 25057-58. EPA goes on to note that these programs may lead to reductions in HAPs emissions that are equivalent or greater than those that would result from the proposed rule. *See id*. at 25058.

In recognition of the environmental benefits that have been or will be achieved by these state plans, EPA should allow states to seek a delegation of the CAA section 112 program, as authorized by the Act. Section 112(*l*) of the CAA allows a state to seek delegation of the section 112 program. A state may request complete or partial authority from EPA to administer a program; such authority "shall not include authority to set standards less stringent than those promulgated by the Administrator under" section 112(*l*)(1). EPA has promulgated regulations regarding the delegation authority at 40 C.F.R. Part 60, Subpart E.

Allowing states to seek delegation of the section 112 program will provide important compliance flexibility for those units and utilities that have already made investments consistent with state environmental programs. Moreover, failure to allow state delegations could undermine these investments. A critical element in many of these state plans is the timing of retirements, repowerings and installations of control equipment. EPA states, "Although some of these state programs may have obtained some important emission reductions to date, they may also allow compliance time-frames for some units that extend beyond those authorized under CAA section

112(i)(3)." 76 *Fed. Reg*. 25057-58. If states can demonstrate that overall emissions reductions are equivalent or greater than those that would be achieved by the proposed rule, EPA should delegate the section 112 program to these states, even if the state emissions reductions would not necessarily occur on the same schedule.

XIV. Conclusion

EEI appreciates EPA's incorporation of some key elements of flexibility in the proposal—including surrogates, work practice standards and emissions averaging—and the Agency's acknowledgement that more than three years may be required for some units to comply. However, EEI urges EPA to make needed modifications in the proposed rule to conform to the requirements of the CAA; provide a categorical one-year extension for units that are not being shut down so that utilities can achieve cost-effective and timely implementation while taking into account potential economic and reliability impacts of compliance; and provide additional flexibility in the proposed standards, including many compliance, testing and monitoring requirements. Because some units may require more than four years for compliance, EEI also urges the President to use his authority to allow additional time.

Attachments (2)

Appendix 1

Levelized Cost - Oil/Gas Steam Units		
Unit Characteristics[1]	Oil/Gas Unit at 10% Capacity factor with no retrofit costs	Oil/Gas Unit at 10% Capacity factor with retrofit costs
FO&M ($/KW-yr)	25.00	25.00
VO&M ($/MWH)	3.00	3.00
Heat Rate (Btu/KWH)	13,000	13,000
Capacity Factor (%)	10%	10%
Retrofit Cost ($/KW)	0	100
Heat Rate Penalty (%)	0.00%	0.00%
FO&M Increase (Incremental - $/KW-yr)	0	0
VO&M Increase (Incremental - $/MWH)	0	0
Capital Charge Rate	11.2%	11.2%
Post-Control Heat Rate	13,000	13,000
Oil Price ($/mmBtu)[2]	12.00	12.00

Results	**Oil/Gas Unit at 10% Capacity factor with no retrofit costs**	**Oil/Gas Unit at 10% Capacity factor with retrofit costs**
Levelized Cost of Generation ($/MWH)	**187.54**	**200.32**
Capital Cost	0.00	12.79
Fixed O&M	28.54	28.54
Variable O&M	3.00	3.00
Fuel	156.00	156.00

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[1] Unit characteristics informed by EPA IMP 4.10 to represent a composite (*i.e.*, typical) oil/gas unit.

[2] Oil pricing is from the low end of the range of pricing utilized by EPA in IPM 4.10. EPA's oil prices range from $8.61/mmBtu to $104.84/mmBtu, depending on region, making EEI's calculation of the levelized cost of generation a conservative one. See http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter11.pdf.

Appendix 2

Estimated Levelized Cost of New Generation Resources, 2016[1]

Table 1. Estimated Levelized Cost of New Generation Resources, 2016.

Plant Type	Capacity Factor (%)	U.S. Average Levelized Costs (2009 $/megawatthour) for Plants Entering Service in 2016				
		Levelized Capital Cost	Fixed O&M	Variable O&M (including fuel)	Transmission Investment	Total System Levelized Cost
Conventional Coal	85	65.3	3.9	24.3	1.2	94.8
Advanced Coal	85	74.6	7.9	25.7	1.2	109.4
Advanced Coal with CCS	85	92.7	9.2	33.1	1.2	136.2
Natural Gas-fired						
Conventional Combined Cycle	87	17.5	1.9	45.6	1.2	66.1
Advanced Combined Cycle	87	17.9	1.9	42.1	1.2	63.1
Advanced CC with CCS	87	34.6	3.9	49.6	1.2	89.3
Conventional Combustion Turbine	30	45.8	3.7	71.5	3.5	124.5
Advanced Combustion Turbine	30	31.6	5.5	62.9	3.5	103.5
Advanced Nuclear	90	90.1	11.1	11.7	1.0	113.9
Wind	34	83.9	9.6	0.0	3.5	97.0
Wind – Offshore	34	209.3	28.1	0.0	5.9	243.2
Solar PV[1]	25	194.6	12.1	0.0	4.0	210.7
Solar Thermal	18	259.4	46.6	0.0	5.8	311.8
Geothermal	92	79.3	11.9	9.5	1.0	101.7
Biomass	83	55.3	13.7	42.3	1.3	112.5
Hydro	52	74.5	3.8	6.3	1.9	86.4

[1] Costs are expressed in terms of net AC power available to the grid for the installed capacity.

Source: Energy Information Administration, Annual Energy Outlook 2011, December 2010, DOE/EIA-0383(2010)

[1] EIA, Levelized Cost of New Generation Resources, Annual Energy Outlook 2011, *available at* http://www.eia.gov/oiaf/aeo/electricity_generation.html.