COMMENTS OF THE CLASS OF '85 REGULATORY RESPONSE GROUP ON THE PROPOSAL ON NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS: COAL- AND OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS REVIEW OF THE RESIDUAL RISK AND TECHNOLOGY REVIEW

Docket ID: EPA-HQ-OAR-2018-0794

I. INTRODUCTION

On April 24, 2023, EPA published in the *Federal Register*, at 88 Fed. Reg. 24,854, a proposal that would amend the National Emission Standards for Hazardous Air Pollutants ("NESHAP") for coal- and oil-fired electric utility steam generating units ("EGUs") — *i.e.*, the Mercury and Air Toxics Standards ("MATS") ("Proposal" or "Proposed Rule").

The Class of '85 ("Class of '85" or "Group") respectfully submits these comments on the Proposed Rule.[1] The Group is a voluntary, ad hoc coalition of over 40 electric generating companies from across the country that has been actively involved in the development of regulations to implement the Clean Air Act ("CAA") for more than 30 years, including EPA's previous MATS rulemakings. Members of the Class of '85 own and operate EGUs subject to MATS in approximately 35 states.

The Proposal has wide-ranging implications for EGUs across the country, including those owned and/or operated by Group members. While the Class '85 supports EPA's proposed determination that certain aspects of MATS should not be revised, the Group requests that the Agency reevaluate those aspects of the Proposal for which it is proposing revisions, including: (i) tightening the surrogate filterable particulate matter ("fPM") standard for coal-fired EGUs to demonstrate compliance with the emission limits for non-mercury ("Hg") metal hazardous air pollutants ("HAPs"); (ii) requiring use of continuous emissions monitoring systems ("CEMS") for demonstrating compliance with the fPM standard; (iii) eliminating the total and individual non-Hg metal HAPs emission limits; (iv) eliminating the low emitting EGU ("LEE") option for fPM and non-Hg metal HAPs; (v) tightening the Hg emission standard for lignite-fired EGUs; and (vi) eliminating the four-hour startup definition.

II. COMMENTS

EPA conducted the MATS Residual Risk and Technology Review ("RTR") pursuant to President Biden's Executive Order 13990.[2] The order required EPA to review certain actions undertaken by the prior administration, including the MATS RTR finalized in May 2020.[3] The 2020 MATS RTR indicated that HAP emissions from the source category are acceptable and did not identify any cost-effective controls that would achieve further HAP emission reductions.[4] While EPA acknowledges in the Proposal that the 2020 Residual Risk Review was sound and is

[1] *See* Attachment A for the list of Class of '85 Regulatory Response Group supporting these comments.
[2] 88 Fed. Reg. 24,854, 24,856 (Apr. 24, 2023).
[3] *See* National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units-Reconsideration of Supplemental Finding and Residual Risk and Technology Review, 85 Fed. Reg. 31,286 (May 22, 2020).
[4] *See id*.

not proposing to modify it, EPA is proposing to determine that the 2020 Technology Review was flawed because it "did not consider developments in the cost and effectiveness of . . . proven technologies, nor did EPA evaluate the current performance of emission reduction control equipment and strategies at existing MATS-affected EGUs."[5] Following the consideration of such factors, EPA is proposing that the updated technology review requires certain changes to MATS.[6] These changes include lowering the fPM limit for coal-fired EGUs, requiring the use of a PM CEMS, eliminating the total non-Hg HAP metals standard and the individual non-Hg HAP metals standards, revising the Hg emission limit for lignite-fired EGUs, and eliminating the four-hour startup definition for MATS compliance purposes.[7]

The Class of '85 is concerned that some of these changes would result in prohibitively high costs for many EGUs (dependent on their specific circumstances) that far exceed their benefits and are not necessary, especially in light of the Agency's finding that the current standards "provide[] an ample margin of safety to protect public health and prevent an adverse environmental effect."[8] Owners and/or operators of certain EGUs subject to MATS could be forced to choose between making massive additional capital investments to comply with the proposed amendments or shutting down prematurely, which could have lasting impacts on reliability in their service areas. The revisions also could have the effect of delaying the transition to clean electric generation at some EGUs by forcing companies to divert resources towards investments in control technology for coal-fired generation that would incentivize continued operation of such units to recoup their investment. Moreover, some of the proposed amendments, such as tightening the fPM standard, could jeopardize the ability of certain EGUs to operate with an appropriate margin for compliance due to technical constraints and site-specific considerations. For these reasons, the Group provides the following comments below.

A. <u>The Group Supports EPA's Proposed Determination that Certain Aspects of MATS Should Not Be Revised</u>.

The Class of '85 agrees with the Agency's finding that the 2020 Residual Risk Review — "indicat[ing] low residual risk from the coal- and oil-fired EGU source category" — was sound.[9] Accordingly, the Group supports EPA's proposed determination that it does not need to revise the acid gas standards for coal-fired EGUs, the standards for continental and non-continental liquid oil-fired EGUs, and the standards for existing integrated gasification combined cycle ("IGCC") EGUs.[10]

Although EPA is not proposing revisions to the standards identified above, the Agency has specifically requested feedback on certain aspects of these standards.[11] The Group provides the

[5] 88 Fed. Reg. at 24,865.
[6] *See id.* at 24,856.
[7] *See id.* at 24,857-58.
[8] 85 Fed. Reg. at 31,314.
[9] 88 Fed. Reg. at 24,866.
[10] *See id.* at 24,882-85.
[11] *See id.* at 24,858.

following comments in response to EPA's requests for feedback on the standards for continental and non-continental liquid oil-fired EGUs.

1. Continental Liquid Oil-Fired EGUs

EPA is not proposing to revise the total HAP metals emission standard, individual HAP metals emission standards, or the HAP metal surrogate fPM emission standard for continental liquid oil-fired EGUs.[12] EPA also is not proposing to revise the limits for limited use liquid oil-fired EGUs but is requesting comments on: (i) whether the current definition of the limited-use liquid oil-fired subcategory remains appropriate; and (ii) the appropriateness of including new HAP standards for EGUs subject to the limited use liquid oil-fired subcategory, as well as the means of demonstrating compliance with the new HAP standards.[13]

The Group urges EPA to retain the current definition of the limited-use liquid oil-fired subcategory. EPA also should not impose new HAP standards on EGUs in this subcategory, given that there are already limits on the amount of fuel oil that can be burned. The Agency has not identified any justification for the costs required for implementation and compliance with new HAP standards.[14] Any changes to the existing HAP standards for EGUs in this subcategory may lead to reliability issues, as these units are crucial to maintaining grid reliability during cold winter spells, other extreme weather events, or when natural gas is curtailed, as acknowledged by the Agency.[15]

2. Non-Continental Liquid Oil-Fired EGUs

EPA is not proposing to revise the standards for non-continental liquid oil-fired EGUs.[16] However, EPA is requesting comments on issues that could lead to changes in the MATS requirements for such units: (i) any special considerations — including the availability of clean fuels, such as distillate fuel oil and natural gas — in non-continental areas; (ii) whether the fPM surrogate emission standard is appropriate for non-continental liquid oil-fired EGUs; (iii) the appropriateness of including new HAP standards for non-continental liquid oil-fired EGUs, as well as the means of demonstrating compliance with the new HAP standards; (iv) whether compliance with a HAP emission limit could be demonstrated by fuel sampling and analysis; and (v) the need for additional, cost-effective methods to minimize HAP emissions in non-continental states and territories.[17]

a) Special Considerations

EPA must account for the differences between non-continental and continental EGUs in considering whether non-continental liquid oil-fired EGUs should be subject to the same requirements as continental liquid oil-fired EGUs. For instance, liquid oil-fired EGUs in Hawaii

[12] *See id.* at 24,884.
[13] *See id.*
[14] *See id.*
[15] *See id.*
[16] *See id.*
[17] *See id.*

and Puerto Rico are uniquely situated because they are geographically isolated, lack connections with continental sources of power, and must spend roughly 20 percent more than continental EGUs on testing services to import expertise and equipment. The electric generating systems in these areas further differ from electric generating systems in the contiguous 48 states due to: (i) limited fuel choices, as natural gas or liquefied natural gas may not be physically accessible or otherwise consistently acquired; (ii) increased need for local generation resources to maintain system reliability; (iii) limited economies of scale, where multiple smaller generation units are required as opposed to a few larger units to maintain reliability; (iv) limited flexibility for scheduling overhauls and other extended planned maintenance outages; and (v) different operational regimes compared to units in interconnected grids. EGUs in non-continental areas lack the compliance options and flexibility available to continental EGUs.

Some non-continental liquid oil-fired EGUs are located in areas with laws establishing aggressive Renewable Portfolio Standards ("RPS"). For instance, Hawaii's RPS requires electric generating companies to sell increasing percentages of electricity generated from renewable sources, where the percentage must reach 40% by 2030, 70% by 2040, and 100% by 2045.[18] Owners and/or operators of EGUs in these areas would thus need to outlay significant investments for both endeavors — complying with any changes to their MATS requirements while simultaneously meeting the RPS — and the costs required for both would ultimately need to be passed down to customers, further increasing electricity costs, which already are nearly three times higher than the average in the continental U.S.[19]

b) Filterable PM Surrogate Emission Standard

Filterable PM is, and continues to be, an appropriate surrogate for individual and total non-Hg HAP metals for oil-fired EGUs. When EPA established fPM as a surrogate for the non-Hg HAP metals, the Agency explained:

> Except for Hg, the best PM controls provide the best controls of metal emissions. Emissions measurements of either filterable particulate, total particulate, individual metals, or total metals provide comparable indications that the best level of control is achieved. *We can find no significant difference in the emissions that would be achieved by using any one of these emissions measurements.*[20]

[18] *See* Hawaii Revised Statutes § 269-92(a).

[19] *See* US Electricity Profile 2021, U.S. Energy Information Administration, released Nov. 10, 2022, https://www.eia.gov/electricity/state/ (listing U.S. total average retail price of 11.10 cents/kWh and Hawaii average retail price of 30.31 cents/kWh).

[20] National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, 77 Fed. Reg. at 9304, 9402 (Feb. 16, 2012) (emphasis added). *See also* EPRI's Comments for EPA's Proposed Rule on National Emission Standards for Hazardous Air Pollutants from Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Industrial Steam Generating Units (76 Fed. Reg. 23,768 (Apr. 28, 2011)), Doc. ID. EPA-HQ-OAR-2009-0234-17621, at 2-38, submitted Aug. 4, 2011 ("The correlations of individual and total non-mercury metals with fPM for oil-fired EGUs are statistically significant to the 95% level, similar to the fPM standard for coal-fired EGUs").

In the Proposal, EPA has not disavowed this determination.[21] Thus, it is thus unclear why EPA is considering eliminating the fPM standard, and how requiring compliance with emission limits for individual HAP metals would address the Agency's concerns regarding risks associated with certain individual HAP metals.[22]

For non-continental liquid oil-fired EGUs, the fPM standard is crucial to simplifying the monitoring requirements and, more importantly, reducing the costs associated with ongoing MATS compliance. The cost of performance testing to demonstrate compliance with the surrogate fPM standard is much lower than the cost of performance testing to demonstrate compliance with the numerous standards for individual non-Hg HAP metals, as well as for total non-Hg HAP metals. Requiring monitoring and testing for each individual non-mercury HAP metal would significantly increase compliance costs and, thereby, electricity rates. Accordingly, EPA should not eliminate or revise the fPM standard.

c) New HAP Standards

EPA should not impose new HAP standards for EGUs in non-continental areas because any additional standards would require large investments to achieve compliance, divert investments away from renewable energy development, or force premature retirement — of which the latter may jeopardize resilience and reliability in these areas.

EPA also should not require oil-fired EGUs in such areas to switch from residual oil to cleaner fuels. Any change to distillate fuel would be cost-prohibitive as natural gas may not be physically accessible or otherwise consistently acquired in non-continental areas. According to one Group member, a switch to distillate oil would increase fuel costs by at least seven percent, resulting in an approximate increase of $61 million per year (without accounting for inflation or grid changes). Additionally, EPA should not require liquid oil-fired EGUs in non-continental areas to switch to cleaner fuels after a certain number of hours of operation. This would force EGUs to undertake significant modifications to plant infrastructure to support two different types of fuel oil. Modifications, such as building additional fuel oil storage tanks, may be difficult at facilities located in urban areas where there is insufficient land available for such an expansion on the site's footprint. Moreover, diverting large capital outlays to such modifications would not be fiscally sound, particularly in areas with aggressive RPS.

Lastly, EPA should not subject oil-fired EGUs in non-continental areas to an annual limit on residual firing. In some of these areas, most of the oil-fired EGUs largely combust residual fuel oil to generate electricity. Imposing an annual limit on residual firing could thus impact grid reliability. Companies need to have the flexibility to operate to meet demand and to provide backup to renewable sources.

[21] *See* 88 Fed. Reg. 24,857 fn. 4.
[22] 88 Fed. Reg. at 24,884.

d) Compliance Via Fuel Sampling and Analysis

EPA should not require compliance with a HAP metal emission limit via fuel sampling and analysis because these tests are expensive and challenging to perform — again, costs that would ultimately be borne by customers.

e) Need for Additional, Cost-Effective Methods

There is no need for additional, cost-effective methods to minimize HAP emissions in non-continental areas, especially as companies are transitioning to clean energy generation over the next few decades. Any changes to the existing MATS standards for non-continental liquid oil-fired EGUs would impose prohibitively high costs, solely for the purpose of achieving MATS compliance during the interim transition period to clean energy generation. By way of example, according to one Group member, installing Hg, hydrogen chloride ("HCl"), hydrogen fluoride ("HF"), and PM emission controls on its non-continental MATS-applicable fleet to comply with the *current* MATS for continental oil-fired EGUs is estimated to cost nearly $1 billion.[23]

Unlike many states in the continental U.S., there is excellent natural air quality in remote island locations due to geographical isolation, island configuration, and trade winds.[24] Any emissions reductions achieved by amending the existing MATS standards likely would have only a de minimis impact on air quality, and the cost of complying with any amendments would be vastly disproportionate to their benefits.

B. EPA Should Reevaluate its Proposal to Tighten the fPM Emission Standard for Coal-Fired EGUs.

Existing coal-fired EGUs currently can demonstrate compliance with the emission limits for non-Hg metal HAPs by meeting: (i) the individual emission limits for each of the 10 non-Hg metals; (ii) an emission standard for total non-Hg metals; or (iii) a surrogate fPM emission standard of 0.030 lb/MMBtu.[25] EPA is proposing to eliminate the non-Hg HAP metals standards, leaving only the surrogate fPM standard. Further, EPA is proposing to tighten the surrogate fPM standard to 0.010 lb/MMBtu, which is comparable to the MATS new source standard of 0.09 lb/MWh fPM (equivalent to a new coal-fired EGU with a heat rate of 9.0 MMBtu/MWh).[26] EPA also is soliciting

[23] The estimate is based on Hawaiian Electric Company's $696 million estimate in 2011 dollars for installing emission control equipment for Hg, HCl, HF, and PM to comply with the proposed numeric emission standards for liquid oil-fired EGUs in the original MATS rule. Given that Hawaiian Electric Company's fleet has not changed, the 2011 estimate scaled to 2023 dollars would reach nearly $1 billion. *See* Hawaiian Electric Company's Comments for EPA's Proposed Rule on National Emission Standards for Hazardous Air Pollutants from Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Industrial Steam Generating Units (76 Fed. Reg. 23,768 (Apr. 28, 2011)), Doc. ID. EPA-HQ-OAR-2009-0234-18477, at 13, (Aug. 3, 2011) ("Hawaiian Electric estimates that installation of emission control equipment for Hg, HCl, HF, and PM would cost at least $696 million, based on preliminary quotes provided by engineering consultants and equipment vendors. To date, no control equipment vendor will provide performance guarantees so this cost estimate does not address the risk associated with failure to comply with the proposed HAP emission limits.").

[24] *See id.* at 12.

[25] *See* Table 2, Emission Limits for New or Reconstructed EGUs, Subpart UUUUU, 40 C.F.R. Part 63.

[26] 88 Fed. Reg. at 24,856.

comment on whether to revise the fPM standard to an even more stringent level of 0.006 lbs/mmBtu.[27]

1. EPA's evaluation of current fPM emission levels is flawed.

EPA's proposal to tighten the fPM standard is based on its review of "developments in the current emission levels of fPM from existing coal-fired EGUs, the costs of control technologies, and the effectiveness of those technologies, as well as the costs of meeting a standard that is more stringent than 3.0 E-02 lb/MMBbtu and the other statutory factors."[28] According to EPA:

> Currently, 96 percent of existing coal-fired capacity without known retirement plans before the proposed compliance period already have *demonstrated* an emission rate of 1.5E-02 lb/MMBtu or lower, 91 percent of existing coal-fired capacity have *demonstrated* an emission rate of 1.0E-02 lb/MMBtu or lower, and 72 percent of existing coal-fired capacity have *demonstrated* an emission rate of 6.0E-03 lb/MMBtu or lower."[29]

The statistics above appear to be based on the evaluation summarized in the 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category ("Technical Memo").[30] EPA should not rely on the 96 percent threshold as justification for setting the proposed fPM limit at 0.010 lb/MMBtu. EPA's reliance on that evaluation is problematic for several reasons, and the Group is concerned that EPA is overstating the universe of units that will be able to meet the proposed standard.[31]

First, the evaluation summarized in the Technical Memo excludes units that have shut down, will shut down, or will no longer burn coal/oil by December 31, 2028, or that reported data in lbs/MWh.[32] By failing to include units that will shut down or no longer burn coal/oil by December 31, 2028, EPA is not appropriately accounting for units that are likely emitting fPM at levels closer to the current standard than the more stringent proposed fPM limit. EPA should have accounted for such units given that affected EGUs will have up to three years after the effective date of the final rule to demonstrate compliance with the revised limit, and some of the excluded units may not have retired or ceased burning coal or oil by the compliance deadline.[33]

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[27] *Id.* at 24,857.
[28] *Id.*
[29] *Id.* at 24,868 (emphases added).
[30] 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category ("Technical Memo"), Doc. ID. EPA-HQ-OAR-2018-0794-5789, posted Apr. 24, 2023.
[31] This is not just a concern for the electric generating industry. Miscommunication of this data to other stakeholders such as Regional Transmission ("RTOs"), North American Electric Reliability Corporation ("NERC"), Independent System Operator ("ISO") New England, Midcontinent ISO ("MISO"), and others could lead to issues with grid stability, which would impact not only Americans but also citizens in neighboring countries (*e.g.*, Canada) where electricity is supplied by these networks.
[32] *See* Technical Memo at PDF p. 2.
[33] 88 Fed. Reg. at 24,868, fn. 20. EPA excluded units that have *announced* that they will shut down by the end of 2028 based on the National Electric Energy Data System ("NEEDS") database, but such retirement plans are not legally binding and thus such units should *not* be excluded from the Agency's evaluation.

If the final rule is issued before December 31, 2025, or if the announced retirements are delayed, these excluded units could become subject to a tighter standard that they would not be able to meet without large capital outlays to install PM control technology despite near-term projected fuel switches or retirement dates that would render such investments not cost-effective. Units that are retiring in the near-term and cannot meet the fPM limit without the installation of controls could be forced to shut down early, which could destabilize electric reliability in their service areas and could have long-lasting effects. Significant investment would be needed to restart certain generating facilities if it was later determined that the decision to shut down early was detrimental to reliable grid operations.

To avoid such outcomes, EPA should try to harmonize the Proposal with other state and federal rulemakings affecting EGUs. As discussed below, a compliance date based on three years after the final rule's effective date is inconsistent with other recent EPA rulemakings, which recognize that significant investments in emissions controls should not be required for EGUs that will retire in the near-term.

Second, the evaluation is based on selected quarterly data from 2017, 2019, and 2021.[34] The Agency fails to explain how and why it selected the specific quarterly data for those years for its evaluation when EPA has all quarterly testing and PM CEMS data for the entire fleet since EGUs began complying with MATS.[35] The Agency also fails to explain why it used a single quarter of data to present the unit's "baseline" and why "[t]he 99th percentile of the *lowest* quarter was chosen to describe the baseline fPM rate for each EGU."[36] This results in a questionable dataset comprised of an extremely small industry sample size and where each EGU is narrowed down to a single data point. EPA should use all data available from coal-fired EGUs — except as noted below with respect to units co-firing natural gas — to provide a full picture of achieved fPM emission rates. At the least, EPA should provide justification for its selection of the data, why reliance on the selected data is appropriate, and why certain quarterly data between 2017 through 2021 were excluded, so that interested stakeholders can verify the accuracy and representativeness of the underlying unit-specific data.[37]

Group members have *attempted* to locate and review the unit-specific data that EPA analyzed (and made available in the docket), but members largely have not been able to mirror that data with their own.[38] Certain stack test reports could not be retrieved from EPA's WebFire

[34] Technical Memo at PDF p. 2. ("Quarterly data from 2017 (variable quarters) and 2019 (quarters three and occasionally four) were first reviewed because data for all affected EGUs subject to numeric emissions limits had been previously extracted from CEDRI. In addition, the EPA obtained first and third quarter data for calendar year 2021 for a subset of EGUs with larger fPM rates (generally greater than 1.0E-02 lb/MMBtu for either 2017 or 2019).")
[35] EPA's explanation that this information had previously been extracted from CEDRI is in fact no explanation at all. *See id.*
[36] Technical Memo at PDF p. 4. (emphasis added).
[37] There is confusion among Group members as to which units EPA included/excluded, and as to which quarterly data sets were included/excluded. EPA failed to explain its rationale for determining which units and data sets should be included or excluded. The lack of explanation, coupled with the large number of supporting documents in the docket, makes it extremely difficult for members to identify the unit-specific data compiled, analyzed, and ultimately relied upon by EPA and, more importantly, to meaningfully review EPA's evaluation.
[38] *Supra* fn. 37.

online database nor were they available in the docket. Among other issues, as summarized in Attachment B, Group members have determined that EPA:

- Included some units that will be converted to gas in 2025.
- Did not include data for all quarters but instead selected only quarters with the lowest emissions for some units and excluded other quarters with higher emissions (peaking for some units, ramping for others).
- Excluded some units with no current plans to retire or switch to natural gas.
- Included some units that have a federally enforceable requirement to cease coal combustion by December 31, 2028 (despite EPA stating that the evaluation excluded coal-fired EGUs that will retire by that date).
- Used the last day of a quarter in some cases and the *average* of 30-day averages for others.
- Included only certain test runs in conducting its distribution analysis.[39]

As to the last point above, EPA should use a historical data pool that encompasses data from different times of year and operating conditions. EPA should include all affected units and all operating quarters in its analysis. Without a more comprehensive data pool, it is difficult to see how EPA could conduct a proper statistical analysis to justify the proposed fPM limit. The Group strongly recommends that EPA correct the deficiencies identified above, as well as make its statistical analysis or Python code used for the fPM evaluation available for public review, to ensure that the proposed fPM limit is not deemed arbitrary and capricious.

Third, the evaluation fails to properly address differences in typical unit operating variability by combining stack test data with PM CEMS data. Stack test data represent unit performance at a discrete point in time under full load conditions, whereas PM CEMS data provide a more comprehensive assessment of unit operating variability under all load and process conditions. These are two different data sets and should be treated independently. This is reflected in EPA's performance specification for PM CEMS, which only requires the readings to be within +/-25% of actual stack testing values two-thirds of the time (with the other one-third of the time not having any accuracy constraint) to be considered as valid readings.[40] EPA fails to explain how using such an error prone data set is justified for establishing an emissions standard. The evaluation fails to recognize that PM CEMS is not constrained to a linear correlation with direct emissions. In cases where non-linear correlations are used, an allowable +/-25% error from the correlated value could have a much larger deviation from the actual measured emissions compared

[39] For the same reasons articulated in fn. 37, there is confusion among Group members as to which test runs EPA included/excluded in its distribution analysis, and EPA's lack of rationale for how it determined which test runs to use.

[40] *See* Appendix F, 40 C.F.R. Part 60, Procedure 2.

to when a linear correlation is used.[41] Any emissions analysis based upon PM CEMS readings must attempt to compare unit performance in the allowable error band.

Further, any unit using a PM CEMS to demonstrate compliance with the emissions limit also must conduct annual emissions measurements under steady-state conditions, which are utilized in either a Response Correlation Audit ("RCA") or Relative Response Audit ("RRA"). The tested unit must show compliance in the short-term via stack testing measurement values and in the long-term via PM CEMS 30-day average values, and EPA needs to account for the fact that there often is an increase in the measured short-term emissions during stack testing. For these purposes, PM CEMS data and PM testing measurements should be treated separately and not merged as a data set. Failing to address these differences is especially problematic because EPA is proposing to require PM CEMS as the sole compliance demonstration method, as discussed in Section II.C below. EPA should thus revise its current "apples-to-oranges" comparison to establish consistently achievable baseline emissions for each unit by using all available data *and* by accounting for any bias related to operating variability.

Fourth, the evaluation fails to take into consideration different control configurations — specifically, the variation in PM removal efficiencies. Some PM control technologies, such as hot-side electrostatic precipitators ("ESPs"), inherently have higher PM emissions.[42] Similarly, depending on the coal combusted, units that utilize hydrated lime as a control technology for minimizing HAPs, like mercury and sulfuric acid, inherently have higher PM emissions. Wet flue gas desulfurization ("WFGD") also may result in higher PM emissions — in particular, higher variability in fPM emission rates — because WFGD can either add particulate from mist eliminators or remove additional particulate. EPA should factor in these specific control configurations. EPA also should analyze more comprehensive data sets across a longer time frame — rather than using a snapshot of EGUs "demonstrating" the proposed limit during selected quarters — prior to concluding that continuous compliance with the proposed limit is achievable.

Fifth, the evaluation fails to recognize that some units have converted to natural gas co-firing. Since these units continue to have the capability to combust coal, all of their emissions data is reported as subject to MATS. However, co-firing natural gas inherently results in significantly reduced fPM emissions, which could bias the data set low. EPA should exclude data from units that co-fire natural gas in evaluating what a revised fPM standard should be. Any proposed fPM limit that EPA establishes should be based on fPM from affected units that only combust coal.

2. Some coal-fired EGUs may not be able to achieve compliance with the proposed fPM emission standard on a continuous basis.

Although EPA claims that 91 percent of existing coal-fired EGUs have demonstrated that they can achieve an emission rate of 0.010 lb/MMBtu, it does not necessarily mean that those

[41] *See* Appendix B, 40 C.F.R. Part 60, Performance Specification 11.
[42] ESPs are capable of collection efficiencies greater than 99 percent. *See* EPA, Monitoring by Control Technique – Electrostatic Precipitators, accessed June 17, 2023, https://www.epa.gov/air-emissions-monitoring-knowledge-base/monitoring-control-technique-electrostatic-precipitators.

EGUs can *continuously achieve* that rate.[43] The same is true for the 72 percent of coal-fired EGUs that EPA claims have demonstrated an emission rate of 0.006 lb/MMBtu.[44]

As explained above, the statistics that EPA has presented are based on its evaluation of "quarterly fPM compliance data for coal-fired EGUs from 2017 to 2021 for units in the contiguous United States based on data availability."[45] It is important to note, however, that EPA's explanation fails to accurately describe the data that EPA used. EPA only used data from specific quarters in 2017, 2019, and 2021.[46] Further, the evaluation fails to consider whether the units can achieve 0.010 lb/MMBtu fPM (or a lower emission rate) *for each quarter* during that time period. In attempting to verify the accuracy of the underlying source-specific fPM data,[47] Group members evaluated their unit-specific data across a wider time frame and found that while some of their units may have met the 0.010 lb/MMBtu or 0.006 lb/MMBtu fPM emission rates from time to time, their units do not consistently achieve those rates.

The evaluation also fails to consider whether the units can meet 0.010 lb/MMBtu or 0.006 lb/MMBtu fPM *continuously*, as will be required if EPA finalizes its proposed requirement that EGUs must use a PM CEMS to demonstrate compliance with the fPM standard.[48] As explained above, in contrast to the continuous measurements taken by PM CEMS, measurements taken via stack testing are conducted under prescribed "representative testing conditions."[49] The majority of data in EPA's evaluation are stack testing fPM data because the majority of EGUs are using stack testing for compliance. Such data do not provide information across a unit's entire load range, including during startups, shutdowns, maintenance, and malfunction events — all of which would be captured by a PM CEMS. Exclusion of such data likely overstates the units that can demonstrate the more stringent limits on a continuous basis. Factors such as current cost-effective control technologies and EGUs' operational limitations could hinder the ability of some coal-fired EGUs to continuously comply with the proposed fPM standard. Other factors include:

- Peak summer conditions. Although some units may be able to achieve a rate of 0.010 lb/MMBtu during shoulder months, they may not be able to continuously meet that limit during peak load conditions when they cannot do off-power rapping or maintenance and cleaning of ESPs to remove buildup on the ESPs' wires and plates. During the summer, most units operate at base load and run at high capacity factors. It may be difficult to maintain optimal operation of control technologies during peak summer conditions. For example, ESPs must be taken off-line for cleaning and require roughly 24 to 48 hours for cooling before temperatures are low enough for maintenance

[43] 88 Fed. Reg. at 24,868.
[44] *Id.*
[45] Technical Memo at PDF p. 2.
[46] *Id.*
[47] *Supra* fn. 37.
[48] *See* 88 Fed. Reg. at 24,857.
[49] *See* EPA, Memorandum re Issuance of the Clean Air Act National Stack Testing Guidance, Apr. 27, 2009, at 14-17, https://www.epa.gov/sites/default/files/2013-09/documents/stacktesting_1.pdf (excluding start up, shutdown, malfunction, and other non-representative operating conditions).

personnel to safely enter the ESP to perform repairs.[50] At a minimum, vacuuming may be required of the ESP inlet and outlet ducts, along with any hoppers that have high levels. Some ESPs may require sandblasting to remove problematic buildup on wires and panels. Unless there are additional outages scheduled for such maintenance, the units may be unable to maintain compliance with the proposed 0.010 lb/MMBtu limit.

- Coal characteristics. The availability of coal is limited to certain regions and, as a result, the characteristics of coal vary depending on location. Characteristics potentially impacting continuous compliance with the proposed fPM standard include:
    - Ash content. Ash content of the coal being fired may impact the ability of units to comply with the proposed limit, regardless of the effectiveness of the control technologies in place.[51]
    - Sulfur trioxide ("SO_3")/Blue Plume. Some units may inject sodium or calcium-based products upstream of the PM collection equipment, which increases PM loading.
- Using #2 fuel oil for startup and stabilization. Using #2 fuel oil for startup and stabilization also may impact the ability of units to comply with the proposed limit. Using any amount of fuel oil decreases the removal effectiveness of the ESPs for a short period of time until enough coal is introduced so that the amount of coal ash in the combustion process has scoured the coating of the collecting plates and wires.
- Other operational factors. Other operational factors such as cleaning frequency, operational duration, and filter change out frequency may impact the performance of controls (*e.g.*, baghouses) and an EGU's ability to comply with the proposed limit.[52]
- Transitioning to renewable generation. As renewable generation increases, fossil fuel-fired generating assets likely will be dispatched in a substantially different manner than before, which EPA should take into account in evaluating whether continuous compliance with the proposed limit is achievable. Capacity factors of coal-fired EGUs are now typically lower during the day when solar and wind are available, but the demand for coal-fired EGUs is greater at night when renewable generation is

[50] When ESP fields fail, it is generally due to grounding issues, which often require physical entry into the ESP to restore fields to service. Although actual repair time is roughly 12 hours, any EGU outage required for ESP repairs will take at least two to three days to complete.

[51] *See* EPA AP-42, Fifth Edition, Vo. 1, Ch. 1.1, Table 1.1-6 "Cumulative Particle Size Distribution and Size-Specific Emission Factors for Dry Bottom Boilers Burning Pulverized Bituminous and Subbituminous Coal," at 1.1-26, https://www.epa.gov/sites/default/files/2020-09/documents/1.1_bituminous_and_subbituminous_coal_combustion.pdf (reflecting direct and linear relationship between ash content and controlled fPM emission).

[52] The quality of fabric filter material not only could impact baghouse performance but also cause other environmental concerns, which it is not clear that the Agency considered. While EPA pointed out that upgrading standard bags to fiberglass bags with polytetrafluoroethylene ("PTFE") membrane coating could reduce fPM emissions by up to 50 percent, PTFE is a renowned PFAS material that could be banned in the near future. *See* Technical Memo at PDF p. 9.

> unavailable.[53] As a result, traditional generation assets likely will have more startup and shutdown periods, more transient operation as load following units, and increased operation at minimum loads — all of which can produce higher PM emissions. This is because control devices perform at their optimum when operating at full-load, steady state conditions, and additional transient operation will negatively affect their removal rates. While PM emissions may be lower during low-load periods, there generally is particulate layout in the duct work during such periods and, as units ramp to higher loads, the particulate re-entrains, potentially leading to higher emissions. At low loads, WFGD mist eliminators operate at reduced efficiency and WFGD slurry carryover can increase PM emissions at reduced loads.

The Group is concerned that EPA is proposing to revise the fPM standard solely on the basis that many units have purportedly *demonstrated* that they can achieve the 0.010 lb/MMBtu emission rate under certain optimum operating conditions based on limited snapshots of monitoring data. But by doing so, EPA runs the risk of eliminating the necessary margin for compliance and thus significantly restricting a unit's operational flexibility. As one Group member pointed out, even with baghouses and reagent injection systems in place for all of its units, not all the units have *continuously* demonstrated the proposed 0.010 lb/MMBtu fPM limit, much less the more stringent 0.006 lb/MMBtu limit, based on historical data (from 2017 to 2021 and including all quarters).

Operational flexibility is critical for EGUs, which might be called on to operate by their balancing authority based on fluctuations in demand, unexpected downtime of other units in the region, extreme weather, and other scenarios that are outside of an individual EGU operator's control. EGUs might need to take derates for a significant period of time to comply with the proposed fPM limit. The Group strongly recommends that EPA consult with Regional Transmission Organizations ("RTOs"), Independent System Operators ("ISOs"), the North American Electric Reliability Corporation ("NERC"), and other similar authorities prior to finalizing a fPM limit that could restrict or eliminate the flexibilities of these units to operate while also maintaining compliance with the limit.

Lastly, in addition to the issues identified above, EPA's evaluation is replete with questionable assumptions and statements. For instance, in the technical reports developed by Sargent & Lundy ("S&L"), on which EPA relies for cost and emissions reductions assumptions, S&L acknowledges that "[b]ased on S&L's recent industry experience, the lowest filterable PM emission rates that an ESP supplier has been willing to guarantee is 0.030 lb/MMBtu for a new

[53] Load demands during the night have a different profile than load demands during the day, requiring large load generation at times or operation at turned-down rates well below the design control basis of coal-fired boilers. System dispatch becomes increasingly less reliable the more solar and wind contribute to load demands during the day because such generation sources are not dispatchable. For instance, during summer storms, which occur rapidly and take out solar and wind power generation, backup power must come from fuel-based generation sources that increasingly operate on a standby mode. However, fuel-based standby generation must remain online 24/7 to meet such system demands. Further, to minimize costs, coal-fired EGUs are turned down at night to loads at which they were not designed to operate, making the entire process operate differently than if operated under normal conditions, thus impacting emissions.

and/or completely rebuilt ESP."[54] Yet, the study states that "it is clear that emission levels down to 0.010 lb/MMBtu and below are achievable in most ESP applications based on the reported emissions data" despite acknowledging that the authors are unable to tie a specific performance improvement to a specific set of ESP upgrades.[55] EPA should not rely on such unsupported statements to justify a fPM limit of 0.010 lb/MMBtu.

3. EPA should harmonize applicability of a revised fPM limit with other EPA rulemakings.

EPA is proposing a compliance date for the revised fPM limit of three years pursuant to CAA Section 112.[56] Should EPA finalize the 0.010 lb/MMBtu fPM emission limit, EPA should include options to offer flexibility to EGUs that also are subject to other regulatory drivers affecting their future operations.

First, EPA should consider establishing additional subcategories of coal-fired EGUs to address unique circumstances and to ensure consistency with other recent EPA rulemakings so that EPA is not establishing requirements that impose unnecessary or conflicting costs on the industry. Specifically, consistent with other rulemaking addressing EGUs, EPA should establish a subcategory for units facing near-term retirements, such as by the end of 2028 or end of 2031, or even later for units with unique circumstances. EPA should allow EGUs in the near-term retirement subcategory to continue to meet a fPM emission limit of 0.030 lb/MMBtu. This would be consistent with the end of 2031 deadline in the proposed Section 111(d) standards for imminent-term retirements.[57] Further, in the Clean Water Act Effluent Limitations Guidelines ("ELG"), EPA exempted EGUs that permanently cease burning coal by December 31, 2028, or, for "early adopters," by December 31, 2032.[58] Additionally, a near-term retirement subcategory would be consistent with the compliance deadline for the secondary NOx emission limit for coal-fired EGUs in EPA's interstate transport federal implementation plan for units that do not have selective catalytic reduction technology ("SCR").[59] For such units, the secondary NOx limit does not

[54] Sargent & Lundy. PM Incremental Improvement Memo, Doc. ID. EPA-HQ-OAR-2018-0794-5836 at 2 (Mar. 2023). *See also* Technical Memo at PDF p. 8.
[55] PM Incremental Improvement Memo at 2.
[56] *See* 88 Fed. Reg. at 24,868 fn. 20.
[57] *See* New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 88 Fed. Reg. 33,240, 33,245 (May 23, 2023) ("For units with operating horizons that are imminent term, *i.e.*, those that (1) [h]ave elected to commit to permanently cease operations before January 1, 2032, and (2) elect to make that commitment federally enforceable and continuing by including it in the State plan, the EPA is proposing that the BSER [best system of emission reduction] is routine methods of operation and maintenance with an associated degree of emission limitation of no increase in emission rate (lb CO_2/MWh-gross basis).").
[58] *See* Steam Electric Reconsideration Rule, 85 Fed. Reg. 64,650, 64,679 (Oct. 13, 2020); *see also* Proposed Revision of Steam Electric EGU ELGs, 88 Fed. Reg. 18,824, 18,857, 18,837 (Mar. 29, 2023) (proposing to maintain the 2028 cessation subcategory and establish an "early adopters" subcategory).
[59] *See* Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023).

become effective until the second control period after the unit installs SCR or the 2030 control period, whichever is later.[60]

All these other proposed and final regulatory requirements allow companies adequate lead time to phase in retirements for their coal-fired EGUs. Creating a subcategory in the MATS rule for units facing near-term retirements that harmonizes the retirement dates with other rulemakings would greatly assist companies with moving forward on retirement plans without running the risk of being forced to retire early, which could create reliability concerns or, in the alternative, deliberating whether to install controls and continue operation longer than planned to recoup investments in the controls.

Second, pursuant to its authority under CAA Section 112, EPA should grant EGUs up to a one-year extension on a case-by-case basis if they are unable to comply with the revised fPM limit within three years after the effective date of the final rule.[61] However, as explained above, the Group strongly urges EPA to harmonize the effective dates of other rulemakings to minimize impacts to grid reliability and cost increases to customers. For units that will continue to operate, significant planning, installation, and implementation of control technologies could be required. Units likely would need to consult with their respective ISOs, RTOs, or other system reliability authorities to ensure that the reliability effects of such outage periods can be coordinated and mitigated.

Furthermore, most units that currently use ESPs likely would need to complete extensive work on their existing controls to optimize their performance so that they can meet the proposed more stringent limits. There are a limited number of specialized vendors/companies with the expertise that could conduct such work, and there currently also is a shortage on the availability of parts. Many of the parts are no longer in production and would have to be custom manufactured, which would add to the timeframe needed for compliance. Even four years for installation of, for instance, baghouses along with new FGD towers, likely would be a huge challenge considering the current limited availability of competent engineering, procurement, and construction firms in the U.S., along with the ongoing supply chain issues for material.

C. EPA Should Retain the fPM Emission Monitoring Options.

EGUs that do not qualify for the LEE program currently demonstrate compliance with the fPM standard by conducting quarterly performance testing (*i.e.*, quarterly stack testing), using a PM continuous parameter monitoring system ("CPMS"), or using a PM CEMS.[62] EPA is proposing to eliminate the quarterly stack testing and CPMS options for all coal-fired EGUs — specifically, requiring all coal-fired EGUs to use PM CEMS "[a]fter considering updated information on the costs for quarterly performance testing compared to the costs of PM CEMS and on the measurement capabilities of PM CEMS, as well as other benefits of using PM CEMS, which include increased transparency and accelerated identification of anomalous emissions."[63] According to EPA, PM CEMS data "supply real-time, quality-assured feedback that can lead to

[60] *See e.g., id.* at 36,664.
[61] *See* 77 Fed. Reg. at 9407; 42 U.S.C. § 7412(i)(3)(B).
[62] *See* 40 C.F.R. § 63.10011(b).
[63] *See* 88 Fed. Reg. at 24,857.

improved control device and power plant operation, which, in turn, can lead to fPM emission reductions."[64]

The Group disagrees with EPA's conclusions and strongly believes that sound engineering approaches using control device operating parameters achieve the same ultimate objective of fPM emission reductions. It is unclear how adding another measurement system, particularly given the challenges with PM CEMS as described below, would be cost-effective. The Group urges EPA to retain the option for quarterly stack testing (without any changes to testing frequency) and the CPMS option for all coal-fired EGUs.

1. Challenges with PM CEMS

EPA should retain the quarterly stack testing and PM CPMS options — particularly if the Agency intends to finalize the proposed 0.010 lb/MMBtu fPM emission limit — to afford entities flexibility in demonstrating compliance with the more stringent limit. Currently, two-thirds of existing EGUs have chosen to demonstrate compliance via the quarterly stack testing approach, and EPA should continue to retain that option in light of the difficulties with using PM CEMS. EPA justifies the proposed requirement to use PM CEMS based on cost, but the Agency understates the costs of PM CEMS and significantly overstates stack testing costs.[65] The costs associated with installing, maintaining, and operating a PM CEMS may far outweigh the costs of demonstrating compliance through stack testing for some EGUs, as discussed below.

In addition, use of PM CEMS may not be appropriate for all coal-fired units. Some Group members have used PM CEMS for many years, or attempted to do so, and have encountered problems with operating their PM CEMS with regards to (i) meeting the Quality Assurance-Quality Control ("QA-QC") criteria required under Procedure 2; and (ii) establishing the correlation curve using Performance Specification 11 ("PS-11"). For some Group members, stack design limits the siting choices for PM CEMS — for instance, when equipment cannot be attached to a brick chimney but must be mounted to a structural shell. The annulus space between the chimney and shell, if not usable, presents a very large obstacle when trying to install a PM CEMS.

First, when a PM CEMS fails to meet the QA-QC criteria required under Procedure 2, the collected data are considered out-of-control and are no longer considered valid.[66] Because the measured emissions values are dependent upon laboratory analysis, an owner/operator has no real time indication that its EGU might have failed the required QA-QC criteria until several weeks after the testing has been completed. This could result in hundreds of hours of monitor downtime being created retroactively after the QA-QC criteria failure has been identified. Monitor downtime is required to be reported as a deviation under the MATS rule, and most states have minimum data availability requirements that could result in enforcement actions. At the more stringent fPM standard of 0.010 lb/MMBtu (or 0.006 lb/MMBtu), the likelihood of out-of-control periods increases. This downtime is not reflective of poor maintenance or operation but rather the difficulties associated with the quality assurance procedure at such low emission levels. Thus, in conjunction with this rulemaking, EPA should include additional provisions in Appendix C of 40

[64] *Id.* at 24,872.
[65] *See id*. at 24,857.
[66] *See* Appendix F, 40 C.F.R. Part 60, Procedure 2.

C.F.R. Part 63, Subpart UUUUU to mitigate the effects of this downtime, such as provisional data periods following a failed RRA or RCA. Moreover, there currently is no calibration procedure available that can accurately verify continuous measurements of fPM at levels as low as 0.010 lb/MMBtu, much less 0.006 lb/MMBtu.[67]

EPA attempts to address these issues by proposing to amend Table 2 of 40 C.F.R. Part 63 Subpart UUUUU to require sample volumes of at least 4 dscm per run, rather than at least 1 dscm per run.[68] While the additional sample volume will reduce measurement uncertainty, it does not address the operating variability that needs to occur during correlation testing to achieve the distinct PM test conditions required under PS-11 and Procedure 2. In addition, when developing the initial correlation curve or conducting ongoing RCAs, emissions controls are de-tuned to simulate upset conditions and to achieve dust loadings at mid- (25-75% of the maximum expected concentration) and high- (50-100% of the maximum expected concentrations) levels.[69] For units equipped with WFGD systems, expanding the test runs to collect 4 dcsm of sample volume significantly increases the flyash carryover to the scrubber.[70] This off-spec material is then required to be landfilled instead of beneficially reused. Furthermore, it can take days to weeks for the scrubber chemistry to again reach optimal, steady-state conditions; and maintaining optimal scrubber chemistry is needed to ensure effective removal of Hg emissions. The increased particulate loading will physically impact the equipment and degrade the scrubber's performance, such as: scaling inside the scrubber vessel; plugging spray headers; causing buildup on mist eliminators; and eroding booster and induced draft ("ID") fan blades and absorber recirculating pumps.

Second, PM CEMS require the use of PS-11 to establish a correlation curve.[71] For the PS-11 PM CEMS correlation test, a minimum of 15 sets of reference method testing must be conducted that are evenly spaced over three different levels of PM mass concentration by varying process operating conditions, by varying PM control device conditions, or by means of PM spiking.[72] If it is not possible to obtain three distinct levels of PM concentration, zero point testing may be used to perform correlation testing over the maximum range of PM concentration that is practical for the PM CEMS.[73] Each run requires roughly three to four hours, and most sources conduct 18 to 20 test runs for a robust correlation.[74] Barring unpredictable circumstances, based

[67] *See* Nicklin, D. et. al., "Techniques to measure particulate matter emissions from stationary sources: A critical technology review using Multi Criteria Decision Analysis (MCDA)," *Journal of Environmental Management*, 296:18-20 (2021).
[68] *See* MATS RTR Rule Text Redline Strikeout document (final) ("Redline Final"), posted on Apr. 25, 2023, at PDF p. 86, 89, 91, 96, 98, Doc. ID. EPA-HQ-OAR-2018-0794-5831. *See also* 88 Fed. Reg. at 24,873-74.
[69] Trying to simulate different ranges of particulates created for test activities often has unintended consequences on an FGD's performance that can take days to normalize and clean up so that the equipment resumes performing as designed. Any additional ash carryover into the FGD increases the opportunity to blind the FGD such that the only recovery is to shut the unit down to add lime or to dump the ash into a storage tank because the material can no longer be stored in the onsite landfill as the chloride content of the sludge, at that point, has become too high. According to at least one member with closed-loop FGDs (without chloride or particulate blowdown capability), detuning did in fact cause the equipment to have long-term operational problems.
[70] Ash reinjection may be not feasible for some sources due to stratification issues or ash drop-out effects.
[71] *See* Appendix B, 40 C.F.R. Part 60, Performance Specification 11.
[72] *See id.*
[73] *See id.*
[74] *See id.*

on the proposed sampling time, PS-11 could require seven to ten days to complete. Additional time likely would be needed to maintain the distinct PM test conditions that are required. Sources also would require accurate, preliminary test results to evaluate each test condition and might even need to obtain final results before concluding the test program, which would further extend the length and cost of the tests. Procedure 2 correlation testing also would be required for existing PM CEMS to ensure the data would fall within +/- 25% of a 0.010 lb/MMBtu limit. The current PM CEMS technology has difficulties monitoring at low emission levels, which could result in the need to conduct annual PS-11 correlation testing to ensure data remained valid. These activities increase the cost of MATS compliance and overall EGU operation, as well as disrupt the normal operation of the EGU.

According to Group members, installation of a PM CEMS at a single unit — including site preparation and engineering activities, analyzer equipment and installation cost, and initial PS-11 correlation testing — is estimated to range from $180,000 to over $400,000 (depending on vendor and brand). Ongoing PM CEMS correlation testing with injection of media in the effluent to artificially raise emission levels costs at least $250,000 per test evolution at one source, and testing is required by MATS once every three years. For some EGUs, annual costs associated with a PM CEMS are estimated to range from $92,900 to over $154,600, whereas annual costs associated with stack testing are estimated to range from $24,000 to $32,000. Thus, EPA may have significantly underestimated annual costs associated with a PM CEMS (from $18,111 to $95,397 depending on type) and overestimated annual costs associated with stack testing ($85,127), particularly when specific control configurations are taken into account.[75]

More importantly, EPA has failed to show how correlations can be developed on data sets where, following PS-11 requirements, the upper end of the emissions testing would be capped at 0.010 lb/MMBtu. Emissions levels are supposed to be evenly distributed between the low, mid, and high PM emission levels. Even when allowing for a low-emitting unit to use a zero point in the correlation, a correlation still needs data variation to be a valid regression model. By limiting the dataset — pursuant to the proposed 0.010 lb/MMBtu fPM limit — EPA needs to establish that the PS-11 correlation would still be valid at such low levels.

2. Challenges with PM CEMS for EGUs that Co-fire

EPA should consider that use of PM CEMS may not be appropriate for EGUs that co-fire coal with another fuel, such as biomass, and units that frequently co-fire fuel oil and coal during startup. PM CEMS costs for such units would be significantly higher because multiple PS-11 correlation curves could be required. Similarly, ongoing QA testing according to Procedure 2 would result in higher costs as additional testing might need to be conducted under different fuel conditions. Until EPA performs additional research to investigate if co-firing results in accurate CEMS measurements, EPA should not enforce the proposed 0.010 lb/MMBtu fPM limit on units during co-firing periods. These periods are likely to increase in frequency as renewables are further integrated into the grid, which would further complicate compliance with the proposed limit.

[75] 88 Fed. Reg. 24,872-73.

Should EPA finalize its proposal to eliminate the stack testing and CPMS options, the Group requests that EPA provide reasonable exemptions, including: (i) allowing coal-fired units that co-fire other fuels the option to continue to use the quarterly stack-testing and CPMS options; and (ii) exempting units from the requirement to use a PM CEMS if they have an fPM control technology and documented Compliance Assurance Monitoring in place. In addition, EPA should allow the option to demonstrate fPM emissions compliance during periods of PM CEMS monitor downtime via stack testing, similar to Part 75 requirements, to provide EGUs the opportunity to avoid reporting PM CEMS downtime as a deviation.

3. Challenges with PM CEMS for IGCC EGUs

EPA is proposing to retain the emission standards for IGCC EGUs, as "there are only two IGCC EGU facilities, and the EPA is unaware of any development in the HAP emission controls used at IGCC units."[76] However, EPA, is proposing to require IGCC EGUs to install a PM CEMS to demonstrate compliance with the existing fPM limit.[77]

The Group urges EPA to retain the 36-month PM stack testing established under the LEE program, quarterly stack testing and CPMS options for IGCC EGUs. IGCC units are not built to accommodate a CEMS, which requires considerable space to install on the stack. Most scrubbed stacks have an annulus space that offers some protection from ambient temperature swings and exposure to the elements. At an IGCC facility, the stack configuration is more akin to that of a combustion turbine, where there is only an elevated grating that is exposed to the elements available for the possible installation of a PM CEMS. Exposure to the elements, particularly in an area with large seasonal fluctuations, would impact the sensitivity and accuracy of the CEMS. The instrument also must be located near the sampling point as transport through an umbilical to the CEMS shelter would affect the resulting measurement.

Additionally, there are no PM control devices at an IGCC unit available for de-tuning, which is required for conducting PS-11 to establish the correlation curve. While particulate spiking is an emerging technology, it requires collecting PM from the actual source and reinjecting the material into the flue gas stream. However, there are no points in the IGCC process where PM could be collected. Without using site-specific PM for spiking, the correlation developed for an optical PM CEMS instrument would not yield a valid correlation for the source. Furthermore, an IGCC is not equipped with an ID fan, which would typically be used to ensure good dispersion of the PM across the duct area. Thus, certification of the PM CEMS on an IGCC is technologically infeasible, and stack testing continues to be the most appropriate means to accurately measure fPM emissions from such units.

D. <u>EPA Should Retain the Total and Individual Non-Hg Metals Emission Limits.</u>

EPA is proposing to remove the total and individual non-Hg metals emissions limits from MATS as "almost all regulated sources have chosen to demonstrate compliance with the non-Hg HAP metal standards by demonstrating compliance with the surrogate fPM standard and because

[76] *Id*. at 24,885.
[77] *Id.*

of the benefits of PM CEMS use for demonstrating compliance."[78] The individual and total non-Hg HAP metal standards directly control the amount of HAPs emitted from EGUs — the purpose of MATS — and EPA's proposed justification for eliminating the standards fails to address why such action is appropriate, particularly considering that there are still regulated sources using the direct individual and total non-Hg HAP metal standards to demonstrate compliance. Eliminating the standards would unfairly impose a costly burden on a very small number of sources merely for the arguable benefit of requiring them to use PM CEMS for compliance.

EPA should retain the individual and total non-Hg HAP metal standards, as they directly regulate the pollutants at issue under Section 112 of the CAA. Retaining the option for compliance with such standards provides compliance flexibility not only to those EGUs that currently comply with those standards, but also to EGUs that currently elect to comply with the fPM standard but that might find it more advantageous and cost-effective to comply with the total or individual non-Hg metals emission standards if EPA finalizes its proposal to tighten the fPM limit. There are unresolved challenges with using PM CEMS, as explained in Section II.C.1, making such monitoring highly impractical for some EGUs.

E. EPA should not eliminate the LEE option for fPM and non-mercury HAP metals.

For non-Hg metals, a unit currently meets the LEE requirements if its emissions are less than 50 percent of the standard.[79] EPA is proposing to remove the LEE option for fPM and non-mercury HAP metals because requiring PM CEMS would render the current stack testing compliance method for the LEE program "superfluous."[80]

If EPA establishes the final fPM standard at 0.010 lb/MMBtu, EPA should nonetheless retain the LEE option and allow LEE to continue demonstrating compliance through stack testing (without any changes to the current test frequency). Stack testing via the three-year cycle after meeting the LEE limit is much less costly than quarterly testing. Thus, units that currently rely on the LEE provisions would face an exponential increase in monitoring costs associated with installing, implementing, and using PM CEMS, including employing additional technicians to operate the equipment. The cost of requiring PM CEMS for LEE is excessive in light of their low fPM emissions, particularly given that EPA has not justified why the LEE option is an insufficient mechanism to maintain compliance with the fPM limit. Many of these costs ultimately would fall on the ratepayers and likely would increase electricity bills for consumers. Further, sources that have qualified for LEE status because of good performance should not be penalized by incurring additional costs, maintenance, and issues that PM CEMS technology would introduce.

If EPA finalizes its proposal to tighten the fPM standard to 0.010 lb/MMBtu, the Agency should not only retain the LEE provision but also should amend 40 C.F.R. § 63.10005(h)(i) to allow units to be considered LEE if they demonstrate that they can meet a standard of 0.006 lb/MMBtu or less, rather than less than 50 percent of the standard. LEE provides important

[78] *Id.* at 24,857.
[79] *See* 40 C.F.R. § 63.10005(h)(i).
[80] 88 Fed. Reg. at 24,857.

compliance flexibility. Under this amended LEE definition, 198 EGUs purportedly would qualify based on EPA's fPM evaluation.[81]

F. EPA Should Reevaluate the Data for Lignite-Fired EGUs.

Lignite-fired EGUs currently must meet an Hg emission standard of 4.0 lb/TBtu or an alternative standard of 0.04 lb/GWh.[82] EPA is proposing that lignite-fired EGUs meet the same Hg emission standard as EGUs firing other types of coal (*e.g.*, bituminous, subbituminous), which is 1.2 lb/TBtu or an alternative standard of 0.013 lb/GWh.[83] EPA's proposal is based on its review of current Hg emission levels and controls for lignite-fired EGUs from information provided to the Agency routinely and via CAA Section 114 responses, as well as information from the U.S. Energy Information Administration.[84] According to EPA, its review of such information "showed developments that demonstrate that lignite-fired EGUs can achieve a Hg emission rate that is much lower than the current standard, and that there are cost-effective control technologies and methods of operation that are available to achieve a more stringent standard."[85]

The Group is concerned that EPA is proposing a substantial reduction in the Hg emission standard based on inaccurate data and a flawed evaluation of the Hg control capabilities of lignite-fired EGUs. First, EPA's Section 114 request was very limited considering the amount of data available and, in many cases, EPA disregarded the very information that was submitted in the responses. Certain units burning large percentages of subbituminous coal have transitioned or are in the process of transitioning to the non-lignite subcategory, and such units should have been removed from EPA's evaluation. Specifically, EPA's evaluation — encompassing a review of 22 EGUs "that were designed to burn lignite utilized refined coal to some extent in 2021"[86] — contains major flaws, as summarized below:

- The majority of these EGUs do not primarily burn all lignite coal.[87]
    - As denoted in Table 10 of the Technical Memo, the evaluation of 22 EGUs includes only four EGUs that burn 99.7 percent or more lignite coal, with the other 18 EGUs burning only 37.6 percent or less lignite coal.[88]
    - EPA treats EGUs burning "refined coal" as burning "refined lignite." EPA also treats EGUs burning subbituminous coal as burning lignite coal, including them in its evaluation of "lignite-fired EGUs.[89] The Agency justifies that treatment by grouping subbituminous and lignite coals together to show how, compared to bituminous coal, they: (i) tend to have "lower halogen content;" (ii) tend to

[81] *See* Technical Memo at PDF p. 2, 4. (EPA evaluated fPM rates from 275 EGUs and determined that 72 percent of the EGUs are attaining fPM emissions below 0.006 lb/MMBtu).
[82] *See* Table 1, Emission Limits for New or Reconstructed EGUs, 40 C.F.R. Part 63, Subpart UUUUU.
[83] 88 Fed. Reg. at 24,857.
[84] *Id.*; *see also* Technical Memo at PDF p. 13-18.
[85] 88 Fed. Reg. at 24,857.
[86] Technical Memo at PDF p. 18.
[87] *See id.*
[88] *See id.*
[89] *See id*.

form elemental mercury that is "more challenging to control'" and (iii) tend to produce ash that is "more alkaline due to the lower amounts of sulfur and halogen."[90] But comparing subbituminous and lignite coals together against bituminous coal is not a proper comparison for determining whether subbituminous coals and lignite coals are similar to each other. Although both generally may share some advantages and disadvantages as compared to bituminous coals, subbituminous and lignite coals remain very different from each other on attributes that significantly affect mercury control.

- As a result of EPA's treatment above, seven EGUs are considered "lignite-fired EGUs" even though they use zero percent lignite coal.[91] This also includes at least one EGU that co-fires natural gas, which influences the Hg lb/TBtu values submitted.[92]

- It is unclear whether the Hg emissions that the Agency reviewed for the 22 EGUs were from units operating at full or partial load.

- Rather than using actual sampled data of lignite Hg concentrations that had been provided in the Section 114 responses, EPA used Integrated Planning Model ("IPM") data to assign inlet Hg concentrations to various lignite-fired EGUs.

As to the last point above, by using IPM data, EPA underestimated the Hg content of lignite coal. In some instances, the Hg concentration of the actual fuel burned is twice as much as the value that EPA assumed is the maximum concentration. The Group strongly requests that EPA reevaluate the inlet Hg content of lignite fuels using actual data provided in the Section 114 responses.

EPA also overlooked key factors associated with lignite fuel. In asserting that the proposed 1.2 lb/TBtu limit could be achieved with additional activated carbon injection, EPA failed to account for the impacts of the higher sulfur content of lignite coal as compared to subbituminous coal, and that such higher sulfur content leads to additional SO_3, which is known to negatively impact the effectiveness of activated carbon.[93]

The Group requests that EPA reassess its evaluation to correct flaws in its analysis for the lignite-fired EGU subcategory, as the Agency's proposal to tighten the Hg emissions standard for such units is unsupported by actual data.

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[90] 88 Fed. Reg. 24,875.
[91] *See id.* at 24,877 (listing Coal Creek 1, Coal Creek 2, Spiritwood 1, Limestone 1, Limestone 2, Red Hills Generating Facility 1, and Red Hills Generating Facility 2 as using 0.0% lignite coal).
[92] *See id.* (including Spiritwood Station 1, which fires 35.6% natural gas and 64.4% "refined coal" and does not use lignite or subbituminous coal).
[93] *See e.g.*, Sjostrom, et. al. "Influence of SO_3 on mercury removal with activated carbon: Full-scale results," *Fuel Processing Technology*, Vol. 90, Issue 11, 1419 (Aug. 19, 2009); SO_3's impacts on plant O&M: Part I, POWER (Oct. 15, 2006), https://www.powermag.com/so3s-impacts-on-plant-om-part-i/.

G. EPA Should Retain the Four-Hour Option for Defining the Startup Period.

EGUs are currently allowed to choose between two definitions of "startup" for purposes of MATS compliance. Specifically, startup ends either (i) when any of the steam from a boiler is used to generate electricity for sale to the grid or for any other purpose; or (ii) four hours after the EGU generates electricity that is sold or used for any other purpose or four hours after the EGU makes thermal energy for industrial, commercial, or cooling purposes, whichever is earlier.[94] EPA is proposing to eliminate the latter definition as it is "currently being used by fewer than 10 EGUs."[95]

The Group urges EPA to continue to allow use of the four-hour startup definition. EPA's determination that only eight EGUs are currently using that option is insufficient justification for eliminating the definition.[96] Given that the Proposal does not speak to any supposed flaws with the definition, EPA should explain why elimination of the four-hour definition from MATS is appropriate when there are units currently relying on it.

Should EPA finalize its proposal to remove the four-hour startup definition, EPA should consider providing reasonable exemptions for the EGUs that currently use that definition, thus gradually phasing out the definition without imposing any additional compliance burdens. EPA also should take into account that a few Group members are currently required to use the four-hour startup definition per federal consent decrees or state agreements.[97] At the very least, such a scenario provides clear justification for a limited exemption, as MATS compliance should not result in an EGU violating its consent decree.

H. The Group Requests that EPA Publish the Proposed Regulatory Text in the *Federal Register*.

EPA failed to publish the proposed regulatory text in the *Federal Register* notice for the Proposal. Nowhere in the *Federal Register* notice did EPA even mention the proposed regulatory text, much less note that it was available in the docket. Locating the proposed regulatory text was exceedingly difficult because (i) the docket contains nearly 570 documents (559 of which are in the Supporting and Related Materials category, as of June 23, 2023); (ii) the proposed regulatory text document is misleadingly titled, "MATS RTR Rule Text Redline Strikeout document,"[98] and thus would not appear among the search results if searching via keywords "regulatory text"; and (iii) even a search of "redline" pulls up 45 documents that must be reviewed to determine whether they contain the final version of the redlined regulatory text.

By posting the proposed regulatory text as a separate document, EPA runs the risk not only of interested stakeholders failing to find it in the docket but also of creating discrepancies between

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[94] *See* 40 C.F.R. § 63.10042.
[95] 88 Fed. Reg. at 24,885.
[96] *See id.* (identifying 14 EGUs that chose to use the four-hour startup definition, six of which have retired).
[97] Table 9 of the Proposal states that Sherburne County Generating Plant Unit 3 ("Unit 3") retires in 2024. Pursuant to an agreement with the state, Unit 3 will be retired no later than December 31, 2030. *See id.*
[98] *See* MATS RTR Rule Text Redline Strikeout document ("Redline"), posted on Apr. 24, 2023, Doc. ID. EPA-HQ-OAR-2018-0794-5780; Redline Final.

the description of the proposal in the *Federal Register* and the proposed regulatory text itself. For instance, as to the LEE option for fPM, total non-Hg metals, and individual HAP metals, the *Federal Register* notice indicates that the option will be removed "no later than 3 years after the promulgation date"; however, the proposed regulatory text (final version) indicates that the option will be available up to 3 years after the effective date of the final rule.[99] Such discrepancies prevent interested members of the public, potentially affected EGUs, and other stakeholders from receiving adequate notice of EPA's proposed action and impair their ability to provide informed comments. EPA also runs the risk of running afoul of its statutory duty under the Administrative Procedure Act ("APA") to provide the public with adequate notice, particularly if the description of the proposal in the *Federal Register* notice fails to accurately capture "either the terms or substance of the proposed rule or description of the subjects and issues involved." To ensure that the public is afforded a meaningful opportunity to comment on proposed rules, the minimum 60-day comment period should not run until the public has received fair and adequate notice of the regulatory language, which is best accomplished by publishing the proposed regulatory text in the *Federal Register*.[100]

The Group thus requests that EPA publish the proposed regulatory text with the Proposal in the *Federal Register*. Furthermore, the Group requests that, for future rulemakings, EPA return to its longstanding practice of including the proposed regulatory text in the *Federal Register* notice for a proposed rule.[101] Such practice would provide clarity around the proposed regulatory action and ensure that all members of the public have adequate notice and an opportunity to comment on the proposed regulatory language.

III. CONCLUSION

The Class of '85 Regulatory Response Group appreciates the opportunity to submit comments on the Proposal. The proposed revisions could result in disproportionate and unintentional consequences at various EGUs by eliminating compliance flexibility under both MATS and the other recent rulemakings affecting the electric generating industry. Therefore, the Group asks EPA to consider the recommendations above to ensure that the costs associated with complying with the various revisions in the Proposal are proportional relative to their benefits and that such costs neither jeopardize maintenance of grid reliability nor hinder the transition to clean energy. Furthermore, the Group asks EPA to reissue the Proposal (along with the proposed regulatory text) addressing the issues identified and discussed in the comments above to provide stakeholders a meaningful opportunity to review an updated and corrected analysis. Revising the

[99] *See* 88 Fed. Reg. at 24,887; Redline Final at PDF p. 100.

[100] 5 U.S.C. § 553(b). As reflected in the Group's request for an extension of the comment period for the Proposal, it is the Group's position that the deadline for submitting comments should not be triggered until EPA has included the proposed regulatory text in the *Federal Register* notice. *See* Class of '85 Regulatory Response Group's Request for Extension of the Comment Period on the National Emissions Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, Doc. ID. EPA-HQ-OAR-2018-0794-5876, at 2-3, submitted May 24, 2023 (denied on June 14, 2023).

[101] Although the Group appreciates the opportunity to review a redline/strikeout that identifies the rule revisions, it is an inadequate substitute for a *Federal Register* notice that includes the new regulatory language and not merely a description of it.

Proposal and reissuing it with the proposed regulatory text would ensure that the final rule is not arbitrary and capricious and is a logical outgrowth of the Proposal.

Dated: June 23, 2023

Respectfully submitted,

The Class of ’85 Regulatory Response Group
contact@class-of-85.com

ATTACHMENT A

AES Corporation
Alliant Energy Corporation
Ameren
Arizona Public Service
Arizona Electric Power Cooperative, Inc.
Arkansas Electric Cooperative Corporation
Basin Electric Power Cooperative
City of Tallahassee
Cleco Corporation
Cogentrix Energy Power Management, LLC
Dairyland Power Cooperative
Dayton Power & Light Company
Dominion Energy
Duke Energy
Entergy Services, LLC
Evergy, Inc.
Florida Municipal Electric Association
Florida Power & Light Company
Gainesville Regional Utilities
Great River Energy
Hawaiian Electric Company, Inc.
Indianapolis Power & Light Company
JEA
Lakeland Electric
Louisville Gas & Electric/Kentucky Utilities
Luminant Generation Company LLC
Minnesota Power
NextEra Energy, Inc.
NRG Energy
Oak Grove Management Company, LLC
OGE Energy Corp.
Orlando Utilities Commission
Portland General Electric
PowerSouth Energy Cooperative
Public Service Company of New Mexico
Rainbow Energy Center, LLC
Salt River Project
Southern Company
Tampa Electric Company
Tucson Electric Power Company
Western Farmers Electric Cooperative
Xcel Energy Inc.

ATTACHMENT B

The table below identifies issues that Group members have noticed in their review of the unit-specific data that EPA used for its fPM evaluation.

Company	Issues Identified
Entergy	• No 2017 data were identified in the docket for any of Entergy's five units. • Only Q3 2019 data were identified in the docket for each of Entergy's five units. • Q1 2021 data were identified in the docket for one unit (White Bluff Unit 1). • Q3 2021 data were identified in the docket for two units (Independence Unit 1 and Nelson Unit 6). • Evaluation included data for White Bluff Units 1 and 2, but both units are subject to a federally enforceable requirement to cease coal combustion by no later than December 31, 2028.
LGE-KU	• Used only last 30-day rolling average of PM CEMS data for one quarter in two years (*e.g.*, the 30-day rolling averages for June 30, 2017 and September 30, 2019). In contrast, for data in 2021, the average of the 30-day rolling averages of PM CEMS data for only two of nine affected units (Mill Creek Unit 4 and Ghent Unit 4) for two quarters in 2021 were used in EPA's analysis (*e.g.*, average of data from first quarter 2021 and average of data from third quarter 2021).
OGE	• Highest emitting unit (Muskogee Unit 6) was not included in the 2021 data set.